4. Natural Bitumen and Extra-Heavy Oil

COMMENTARY

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Introduction

Since 2005, oil price increases have greatly increased investment in the production of extra-heavy oil and natural bitumen (tar sands or oil sands) to supplement conventional oil supplies. These oils are characterised by their high viscosity, high density (low API gravity), and high concentrations of nitrogen, oxygen, sulphur, and heavy metals. Extra-heavy oil and natural bitumen are the remnants of very large volumes of conventional oils that have been generated and subsequently degraded, principally by bacterial action. Chemically and texturally, they resemble the residuum produced by refinery distillation of light oil. Although these viscous oils are much more costly to extract, transport and refine than conventional oils, production levels have increased to more than 1.6 million barrels per day, or just under 2% of world crude oil production.

The resource base of extra-heavy oil and natural bitumen is immense and can easily support a substantial expansion in production. This resource base can make a major contribution to oil supply, if it can be extracted and transformed into useable refinery feedstock at sufficiently high rates and at costs that are competitive with alternative resources. Technology must continue to be developed to address emerging challenges (both environmental and economic) in the market supply chain. (Definitions follow this Commentary).

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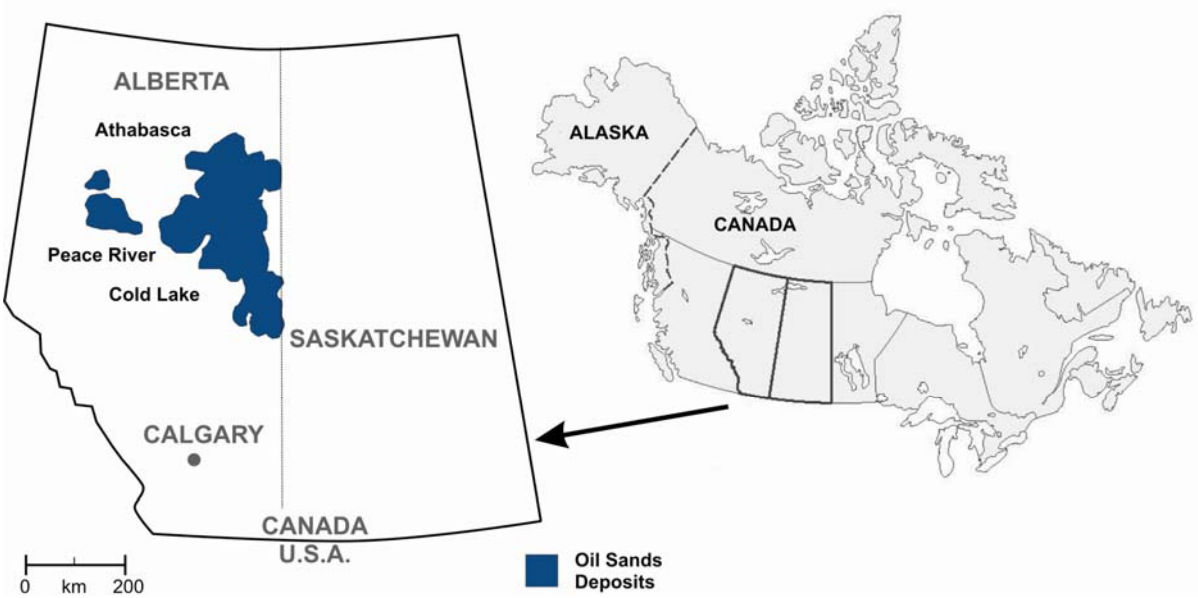
Figure 4-1 Location of the oil sands deposits of Canada
Source: modified from McPhee and Ranger, 1998



