Tar Sands as a U.S. Energy Resource

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While only 1.2 trillion barrels of the world’s original reserves of conventional crude oil remain to be produced,1 resources of heavy oil total more than five trillion barrels (Figure 1).2,3 One category of heavy oil, natural bitumen,* is a largely untapped resource. Natural bitumen is commonly called “tar sands” in the U.S. and “oil sands” in Canada.

**Commercial Production**

**Of Natural Bitumen**

Natural bitumen has never been produced commercially in the U.S. in significant quantities, but bitumen production in Canada is a thriving industry. The commercial development of oil sands in Canada’s Alberta Province started in the late 1960’s when Great Canadian Oil Sands (now Suncor Energy) opened a mine north of Fort McMurray and built a plant to upgrade oil sands to synthetic crude oil (“syncrude”). As world oil prices rose at the turn of the century, oil sands development in Alberta began to grow at such a rapid pace that syncrude from oil sands now accounts for more than half of Canada’s total oil production. Longer term, oil sands production from Alberta has the potential to double within the next five years and triple by 2020 if currently proposed recovery projects start up as scheduled.⁴

**Commercial Processes for Recovering Natural Bitumen**

Bitumen deposits located near the surface can be successfully recovered by open-pit mining, and initially, Canadian oil sands were recovered exclusively by this method. However, most bitumen is found in formations buried too deep for surface mining to be practical, and processes have subsequently been developed that economically produce bitumen “in situ,” i.e., bitumen is produced directly from its underground deposit.

Many operators in Canada are now producing oil sands in Alberta using some version of an in situ process developed in the mid-1990’s known as *steam-assisted gravity drainage* or SAGD (pronounced “SAG-dee”). In the U.S., a significant modification of SAGD, *continuous heavy oil*

*Heavy oil is defined as crude oil having an API gravity of less than 20 degrees (equivalent to a specific gravity of 0.934) and a viscosity of less than 10,000 centipoise. Natural bitumen is naturally occurring heavy oil having a viscosity greater than 10,000 centipoise.*

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**Figure 1.** Distribution of remaining worldwide supplies of conventional crude oil versus untapped resources of heavy oil and natural bitumen.
production (CHOP), is being readied for a commercial-scale test. The consortium developing CHOP expects the process to produce considerably more heavy oil or bitumen at significantly less cost than SAGD.

Bench-scale and commercial-scale operations in Canada of various versions of production sustained by in situ combustion — whereby air is injected into a bitumen formation to ignite a portion of the oil in place — are ongoing. Results to date indicate that two processes incorporating in situ air-injection, toe to heel air injection (THAI) and combustion overhead gravity drainage (COGD), may recover bitumen more efficiently than the SAGD process.

Field demonstrations of another in situ process, fracture-assisted steamflood technology (FAST), were conducted in the U.S. in the late 1970’s, but FAST has never been applied on a commercial scale.

The SAGD Process
Steam-assisted gravity drainage utilizes production units consisting of pairs of parallel, horizontal wells drilled into a bitumen formation (Figure 2). The upper well injects steam into the formation throughout its length. The injected steam heats the bitumen and lowers its viscosity which allows it, under the influence of gravity, to flow down around a developing steam chamber that rises above the injection well. The lower well collects, throughout its length, the water that results from the condensation of the injected steam along with a portion of the bitumen within the formation. The water and bitumen collected in the lower well are transported to the surface for processing into syncrude. The large density contrast between the steam within the steam chamber and the water plus dense bitumen outside the steam chamber prevents steam production from the lower well.

SAGD is not entirely without drawbacks. Steam injection, which is integral to the process, requires large amounts of both fresh water and extensive wastewater handling facilities. To produce the steam, abundant supplies of cheap natural gas or some other inexpensive energy source must also be available. Further, steam production generates greenhouse gases; in particular, copious quantities of carbon dioxide. And finally, since SAGD relies on gravity drainage as its sole means of bitumen recovery, the process is only economic in relatively thick and homogeneous reservoirs.5

The CHOP Process
In the CHOP process, horizontal wells are sited in a single plane near the bottom of a heavy oil or bitumen reservoir to continuously inject steam into the reservoir, thereby heating the oil and
reducing its viscosity, as is done in SAGD. But unlike SAGD, the reduced-viscosity oil — along with a portion of the condensing steam that has been injected — is produced from the same well that is injecting the steam (Figure 3). When completed for production, a CHOP process well has a perforated casing string through the horizontal portion of the well, an injection tubing string that runs through the entire length of the casing string, and a production tubing string that terminates below a dual packer where the well becomes horizontal. A CHOP well is expected to successfully inject steam that will rise up into the formation and reduce the viscosity of oil above the well. It is then expected that this low-viscosity oil will migrate back into the same well and reach the surface.

