Alberta's crude oil reserves largest on Earth

Crude oil reserves in the province of Alberta's bitumen sands have widely been considered third, and sometimes second, largest on earth. However, recently developed in situ thermal recovery techniques indicate that Alberta's recoverable crude oil reserves are the largest on earth. And results from recent commercial pilots indicate very large new reserves in Alberta's bitumen carbonates. Author Mike Priaro explains the nature and accessibility of Alberta's reserves.

Mike Priaro

Over 200 years ago the first Europeans noted bitumen seeps along the banks of the Athabasca River in northern Alberta. The local Aboriginal people had long used bitumen to waterproof canoes. Bitumen is crude oil with a specific gravity greater than fresh water and is a semi-solid fluid at room temperature that does not flow at commercial rates to a wellbore under normal reservoir conditions.

Shallow, bitumen-saturated unconsolidated sands or hard-rock carbonate (limestone and dolomite) reservoirs are now known to underlie 54,132 square miles of land in northern Alberta.

Depending on depth beneath surface, bitumen is extracted either by surface strip-mining or by various in situ techniques using wells.

In the surface mineable area, estimated at 1,854 square miles, bitumen reservoirs lie less than 250 feet below surface and bitumen is economically extracted by strip-mining with recovery exceeding 90 percent. The eight surface strip-mining projects currently operating and under active development in Alberta are: CNRL Horizon; Suncor Fort Hills; Imperial/ExxonMobil Kearl; Shell Muskeg River; Shell Jackpine; Suncor; Syncrude; and Total Joslyn North. The just-commissioned Kearl project and the in-development Fort Hills project are the first surface strip mines without upgraders. Kearl is the first to use a solvent process to separate bitumen from sand.

At greater depths bitumen extraction is done in situ using enhanced recovery techniques of cyclic steam stimulation (CSS) or steam-assisted gravity drainage (SAGD). SAGD is currently the technique of choice for almost every in situ project under development, in-approval, or planned The Alberta Energy Resources Conservation Board (ERCB) forecasted1 bitumen production doubling to 3.8 million bbl/d from 2012 to 2022 with an ever-increasing percentage of in situ production.

Recovery factors measure how efficiently original-oil-in-place (OOIP) is recovered by production technology. Improvements in technology such as co-injection with air and chemical additives, use of solvents, inclined and horizontal drilling, and fracturing of the formation have been highly successful, improving CSS recovery factors to 40 percent from previous rates ranging from 25-30 percent.2,3 Recovery factors for SAGD typically exceeding 50 percent4 and sometimes reaching 70-80 percent[5] are well-documented but are not yet adequately recognized by the ERCB1.

In 2013, the ERCB estimated 1,270 billion bbl of OOIP in Alberta's bitumen sands deposits, 406 billion bbl of OOIP in Grosmont bitumen carbonates and another 168 billion bbl OOIP in other bitumen carbonate formations such as the Nisku to give total bitumen OOIP in Alberta of 1,844 billion bbl1. The ERCB recognized an average recovery factor of only 25 percent in only the bitumen sands to estimate Alberta reserves of 315 billion bbl1.

Pictured: Alberta's Bitumen Deposits and Areas. Source; ERCB ST98-2013.

The ERCB estimated[1] that seven percent of the OOIP in the bitumen sands is ultimately accessible by surface strip mining and 93 percent by in situ methods. Applying a recovery factor of 90 percent to strip mine-accessible bitumen sands and a recovery factor of 45 percent to in situ-accessible bitumen sands to total OOIP of 1,270 billion bbl indicates 575 billion bbl of technically recoverable reserves in Alberta's bitumen sands, after deducting six percent shrinkage.

Bitumen-saturated carbonate formations lie just below Alberta's bitumen sands. In the 1980s, pilot projects in the Grosmont carbonate using CSS in vertical wells produced promising amounts of bitumen. However, those trials ended in 1986 when the price of oil dropped. Since then, application of recently-developed technologies such as horizontal drilling, SAGD and 3-D seismic have dramatically improved recovery factors in both Alberta's bitumen sands and carbonates. OSUM Oil Sands Corp. and Laricina Energy, both applying the new technologies in the bitumen carbonates, recently completed successful commercial-scale pilots. Both are now proceeding to step-by-step full-scale development of their bitumen carbonate leases. Grosmont carbonate core tests show recovery factors of 30 to 60 percent[6] under SAGD which compares favourably to bitumen sands core tests. The ERCB estimated an additional 424 billion bbl of OOIP in Alberta's tight oil shales and siltstones1. These contain conventional light crudes in a variety of different formations but little development has occurred to-date and no technically-recoverable reserves are yet booked.