Resource Quantities and Geographical Distribution

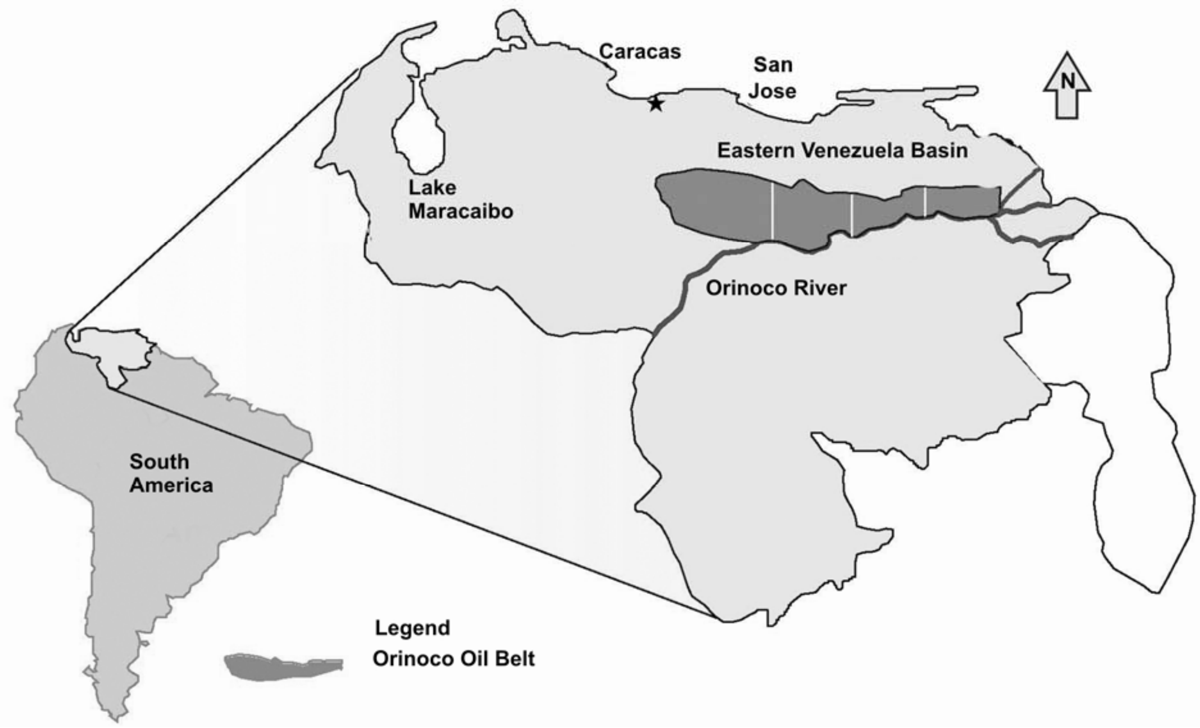
Resource quantities reported here are based upon a detailed review of the literature in conjunction with available databases, and are intended to suggest, rather than to define, the resource volumes that could someday be of commercial interest. Precise quantitative reserves and oil-in-place data on a 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 has been calculated from an estimate of the recoverable volumes, using assumed recovery factors. For deposits in clastic rocks the in-place volume was calculated as 10 times the original recoverable volumes (cumulative production plus an estimate of the remaining recoverable volume) and for carbonate reservoir accumulations the original oil in place was calculated as 20 times the estimated original recoverable volume. 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).

Natural bitumen

A summary of natural bitumen and extra-heavy oil resource quantities is given in Tables 4-1 and 4.2. Natural bitumen is reported in 586 deposits in 22 countries (Table 4-1). It occurs in clastic and carbonate reservoir rocks and commonly in small deposits at, or near, the earth's surface. Natural bitumen accumulations have been mined since antiquity for use as paving materials and sealants. In some places such deposits are extremely large, both in areal extent and in the resources they contain, most notably those in northern Alberta (Fig. 4-1), in the Western Canada Sedimentary Basin. The three Alberta oil sands areas, Athabasca, Peace River, and Cold Lake, together contain at least two-thirds of the world's discovered bitumen in place (1.7 trillion barrels) and are at the present the only bitumen deposits that are commercially exploited as sources of synthetic oil. More than one third of the crude oil produced in Canada currently comes from the Alberta natural bitumen deposits.

Outside of Canada, 359 natural bitumen deposits are reported in 21 other countries (Table 4-1). Although Kazakhstan and Russia have the largest amounts of bitumen after Canada, both countries also have large volumes of undeveloped, and undoubtedly less costly, conventional oil. In Kazakhstan, the largest number 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

Figure 4-2 Location of the Orinoco Oil Belt in Venezuela
Source: modified from Layisse, 1999



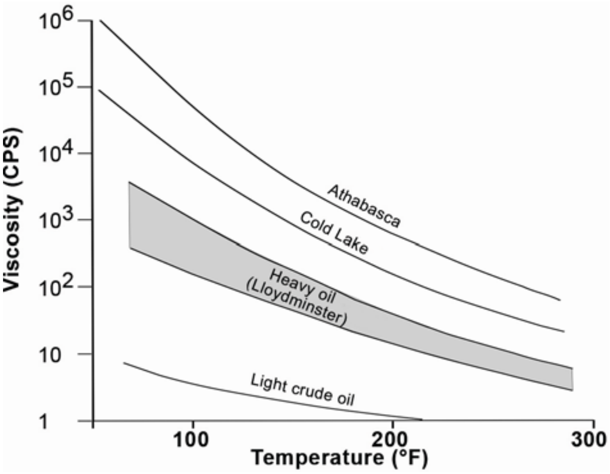
Caspian, Timan-Pechora, and Volga-Ural basins are geologically similar to the Western Canada Sedimentary Basin. Very large resources occur in the basins of the Siberian Platform of Russia (Meyer and Freeman, 2006). Many more deposits are identified worldwide but, as in the case of oil seepages, no resource estimates are reported for them. The volumes of discovered and prospective additional bitumen in place amount to 2 469 billion barrels and 803 billion barrels, respectively.

Extra-heavy oil

Extra-heavy oil is recorded in 166 deposits world wide (Table 4-2). Extra-heavy oil deposits are found in 22 countries, with 13 of the deposits being located offshore or partially offshore (Table 4-2). Only one deposit is sufficiently large to have a major supply and economic impact on crude oil markets. That deposit, 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 about 2.2 trillion barrels. In 2005 the upgraded extra-heavy oil produced from this deposit amounted to about 570 thousand b/d, and accounted for almost 20% of the oil production of Venezuela, the world's third leading crude oil exporter. Some of the deposits are separate reservoirs or a single field that consist entirely of extra-heavy oil, whereas other deposits occur as extra-heavy oil reservoirs associated with conventional oil reservoirs in fields known to be primarily conventional. The extra-heavy oil of the Orinoco Oil Belt does not occur with conventional oil reservoirs. Table 4-2 shows in place discovered volume and total in place volumes amounting to 2 294 billion barrels and 2 484 billion barrels, respectively.

