4. Natural Bitumen and Extra-Heavy Oil

COMMENTARY

Introduction

Natural bitumen and extra-heavy oil are characterised by high viscosity, high density (low API gravity), and high concentrations of nitrogen, oxygen, sulphur, and heavy metals. These characteristics result in higher costs for extraction, transportation, and refining than are incurred with conventional oil. Despite their cost and technical challenges, major international oil companies have found it desirable to acquire, develop, and produce these resources in increasing volumes. Large in-place resource volumes provide a reliable long-term flow of liquid hydrocarbons and provide substantial payoff for any incremental improvements in recovery. High oil prices during 2007 and 2008 spurred new development and production which, in turn, have intensified concern about environmental effects of production increases.

Natural bitumen and extra-heavy oil are the remnants of very large volumes of conventional oils that have been generated and degraded, principally by bacterial action. Chemically and texturally, bitumen and extra-heavy oil resemble the residuum generated by refinery distillation of light oil. The resource base of natural bitumen and extra-heavy oil is immense and not a constraint on the expansion of production. These resources can make an important contribution to future oil supply if they can be extracted and transformed into usable refinery feedstock at sufficiently high rates and at costs that are competitive with alternative sources.

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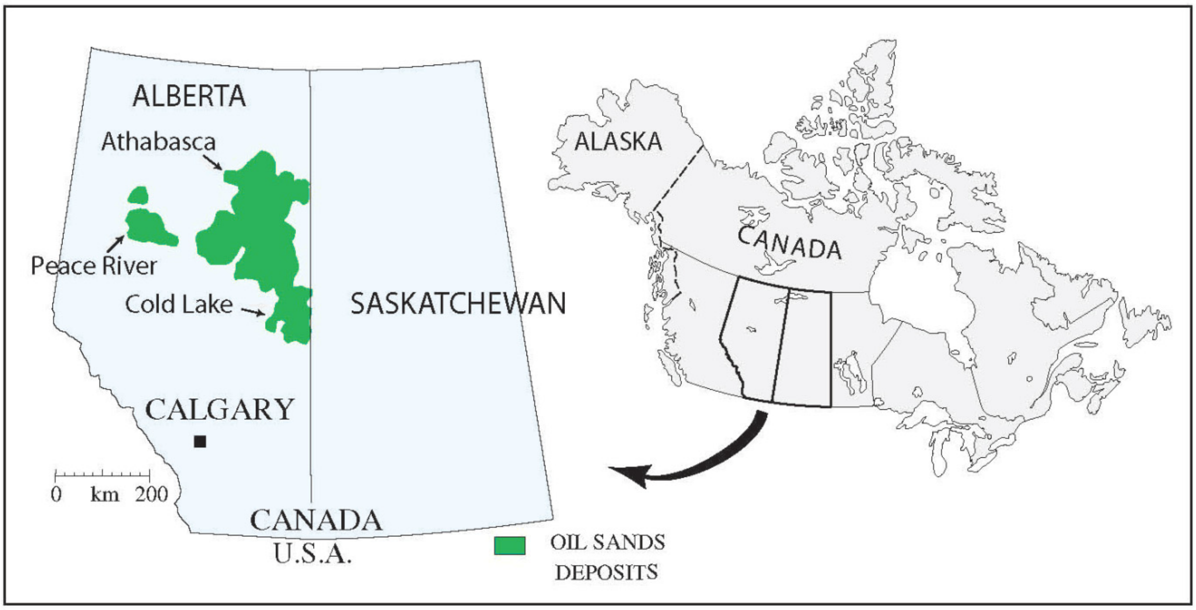
Figure 4.1 Location of the oil sands deposits of Canada
(Source: modified from McPhee and Ranger, 1998)



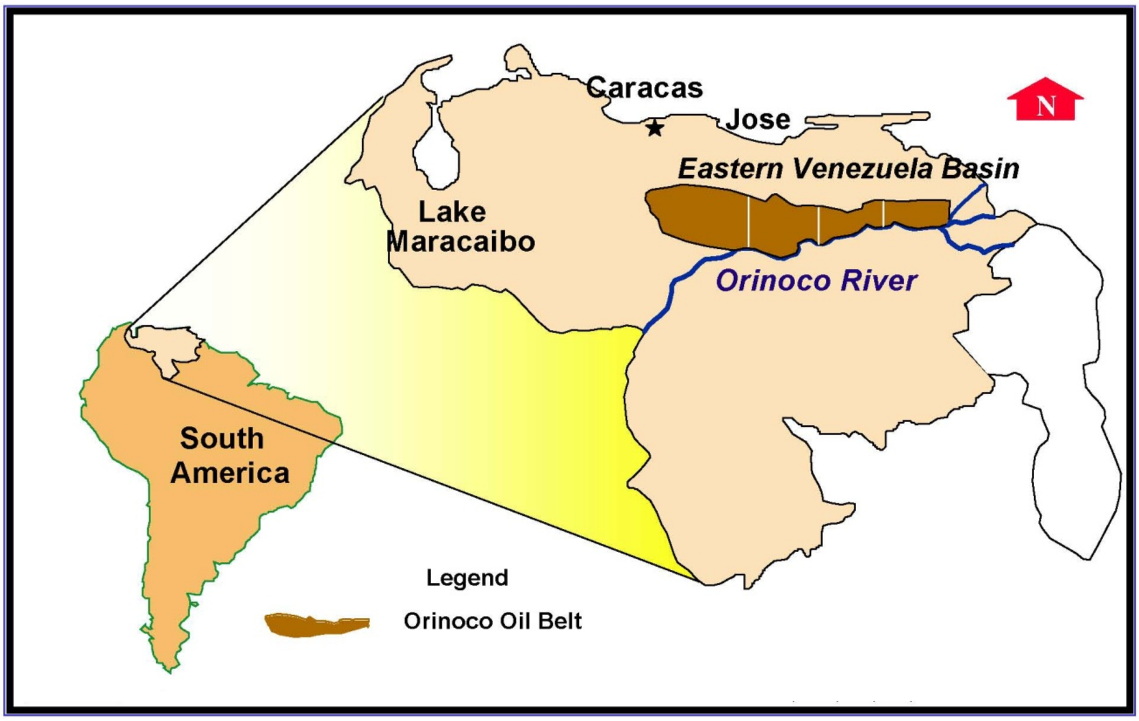
Production and upgrading technologies must continue to advance to address emerging environmental constraints.

Resource Quantities and Geographical Distribution

Resource quantities reported here are based upon a detailed review of the literature in conjunction with available databases, and are intended to suggest, rather than define, the resource volumes that could someday be of commercial value. Precise quantitative reserves and oil-in-place data for natural bitumen and extra-heavy oil on a reservoir basis are seldom available to the public, except in Canada. In cases where in-place resource estimates are not available, the in-place volume was calculated from an estimate of the recoverable volumes based on assumed recovery factors. For deposits in clastic rocks the original in-place volume was calculated as 10 times reported original recoverable volumes (cumulative production plus an estimate of the remaining recoverable volume) (Meyer and Schenk, 1986, 1988). For carbonate reservoir accumulations the original oil in place was calculated as 20 times the estimated original recoverable volume (Meyer, Fulton, and Deitzman, 1984). Geologic basin names used in the descriptions are standard and correspond to sedimentary basins shown on the map compiled by St. John, Bally, and Klemme (1984). The basins which are known to contain heavy oil and natural bitumen are described in Meyer, Attanasi, and Freeman (2007).

