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Thermal Techniques for the Recovery of Heavy Oil and Bitumen

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Abstract

Over 90% of the world's heavy oil and bitumen (oil sands) are deposited in Canada and Venezuela. Alberta holds the world's largest reserves of bitumen and the reserves are of the same order of magnitude as reserves of conventional oil in Saudi Arabia. Up to 80% of estimated reserves could be recovered by in-situ thermal operation. As the resources available for conventional crude in Canada continue to decline, further development of heavy oil and oil sands in-situ recovery technologies is critical to meeting Canada's present and future energy requirements.

Sophisticated technologies have been required to economically develop Canada's complex and varying oil fields. Various existing in-situ technologies such as hot water injection, steam flooding, cyclic steaming and combustion processes have been successfully applied in Venezuela and California. Most recently, advances made in directional drilling and measuring while drilling (MWD) technologies have facilitated development of new in-situ production technologies such as the steam assisted gravity drainage (SAGD), expanding solvent-SAGD (ES-SAGD) and solvent vapor extraction (VAPEX) that have significantly improved well-bore reservoir contact, sweep efficiencies, produced oil rates and reduced production costs.

This paper provides an overview of existing and new thermal in-situ technologies and current projects. Potential of new technologies are assessed and compared to various existing in-situ thermal processes. Critical issues affecting production performance are discussed.

Canadian Bitumen Resource

The Canadian bitumen deposits are almost entirely located in the province of Alberta. Three major deposits are defined as Athabasca, Cold Lake and Peace River. Figure 1 shows the major oil sands deposits of Canada. The average depths of the deposits are 300, 400 and 500 m, respectively. Table 1 is a summary comparison of the initial bitumen volume-in-place for the three deposits[1]. The Alberta Energy and Utilities Board (AEUB)[1] estimate the total initial volume-in-place of bitumen to be 259.1 billion m^3. This estimate could ultimately reach 400 billion m^3 by the time all exploratory developments are completed. This shows that Canada has the world's largest bitumen deposits. Out of the total volume, 24 billion m^3 are available for surface mining techniques. Athabasca deposit is the only deposit with surface mineable reserves. About 376 billion m^3 lie too deep to be surface-mined and are exploitable by in-situ technologies. However, approximately 12%, or ~ 50 billion m^3 of the total volume-in-place is estimated to be ultimately recovered by existing technologies. That percentage is expected to increase as more advances in recovery technologies are made. Figure 2 shows reservoir characteristics for the three deposits[2]. The Athabasca deposit has Alberta's largest reserve of bitumen that lies in the McMurray formation. The deposit has three layers of oil sands (McMurray, Clearwater and Grad Rapids) separated by shale layers. The deposit is covered by a sand stone overburden and has an area of ~41,000 square kilometers. The Cold Lake deposit is made up of four separate reservoirs that lie in McMurray, Clearwater, Lower Grand Rapids and Upper Grand Rapids and covers an area of approximately 21,000 square kilometers. The oil deposits lie under a thick overburden that prohibits surface mining and can only be produced by in-situ techniques. Most of the Peace River deposit lies under the deepest overburden as compared to Athabasca and Cold Lake deposits. The rich Peace River deposit is contained in the Bluesky and Gething formations. Figure 3 compares Canada's proven oil reserves with those of the world deposits[3].

Table 2 shows existing and planned in-situ heavy oil and oil sands projects[4]. Table 3 and Figure 4 display the forecast of Canadian crude oil production to the year 2015[5]. This paper focuses on the in-situ production technologies for heavy oil and oil sands (bitumen).

Canadian Oil Sands and Bitumen Properties

The oil sands of Alberta are generally unconsolidated. Quarts constitute 90% of the solid matrix and the remaining is silt and clay. The bitumen saturation of the reservoirs is a function of the porosity and permeability. A typical composition of rich oil sands contains approximately 83% sand, 14% bitumen and 3% water by weight. The average composition of Alberta bitumen is 84% Carbon, 10% Hydrogen, 0.9 Oxygen, 0.4 Nitrogen and 4.7% Sulphur[6]. The density and viscosity of bitumen varies by location and the API gravity ranges between 8 and 12. Table 4 shows the API classifications[7]. Figure 5 shows a typical viscosity versus temperature curve for Athabasca bitumen. Until recently, the low API and high viscosity caused great difficulty in extraction of the bitumen. Perhaps the fortunate characteristic of the oil sands is that the bitumen is not in direct contact with the sand grains and the grains are dominantly water wet. Figure 6 shows that most of the water forms pendular rings around the sand grains[8]. Produced bitumen must be upgraded through the addition of hydrogen, or rejection of carbon, to be an acceptable feedstock for the refineries. The bitumen is blended with diluent to meet pipeline specification for density and viscosity during transportation to refineries.

In-Situ Technologies

Steam Flooding

Steam flooding as a method of in-situ recovery has been used for years to recover heavy oil mostly from California and Venezuela heavy oil fields and in some Canadian fields (Pikes peaks, Tangleflags[9]). It has met limited success in Canadian oil sands areas because of the relatively low initial mobility of the bitumen.

This recovery process involves the injection of steam from a vertical injector to drive oil towards a vertical producer over a distance like in the conventional water flooding operation. It is a pattern drive operation. Figure 7, illustrates the steam drive process. The process sweeps more area than the cyclic steam stimulation (CSS) and it also recover more oil than CSS, usually up to 50% of OOIP (original-oil-in-place). However, thermal efficiency of the process is lower than the CSS process. Recent improvements have used a combination of horizontal and vertical wells for steam flooding in heavy oil reservoirs but a lot of technical challenges remained, such as, minimization of the impact of bottom water and gas cap.

Cyclic Steam Stimulation (CSS)

In cyclic steam stimulation (CSS) recovery process, high temperatures steam is injected at high pressure into oil sands reservoirs. The pressure dilates or fractures the formation and the heat reduces the viscosity of the bitumen. The heated bitumen is then pumped into the surface, from the same injection well, after some period of soaking to allow injected steam to spread and heat more oil. The process is repeated in cycles. Figure 8 illustrates the CSS process.

This process was accidentally discovered in 1959 in the field in Western Venezuela[9]. The process can use either horizontal or vertical wells depending on the thickness of the oil-bearing formation.

The main advantage of this process is quick oil production but recovery as percentage of the OOIP is much lower (15-20% IOIP) than other thermal recovery processes, especially in conventional CSS that uses only vertical wells for heavy oil such as those in Venezuela and California. CSS is not suited for all reservoirs particularly those with low reservoir drive such as solution gas drive.