In total, Tables 4-1 and 4-2 report a total in-place bitumen volume of 5 756 billion barrels. This volume is slightly *less than, but of the same order of magnitude as, the estimated volume of original oil in place in the world's known conventional oil fields.* Successful commercial production from the Orinoco Oil Belt and the Alberta bitumen accumulations have proven production strategies and technologies that are likely to be applied to the smaller accumulations represented in Tables 4-1 and 4-2. With the recognition of the commercial potential of these immense resources, *additional* deposits and volumes are likely to be reported in the future.

Figure 4-3 Response of viscosity to change in temperature for some Alberta oils
Source: Raicar and Procter, 1984



Economics of Production, Transportation, and Refining Technology

Production technologies: Canada

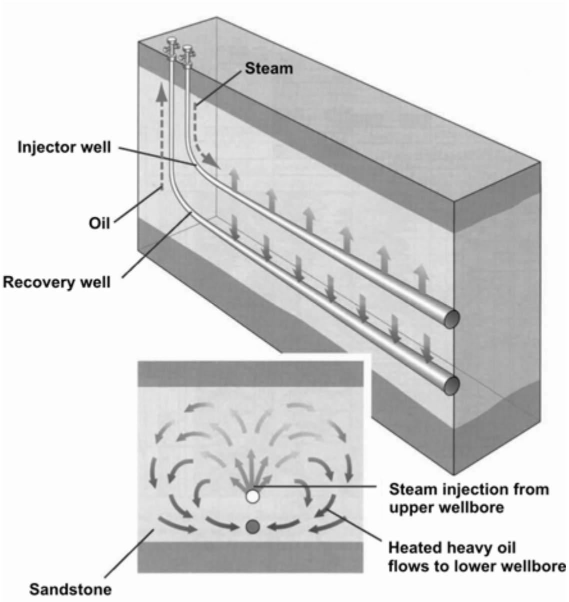
Natural bitumen deposits occurring at depths of up to 250 feet can be surface-mined. The bitumen is then separated from the mined sand by a hot water process. The bitumen mined at two of the three operating mining/separation projects (Suncor Energy and Syncrude Canada) is upgraded onsite into a synthetic crude oil (SCO), which is then transported by pipeline to conventional refineries. The third project, Albian Sands Energy, transports a mixture of bitumen and diluents to the Scotford upgrading facility about 270 miles south, near Edmonton. In 2005, mined production amounted to 551 thousand b/d for the three Alberta oil sand mining projects. Of the 174 billion barrels of bitumen estimated by the Alberta Energy and Utilities Board (EUB, 2006) to be recoverable from identified deposits, 32 billion barrels is accessible with current surface-mining technology.

In a limited number of areas, bitumen that is too deep for surface mining is produced from wells for short periods without injection of steam. In cold production with sand (Cold heavy oil production with sand - CHOPS) bitumen and sand are pumped to the surface through the well bore and then separated. Sand production creates channels or high-permeability zones for the bitumen to flow through (Dusseault, 2001).

Most bitumen deposits are not amenable to cold production over extended periods, so steam is commonly injected into the reservoir to raise the temperature and reduce the viscosity of the bitumen. Fig. 4-3 shows the dramatic reduction in fluid viscosity with increasing temperatures for the bitumen at Athabasca and Cold Lake. Steam can be injected through vertical or lateral (horizontal) wells. At Cold Lake, bitumen has historically been produced with cyclic steam stimulation. In this process, steam is injected into the formation during the 'soak' time period or cycle to heat the formation. The production cycle begins after injection wells are converted to producers and ends when the heat is dissipated within the produced fluids. This cycle of soak and produce is repeated until the response becomes marginal because of increasing water production and declining reservoir pressure. After a number of cycles, steam may also be injected as a steam flood to improve reservoir pressure (Dusseault, 2006).

An alternative extraction method is the steam-assisted gravity drainage (SAGD) process (Fig. 4-4), where a horizontal steam-injection well is drilled about 5 metres above a horizontal

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]



production well. Injected steam creates a heated chamber, the heated bitumen is mobilised, and gravity causes the fluid to move to the producing well where it is pumped to the surface. Diluents may also be injected to assist in lowering the viscosity of the reservoir fluids.

When the EUB 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%. The EUB estimate of the recovery efficiency of mining and extraction of the in-place bitumen is 82% (National Energy Board [NEB], 2006).

Production technology: Venezuela

In the Orinoco Oil Belt, cold production of extra-heavy oil is achieved through multilateral (horizontal) wells that are precisely positioned in thin but relatively continuous sands, in combination with electric submersible pumps and progressing cavity pumps. Horizontal multilateral wells maximise the borehole contact with the reservoir. Extra-heavy oil mobility in the Orinoco Oil Belt reservoirs is typically greater than that of bitumen in the Alberta sands because of higher reservoir temperatures, greater reservoir permeability, higher ratio of gas to oil, and the lower viscosity of extra-heavy oil (Dusseault, 2001). 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. It is fully expected that the Orinoco projects will install enhanced recovery methods after the cold production phase of recovery is completed. While it is generally recognised that thermal recovery methods will be applied following cold production, other tertiary recovery methods involving gas injection and in-situ combustion could also be profitably applied to the extra-heavy oil and natural bitumen reservoirs following steam thermal recovery methods (Dusseault, 2006).