Natural Bitumen - is reported in 598 deposits in 23 countries (Table 4.1). No deposits are reported offshore. It occurs both in clastic and carbonate reservoir rocks and commonly in small deposits at, or near, the earth's surface. Natural bitumen deposits have been mined since antiquity for use as sealants and paving materials. In a few places such deposits are extremely large, both in areal extent and in resources they contain, most notably those in northern Alberta, in the Western Canada Sedimentary Basin. Although these oil sands extend eastward into Saskatchewan, resource estimates for this province have yet to be published. The three Alberta oil sand areas (Fig. 4.1), Athabasca, Peace River, and Cold Lake, together contain 1.73 trillion barrels of discovered bitumen in place (Energy Resources Conservation Board [ERCB], 2009a), representing two-thirds of that in the world and at this time are the only bitumen deposits being commercially exploited as sources of synthetic crude oil (SCO). More than 40% of the crude oil and bitumen produced in Canada in 2008 came from the Alberta natural bitumen deposits.

Figure 4.2 Location of the Orinoco Oil Belt in Venezuela
(Source: modified from Layrisse, 1999)



Outside of Canada, 367 natural bitumen deposits are reported in 22 other countries. The largest volumes of bitumen after Canada are in Kazakhstan and Russia, both well endowed with less costly conventional oil. In Kazakhstan, the largest numbers of bitumen deposits are located in the North Caspian Basin, and many of Russia's bitumen deposits are located in the Timan-Pechora and Volga-Ural basins. The North Caspian, Timan-Pechora, and Volga-Ural basins are geologically similar to the Western Canada Sedimentary Basin (Meyer, Attanasi, and Freeman, 2007). Very large resources occur in the basins of the Siberian Platform of Russia (Meyer and Freeman, 2006). Although many more deposits are identified worldwide as evidenced by oil seepages, no resource estimates are reported. The volumes of discovered and prospective additional bitumen in place amount to 2 511 billion barrels and 817 billion barrels, respectively.

Extra-heavy Oil - oil is recorded in 162 deposits world wide (Table 4.2). Extra-heavy oil deposits are located in 21 countries. There are 13 deposits offshore or partially offshore. The Orinoco Oil Belt (Fig. 4.2) in the Eastern Venezuela Basin accounts for about 90% of the discovered plus prospective extra-heavy oil in place, or nearly 1.9 trillion barrels. The Orinoco extra-heavy oil production capacity in 2008 was 640 000 b/d. The corresponding SCO plant upgrade capacity is 580 000 b/d and is located at the Jose refinery on the northeastern coast of Venezuela (U.S. Energy Information Administration [EIA], 2009a). Extra-heavy oil production accounts for more than 20% of Venezuela's oil production. Some fields are comprised only of extra-heavy reservoirs whereas other such reservoirs occur in fields producing mainly from conventional reservoirs. Table 4.2 shows an in-place discovered volume of 1 960 billion barrels and a total in-place volume of 2 150 billion barrels.

In total, Tables 4.1 and 4.2 report a total in-place extra-heavy oil and bitumen volume of 5 478 billion barrels. This volume is slightly *less but of the same order of magnitude as the estimated volume of original oil in place in the world's known conventional oil fields.* The commercially successful projects in the Orinoco Oil Belt and Alberta have proven production strategies and technologies that are being considered for smaller deposits elsewhere. The commercial value achieved is likely to lead to exploration that could result in additional deposits and verification of larger resource volumes at identified deposits.

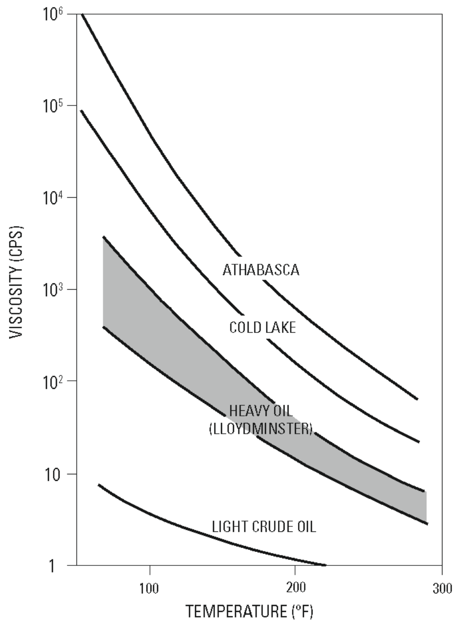


Figure 4.3 Response of viscosity to change in temperature for some Alberta oils (Source: Raicar and Procter, 1984)

Economics of Production, Transportation and Refinery Technology

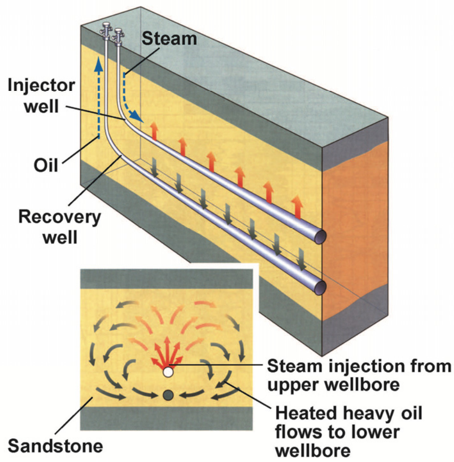
Production technologies: Canada

Natural bitumen deposits occurring to depths to 250 feet can be mined from the surface. The mined bitumen is then separated from the host sand by a hot water process. The bitumen mined at three of the four Athabasca operating mining/separation projects is upgraded onsite into a synthetic crude oil that is then transported by pipeline to conventional refineries. The fourth project, Albian Sands Energy, also in Athabasca, transports a mixture of bitumen and diluents to the Scotford upgrading facility about 270 miles south near Edmonton. In 2008, production amounted to 722 000 b/d for the four Alberta oil sand mining projects. Of the 170 billion barrels of bitumen estimated by the Alberta Energy Resources Conservation Board (ERCB) (2009a) to be recoverable from identified deposits, 34 billion barrels or 20% is accessible with current surface mining technology. In February 2009, the Alberta ERCB issued new environmental standards for reduction of tailing pond sizes and acceleration of their reclamation. Operators must modify procedures to meet the standards (ERCB, 2009b).

Some areas are too deep for surface mining. The bitumen can then be produced cold from some wells for short periods without utilising enhanced recovery methods. In cold heavy oil production with sand (or CHOPS) bitumen and sand are pumped to the surface through the well bore and then separated at the surface. The sand production creates channels or high permeability zones through which the bitumen flows most efficiently (Dusseault, 2001).

For most bitumen deposits cold production for extended periods is not possible. Heat and/or solvents may be injected into the reservoir to reduce the viscosity of bitumen. Steam injection raises the temperature of bitumen in the reservoir. Fig. 4.3 shows the dramatic reduction in fluid viscosity with increasing temperatures for the bitumen at Athabasca and Cold Lake (Alberta, Canada). Steam can be injected through vertical or horizontal wells. In the cyclic steam stimulation process, which is commonly applied at Cold Lake, steam is injected into the formation during the ‘soak’ cycle to heat the formation. A production cycle starts when the steam injection wells are converted to producers and ends when the dissipated heat is insufficient to lower bitumen viscosity. The cycles of soak and production are repeated until the response becomes marginal because of increasing water production and declining reservoir pressure. After as many as six cycles, the recovery technology may be converted to a continuous steam flood to enhance production rates (Dusseault, 2006).