The most widely known cyclic steaming operation in Canada today is the Imperial Oil's Cold Lake cyclic steam operation, which started with pilot field projects in 1964[10] and Husky Oil's cyclic steaming operation at at Pikes Peak[11]. Shell Canada Inc. also operates a variation of the cyclic thermal in-situ recovery process called soak-radials at its Peace River lease[12].

Recent improvement in CSS at Shell Canada's Peace River operations uses J-wells configuration. This entails drilling lateral wells from the base to the top of the reservoir at angles above 90 degrees. Initial performance of this well configuration shows encouraging results with high oil-steam ratio than conventional CSS wells and more effective steam distribution[12].

In some fields, CSS might be followed with another thermal recovery operation in order to be able to recover the remaining oil-in-place.

In-Situ Combustion

In-situ combustion involves injection of air and the creation of a combustion (oxidation) front or zone within a heavy oil or bitumen reservoir that pushes the fluids (including gases from the injected air e.g. nitrogen and by-products of combustion) ahead of the zone. In the original concept of in-situ combustion, the well configuration is similar to that of the conventional water flooding which uses two vertical wells with combustion zone moving from the injector to the producer over time. The conventional in-situ combustion is plagued with a lot of technical issues in the field such as high temperature of combustion and gases gravity segregation. Recent advances have being made to over come some of these issues.

Petrobank Energy and Resources Limited of Canada is planning to use a variant of in-situ combustion, called THAI (Toe-to-Heel-Air-Injection)[13-14]. The company plans to run field pilot of THAI at its Whitesands lease. The THAI process uses a horizontal well as a producer and a vertical well as an air injector. Figure 9 illustrates the concept of the THAI process.

When air is injected through a vertical injector, combustion "front" is created in which oil in the reservoir is burnt to generate heat. The heat reduces oil viscosity, allowing the oil to flow by gravity to the lower horizontal producer. The combustion front sweeps from toe to heel recovering more oil than other known air injection processes (estimated at 80%) the. A recent paper[15] gives a full description of the THAI technology background, reservoir and sites features, processing plant design, pilot objectives and the expected economics.

Another variant of the THAI process, called CAPRI (catalytic THAI)[16]. This is similar to THAI except that a down-hole catalyst that can upgrade the heavy oil/bitumen is placed around the producer during completion. This process is planned to be tested after the basic THAI process has been demonstrated in the field pilot.

Steam Assisted Gravity Drainage (SAGD)

SAGD and its various variants are becoming dominant technologies employed in the recovery of heavy oil and oil sands. Canada has played a leading role in the development and application of the SAGD process. A number of oil companies are currently involved in SAGD pilots and commercial application of the technology in Canada.

In the SAGD process, two superposed horizontal wells 5 m apart are placed near the bottom of the formation (Figure 10). The top horizontal well is used to inject steam, which rises under bouncy forces and forms a steam chamber above the well. The bottom well is used to collect the produced liquids (formation water, condensate and oil). Steam is fed continuously into a growing steam chamber. The rising steam condenses on the boundary of the chamber heating and entraining the oil to the production well. The process is a counter-current gravity drainage process and therefore depends primarily upon the density difference between the rising steam and the liquid phase as well as on the effective vertical permeability of the reservoir. Butler[17] developed an empirical correlation for determining the maximum oil rate from the SAGD process. This correlation is given by the following equation:

$$q = 2\sqrt{\frac{1.5\phi\Delta S_o k g \alpha H}{m v_s}}$$

The Underground Test Facility (UTF-Phase A)[18] at Fort McMurray, Alberta, Canada was constructed in 1985 by the Alberta Oil Sands Technology and Research Authority (AOSTRA) to test the concept of SAGD. Three pairs of 60-m long horizontal wells were drilled from a tunnel at angles of 15 to 20 degrees to the horizontal. In each horizontal well pair, the lower well (producer) was placed 1-2 m above the limestone with the upper well (injector), located 5 m above the producer (See Figure 11). The process concept was subsequently tested from December 1987 to mid 1990. The UTF-Phase A project was the first successful field demonstration of the SAGD process. Following the UTF Phase A, Phases B, D and E were initiated in the early nineties utilizing 500-m long horizontal wells to test surface accessed horizontal wells and the commercial viability of the SAGD process. Figure 12 illustrates an example of field performance from the UTF Phase B[19].

Following the success of the UTF project (now called the Dover project) at Fort McMurray, Alberta, a number of field pilots are in progress in other heavy oil and bitumen reservoirs in western Canada (Alberta and Saskatchewan). Table 2 lists current in-situ thermal projects as reported in reference 4. Most of these projects use surface accessed horizontal wells for SAGD and extend SAGD applications to problem reservoirs. These reservoirs often have lower permeabilities, are deeper, have bottom water transition zones, with initial gas-saturated “live” oil and top water / gas caps. In Alberta, the success of these pilots has led to a number of commercial SAGD projects that are currently underway. Current developments of the SAGD process at the ARC are aimed at improving oil rates, improving OSR, reducing energy and minimizing water requirements.

Recent Advances in Directional Drilling and Measurement While Drilling

Horizontal wells have been drilled in various types of reservoirs including light, heavy and extra-heavy oil reservoirs. The use of horizontal drilling technology in conjunction with the steam-assisted gravity drainage (SAGD) concept offers a cost-effective alternative to conventional thermal methods such as steam drive and cyclic steam stimulation (CSS) with vertical wells.

An important factor in planning the SAGD well pair is the distance between the injection and production wells in the horizontal section. The distance between the injector and producer varies from 2-10 m depending on reservoir characteristics such as vertical permeability, thermal conductivity and viscosity. If the wells are close together, a faster start up time can be achieved and results in higher economic gains. If the wells are put too far apart, then heating the layer between the injector and producer becomes more difficult in some cases and can result in a very long start up time.

The lateral shift must also be considered in drilling paired horizontal wells. Since the injector well is usually drilled above the lower producer well, one must have an understanding of how much drift from side to side laterally the upper well can be from the lower well without risking a significant reduction in production or greatly increased start-up time. The stringent requirements for SAGD well pairs drilled from the surface cannot readily be met by conventional wellbore surveying tools and methods. The position uncertainty of horizontal wells drilled and surveyed using available steering tools, MWD or gyros exceeds the SAGD tolerances and can exceed the separation requirements themselves.