Production economics: Canada

Fig. 4-5 shows the NEB estimates of bitumen and synthetic oil supply costs in 2005 Canadian dollars (1 CDN$ = US$ 0.85). The NEB cost estimates assume a US price of West Texas Intermediate of US$ 50/bbl, NY Exchange price of gas at US$ 7.5/million Btu and a 10% real return. Costs associated with cold production

Figure 4-5 Estimates of operating (Opex) and supply costs by production method
Source: NEB, 2006

Production method	Product	Opex	Supply cost
	[CDN$ (2005) * per barrel at plant gate]		
Cold (Wabasca, Seal)	Bitumen	6-9	14-18
Cold heavy oil with sand (Cold Lake)	Bitumen	8-10	16-19
Cyclic steam (Cold Lake)	Bitumen	10-14	20-24
SAGD	Bitumen	10-14	18-22
Mining/extraction	Bitumen	9-12	18-20
Integrated/mining extraction, upgrading	Syncrude **	18-22	36-40

* Canadian dollar assumed at US$ 0.85
** SCO

are low because of low operating costs. However, recovery by cold production is also low and for the Alberta sands not sustainable for long periods of time. The SAGD process costs appear to be slightly lower than cyclic steam costs. The range of costs for the mining/extraction process is within the cost range of the SAGD process. The NEB's published per barrel cost of supply estimates were based on historical information, regulatory filings for new operations, and internal engineering cost models. The capital investment costs are CDN$ 15 000 - 20 000 per sustainable daily barrel (NEB, 2006), so a project capable of producing 30 000 b/d would have a nominal investment cost of CDN$ 450 to 600 million.

In most cases operating costs account for half of the supply costs. For the thermal processes, the cost of natural gas used to generate steam makes up approximately 65-75% of operating costs. Under favourable conditions, each barrel of bitumen produced consumes 1.05 thousand cubic feet of natural gas, based on a steam-to-oil ratio of 2.5:1. If gas is used as fuel in the mining/extraction configurations, gas requirements are 0.7 thousand cubic feet per barrel of bitumen produced. There is great concern regarding the large volumes of water and natural gas used in the thermal recovery processes. Recent research has focused on reducing thermal process gas requirements by substituting other fuels or by reducing the steam-to-oil ratio by injecting solvents into the reservoir. Unless there is onsite upgrading to SCO, the product that will be transported to upgrading facilities will be a blend of two-thirds bitumen and one-third diluents. The availability of natural gas liquids or light oil to use as diluents in transporting the bitumen to upgrade facilities is also a potential challenge to expansion.

Production economics: Venezuela

The unit supply cost for the Orinoco extra-heavy oil utilising cold production is much lower than the supply cost for cold production of bitumen in Canada because of more favourable fluid and reservoir conditions. The sustainability of a well production plateau is much longer, and the level well production is as much as an order of magnitude higher in Orinoco extra-heavy oil than in the Canadian bitumen projects. Current estimates of the supply costs for the Orinoco extra-heavy crude oil are as little as half of the supply cost for Canadian bitumen (Fig. 4-4).

Transportation and Upgrading

Transportation technology

The transportation of the extra-heavy oil and bitumen outside the concession or lease requires that the oil be heated, or alternatively blended with diluents (naphtha, gas condensates, or light oils), to reduce viscosity, or the oil be upgraded on-site. The degree of upgrading depends on the quality of the extracted oil and the desired standard of the SCO, that is, the target API gravity and sulphur content. In many cases the specifications for the SCO will depend on the availability of merchant refinery capacity capable of accepting and profitably refining it, or specifications may depend on the requirements of a captive refinery. A captive refinery is one that is obligated because of ownership or contract to refine a particular producer's crude oil.

Upgrading technology

For light oil refinery feedstock, simple atmospheric/vacuum distillation processes might yield an acceptable slate of primary products that included high-value transportation fuels: gasoline, jet fuel, and diesel fuels. With simple distillation, the heavier the refinery feedstock oil, the lower the yield of high-value transportation fuels and the higher the percentage residuum yield. Refineries steeply discount the price they are willing to pay for the heavy oil feedstocks that have low yields of the high-value products.

The upgrading process of heavy oil and natural bitumen starts with atmospheric and vacuum distillation processes that recover the diluents for recycling to the field, and which also produce gas oil and residue. The gas oil can be treated with hydrogen to reduce sulphur and nitrogen (producing hydrogen sulphide and ammonia). The two options are hydrotreating (a catalytic reaction) and hydrocracking the gas oil (carried out under mild conditions). The typical 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) hydrocracking, which adds hydrogen as the residue is heated under high temperature and high pressures (high conversion), so that liquid yields are maximised under high conversion (Vartivarian and Andrawis, 2006). Hydrogen for hydrotreating and hydrocracking is either purchased or generated by passing natural gas over steam (steam-methane reforming process). Because the residue hydrocracking occurs under extremely high temperatures and pressures, investment costs for process equipment are much higher than for the other resid conversion processes (Speight, 1991).