Figure 4.4 Stacked pair of horizontal wells, SAGD natural bitumen recovery
(Source: Graphic copyright Schlumberger *Oilfield Review*, used with permission [Curtis, *et al*., 2002])



In the steam assisted gravity drainage or SAGD process (Fig 4.4), a horizontal steam-injection well is drilled about 5 metres above a horizontal production well. Injected steam creates a heated chamber, the heated bitumen is mobilised, and gravity causes the fluid to move downward to the producing well where it is pumped to the surface. Diluents may also be injected to assist in lowering viscosity of the reservoir fluids. The reservoir must exhibit a minimum threshold of vertical permeability for the SAGD process to be successful.

When the Alberta ERCB estimates recoverable bitumen resources, it assumes the following recovery factors for the original bitumen in place: cold production, 5%; cyclic thermal production at Cold Lake, 25%; SAGD at Peace River, 40%; and SAGD at Athabasca, 50% (2009a). The recovery efficiency of mining and extraction of the in-place bitumen is estimated at 82% (National Energy Board of Canada [NEB], 2006).

Production technologies: Venezuela

Compared to the Alberta oil sands, reservoirs in the Orinoco Oil Belt have higher reservoir temperatures, greater reservoir permeability, and higher gas-to-oil ratios, which gives the oil lower viscosity and greater mobility (Dusseault, 2001). In the Orinoco Oil Belt, extra-heavy oil production is cold and achieved through multi-lateral (horizontal) wells in combination with electric submersible pumps and progressing cavity pumps. These wells are precisely positioned in thin, but relatively continuous sands. Horizontal multilateral wells maximise the well bore contact with the reservoir. Efforts are also continuing to improve production of viscous oil through down-hole electrical resistance heating. The recovery factor for the cold production of extra-heavy oil in the Orinoco is estimated to be 8-12% of the in-place oil.

The Government of Venezuela has partitioned the heavy oil belt into six areas and subdivided the areas into blocks which have become the project units (EIA, 2009a). The plan is to start enhanced recovery methods after the cold production phase. Enhanced recovery might be steam and/or solvent injection or *in situ* combustion. New projects are required to include upgrading facilities, located near the coast.

Production economics: Canada

Fig. 4.5 shows the Canadian Energy Research Institute (CERI) estimates of bitumen and synthetic oil supply costs in end-2007 Canadian dollars for start of construction in 2008 and an assumed exchange rate of CDN$ 1 = US$ 0.95 (McColl, et al., 2008). The cost estimates (McColl, et al., 2008) assume a 10% real return on investment, 2.2% inflation and a gas price forecast ranging from CDN$ 6.50 to 9.00 per million British Thermal Units. The SAGD supply cost estimates are slightly lower than cyclic steam costs. The range of costs for the mining/extraction process is within the cost range of the thermal processes. CERI's

Figure 4.5 Estimates of operating cost (Opex) and supply costs by production method (Source: McColl, *et al*., 2008)

			CDN$ (2007) * per barrel at plant gate	
Production method	**Quantity b/d**	**Product**	**Opex ****	**Supply cost *****
Cyclic steam (Cold Lake)	30 000	Bitumen	20	36-37
SAGD	30 000	Bitumen	19	34-35
Mining/extraction	100 000	Bitumen	13	36-37
Integrated/mining, extraction, and upgrading ****	100 000	SCO	23	72

* US$ / CDN$ = 0.95
** Opex is operating cost exclusive of taxes and fuel cost
*** Assumes CO_2 compliance cost of $ 15 per tonne for excess emissions over 100 000 tonnes/yr
**** Upgrading assumes 1 barrel SCO requires 1.15 barrels of bitumen

published supply cost estimates (McColl, et al., 2008) include all taxes and a CDN$ 15 charge per tonne of CO_2 in excess of 100 000 tonnes per year. The SAGD and cyclic steam stimulation capital investment costs are CDN$ 30 000-35 000 per sustainable daily barrel, so a project capable of producing 30 000 barrels per day would have a nominal investment cost from CDN$ 0.9 to just over 1.0 billion. Investment per daily barrel for the mining and extraction process is CDN$ 48 000. For a stand-alone upgrade plant of 100 000 barrels SCO per day, investment per daily barrel is CDN$ 46 000.

For thermal production methods, each barrel of bitumen produced requires 1.0-1.1 tcf of natural gas, based on a dry steam-to-oil ratio of 2.5:1. For mining/extraction configurations, gas requirements are 0.5 tcf per barrel of bitumen produced. Comparable CO_2 generation rates for thermal methods are 51.4-61.7 kg/bbl and 26.7 kg/bbl for mining and extraction, while a stand-alone upgrading configuration emits 51.4 kg/bbl (McColl, et al., 2008).

Concerns about the volumes of gas consumed and generation of CO_2 involved in the thermal recovery processes, along with availability of water and diluents, have been raised as critical environmental issues. The industry appears anxious to adopt technology to address these issues. Nexen and OPTI Canada's Long Lake SAGD project (startup 2009) upgrades bitumen to 39^{o} API SCO on-site and uses the by-product asphaltenes to produce the synthesis gas for the SAGD steam generation, the cogeneration facility, and the upgrade plant. This design uses little if any outside gas and no diluents and provides the option of capturing a pure CO_2 stream for later sequestration. After years of laboratory and pilot testing, toe-to-heel-air injection (THAI[1]) *in situ* process is in the initial stages of full-scale commercial application at the May River Project (Petrobank Energy and Resources, 2010). This *in situ* combustion process uses little outside fuel or water to produce an upgraded oil product that is ready for pipeline transportation without diluents. However, the process requires an impermeable cap rock, a thick sand, and sufficient reservoir depth to permit operation at a high pressure.

Production economics: Venezuela

The unit supply cost for the Orinoco extra-heavy oil produced cold with multilateral wells is much lower than Canadian cold production costs of bitumen, because favourable fluid and reservoir conditions result in sustained high production rates per well. Current estimates of the supply costs for the Orinoco extra-heavy crude oil are as little as one-third of Canadian bitumen SAGD supply costs (Fig. 4.5).

[1] Any use of trade, firm, or product names is for descriptive purposes only and does not imply the endorsement of the U.S. Government

Transportation and Upgrading

Transportation

Unless there is on-site upgrading, transportation of the extra-heavy oil and bitumen requires that the oil be heated or, alternatively, blended with diluents (naphtha, gas condensates, or light oils) to reduce viscosity. Dilbit, a bitumen blend, consists of up to 67% bitumen and 33% natural gas liquids (or a 50/50 blend of bitumen and naphtha). The Synbit blend is half bitumen and half SCO. The total costs of transporting a given volume of produced raw bitumen are much greater than the costs of transporting the same volume of produced conventional oil because the additional volume of diluents, amounting to at least 50 to 100% by volume of bitumen, must also be transported. Additional costs are incurred if the diluents are recovered and shipped back to the producing field. In the Orinoco Oil Belt the produced extra-heavy oil is blended with lighter oils and transported to coastal upgrading plants.

Upgrading technology

In the crude oil distillation process the heavier the feedstock oil, the lower are yields of the valuable light fractions, and the greater is the residuum yield. The low yield of high-valued products explains why most refineries steeply discount the prices they pay for heavy oil relative to light oil. Upgrading bitumen and extra-heavy oil is profitable when the spread between the light and heavy oil prices is sufficient to cover the costs of upgrading.