Recently, the use of Magnetic Guidance Tools (MGT) has facilitated drilling of two wells at close proximity, which do not normally exist in conventional horizontal drilling. In addition, this has resulted in better determination of surface location of the injector relative to the producer and reduced possibilities of collision as the two wells converge in the build section. Also, the use of rotary and rotary-steerable downhole mud motor and geo-steering tools for directional steering of wells have resulted in better and more accurate well placement within the reservoir target zone[20].

Expanding Solvent-SAGD (ES-SAGD) Technology

Progress has been made in the development of combined steam-solvent injection processes, which is a novel approach for combining the benefits of steam and solvents in the recovery of heavy oil and bitumen. A newly patented[21] Expanding Solvent-SAGD “ES-SAGD” process has been successfully field-tested and has resulted in improved oil rates and OSR, and lower energy and water requirements as compared to conventional SAGD.

Figure 13 illustrates the ES-SAGD concept. In this concept, a hydrocarbon additive at low concentration is co-injected with steam in a gravity-dominated process, similar to the SAGD process. The hydrocarbon additive is selected in such a way that it would evaporate and condense at the same conditions as the water phase[22]. By selecting the hydrocarbon solvent in this manner, the solvent would condense, with condensed steam, at the boundary of the steam chamber. In the ES-SAGD process, the solvent is injected with steam in a vapor phase. Condensed solvent around the interface of the steam chamber dilutes the oil and in conjunction with heat, reduces its viscosity.

As illustrated in Figures 14 and 15[22], as the carbon number of the solvent increased, the vaporization temperature increased. Hexane has the closest vaporization temperature to the injected steam temperature (215 °C at the operating pressure of 2.1 MPa) and resulted in a higher oil drainage rate. On the other hand, C_8 has a vaporization temperature that exceeded the injected steam temperature and a decline in oil drainage rate is noticed as compared to Hexane.

EnCana Corporation of Canada has piloted the SAGD-solvent process at its Senlac Thermal project in 2002 for heavy oil and has tested and still operating this process at its Christina Lake SAGD project for bitumen[10,23]. Figures 16A and B illustrate EnCana's field performance from SAGD-solvent as compared to SAGD[23].

At the Christian Lake project, conventional SAGD was operated for about 5 months followed by introduction of the SAGD-solvent for about half a year till February 2005[23]. A significant improvement of oil production rate and SOR were observed within this short time interval. A major improvement in produced oil quality was also observed.

Liquid Addition to Steam for Enhancing Recovery (LASER)

LASER[24] involves the injection of a liquid hydrocarbon (C5+) as steam additive in CSS mode of operations[24-25]. It was first tested in the laboratory with Cold Lake bitumen[24] and it is presently being field-tested[25] by Imperial Oil Resources at its Cold lake bitumen lease.

The initial laboratory tests show promising results over conventional CSS and as a result of this, a field pilot was designed based on expectations of improved oil-steam-ratio (OSR) and better recovery of injected diluent. These two important factors are the major economic determinants and evaluation criteria of any steam-solvent based recovery process of in-situ bitumen recovery. Based on these promising results, a design of LASER demonstration pilot scope and facilities were presented[24].

Eventually, a field pilot was initiated and the results of the pilot tests are very encouraging. The pilot involves co-injection of steam and 6% by volume fraction of C5+ condensate (diluent) into 8 wells during CSS cycle 7. The performance in terms of recovered diluent (80%) exceeded the 66% expected based on laboratory testing. The field pilot OSR was also consistent with 33% expected improved performance over CSS in the laboratory testing. Figures 17A and B illustrate field performance improvement from LASER as compared to CSS[25]. Details of the technical and economics issues involved in the laboratory and the field tests can be found in references 24 and 25.

Vapor Extraction (VAPEX)

VAPEX is a non-thermal process that is similar to the SAGD except that a vaporized hydrocarbon solvent or a mixture of hydrocarbon solvents is injected instead of steam. The solvent diffuses into the oil and reduces its viscosity. This allows the oil to flow into the lower well bore (the producer). The objective is to keep the solvent as much as possible in the vapor phase close to its vapor pressure. The added advantage of VAPEX is that the solvent might cause partial upgrade of the oil through de-asphalting. A main disadvantage of the VAPEX process is that the rate of oil production is very low as compared to SAGD. Figure 18 illustrates the VAPEX process concept.

Additional laboratory and field-scale testing are still ongoing to improve this technology. Researchers at the Alberta Research Council, the University of Alberta and the University of Calgary are conducting more laboratory experiments testing of this recovery process. Field-scale testing includes the Dover VAPEX Project (DOVAP) and the Plover lake Project of Nexen Inc. of Canada.

The DOVAP is a consortium[26,27] made up of several bitumen and heavy oil producers with additional contributions from the Alberta provisional government and the federal government of Canada. The project is located at the Dover Underground Test Facility. The project employs two horizontal well pairs and monitoring wells. One pair will use a cold start up process while the other pair will employ a hot start up process with steam injection. A major objective of this project is to evaluate overall effectiveness of the VAPEX process.

Concluding Remarks

As the resources available for conventional oil in Canada and worldwide continue to decline, further development of heavy oil and oil sands recovery technologies is critical to meeting present and future energy requirements.

Sophisticated technologies have been required to economically develop complex and varying oil fields. Even though some existing in-situ technologies such as steam drive, cyclic steaming and combustion processes have been successfully applied in Venezuela and California, there have limited successes in Canadian reservoirs due to the complex nature of those reservoirs. New processes such as SAGD and ES-SAGD are novel technologies that integrate advances made in directional drilling and measuring while drilling (MWD) technologies with steam injection technology. These technologies hold great promise for in-situ development of heavy oil, extra-heavy oil and bitumen reservoirs and significantly improve well-bore reservoir contact, sweep efficiencies, produced oil rates and production costs.

At present, there is not enough field data to assess the potential application of the vapor extraction (VAPEX) and THAI processes.