Bitumen upgrading: Canada

The yield of upgraded oil (SCO) from natural bitumen, based on data from Alberta, varies with the technology employed, the consumption of the product for fuel in the upgrader, the extent of natural gas liquids recovery, 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 uses delayed coking for a yield of 0.81 barrels of oil 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 upgrading plant at Scotford, which applies hydrocracking to both the distillation gas oil and residue, is 0.9 (NEB, 2004).

Figure 4-6 Commercial operations in the Orinoco Oil Belt
Source: US DOE Energy Information Administration, 2006

Project name (new name)	Petrozuata (Junin)	Cerro Negro (Carabobo)	Sincor (Boyaca)	Hamaca (Ayacucho)
Startup	October 1998	November 1999	December 2000	October 2001
Extra-Heavy Oil Production - b/d	120 000	120 000	200 000	200 000
API gravity	9.3°	8.5°	8.0-8.5°	8.7°
Synthetic Oil production - b/d	104 000	105 000	180 000	190 000
API gravity	19-25°	16°	32°	26°
Sulphur - % weight	2.5	3.3	0.2	1.2

As of 2005, 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. The diluents account for 33% of the blend (NEB, 2006). New and expansion projects could increase bitumen production to 3 mb/d by 2015 (Alberta EUB, 2006). If such an expansion is realised, on-site upgrading could be attractive to both mining and in-situ projects, by eliminating the need for diluents for transportation. Their elimination would reduce the volume of diluents the industry needs and increase the effective capacity of product pipelines to refineries. The by-product coke from upgrading plants could provide a substitute for the natural gas used for steam generation for in-situ projects (Luhning, et al., 2002). The principal challenges are the additional capital cost required and the scale of the bitumen production project needed to take advantage of economies of scale at the upgrading facility.

Extra-heavy oil upgrading: Orinoco Oil Belt

Fig. 4-6 shows the upgrade plant capacities and product specifications for the four commercially-operating Orinoco extra-heavy oil production projects. Upgrading occurs before export because of the limited availability of light Venezuelan crude oils for blending and the location of the upgrading plants on the northeast coast of Venezuela. All of the plants recover and recycle diluents to their fields. Each also uses delayed coking to upgrade residue and hydrotreat the coking process by-product naphtha for removal of sulphur and nitrogen. The Sincor project produces a low-sulphur light SCO 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%. Although the light and low-sulphur synthetic oils are generally the easiest to market to refiners and command the highest prices, most of the lower-quality synthetic crude oil produced by the Petrozuata and Cerro Negro projects are transported to captive refineries in the US and Caribbean (Chang, 1998). The extracted extra-heavy oil and bitumen-diluent blends require similar upgrading processes, suggesting that upgrading costs will be comparable.

Economics of Upgrading and Markets for Upgraded Oil

Fig. 4-7 shows selected published estimates of capital costs (Vartivarian and Andrawis, 2006) that were expressed on a per daily barrel of (upgraded) synthetic oil (syncrude) plant output capacity. The purpose of the Vartivarian and Andrawis study was to compare costs of a number of alternative plant process configurations having a nominal input capacity of 100 000 b/d of bitumen/diluent feedstock, consisting of 80% bitumen and 20% diluent. The bitumen had an assumed gravity of 8.6° API and a sulphur content of 4.8%. Fig. 4-7 shows plant process investment cost and investment per barrel of output capacity, along with the syncrude product specifications. The investment

Figure 4-7 Investment cost per daily barrel for upgrading bitumen to various grades of synthetic crude oil
Source: Vartivarian and Andrawis, 2006

Process configuration	Syncrude output (b/d)	API Gravity (API°)	Sulphur (wt %)	Investment cost ($ million)	Capex * ($ thousand per daily barrel)
RVBR	81 508	12.5	4.10	889	10.9
GOHT	80 048	18.0	3.80	1 278	16.0
GOHT, RVBR	84 576	20.8	3.30	1 333	15.8
SDA, GOHC	86 900	23.6	3.20	1 350	15.5
RDCK, GOHT	67 538	32.4	0.13	1 250	18.5
RDCK, GOHC	71 009	46.8	0.00	1 556	21.9
RHCR, GOHT	87 832	25.9	0.90	1 694	19.3
RHCR, GOHC	93 126	40.4	0.90	2 000	21.5

* Capex = capital investment per daily barrel of plant output capacity
RVBR = visbreaking applied to residue from distillation processes
GOHT = hydrotreating of gas oil from distillation processes
SDA = solvent de-asphalting applied to residue from distillation processes
GOHC = hydrocracking of gas oil from distillation processes
RDCK = delayed coking applied to residue from distillation processes
RHCR = hydrocracking applied to residue from distillation processes
Assumed 100 000 b/d input of which 20 000 b/d is diluent recycled to field, 80 000 b/d bitumen at 8.6° API gravity and 4.8% sulphur
All configurations assume bitumen is passed through atmospheric/vacuum distillation processes
Costs are 2005 US$

costs were based on US Gulf Coast costs in 2005 US dollars. The greater the intensity of the processing, as indicated by the quality of the synthetic oil product (higher API gravity and lower sulphur content), the higher the investment cost per daily barrel. The plant investment costs are from 29-36% greater when the high temperature/pressure residue hydrocracking process (configurations with RHCR – Fig. 4-7) is used than if the residue is coked (configurations with RDCK – Fig. 4-7). The configurations with this higher cost process (RHCR), however, result in 30% greater synthetic oil output than under coking. The economic benefits of the higher-cost process depend on syncrude prices.