In the upgrading process, extra-heavy oil or bitumen is passed through atmospheric and vacuum distillation processes that produce gas oil and residue and that also recover the diluents for recycling. The gas oil can be treated with hydrogen to reduce sulphur and nitrogen (producing hydrogen sulphide and ammonia). Gas oil is either hydrotreated (a catalytic reaction) or hydrocracked under mild conditions. Specific options for treating the residue (often called resid conversion) are (1) solvent deasphalting applied as pretreatment of the residue for removal of asphaltic materials (Speight, 1991), (2) visbreaking, which is a mild thermal cracking operation used to reduce the viscosity of the residue, producing a low grade gasoline, heavy gas oil distillates, and a residual tar, (3) coking, which is used to break the heaviest fractions of the residue into elemental carbon (coke) and lighter fractions, and (4) residue hydrocracking, which adds hydrogen to the residue to maximise SCO output as the residue is heated under high temperature and high pressures (Vartigan and Andrawis, 2006). Hydrogen for hydrocracking is purchased or generated by passing natural gas over steam (steam-methane reforming process). The high pressures and temperatures required of process equipment and the required hydrogen are sources of increased costs for residue hydrocracking (Speight, 1991). Carbon-rejection processes, such as coking, lead to penalties in the volume of SCO, whereas the hydrogen-addition processes, such as residue hydrocracking, lead to increased product volumes.

Figure 4.6 Commercial operations in the Orinoco Oil Belt
(Source: Energy Information Administration, 2009)

Area Name: **(Original project name):**	**Junin (Petrozuata)** [i]	**Carobobo (Cerro Negro)** [ii]	**Boyaca (Sincor)** [iii]	**Ayacucho (Hamaca)** [iv]
Startup	October 1998	November 1999	December 2000	October 2001
Extra-Heave Oil Production – b/d	120 000	120 000	200 000	200 000
API gravity	9.3º	8.5º	8.0-8.5º	8.7º
Synthetic Oil production – b/d	104 000	105 000	180 000	190 000
API gravity	19-25º	16º	32º	26º
Sulphur - % weight	2.5	3.3	0.2	1.2

i PDVSA 100%
ii PDVSA 83.34%; BP 16.66%
iii PDVSA 60%; Total 30.3%; Statoil 9.7%
iv PDVSA 70%; Chevron 30%

Bitumen upgrading: Canada

As of 2008, about 60% of the crude bitumen produced in Alberta was converted into various grades of SCO. The remaining 40% was blended with diluents (light oils, gas condensates or natural gas liquids) and shipped to refiners having the capability to accept the heavy oil blend (Canadian Association of Petroleum Producers, 2009).

The yield of SCO from the natural bitumen varies with the technology employed, consumption of the product for fuel in the upgrade, and the degree of residue upgrading. The Suncor, Syncrude, and Albian Sands projects mine natural bitumen and extract the oil from the mined sand. The Suncor project, for example, uses delayed coking for a yield of 0.81 barrels of SCO per barrel of natural bitumen input. The Syncrude project, which uses fluid coking combined with hydrocracking the gas oil fraction, has a yield of 0.85 barrels of oil per barrel of bitumen (Speight, 1990). The yield for the Albian Sands plant at Scotford, which applies hydrocracking to both gas oil and residue, is 0.9 (NEB, 2004).

Extra-heavy oil upgrading: Venezuela

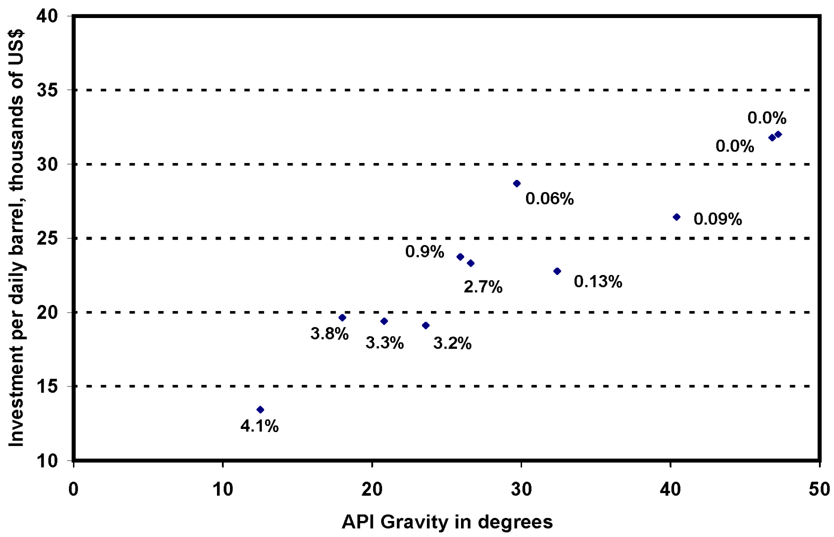
Fig. 4.6 shows the upgrade plant capacities and product specifications for the four commercially-operating Orinoco Oil Belt extra-heavy oil production projects. The limited availability of Venezuelan light crude oils for blending makes it economic to upgrade the Orinoco oil prior to export. Upgrade plants are located on the northeast coast of Venezuela. All the plants recover and return diluents to their fields. Each also uses delayed coking to upgrade residue and hydrotreatment for removal of sulphur and nitrogen from the coking process by-product naphtha. The Sincor project produces a low-sulphur light synthetic crude oil by hydrocracking the heavy gas oil generated from gasifying part of the coke from the coking process. The conversion efficiency of extra-heavy oil into synthetic crude varies from 87-95%. The variety of SCO qualities reflects the needs of the original operators. Upgrade plants producing the lower gravity (heavy) SCO shipped their products to captive refineries in the U.S. and Caribbean (Chang, 1998). Extra-heavy oil and bitumen use similar processes, so upgrading costs are comparable.

Upgrading costs and markets

In general the upgrade costs increase with the required quality of the SCO. Based on the CERI (McColl, et al., 2008) study, the supply cost of upgrading bitumen to an SCO of about 39° API and less than 0.3% sulphur is estimated to be CDN$ 32 per barrel, exclusive of the feedstock bitumen, assuming a plant capacity of 100 000 b/d SCO and a conversion efficiency of 86%.

Figure 4.7 Initial investment cost per daily barrel for upgrading bitumen to various grades of synthetic crude oil

(Source: based on Vartivarian and Andrawis, 2006, adjusted to late 2007 US$)



(% sulphur adjacent to plot points)

In an early study, Vartivarian and Andrawis (2006) published cost data coupled with upgrade plant process configurations designed to upgrade 8.6° API (4.8% sulphur) bitumen to various product SCO grades as measured by API gravity and sulphur content. These data have been adjusted to reflect U.S. cost increases from 2005 to late 2007 with adjusted data expressed as the required investment per daily barrel of SCO output. Fig. 4.7 shows (1) the wide range in initial investment costs per daily barrel of SCO output depending on product quality and (2) that, on the basis of the investment required per daily barrel of SCO, for a plant with a capacity of 80 000 b/d, the initial investment is in the billions of dollars even for the lowest-cost upgrade level.

Plants that upgrade extra-heavy oil and bitumen are chemical process plants that are subject to significant scale economies, that is, per barrel cost declines as size increases. Furthermore, when plant size is optimal for the market served, the plant generally must operate at high utilisation rates to be profitable. The most profitable upgrade plant design depends on the value placed on its synthetic crude product by refinery purchasers as well as the cost of inputs to the upgrade plant. SCO market value is determined by the availability of competing crude oils of the same or superior quality and the technical capability and excess capacity at local or operator-owned (captive) refineries to accept the crude and, in turn, to produce high-value products.