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Nomenclature

g	=	acceleration due to gravity, m/s^2
ϕ	=	fractional porosity
v_s	=	kinematic viscosity of oil, m^2/s
q	=	oil drainage rate per unit length of well, m^2/s
S_o	=	oil saturation
m	=	oil viscosity parameter
k	=	permeability, m^2
H	=	reservoir height, m
α	=	reservoir thermal diffusivity, m^2/s

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Table 1: Summary Comparison of Athabasca, Cold Lake and Peace River Bitumen

Deposit	**Initial Volume In Place (10^9 m^3)**
Athabasca	206.7
Cold Lake	31.9
Peace River	20.5
Total	**259.1**

Table 2: Inventory of major thermal in-situ projects

Project	**Owner and Operator**	**Status**	**Production (bpd)**
Foster Creek Thermal Project - Phase 1	Encana Corporation	Operating	22,000
Foster Creek Thermal Project Expansion - Phase 2	Encana Corporation	Construction starts 2005	13,000 [a]
Foster Creek Thermal Project - Phase 3	Encana Corporation	Construction starts 2005	40,000 [e]
Foster Creek Thermal Project - Phase 4	Encana Corporation	Construction starts 2007	30,000 [e]
Christina Lake - Phase 1	Encana Corporation	Producing	10,000
Christina Lake - Phase 2	Encana Corporation	Construction TBA	30,000 [e]
Christina Lake - Phase 3	Encana Corporation	Construction starts 2007	30,000 [e]
Great Divide	Connacher Oil & Gas Ltd.	Production in 2006	10,000 [e]
Kirby	Canadian Natural Resources Limited (CNRL)	Application Submitted	30,000 [e]
Sunrise Thermal Project at Kearl Lake - Phase 1	Husky Energy Ltd.	Awaiting approval	50,000 [e]
Sunrise Thermal Project at Kearl Lake - Phase 2	Husky Energy Ltd.	Awaiting approval	25,000 [e]
Sunrise Thermal Project at Kearl Lake - Phase 3	Husky Energy Ltd.	Awaiting approval	25,000 [e,f]
*Joslyn Creek - Phase 1	Deer Creek Energy Ltd* & Enerplus Resources Fund	Construction began 2004	600
*Joslyn Creek - Phase 2	Deer Creek Energy Ltd* & Enerplus Resources Fund	Awaiting approval	10,000 [e]
*Joslyn Creek - Phase 3A	Deer Creek Energy Ltd* & Enerplus Resources Fund	Construction starts 2007	30,000 [e]
*Joslyn Creek - Phase 3B	Deer Creek Energy Ltd* & Enerplus Resources Fund	Construction starts 2009	30,000 [e]
Long Lake - Phase 1	OPTI Canada & Nexen Inc	Construction starts 2004	70,000 [e]
Long Lake - Phase 2	OPTI Canada & Nexen Inc	Construction starts 2011	70,000 [e]
Jack fish Project	Devon Energy Corporation	Construction starts 2005	35,000
MacKay River - SAGD Phase 1	Petro-Canada	Construction starts 2002	30,000
Meadow Creek – SAGD Phase 2	Petro-Canada & Nexen Inc	On hold	80,000 [e]
Lewis	Petro-Canada	Construction TBA	80,000 [e]
Surmont - Stage 1	ConocoPhilips, Total, Devon Energy**	Construction began 2003	27,000
Surmont - Stage 2	ConocoPhilips, Total, Devon Energy**	Construction TBA	25,000 [e]
Surmont - Stage 3	ConocoPhilips, Total, Devon Energy**	Construction TBA	25,000 [e]
Surmont - Stage 4	ConocoPhilips, Total, Devon Energy**	Construction TBA	25,000 [e]
Hangingstone Demo Project	JACOS & Nexen Inc	Stage 3 production began 2000	4,000 [e]
Hangingstone Commercial Project	JACOS & Nexen Inc	Construction starts 2006	50,000 [a,f]
Whitesands Pilot Project	Petrobank Energy & Resources Ltd.	Construction began 2004	TBA
Firebag - Base Operations	Suncor Energy	Construction began 2004	35,000 [e]
Firebag - Expansion	Suncor Energy	Producing in 2008	105,000 [e]
Cold lake - Phases 1-10	Imperial Oil Limited	Completed in 1986	120,000
Cold lake - Phases 11-13	Imperial Oil Limited	Completed in 2002	30,000
Nabiye - Phases 14-16 of Cold Lake	Imperial Oil Limited	Construction to be Completed in 2006	30,000[e]
Mahikan North - Extension of Phases 9 & 10 of Cold Lake	Imperial Oil Limited	Construction to be Completed in 2006	Production levels maintained
Orion EOR	BlackRock Ventures Inc	Under construction	20,000 [e]
Primrose	CNRL	Start up in 1987	108,000 [g]
Primrose - North	CNRL	Under construction	30,000 [e]
Primrose - East	CNRL	Start up expected in 2007 or 2008	120,000 [e,g]
Tucker lake	Husky Energy Ltd.	Construction began 2004	30,000 [e]
Lindberg/Elk Point, Frog Lake/Marwayne Bitumen recovery	Petrovera Resource Ltd.	Under construction	30,000[e]
Peace River	Shell Canada Limited	Production began 1979	12,000
Peace River Expansion	Shell Canada Limited	Construction starts 2007	18,000[a]
Seal Project	BlackRock Ventures Inc	Producing	16,000

(Projects as listed in reference 4)

Foot Notes:

* - recently (August 2005) acquired by Total
** - shares sold to ConocoPhilips and Total in May 2005
a - added production
e - expected
f - additional phase could increase production
g - include Wolf Lake Central Processing Facility
TBA -to be announced

Table 3: Canadian Crude Oil Production

Thousand Barrels Per Day

Crude Type	1990	2000	2010	2015
Conventional				
Light/Medium Crude	940	734	469	382
Heavy Crude	263	510	440	344
Pentanes	116	194	157	153
Oil Sands				
Bitumen	136	289	989	1,394
Synthetic	209	320	895	1,298
Offshore East Coast	0	145	245	290
Canada	1,664	2,192	3,195	3,861

Table 4: API Classifications

Classification	API	In-Situ Viscosity (mPa.s)
Light	> 31.1	
Medium	22.3-31.1	
Heavy	10-22.3	
Extra Heavy	<10	<10,000
Bitumen	<10	>10,000