The two features to notice about Fig. 4-7 are firstly, the wide range in initial investment costs per daily barrel of synthetic crude oil output and secondly, the absolute level of investment required; never less than 800 million dollars and could easily exceed 2 billion dollars. The investment per daily barrel of bitumen production capacity (mine and extraction or in-situ recovery) is of the same order of magnitude as the required investment per daily barrel for the upgrader facility. If the per daily barrel of production cost was CDN$ 20 000 or US$ 17 000, the combined cost of the production/upgrading facility for a high-quality syncrude could be US$ 37 000 per daily barrel, or almost US$ 3 billion for an integrated project to supply the upgrader at 80 000 barrels of bitumen per day. Such capital requirements would be well beyond the reach of small operators.

Plants that upgrade extra-heavy oil and bitumen demonstrate the generic characteristics of chemical process industries. They are subject to significant economies of scale, that is, unit capacity investment cost increases rapidly as capacity is reduced below optimal size, and optimal-size plants 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 on the cost of inputs to the upgrade plant. This market value is determined by the availability of competing crude oils of the same or superior quality and

Occurrences of natural bitumen and extra-heavy oil are widespread; the volume of oil in place appears to be of at least the same order of magnitude as the volume of original oil in place at known conventional oil accumulations.

the technical capability of local or captive refineries to accept the crude and in turn, to produce high-value products.

Past conduct may indicate the pattern of future development. Partners of the Petrozuata and Cerro Negro projects in the Orinoco Oil Belt had captive US and Caribbean refineries which influenced the design of the San Jose upgrading facilities. The initial Canadian mining operations built on-site upgrading facilities that produced a syncrude that was matched with available refinery capacity.

Downstream vertical integration is the economic term used when a raw materials producer performs the next stages of processing, such as refining or smelting and even selling finished products. Alternatively, if a steel maker starts a mining subsidiary to supply the ore to the steel plant, it is upstream vertical integration. A primary motivation for economic integration downstream is to manage the risks inherent in raw materials markets by providing a means through a captive upgrading facility and perhaps refinery to market the bitumen product. The refiner's price differential between heavy oil and light oil can be notoriously unstable, so there is a real risk to the bitumen producer of its being unable to recover costs, particularly in the light of the relatively high raw bitumen production supply costs presented in Fig. 4-5. In general, in a rising price regime heavy oil price increases will be smaller on a dollar basis than light oil prices, leading to an increasing price differential. The price differential between light and heavy oil also increases as inventories build at refineries. A prolonged period of oversupply of conventional oil and the subsequent bitumen price decline could drive prices to levels below operating cost. It is not surprising that most of the announced new projects specify either a captive upgrading facility or a strategic alliance (de-facto vertical integration) between producers, merchant upgrading plants, and refiners as a response to market risks.

Summary and Implications

Occurrences of natural bitumen and extra-heavy oil are widespread; the volume of oil in place appears to be of at least the same order of magnitude as the volume of original oil in place at known conventional oil accumulations. The Alberta bitumen deposits are the only bitumen projects that are currently produced and upgraded to refinery feedstock or SCO. The commercially successful Orinoco Oil Belt and Alberta oil sands extraction and upgrading technologies will probably be applied to other deposits listed in Tables 4-1 and 4-2. These projects have demonstrated, at least for the Orinoco Oil Belt and the Canadian oil sands, that these resources can be extracted and upgraded at rates that make an important contribution to each country's petroleum supply and at costs that are currently competitive with conventional non-Opec resources.

Estimates of supply costs per barrel for natural bitumen are higher than for many sources of conventional crude oil supply. Moreover, market prices of raw bitumen/diluent blend are discounted by refiners relative to conventional oil prices. As a response to the risk in the volatility of bitumen and heavy oil prices, operators of new projects will either vertically integrate extraction with upgrader/refinery facilities or develop alliances for upgrading/refining their extracted product.

Venezuela has agreements with several national oil companies to evaluate areas of the Orinoco Oil Belt outside of the current project areas for expansion of its extra-heavy oil production base. In Canada the large number of proposed projects that would expand bitumen production has raised some concern about the adequacy of natural gas, diluents, and fresh water supplies. The technologies known as VAPEX (Vapor-Assisted Petroleum Extraction) and THAI (Toe-to-Heel Air Injection) are designed to address the water and gas inadequacy concerns. These are in the field testing stages. In the VAPEX process, a mixture of light hydrocarbon liquids is injected into the reservoir to enhance the reduction in bitumen viscosity induced by steam injection. The enhancement of viscosity reduction brought about by the VAPEX process reduces the steam (water and natural gas) requirements for SAGD projects. The THAI process entails igniting oxygen through a vertical air injection well to lower the viscosity of the bitumen and then recovering the bitumen through a horizontal production well, thus eliminating the need for gas and water for steam injection.

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DEFINITIONS

In this chapter 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 original oil in place: the oil 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 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 hydrocarbons are broken down into smaller, lower-boiling 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° 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 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 higher liquid recovery. Temperatures in the coking vessels are from 480° to 565°C (Speight, 1986). Fluid coking is 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 hydrogenates 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 taken as having a gravity of less than 4°. (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 US 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.