In computer simulations of CHOP and SAGD operating in the same reservoir, CHOP wells produced considerably more oil in considerably less time than SAGD wells when both processes were produced to exhaustion.6

The longer time required to produce SAGD wells is consistent with the difference between SAGD’s and CHOP’s recovery method. Oil mobilized by the steam chamber above the injection well of a SAGD pair of wells must migrate to the production well of the pair of wells that is typically five meters below the injection well. Consequently, the mobilized oil cools significantly as it moves by gravity drainage down into the formation before it is collected. This cooling increases the viscosity of the oil, slowing its production rate. Oil mobilized by CHOP is not expected to cool significantly because it enters the same well that is injecting steam.

CHOP technology was developed and patented by Frank J. Schuh Inc. (FJSI). Palo Petroleum Inc. has entered into an exclusive license agreement with FJSI to implement CHOP and is organizing a field-scale pilot of the process to be conducted in 2011.

**In Situ Combustion Processes**

Air injection to produce oil from a bitumen formation is a relatively new combustion process that combines vertical air-injection wells with horizontal production wells (Figure 4). In the process, air is injected to initiate a combustion front so that a portion of the bitumen in the formation is burned. This combustion generates heat, which reduces the viscosity of the bitumen so that, due to gravity, it flows downward to the horizontal production wells. The combustion front sweeps the bitumen across the length of the horizontal producing well, recovering a projected 60 to 80 percent of the original bitumen-in-place while partially upgrading it to syncrude.

**The THAI Process**

The in situ combustion process known as THAI (Toe to Heel Air Injection) was conceived in
1993 and has since been advanced through laboratory experiments employing bench-scale models, field-scale studies using computer simulation, and an on-going commercial-scale pilot project. Petrobank Energy and Resources Ltd., who owns all the intellectual property rights associated with the THAI technology, has patented the process in Canada, the U.S., and Venezuela.

To demonstrate the economic viability of the process, Petrobank is currently conducting a commercial-scale project in the Alberta oil sands through its affiliate Whitesands Insitu Ltd. The project is sited on a portion of 60 sections (38,500 acres) of oil sands leases owned by PetroBank in the heart of the Alberta oil sands fairway. The project was originally designed around three well pairs producing to a central facility, but has since expanded to host up to six well pairs. Air injection commenced on the first well pair in July 2006. Air injection on the second and third well pairs was initiated in January 2007 and June 2007, respectively.7

PetroBank states that, based on its research and development program to date, the THAI process has the potential to operate successfully in bitumen formations that are lower in pressure, thinner, and deeper than the formations that can be successfully produced using SAGD. In addition, PetroBank anticipates that in reservoirs where both THAI and SAGD can operate successfully, THAI can recover a larger portion of the bitumen-in-place.8

Proved reserves attributable to PetroBank’s THAI production of its oil sands were 3.0 million barrels as of yearend 2010.9

The COGD Process

COGD is a proprietary in situ combustion process developed by Excelsior Energy Ltd. in consultation with advisors from the Schulich School of Engineering at the University of Calgary. COGD employs an array of vertical air-injector ignition wells above a horizontal production well located at the base of the bitumen pay zone. A multi-step, pre-ignition heating cycle using steam prepares the cold bitumen for ignition and develops enhanced bitumen mobility within the reservoir. The pre-ignition heating uses cyclic steam and steam flood techniques to predispose the viscous oil reservoir to form a combustion chamber similar in geometry to the steam chamber in the SAGD process.

Upon completion of the initial heating cycle, ignition of a portion of the bitumen is achieved by injecting air into the formation. With ignition, a combustion chamber develops above and along the length of the horizontal well with combustion gases segregated in the upper part of the reservoir and hot bitumen flowing by gravity into the horizontal production well (Figure 4). Combustion gases, that are collected in vertical vent wells positioned on the flank of the production pattern, are returned to a central facility for treating.10
In June 2009, Excelsior submitted an application to develop an experimental pilot project on its Hangingstone property, which is located in Alberta two miles south of Fort McMurray. Using the COGD technology depicted in Figure 5, the project is expected to produce partially upgraded bitumen at a rate as high as 1,000 barrels per day.\textsuperscript{11}

The FAST Process
In the 1970’s, Conoco Inc. (now ConocoPhillips Company) developed a bitumen recovery technology specifically to recover oil from the San Miguel tar sands in Maverick County, Texas. Recognizing that a heated communication path between steam-injector wells and corresponding producer wells would be extremely difficult to establish in the highly viscous tar, Conoco patented the FAST process (Fracture-Assisted Steam Technology), which combines horizontal fracturing with conventional steam-injection methods, thereby introducing what was at the time a new, high-rate steamflood process.