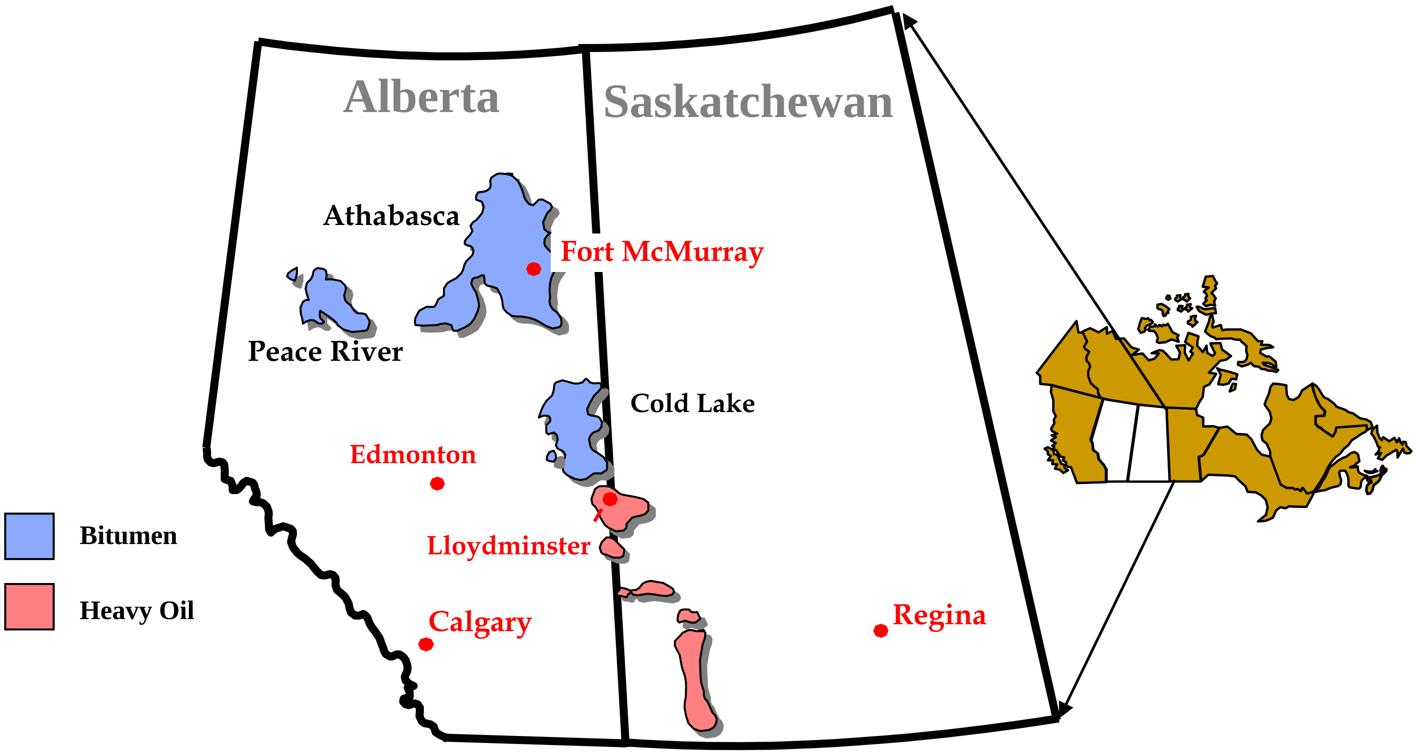
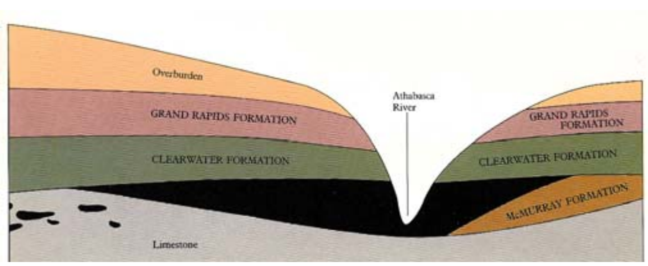
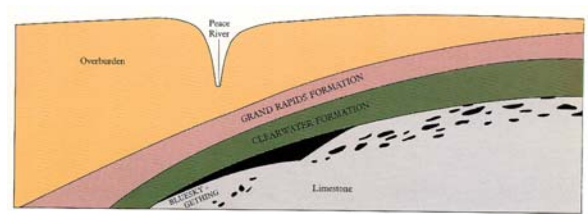


Figure 1: Major oil Sand Deposits of Canada

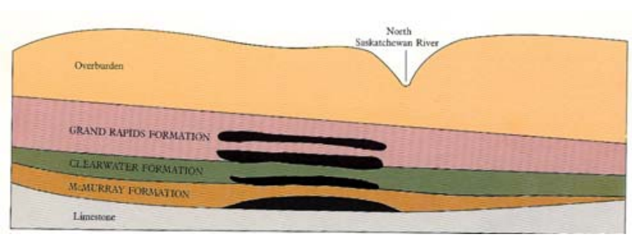
(Courtesy R. Sawatzky – ARC)