Downstream vertical integration is the economic term to describe a situation where a raw materials producer performs the next stages of processing, such as refining or smelting and even selling finished products. Alternatively, upstream vertical integration is a term that describes the situation when a processor or retailer starts a mining or extraction subsidiary in order to supply processing plants and retail outlets. One motivation for economic integration is to manage the risks inherent in raw materials markets by providing a means through a captive upgrading facility and perhaps a refinery to assure a market for the bitumen-derived products. Extra-heavy oil and bitumen production are high-cost sources of oil for the eventual production of high-value transportation fuels. The refiner’s price differential between heavy oil and light oil can be notoriously unstable so there is a real risk that the bitumen producers and upgrade plant operators may be unable to recover operating costs when light oil is in oversupply and light oil prices are in decline.

Technological innovations to meet environmental regulation

In North America, access to resources and the security of crude oil supply have motivated the utilisation of Canadian oil sands. Bitumen is now commercially produced in numerous large-scale projects with both mining and *in situ* recovery technologies. With the industry's maturation, a regulatory framework must be implemented to ensure that the private costs of producing and upgrading bitumen reflect the full cost to society of the resources used to produce SCO. Currently mining, *in situ* extraction of bitumen, and upgrading are more energy- and water-intensive than production of conventional oil and thus generate greater amounts of CO_2 per barrel of refinery feedstock. New technologies can offset and perhaps eliminate the differences.

For mining, new tailings pond performance standards (ERCB, 2009b) reduce the area and life of tailings ponds and accelerate the reclamation of pond and mined-out areas. Various additives to the tailings slurry may accelerate the settling process. An alternative bitumen and sand separation process results in dry tailings, which eliminate the tailings problem (Collison, 2008).

Three *in situ* extraction processes are in various developmental stages that promise to significantly reduce resources used and emissions generated by *in situ* bitumen extraction. In the VAPEX (vapor-assisted petroleum extraction) process, a solvent blend of propane, butane, naphtha, and methane is injected into the formation as a vapour by an upper horizontal well. The solvent mixes with bitumen to reduce its viscosity. Production occurs through a lower horizontal well. The process uses no water and produces no CO_2, but it is not yet commercial, because it is slow, and a practical system for recovery of the costly solvent has not been demonstrated. A hybrid solvent steam process (SAP) has enabled incremental reductions in the amount of steam required, energy consumption, and thus CO_2 emissions (National Petroleum Council [NPC], 2007).

In the Electro-Thermal Dynamic Stripping process (McGee, 2008) the bitumen's viscosity is reduced by heat generated from electrical energy delivered by electrodes inserted into the formation. No water or gas is used in the process. Scaled-up tests must develop ways to enhance well production rates and allow increased spacing of electrode and production wells.

The THAI process involves igniting bitumen at the toe of a horizontal production well and feeding the combustion front with compressed air injected by a vertical well. The heat reduces viscosity of the bitumen, allowing recovery through the production well. As the combustion front moves from the toe of the production well to the heel, a natural coking reaction uses precipitated asphaltenes as fuel, thus raising the API gravity of the produced oil. This process, owned by Petrobank Energy and Resources, has been field tested in a pilot configuration for several years at the Whitesands project.

Process development now focuses on increasing the well production rates to commercial levels and improving the quality of upgraded oil. Petrobank is applying the process to commercial-scale operations at the May River bitumen project and to a heavy oil deposit in Saskatchewan (Petrobank Energy and Resources Ltd., 2010). With the possible exception of an operation in Romania, other *in situ* process technologies have yet to be proven commercially successful.

Another experimental procedure is to introduce bacteria into the reservoir to upgrade the bitumen to light oil or natural gas. The challenge with this approach is to accelerate reaction times and create reservoir conditions amenable to high rates of extraction.

Summary and Implications

The volume of original oil in place in known deposits of natural bitumen and extra-heavy oil appears to be at least of the same order of magnitude as the volume of original oil in place at discovered conventional oil accumulations. Although occurrences of natural bitumen and extra-heavy oil are globally widespread, the massive deposits in Canada and Venezuela account for high percentages, (69% and 98%, respectively) of the discovered resources. Trade press reports prior to the decline in oil prices in 2008, indicated that the production technologies used in the Orinoco Oil Belt and Alberta bitumen deposits were being considered in connection with the development of other deposits. The Orinoco Oil Belt and the Alberta oil sands projects have demonstrated that these resources can be extracted and upgraded at rates that can make an important contribution to each country's petroleum supply and at costs that are competitive with high-cost conventional resources. The Venezuelan government has a stated goal of producing 6.86 million b/d from the Orinoco projects by 2021 (*Oil&Gas Journal*, 2010) and the Alberta ERCB estimates the production from Alberta's oil sands will be increased to 2.95 million b/d by 2018.

Innovations in *in situ* recovery are driven by the need to reduce resource and energy costs as well as emissions of greenhouse gases. New technologies also aim to eliminate plant upgrading by upgrading *in situ*. This generally requires raising reservoir temperatures higher than typically achieved by steam injection. The THAI process performs some upgrading. Theoretically, electrical heating might supply sufficiently high temperatures. The application of solvents and catalysts is also being evaluated. The introduction of bacteria in the reservoir to upgrade bitumen *in situ* is also an area of active research (NPC, 2007).

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DEFINITIONS

In Tables 4.1 and 4.2 the following definitions apply:

Discovered original oil in place: the volume of oil (natural bitumen/extra-heavy oil) in place reported for deposits or parts of deposits that have been measured by field observation. In the literature, estimates of the in-place volumes are often derived from the physical measures of the deposit: areal extent, rock grade, and formation thickness.

Prospective additional resources: the oil or bitumen in unmeasured parts of a deposit believed to be present as a result of inference from geological (and often geophysical) study.

Original oil in place: the amount of oil or bitumen in a deposit before any exploitation has taken place. Where original oil in place is not reported, it is most often calculated from reported data on original reserves (cumulative production plus reserves). Although admittedly inexact, this is a reasonable way to describe the relative abundance of the natural bitumen or extra-heavy oil.

Original reserves: reserves plus cumulative production. This category includes oil that is frequently reported as estimated ultimate recovery, particularly in the case of new discoveries.

Cumulative production: total of production to latest date.

Reserves: those amounts of oil commonly reported as reserves or probable reserves, generally with no further distinction, are quantities that are anticipated to be technically (but not necessarily commercially) recoverable from known accumulations. Only in Canada are reserves reported separately as recoverable by primary or enhanced methods. Russian A, B, and C1 reserves are included here. The term reserve, as used here, has no economic connotation.

Coking: a thermal cracking process that converts the heavy fraction of residue or heavy oils to elemental carbon (coke) and to lighter fractions of the residue, including naphtha or heavy gas oils.

Conventional oil: oil with an API gravity of greater than 20° (density below 0.934 g/cm^3). API gravity is the inverse of density and is computed as (141.5/sp g)-131.5 where sp g is the specific gravity of oil at 60 degrees Fahrenheit.

Cracking: a general term used for a process in which relatively heavy or more complex hydrocarbon molecules are broken down into lighter or simpler, lower-boiling temperature molecules.

Delayed coking: a coking process that recovers coke and produces heavy gas oils from the residuum following the initial distillation of the feedstock oil. The process uses at least two sets of large drums that are alternatively filled and emptied while the rest of the plant operates continuously. Drum temperatures are 415° to 450°C.

Extra-heavy oil: extra-heavy oil is commonly defined as oil having a gravity of less than 10° API and a reservoir viscosity of no more than 10 000 centipoises. In this chapter, when reservoir viscosity measurements are not available, extra-heavy oil is considered to have a lower limit of 4° API.