In applying FAST, as shown on Figure 6, production wells are fractured horizontally with cold water and immediately stimulated with high-pressure steam to provide a heated target. Horizontal fractures are then propagated from injection wells to the production wells and steam is injected at high rates and pressures to hold the fractures open, heat the formation, and mobilize the in situ bitumen. Injection rates are then reduced to promote efficient displacement of the bitumen that has been liquefied to the producing wells.\textsuperscript{12}

FAST has some of the same drawbacks as SAGD, in that large quantities of steam are used in the process, requiring extensive supplies of fresh water and wastewater handling facili-
ties, as well as abundant supplies of cheap energy to produce the steam. Theoretically, the application of FAST is not limited to relatively thick and homogeneous reservoirs as is the case for SAGD, but the process does rely on horizontal fracturing of the bitumen formation to induce channels through which the bitumen can flow, and the positioning of horizontal fractures within a formation is more difficult to control than the positioning of the horizontal wells used in SAGD.

**In Situ Production Projects in U.S. Tar Sands**

Based on U.S. Department of Energy data, the largest known bitumen accumulations in the U.S. with characteristics suitable for in situ recovery are the San Miguel tar sands in Texas and the Tar Sand Triangle formation in Utah.\(^{13}\)

Of the two deposits, the San Miguel is in the less environmentally-sensitive area and is therefore more readily accessible to commercial recovery projects. The deposit is located in the Maverick Basin of southwest Texas, a remote, under-populated area of little scenic interest where extensive facilities for producing natural gas and conventional crude oil have long been in place. Consequently, it is this deposit that in the past, as well as in the recent present, has attracted the interest of both major and independent oil producers.

The San Miguel tar sands is essentially a virgin deposit which was discovered in the 1960’s. While numerous schemes have been tested by various companies to recover its bitumen, the most successful project in the San Miguel reported to date is the application of Conoco’s FAST process. In two full-scale pilots of FAST conducted several decades ago, Conoco demonstrated the feasibility of recovering San Miguel bitumen in commercial quantities.

**Conoco’s Production in the San Miguel**

In December 1977, Conoco initiated a test of FAST in the San Miguel-4 Sand. The recovery process was applied to a single inverted 5-spot production pattern, encompassing 5 acres on Conoco leases within the Street Ranch in Maverick County (Figure 7). During a 31-month period, the pilot produced 169,000 barrels of −2° API heavy oil at an average production rate of 185 barrels per day (B/d). Post-pilot cores indicated residual oil saturations as low as 8 percent and an average recovery efficiency within the pilot area of 50 percent.\(^{14}\)

In August 1981, Conoco initiated a second commercial-scale pilot employing FAST on a single inverted 7-spot production pattern across 7.5 acres in the San Miguel-4 on Conoco leases within the Saner Ranch, also in Maverick County (Figure 8). Over a 22-month period, the second test produced 133,000 barrels of 2° API gravity oil at rates exceeding 300 B/d, representing a recovery of about 45 percent of original oil-in-place with a 31 percent improvement in steamflood efficiency over the Street Ranch test.\(^{15}\)
The Syntaro Project in the San Miguel

In June 1982, ENPEX Corporation of Del Mar, Calif., executed a filing with the U.S. Synthetic Fuels Corporation (SFC) to undertake the Syntaro Project. Syntaro was to be an integrated system for the production of 5,700 B/d of San Miguel bitumen using the FAST process on leases provided by Pickens Energy Corporation. The bitumen would be upgraded to 7,000 B/d of finished petroleum products in a refinery at Carrizo Springs, Tex., operated by Tesoro Petroleum Company. In addition to ENPEX, Pickens Energy, and Tesoro, project participants included C-E Lummus Company, Getty Oil (now Getty Petroleum Marketing Inc.), M.H. Whittier Corporation, and Superior Oil Company Inc.\textsuperscript{16}

Project planning for Syntaro proceeded to an advanced state, but the project was never launched because SFC was abolished by Congress in 1985 in response to globally declining prices for crude oil.

TXCO/Pearl Operations in the San Miguel

In 2007, TXCO Resources Inc., headquartered in San Antonio, and Black Pearl Resources Inc. (formerly Pearl Exploration and Production Ltd.), headquartered in Calgary, evaluated various production technologies for producing the San Miguel tar sands. In a joint venture, TXCO and Black Pearl operated a commercial-scale pilot on TXCO leases in Maverick County.

A two-well, cyclical steam pilot (Figure 9) was subjected to multiple production phases at a formation temperature of approximately 270\degree F. When engineering studies indicated that oil mobility would be optimized at temperatures in excess of 400\degree F, the TXCO/Pearl team began an expansion of the project to include three additional wells.

TXCO and Black Pearl also drilled two 2,000-foot horizontal wells spaced 200 ft apart on TXCO leases, together with five vertical wells spaced 25 to 100 ft from the horizontal wells.

Additional drilling was also scheduled for 2007. The first of 16 wells for a second pilot to be located several miles updip from the first pilot were to be drilled for the purpose of evaluating alternative recovery methods, including SAGD and FAST.\textsuperscript{17} However, these latter activities were suspended in 2008 due to low crude oil prices.
References