Athabasca Deposit



Peace River Deposit



Cold Lake Deposit

Figure 2: Athabasca, Cold Lake and Peace River Reservoirs characteristics

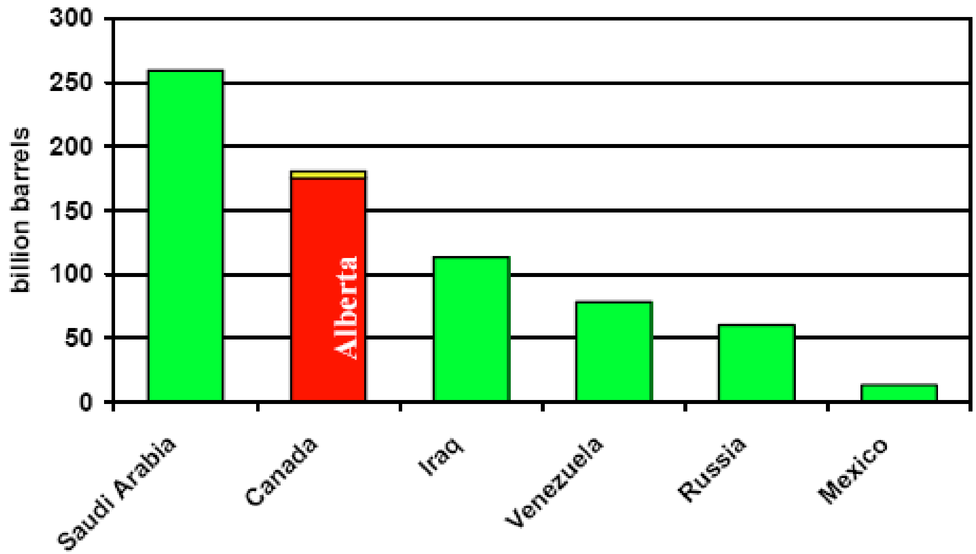


Figure 3: Comparison of Alberta and World Proven Oil Reserves

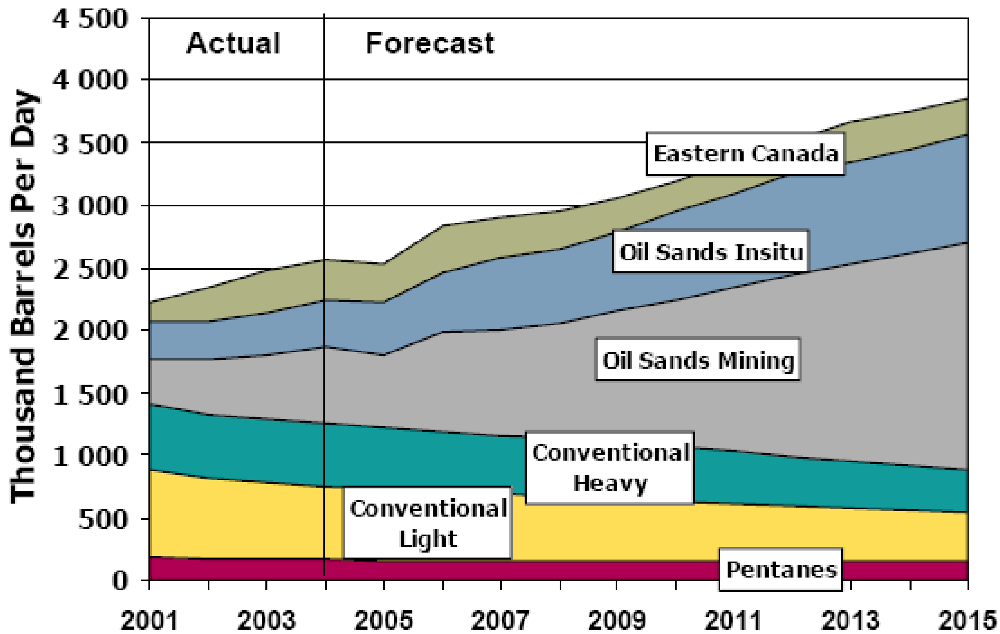


Figure 4: Canadian Crude Oil Production forecast (moderate estimate)

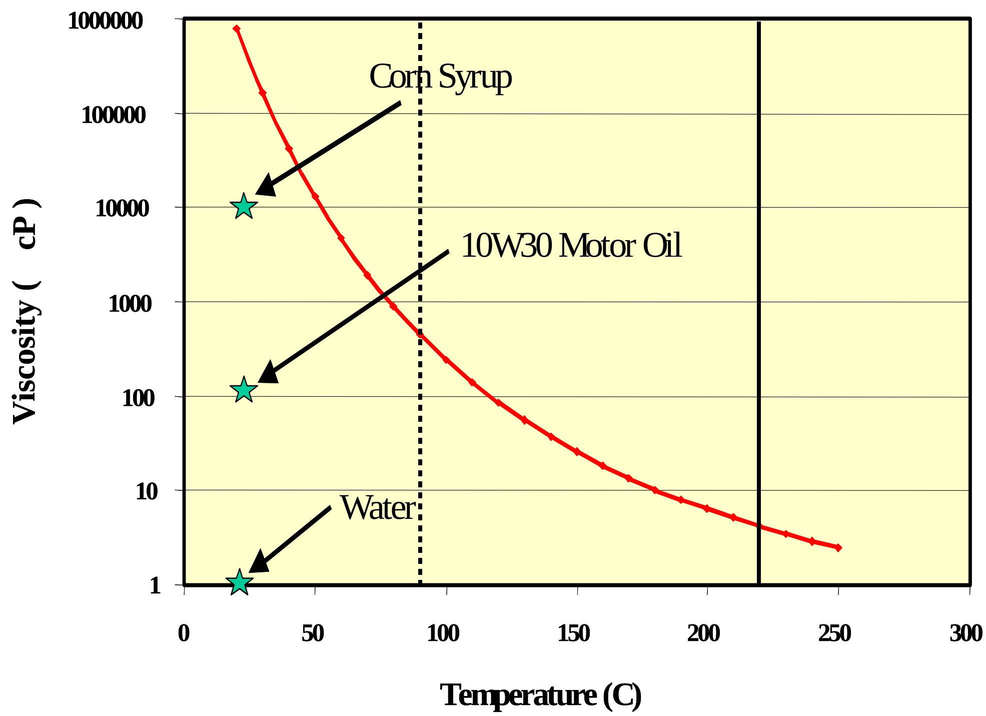


Figure 5: A Typical Viscosity-Temperature Profile of Athabasca Bitumen

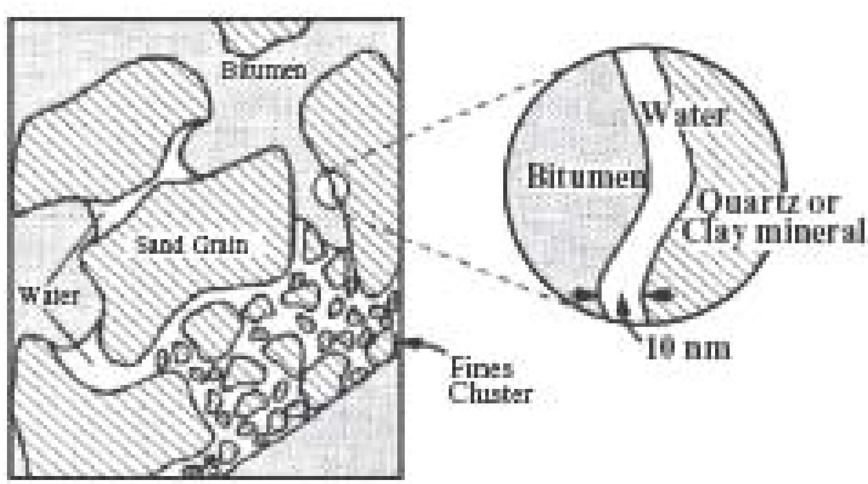


Figure 6: The classical model of the structure of Athabasca Oil Sands

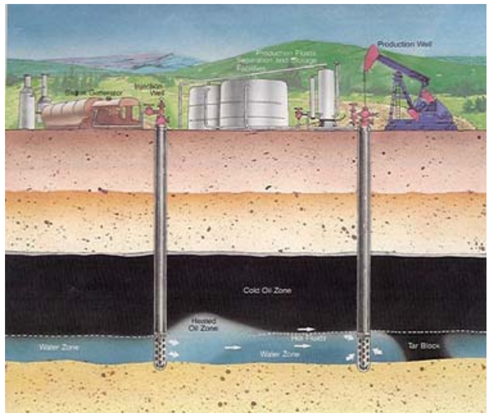


Figure 7: Illustration of the Steam Drive Process

(AOSTRA- 1989)

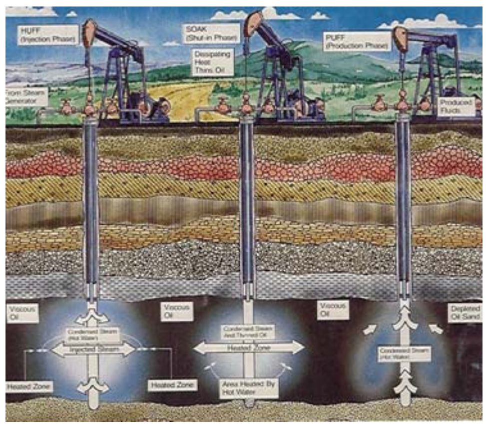


Figure 8: Illustration of the Cyclic Steam Stimulation Process (CSS).