Flexi-coking: an extension of fluid coking, which includes the gasification of the coke produced in the fluid coking operation and produces a coke gas (Speight, 1986). Flexi-coking is a trademark name of an ExxonMobil proprietary process.

Fluid Coking: a continuous coking process where residuum is sprayed onto a fluidised bed of hot coke particles. The residuum is cracked at high temperatures into lighter products and coke. Coke is a product and a heat carrier. The process occurs at much higher temperatures than delayed coking but leads to lower coke yields and greater liquid recovery. Temperatures in the coking vessels are from 480° to 565°C (Speight, 1986). Fluid coking is a trademark name of an ExxonMobil proprietary process.

Gas oil: hydrocarbon mixture of gas and oils that form as product of initial distillation of bitumen or heavy oil feedstock.

Heavy oil: oil with API gravity from 10° to 20° inclusive (density above 1.000 g/cm^3).

Hydrocracking: a catalytic cracking process that occurs in the presence of hydrogen where the extra hydrogen saturates or hydrogenerates the cracked hydrocarbons.

Natural bitumen: natural bitumen is defined as oil having a viscosity greater than 10 000 centipoises under reservoir conditions and an API gravity of less than 10° API. In this chapter, when reservoir viscosity measurements are not available, natural bitumen is defined as having a gravity of less than 4° API. (Natural bitumen is immobile in the reservoir. Because of lateral variations in chemistry as well as in depth, and therefore temperature, many reservoirs contain both extra-heavy oil, and occasionally heavy oil, in addition to natural bitumen).

Oil Field: a geographic area below which are one or more discrete reservoirs from which petroleum is produced. Each reservoir may be comprised of one or more zones, the production from which is commingled. The production from the reservoirs may be commingled, in which case production and related data cannot be distinguished.

TABLES

TABLE NOTES

The data in the tables are estimates by Richard Meyer of the U.S. Geological Survey. They have been based upon a detailed review of the literature combined with available databases, and suggest (but do not define) the resource volumes that could someday be of commercial interest

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Table 4.1 Natural Bitumen: resources, reserves and production at end-2008

	Deposits	Discovered original oil in place	Prospective additional resources	Total original oil in place	Original reserves	Cumulative production	Reserves
	number	million barrels					
Angola	3	4 648		4 648	465		465
Congo (Brazzaville)	2	5 063		5 063	506		506
Congo (Democratic Rep.)	1	300		300	30		30
Madagascar	1	2 211	13 789	16 000	221		221
Nigeria	2	5 744	32 580	38 324	574		574
Total Africa	**9**	**17 966**	**46 369**	**64 335**	**1 796**		**1 796**
Canada	231	1 731 000	703 221	2 434 221	176 800	6 400	170 400
Trinidad & Tobago	14	928		928			
United States of America	204	37 142	16 338	53 479	24	24	
Total North America	**449**	**1 769 070**	**719 559**	**2 488 628**	**176 824**	**6 424**	**170 400**
Colombia	1						
Venezuela	1						
Total South America	**2**						
Azerbaijan	3	<1		<1	<1		<1
China	4	1 593		1 593	1		1
Georgia	1	31		31	3		3
Indonesia	1	4 456		4 456	446	24	422
Kazakhstan	52	420 690		420 690	42 009		42 009
Kyrgyzstan	7						
Tajikistan	4						
Uzbekistan	8						
Total Asia	**80**	**426 771**		**426 771**	**42 460**	**24**	**42 436**
Italy	16	2 100		2 100	210		210
Russian Federation	39	295 409	51 345	346 754	28 380	14	28 367
Switzerland	1	10		10			
Total Europe	**56**	**297 519**	**51 345**	**348 864**	**28 590**	**14**	**28 577**

Table 4.1 Natural Bitumen: resources, reserves and production at end-2008

	Deposits	Discovered original oil in place	Prospective additional resources	Total original oil in place	Original reserves	Cumulative production	Reserves
	number			million	barrels		
Syria (Arab Rep.)	1						
Total Middle East	**1**						
Tonga	1						
Total Oceania	**1**						
TOTAL WORLD	**598**	**2 511 326**	**817 273**	**3 328 598**	**249 670**	**6 462**	**243 209**

Source: R.F. Meyer, U.S. Geological Survey

Table 4.2 Extra-Heavy Oil: resources, reserves and production at end-2008

	Deposits	of which: deposits offshore	Discovered original oil in place	Prospective additional resources	Total original oil in place	Original reserves	Cumulative oil production	Reserves
	number	number			million barrels			
Egypt (Arab Rep.)	1		500		500	50		50
Total Africa	**1**		**500**		**500**	**50**		**50**
Mexico	2		60		60	6	5	1
Trinidad & Tobago	2		300		300			
United States of America	54	1	2 609	26	2 635	235	216	19
Total North America	**58**	**1**	**2 969**	**26**	**2 995**	**241**	**221**	**20**
Colombia	2		380		380	38	8	30
Cuba	1	1	477		477	48		48
Ecuador	3		919		919	92	50	42
Peru	2		250		250	25	18	7
Venezuela	33	2	1 922 007	189 520	2 111 527	72 556	14 702	57 854
Total South America	**41**	**3**	**1 924 033**	**189 520**	**2 113 553**	**72 759**	**14 778**	**57 981**
Azerbaijan	1		8 841		8 841	884	759	125
China	12		8 877		8 877	888	137	750
Uzbekistan	1							
Total Asia	**14**		**17 718**		**17 718**	**1 772**	**896**	**875**
Albania	2		373		373	37	3	34
Germany	1							
Italy	31	6	2 693		2 693	269	179	90
Poland	2		12		12			
Russian Federation	6		177		177	6		6
United Kingdom	2	2	11 850		11 850	1 085	1 009	76
Total Europe	**44**	**8**	**15 105**		**15 105**	**1 397**	**1 191**	**206**

Table 4.2 Extra-Heavy Oil: resources, reserves and production at end-2008

	Deposits	of which: deposits offshore	Discovered original oil in place	Prospective additional resources	Total original oil in place	Original reserves	Cumulative oil production	Reserves
	number	number	million barrels					
Iran (Islamic Rep.)	1	1						
Iraq	1							
Israel	2		2		2	<1		<1
Total Middle East	**4**	**1**	**2**		**2**	**1**		**1**
TOTAL WORLD	**162**	**13**	**1 960 327**	**189 546**	**2 149 873**	**76 220**	**17 086**	**59 133**

Source: R.F. Meyer, U.S. Geological Survey

COUNTRY NOTES

The Country Notes on Natural Bitumen and Extra-Heavy Oil have been compiled by the authors of the Commentary. Names of sedimentary basins and reference locations are from *Sedimentary Provinces of the World* by St. John, Bally and Klemme (1984). In the case of Canada, additional information supplied by the WEC Member Committee has been incorporated.

Albania

Two of Albania's oil fields contain extra-heavy oil accumulations, and both are located in the Durres Basin.

Angola

Two natural bitumen deposits are located in the Cuanza Basin in Bengo province. They contain about 4.5 billion barrels of oil in place, but have not been worked as an energy source. Their development could be an option after most of Angola's conventional oil resources have been produced.

Azerbaijan

The natural bitumen resources are small and will probably not be used as a source of energy in the near future. The deposits are located within the South Caspian Basin, and the best known is Cheildag (Waters, 1974). The large extra-heavy oil accumulation was discovered in 1904.

Canada

Resource information for the Alberta bitumen deposits is derived from the Alberta Energy Resources Conservation Board (ERCB, 2009), supplemented by estimates for Peace River (Harrison, 1984) and Athabasca (McPhee and Ranger, 1998, and Harrison, 1984).