Table 4-1 Natural Bitumen: resources, reserves and production at end-2005

	Deposits	Discovered original oil in place	Prospective additional original oil in place	Total original oil in place	Original reserves	Cumulative production	Reserves
	(number)			(million barrels)			
Angola	3	4 648		4 648	465		465
Congo (Brazzaville)	1	63		63	6		6
Congo (Democratic Rep.)	1	300		300	30		30
Madagascar	1	2 211		2 211	221		221
Nigeria	1	5 744	32 580	38 324	574		574
Total Africa	**7**	**12 966**	**32 580**	**45 546**	**1 296**		**1 296**
Canada	227	1 693 843	703 221	2 397 064	178 580	4 975	173 605
Trinidad & Tobago	14	628		628			
United States of America	201	37 142	16 338	53 479	24	24	
Total North America	**442**	**1 731 613**	**719 559**	**2 451 171**	**178 604**	**4 999**	**173 605**
Venezuela	1						
Total South America	**1**						
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	14	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	**54**	**297 519**	**51 345**	**348 864**	**28 590**	**14**	**28 577**

Table 4-1 Natural Bitumen: resources, reserves and production at end-2005

	Deposits	Discovered original oil in place	Prospective additional original oil in place	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	**586**	**2 468 869**	**803 484**	**3 272 352**	**250 950**	**5 037**	**245 914**

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

Table 4-2 Extra-Heavy Oil: resources, reserves and production at end-2005

	Deposits	of which: deposits offshore	Discovered original oil in place	Prospective additional original oil in place	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**
Canada	4							
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	**62**	**1**	**2 969**	**26**	**2 995**	**241**	**221**	**20**

Table 4-2 Extra-Heavy Oil: resources, reserves and production at end-2005

	Deposits	of which: deposits offshore	Discovered original oil in place	Prospective additional original oil in place	Total original oil in place	Original reserves	Cumulative oil production	Reserves
	(number)	(number)			(million barrels)			
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	2 256 159	189 520	2 445 679	72 556	14 001	58 555
Total South America	**41**	**3**	**2 258 185**	**189 520**	**2 447 705**	**72 759**	**14 077**	**58 682**
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**
Iran (Islamic Rep.)	1	1						
Iraq	1							
Israel	2		2		2	<1		<1
Total Middle East	**4**	**1**	**2**		**2**	**1**		**1**
TOTAL WORLD	**166**	**13**	**2 294 479**	**189 546**	**2 484 025**	**76 220**	**16 385**	**59 834**

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

COUNTRY NOTES

With the exception of Canada, 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, the information has been supplied by the WEC Member Committee.

Albania

Two of Albania's oil fields contain extra-heavy oil accumulations, both 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

Canada has three major oil sands deposits in Alberta, the Athabasca deposit, centered on the city of Fort McMurray, the Cold Lake deposit, north of Lloydminster, and the Peace River deposit, in northwest Alberta.

In the Athabasca area, where 80% of oil sands exist, the mineable portion of the Wabiskaw-McMurray formation (Cretaceous age) is estimated to contain 16 billion cubic metres in-place. A further 253 bcm of in-place bitumen resource is associated with the in-situ projects.

The Canadian Association of Petroleum Producers (CAPP) estimates of established reserves at year-end 2004 were 28 bcm, which is consistent with Alberta Energy and Utilities Board (EUB). Cumulative production is about 0.7 bcm. About 20% of established reserves are mineable and 80% require in-situ recovery. The ultimate potential (with improved economics and technology) of bitumen reserves is 55 bcm, including 8 bcm from surface mineable recovery methods.

Mineable Reserves. The surface-mineable oil sands area is defined by the amount of overburden that has to be removed to reach bitumen ore. Overburden of 75 m or less is considered to be surface-mineable. The EUB has designated over 850 000 acres where the overburden is less than 75 m. All other oil sands deposits that are below 75 m of depth are classified as in-situ. Due to low gravity and high viscosity, these oil sands require enhanced recovery schemes, such as thermal stimulation, in order for the bitumen to become mobile and produceable by pumping.

The quantity of volume in-place that is economic to produce is based on economic strip ratio

Oil Sands Mining Projects

Operator	Project	Capacity 000 m^3/d		Expansion
		Current	Projected	
Syncrude	Syncrude	56	80	2012-15
Suncor	Millennium/Voyageur	41	80	2008-12
Shell	Athabasca	25	96	2010-15
CNRL	Horizon		37	2009-11
True North/UTS	Fort Hills		32	2011-14
Imperial	Kearl Lake		48	2011-15
Synenco	Northern Lights		16	2011-13
Total	Joslyn		32	2011-14
Fort MacKay First Nation			8	

criteria, a minimum bitumen saturation of 7 mass per cent bitumen, and a minimum saturated zone thickness of 3.0 m. The EUB also applies factors that sterilise volumes from being mineable, such as corridors along rivers, surface facilities, tailings ponds, and waste dumps. Mining and extraction operations result in an average loss of 18% of bitumen in-place volume.