Applying 45 percent recovery to Alberta's bitumen carbonates OOIP totaling 574 billion bbl indicates crude oil reserves in the bitumen carbonates of 243 billion bbl after deducting six percent shrinkage. Applying 10 percent recovery to OOIP of 424 billion bbl in Alberta's tight oil shales and siltstones indicates 40 billion bbl of crude oil reserves. Adding these reserves to the previously calculated 575 billion bbl of crude oil reserves for strip mining and in situ bitumen sands indicates total technically-recoverable reserves of oil in Alberta of 858 billion bbls as shown below:

Alberta's technically-recoverable oil reserves

Alberta bitumen and oil deposits	OOIP (billion bbl)	Recovery factor (percent)	Technically-recoverable oil reserves (billion bbl)	Oil reserves after 6 percent shrinkage (billion bbl)
Bitumen sands strip mining	89	90	80	75
Bitumen sands in situ	1,181	45	531	500
Bitumen carbonates in situ	574	45	258	243
Tight oil shales and siltstones	424	10	42	40
Totals:	2,268	—	912	858

A 2009 US Geological Survey study[7] estimated mean OOIP of 1,300 billion bbl in Venezuela's Orinoco oil belt and applied a 45 percent recovery factor for Orinoco heavy oil and shrinkage of six percent to estimate technically-recoverable reserves of 550 billion bbl. The US EIA currently estimates a much lower figure of 298 billion bbl for Venezuela's proved reserves.[8]

OPEC listed Saudi proved oil reserves of 260 billion bbl in 2012[9]. With total production of 125 billion bbl since the discovery of oil in Saudi Arabia and original-oil-in-place of 716 billion bbl, the Saudis claim a recovery factor of about 54 percent. The Saudis have not made any significant revisions to oil reserves since 1988 — a cause for concern. Diplomatic cables leaked by Wikileaks in 2011 warned the US that oil reserves in Saudi Arabia might in fact be 40 percent lower than claimed by OPEC. Others have questioned Saudi Arabia's remaining oil reserves. For example, in a 2012 paper[10], Dr. Mamdouh G. Salameh estimated Saudi proved reserves at the end of 2011 at only 60-85 billion bbl based on original recoverable reserves of 185-210 billion bbl.

As summarized below, Alberta's remaining crude oil reserves are the largest on earth, by far, using a comparatively conservative average recovery factor:

Largest crude oil reserves on earth

Jurisdiction	Original-oil-in place (billion bbl)	Remaining crude oil reserves (billion bbl)	Average recovery after shrinkage (percent)
Alberta	2,268	846	37
Venezuela	1,300	550	42
Saudi Arabia	716	260	54

More rapid increases in production of Alberta's bitumen are, or will be, constrained by factors including:

- lack of take-away capacity in the form of pipelines, rail terminals, safe trackage, and tank cars;
- lack of access to tide water and safe, environmentally-acceptable marine terminals;
- lengthy environmental approvals processes for pipelines;
- environmentalists and First Nations (Native Aboriginals) opposition to increasing air, water and greenhouse gas emissions and land disturbances of extraction operations;
- environmental concerns about risks of dilbit spills in inland and coastal waters from pipelines and marine tankers;
- shortages of skilled labour to construct and operate new projects;
- cost escalations due to labour, engineering and process equipment manufacturing shortages;
- physical difficulties and costs transporting massive upgrader and other process modules to northern Alberta;
- costs and availability of diluents;
- insufficient bitumen crude upgrading and refining capacity;
- lack of Canadian domestic capital and lack of diversity in markets resulting in discounted prices;
- recent competition from U.S. light, tight oil production; and
- growing resource nationalism in Canada regarding export of raw bitumen, low royalties levied on raw bitumen, and royalty reductions granted for costs of diluent in dilbit.

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Footnotes

1. ERCB Report ST98-2013.
2. Source; Imperial Oil, http://www.imperialoil.ca/Canada-English/files/News/N_S_Speech060608.pdf
3. Source: Current Overview of Cyclic Steam Injection Process, Alvarez, Johannes and Han, Sungyun, Texas A&M University, Department of Petroleum Engineering. Journal of Petroleum Science Research, Volume 2 Issue 3, July 2013.
4. See: https://www.cnrl.com/operations/north-america/north-american-crude-oil-and-ngls/thermal-insitu-oilsands/
5. Source: Cenovus, Telephone Lake Project, Volume 1 — Project Description, December 2011, page 4-25, http://www.cenovus.com/operations/docs/telephone-lake/Volumepercent201/V1_Sec4.pdf
6. Source; Macquarrie Equity Research, February, 2010, pg. 26. See: http://www.sunshineoilsands.com/uploads/files/macquarie_report_01_10.pdf
7. Source: US Geological Survey study, An Estimate of Recoverable Heavy Oil Resources of the Orinoco Oil Belt, Venezuela; See http://pubs.usgs.gov/fs/2009/3028/pdf/FS09-3028.pdf
8. Source: US Energy Information Administration. See: http://www.eia.gov/cfapps/ipdbproject/IEDIndex3.cfm?tid=5&pid=57&aid=6
9. OPEC Annual Statistical Bulletins. See http://www.opec.org/opec_web/en/publications/202.htm
11. Source: The Shifting Sands under Saudi Oil Prowess, Dr. Mamdouh G. Salameh. See; http://www.usaee.org/usaee2012/submissions/OnlineProceedings/Conference.pdf
12. Note: Cumulative bitumen production of 12 billion bbl to the end of 2013 was deducted.