Deposits are found in Lower Cretaceous sandstones and in the Mississippian and Devonian carbonates unconformably overlain by Lower Cretaceous strata. The oil sands occur along the up-dip edge of the Western Canada Sedimentary Basin. East of the Athabasca and Cold Lake deposits, in Alberta and Saskatchewan, large quantities of heavy and medium oil are found in the Lower Cretaceous sandstones, but occurrences of extra-heavy oil are few and of limited economic importance. At least one firm has announced plans to test whether the oil sands deposits extend into Saskatchewan.

Saskatchewan's oil sands reserves are not yet recognised as proved owing to a lack of an accepted geological survey. According to Oil Sands Quest there could be 50 to 60 billion barrels of bitumen in northwest Saskatchewan.

In 2009 the ERCB predicted that by 2018, bitumen production will increase to almost 2.95 million b/d, up from 1.3 million b/d (before upgrading) in 2008 – 55% of production. Mined output would increase to 1.56 million b/d from 720 000 b/d and *in situ* production to 1.39 million b/d from 580 000 b/d. Industry estimates that two tonnes of oil sands can produce 1.2 barrels of non-upgraded bitumen or 1 barrel of upgraded synthetic crude oil.

During 2009, many projects were delayed. Cost levels declined but some projects are still delayed, because of concern about potential CO_2 emissions constraints. Because production and upgrading costs for bitumen are high relative to conventional oil, the economic viability of the oil sands industry is dependent on a continuation of the recent level of prices of crude oil, at least until further cost-reducing technologies are devised and implemented.

According to the Province of Alberta, an estimated 1.7 to 2.5 trillion barrels of oil are trapped in a complex mixture of sand, water and clay. Bitumen already discovered amounts to 1.7 trillion barrels. The Province of Alberta indicates that additional oil is believed to exist owing to geological characteristics which could raise the total volume of bitumen in place to 2.5 trillion barrels.

According to ERCB, an estimated 315 billion barrels of bitumen is expected to be recovered from the oil sands with advances in technology. The ultimate potential (recoverable) figure has been adopted by the Government of Canada.

China

Four natural bitumen accumulations have been identified in the Junggar Basin with resources of about 1.6 billion barrels of bitumen. Ten of the 12 extra-heavy oil accumulations are located in the Bohai Gulf Basin with the other two located in the Huabei and the Tarim Basins.

Colombia

The two extra-heavy oil accumulations are part of a single field in Colombia in the Barinas-Apure Basin. There are numerous oil seepages and small bitumen deposits, especially in the Middle and Upper Magdalena Basins. None of these deposits appears to be sufficiently large to be an important commercial source of synthetic oil.

Congo (Brazzaville)

Heavy oil is found in reservoirs offshore Congo but no extra-heavy oil is known. The natural bitumen deposit at Lake Kitina in the Cabinda Basin has been exploited for road material. In 2008, Eni agreed to evaluate and produce bitumen in a concession that includes the Lake Kitina area (Tchikatanga area) and Lake Dionga area (Tchikatanga-Makola area). Estimated recoverable oil is about 500 million barrels.

Congo (Democratic Republic)

A natural bitumen deposit occurs in the Democratic Republic of Congo in the Cabinda Basin near the border with Cabinda. It has served as a source of road material, with nearly 4 000 tonnes (24 000 barrels) having been produced in 1958. This deposit is not likely to become a source of synthetic oil.

Cuba

Most of the oil produced from Cuba is heavy. Cuba contains numerous oil seepages but no significant natural bitumen accumulations. The extra-heavy oil accumulation is located partially offshore in the Florida-Bahamas Basin (also called the Greater Antilles Deformed Belt).

Ecuador

Ecuador is endowed with large amounts of heavy oil but only a small amount, all in the Putumayo Basin, is extra-heavy. Natural bitumen is restricted to scattered oil seepages.

Egypt (Arab Republic)

Many fields containing heavy oil are found in Egypt, but very little of this is extra-heavy. The single extra-heavy oil accumulation is undeveloped.

Georgia

The only significant natural bitumen deposit in Georgia is in the South Caspian Basin, at Natanebi. Neither heavy nor extra-heavy oil are known in Georgia, although conventional oil has been produced there for more than a century.

Germany

Heavy oil is produced from many fields in Germany, but extra-heavy oil has not been reported. Highly viscous natural bitumen is present in the Nordhorn deposit, in the Northwest German basin.

Indonesia

In Indonesia although many fields produce heavy oil there does not appear to be a large extra-heavy oil resource. Natural bitumen occurs in the well-known Buton Island deposit. This has long been utilised as a source of road asphalt.

Iran (Islamic Republic)

The principal extra-heavy oil accumulation is part of an offshore discovery. A number of Iranian fields produce heavy oil.

Iraq

Oil seepages have been known and utilised in Iraq throughout historical time, but are insufficient for serving as sources of synthetic oil. Although heavy oil fields are productive in the country, very little extra-heavy oil has been identified.

Israel

The extra-heavy oil that is known in Israel is located in the Dead Sea province. Natural bitumen occurs only as Dead Sea asphalt blocks, which occasionally rise to the surface.

Italy

Italy has 16 natural bitumen deposits and 31 extra-heavy oil deposits. The 269 million barrels of original reserves of extra-heavy oil in Italy are found in six separate basins, similar geologically to the Durres Basin of Albania. The most important of these is the Caltanisetta Basin, mostly offshore and including the Gela field. These fields are all found in the foredeep portion of the basins, where the sediments are thickest and most structurally disturbed. The viscous nature of the oil, the offshore environment, and the limited resources create challenges to economic development of these accumulations.

Kazakhstan

Although Kazakhstan possesses large resources of conventional and heavy oil, it contains little if any extra-heavy oil. It does have significant resources of natural bitumen in the North Caspian Basin. As with nearly all the large natural bitumen deposits, the geological setting, like that of the Western Canada Sedimentary Basin, is conducive to the development of natural bitumen. In the light of the very large resources of conventional oil and natural gas in this country, development of the bitumen as a source of synthetic oil is unlikely in the foreseeable future.

Kyrgyzstan

Little is known about these deposits except their location in the Fergana Basin. They have yet to be evaluated.

Madagascar

Bemolanga is the only natural bitumen deposit in Madagascar. In 2008 Total Oil acquired from Madagascar Oil a 60% interest (including operatorship) in the concession to develop the Bemolanga deposit. The partnership estimates 2.5 billion barrels is recoverable out of an in-place amount of 16 billion barrels, as evaluated by DeGolyer and MacNaughton. A large heavy-oil deposit, Tsimiroro, has been the subject of a number of unsuccessful production tests but no extra-heavy oil has been identified in the country.

Mexico

Mexico, with numerous heavy oil fields, contains very few extra-heavy oil reservoirs. The latter are small in resources and production. Oil seepages are common in the country, but no large natural bitumen deposits have been found.

Nigeria

Natural bitumen in place, possibly totaling as much as 38.3 billion barrels, is located in southwestern Nigeria, in the Ghana Basin. This extensive deposit has not yet been evaluated as a source of synthetic oil and its production will no doubt be delayed as long as Nigeria is a leading producer of conventional oil.

Peru

Peru contains numerous heavy oil deposits, mostly in the Oriente Basin. However, the recoverable oil from the two known extra-heavy oil accumulations is relatively small.

Poland

With current technology, the two extra-heavy oil reservoirs of Poland are marginally economic.