(AOSTRA- 1989)

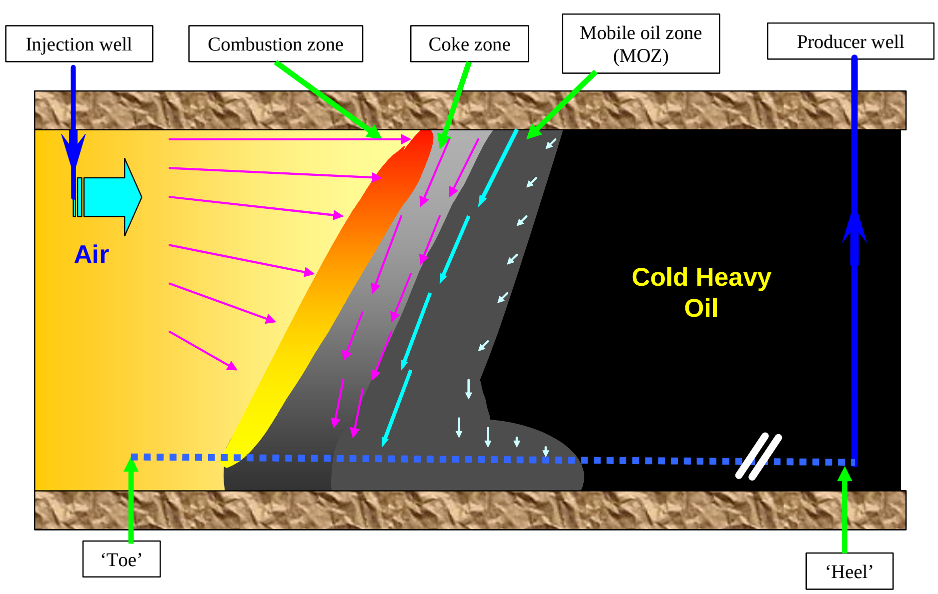


Figure 9: Illustration of the THAI Process Concept

(Courtesy A. Turta – ARC)

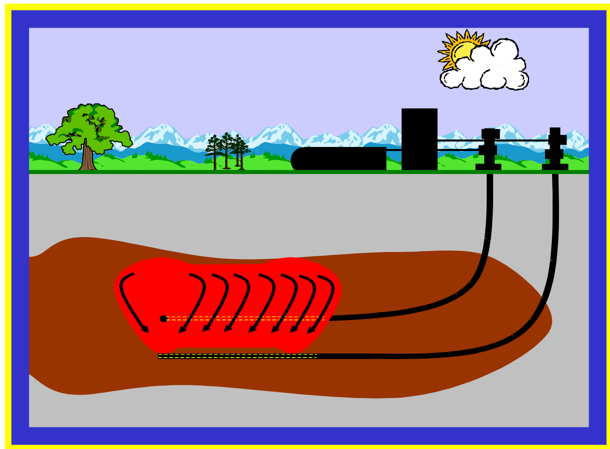


Figure 10: Illustration of the SAGD Process

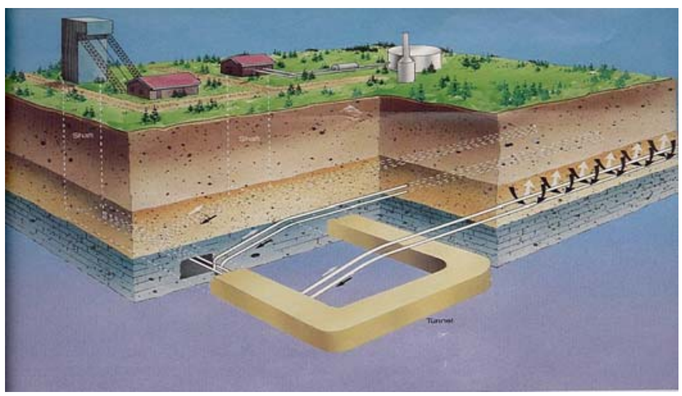


Figure 11: UTF Phase A

(AOSTRA- 1989)