Active projects shown in the table above have produced 0.5 bcm at end-2004. The Suncor mining project began operation in 1967, produced less than 8 000 m^3/d for most of the period through the end of the 1980s, and then grew to production of 35 000 m^3/d in 2004. The Syncrude project began operation in 1977 and has produced over 32 000 m^3/d since 1995. The Albian project, led by Shell Canada, began operation in January 2004 and reached its design capacity of 25 000 m^3/d in mid-2005.

In-Situ Reserves. Established reserves are based on economic cutoff limits and recovery factors. Commercial projects, given production history, were assigned thermal recovery factors from 25-40%, depending on the producing formation. A relatively small quantity, 0.2 bcm, has been produced by in-situ projects.

Prior to the extraordinary increase in world crude oil prices since 2002, thermal production of bitumen from oil sands was stagnant, at approximately 48 000 m^3/d. Supply was dominated by cyclic steam projects of Imperial Oil at Cold Lake, and Canadian Natural Resources at Primrose, both projects initiated before the 1986 collapse in world oil prices. The 1996 agreement between Alberta and Ottawa on a generic oil sands regime, and the recovery of world prices which began in early 1999 encouraged the owners of oil sands to begin cautiously advancing in-situ projects. Since 2002, project proposals have grown dramatically.

The following table summarises the largest commercial and proposed projects.

Oil sands production will become an increasing part of Canada's crude oil supply, despite some challenges such as: capital cost escalation, operating costs, labour and infrastructure availability.

Record high oil prices have raised international awareness of Alberta's oil sands resources. Proposed projects for surface mining and in-situ reserves have mushroomed in the heated market for crude supply. Recent projections suggest that oil sands output could increase to between 240 000 m^3/d and 480 000 m^3/d by 2015, depending on the economic conditions.

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.

Columbia

The two extra-heavy oil accumulations are part of a single field in Colombia in the Barinas-

Oil Sands In-Situ Projects

Operator	Project	Capacity 000 m^3/d		Expansion
		Current	Projected	
Imperial	Cold Lake	24	29	
EnCana	Foster Creek	6	80	2006-15
Suncor	Firebag	5	19	2006-12
Petro-Canada	MacKay River	5	11	
Blackrock		2	4	2012
Shell	Cadotte Lake	2	16	2010-15
CNRL	Birch Mountain		43	2012-18
Husky	Sunrise		32	2008-15
Nexen/Opti	Long Lake		23	2007-10
Conoco-Phillips/Total	Surmont		16	2006-12
Others		19	45	2006-10

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.

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 Putamayo 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 14 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 and that they have yet to be evaluated.

Madagascar

Bemolanga is the only natural bitumen deposit in Madagascar. It is large and attempts at producing synthetic oil have thus far failed. A large heavy-oil deposit, Tsimiroro, has similarly 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 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 of that country 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 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 deposit 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 and Tobago

Trinidad and Tobago is rich in heavy oil, but only 300 million barrels of oil in place is extra-heavy. The country has more than 600 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.

Asphalt (Pitch) Lake, at La Brea, contains a semi-solid emulsion of soluble bitumen, mineral matter, and other minor constituents (mainly water). It 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 US natural bitumen is deposited in basins similar to the Western Canada Sedimentary Basin. Such basins possess ideal conditions for occurrences of degraded oil. However, the bitumen deposits of the United States are much smaller, much less numerous, but more scattered. About 98% of the reported extra-heavy oil is found in basins which 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 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. The largest deposits in the lower conterminous 48 states are in Utah. During the 1980s US 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 later 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 the Venezuelan 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, and as of 2006 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 2001, Venezuela passed the new Hydrocarbons Law that increased royalties and required all new projects with foreign oil firm participation to be formed as joint ventures with PDVSA (Petróleos de Venezuela) as majority owner.

Venezuela, through PDVSA, started a reserves certification programme to increase the proved reserves in the Orinoco Oil Belt. The companies that participate in the certification programme will be considered first for upstream development. Participation in the programme has been by foreign national oil companies: Petrobras (Brazil), Petropars (Iran), CNPC (China) and ONGC (India). Petrobras and PDVSA have already established a joint venture to develop the Carabobo 1 block. The project is supposed to produce 200 000 b/d of extra-heavy oil at its peak. An offsite upgrade facility is included. Project investment costs are expected to be $4 billion. Some of the partnerships of currently-operating extra-heavy oil projects are seeking to increase reserves and production at their projects. However, the Venezuelan government has announced its intention to nationalise the Orinoco projects.

In the early 1980s Intevep, the research affiliate of the state oil company PDVSA, developed a method of utilising some of the hitherto untouched potential of Venezuela's extra-heavy oil resource. The extra-heavy oil (7.5-8.5º gravity API) was extracted from the reservoir and emulsified with water (70% natural bitumen, 30% water, <1% surfactants). The resulting product was called Orimulsion®. Initial tests were conducted in Japan, Canada and the United Kingdom, and exports began in 1988. Bitúmenes del Orinoco S.A. (Bitor), a PDVSA subsidiary, operated a 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. In 2006, PDVSA and CNPC (Chinese National Oil Company) initiated the Sinovensa project, to supply two power plants in China and to meet some of PDVSA's commitments to supply Orimulsion®. However, in September 2006 the Minister of Energy and Petroleum announced that the Sinovensa operation would cease production at the end of the year.