Russian Federation

Extra-heavy oil has been identified in the Russian Federation in small amounts in the Volga-Urals and North Caucasus-Mangyshlak Basins (S.I. Goldberg, written communication). As is the case with many countries, accurate and timely data are insufficient for making well constrained estimates.

Information relating to natural bitumen deposits indicates that very large resources are present in the east Siberia platform in the Tunguska Basin (Meyer and Freeman, 2006). This is harsh terrain and only the Olenek deposit has been studied in sufficient detail to permit the estimation of discovered bitumen in place. The Siligir deposit has been frequently cited in reports of world bitumen deposits, but the primary source for these citations has not been located. It may be assumed that the estimate of more than 51 billion barrels for the basin is conservative. This area is so remote, and Russia’s conventional oil and gas resources so great, that it is not likely that attempts will be made in the near future to exploit this natural bitumen. Most of the other Russian bitumen deposits are located in the Timan-Pechora and Volga-Urals Basins, which are analogous geologically to the Western Canada Sedimentary Basin. However, these deposits are scattered and the recoverable portions are not quantitatively large. The deposits in the Tatar Republic have been studied extensively and efforts to exploit them may be conducted in the future.

Switzerland

The Val de Travers natural bitumen deposit in Switzerland is small, but representative of many such occurrences in Western European countries. Most of these have been known for centuries and a few have been mined, mainly for road material.

Syria (Arab Republic)

The Babenna natural bitumen in Syria was mined for many years for asphalt. It is one of numerous such deposits throughout the Middle East, those in Syria and Iraq being especially prominent since antiquity. They are not regarded as potential commercial sources of synthetic oil.

Tajikistan

Little is known about the four bitumen accumulations except that three are located in the Amu Darya Basin and the fourth is located in the Fergana Basin.

Tonga

The Tonga natural bitumen accumulation was found as a seep but has yet to be evaluated.

Trinidad & Tobago

Trinidad & Tobago is rich in heavy oil, but only 300 million barrels of oil in place is extra-heavy. The country has more than 900 million barrels of oil in place in natural bitumen deposits, including Asphalt (Pitch) Lake. All these deposits are located in the Southern Basin, which is small, highly faulted, but highly productive of other hydrocarbons.

Asphalt (Pitch) Lake, at La Brea, which contains a semi-solid emulsion of soluble bitumen, mineral matter, and other minor constituents (mainly water), has been mined since at least 1815 but mostly for use as road-surfacing material. The lake contains 60 million barrels of bitumen, a sufficient supply for the foreseeable future. Production is between 10 000 and 15 000 tonnes per year (equivalent to 60 000 to 92 000 barrels per year), most of which is exported. In combination with asphalt from refined crude oil, the product is used for road construction. In addition, it can be used in a range of paints and coatings and for making cationic bitumen emulsions. Production of these emulsions of bitumen, water, and soap began in late 1996 and the emulsions are now used widely throughout the industrialised world in place of solvent-based bitumen emulsions.

United Kingdom

Offshore the United Kingdom has two extra-heavy oil deposits. One is a discovery in the West of Shetlands Basin, for which few data are available. The other is the producing Piper field in the North Sea Graben, which contains oil between 8.7º and 37º API gravity.

United States of America

The United States was endowed with very large petroleum resources, which are to be found in nearly all the various types of geologic basins. The resources of extra-heavy oil and natural bitumen likewise are distributed in numerous geological settings. Geologically, about 80% of the discovered U.S. natural bitumen is deposited in basins similar to the Western Canada Sedimentary Basin. Such basins possess ideal conditions for occurrences of degraded oil. However bitumen deposits of the United States are much smaller, much less numerous, and more scattered. About 98% of the reported extra-heavy oil is found in basins that evolved along the rift-faulted, convergent continental margin of California where the island arcs which originally trapped the sediments against the land mass to the east have been destroyed.

Distillation of oil from Casmalia tar sands in California was first attempted in 1923. Many tar sands deposits in the United States have served as sources of road asphalt, but this industry disappeared with the advent of manufactured asphalt tailor-made from refinery stills. Largest deposits in the lower conterminous 48 states are in Utah. During the 1980s U.S. energy analysts studied criteria, both technical and economic, for supply of synthetic crude oil from tar sands and several tar sands pilot projects were started. With the decline in and stagnation of crude oil prices from the latter 1980s to about 2000, there was little interest in pursuing these projects. The recent sustained increases in oil prices have revived this interest.

The extra-heavy oil accumulations in California account for about 97% of the extra-heavy oil produced to date. These are typically reservoirs found in large fields, multiple reservoir fields, and fields that may have already installed a thermal recovery operation for production of heavy oil in underlying reservoirs or overlying reservoirs.

Uzbekistan

Little is known about the eight natural bitumen occurrences in Uzbekistan except that six occur in the Fergana Basin and two are located in the Amu Darya Basin. The single occurrence of extra-heavy oil is reported as part of the Khaudag deposit in the Amu Darya Basin (S.I. Goldberg, written communication). Its size is unknown.

Venezuela

A small amount of Venezuela's extra-heavy oil resource is found in the Maracaibo Basin, but the resources of worldwide significance lie in the Orinoco Oil Belt along the southern, up-dip edge of the Eastern Venezuela Basin. One natural bitumen deposit, Guanoco Lake, is found near the Caribbean coast on the north side of the Eastern Venezuela Basin. The deposit has been estimated to contain 62 million barrels of oil in place (Walters, 1974).

Four joint ventures for the exploitation of extra-heavy crude have been operating since 2001; as of 2006 they have an extra-heavy oil production capacity of 640 000 b/d. All the projects, in one way or another, involve production, transportation, and upgrading facilities. In 2007, Venezuela nationalised the production joint ventures that had been allowed to have foreign ownership. PDVSA (Petróleos de Venezuela, the state oil company) is now majority owner of the four operating projects.

Venezuela, through PDVSA, started a reserves certification programme to increase the proved reserves in the Orinoco Oil Belt. Twenty seven blocks have been selected for development, some of which are being studied by foreign, mostly state, oil companies working with PDVSA. After reserves in a particular block have been certified, the operator who prepared the evaluation may take a minority ownership in a joint venture with PDVSA. Each project must build an upgrade facility, usually in the northeastern coastal area. The scheme has attracted a number of national oil companies: Petrobras (Brazil), Petropars (Iran), CNPC (China) and ONGC (India). Eni and PDVSA have already established a joint venture to develop and upgrade oil from the Junin Block 5.

In the early 1980s Intevep, the research affiliate of PDVSA, developed a method of utilising some of the hitherto untouched potential of Venezuela's extra-heavy oil resource. The extra-heavy oil (7.5º-8.5º gravity API) is extracted from the reservoir and emulsified with water (70% natural bitumen, 30% water, <1% surfactants). The resulting product, called Orimulsion® can be pumped, stored, transported and burnt under boilers using conventional equipment with only minor modifications. Initial tests were conducted in Japan, Canada and the United Kingdom, and exports began in 1988. Orimulsion® is processed, shipped and marketed by Bitúmenes del Orinoco S.A. (Bitor), a PDVSA subsidiary.

Bitor operates an Orimulsion® plant at Morichal in Cerro Negro with a capacity of 5.2 million tonnes per year. In 2005 PDVSA announced it would cease Orimulsion® production because it was more profitable to sell the extracted oil as feedstock to extra-heavy oil upgraders. However, in 2006, PDVSA and CNPC (China National Petroleum Corporation) initiated the Sinovensa project, to supply two power plants in China and meet some of PDVSA's commitments to supply Orimulsion®. Sinovensa currently produces 80 000 b/d and expects to expand to 125 000 b/d.