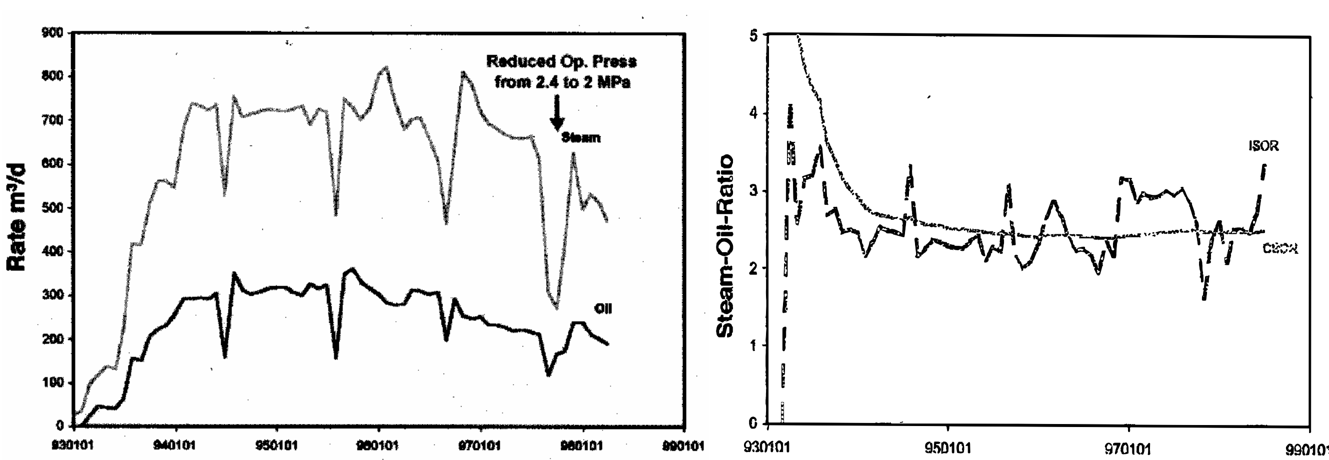


Figure 12: UTF/Dover Phase B performance

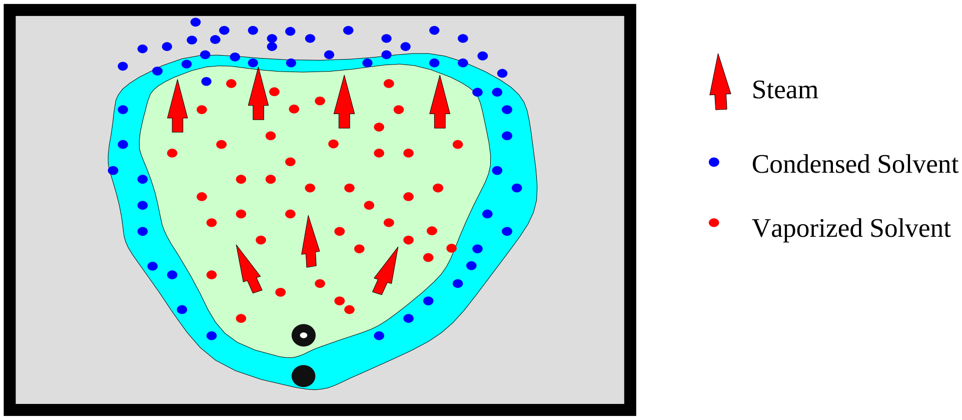


Figure 13: The ES-SAGD Process Concept

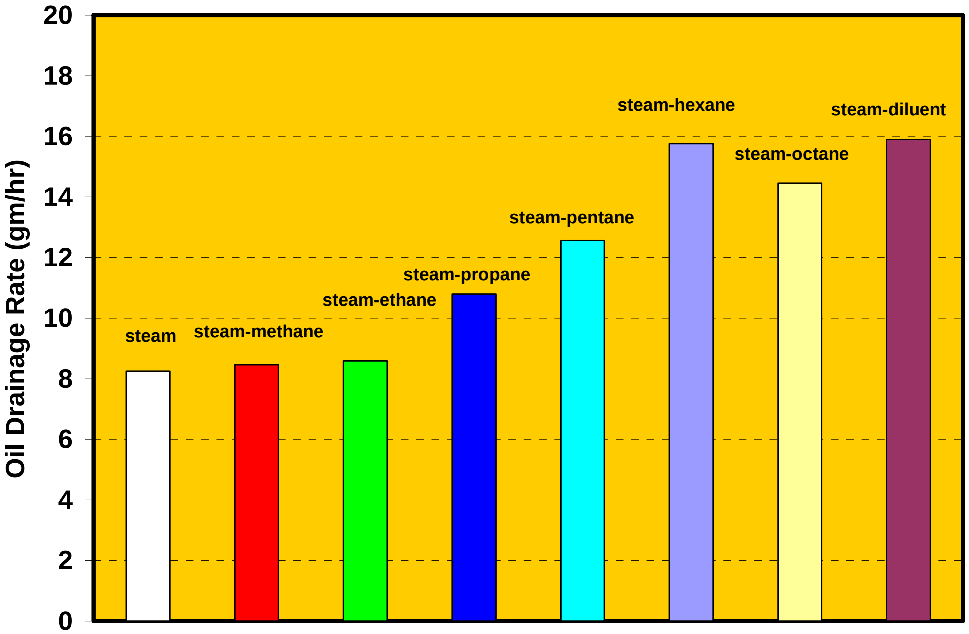


Figure 14: Variation of the oil drainage rate with carbon number

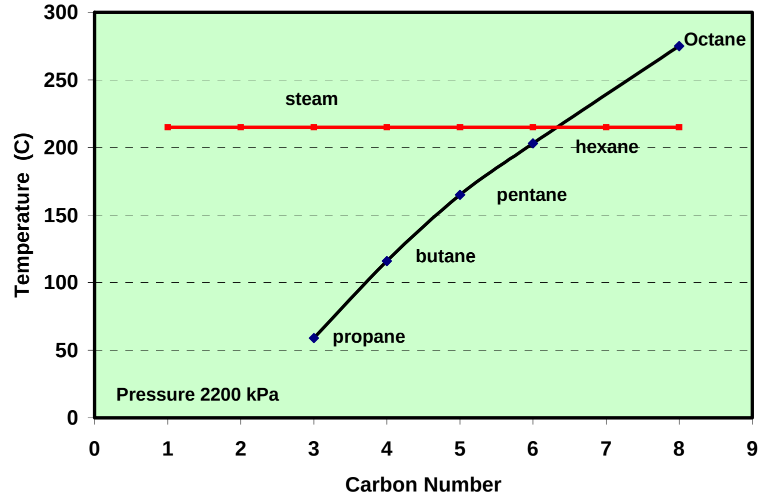


Figure 15: Comparison of Solvent Vaporization Temperature with Steam Temperature

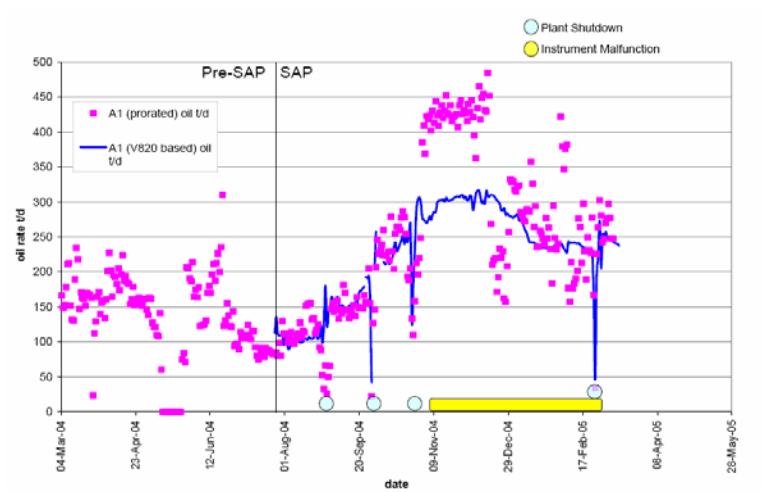


Figure 16A: EnCana's Steam-Solvent Injection Field Performance (Oil Rate)

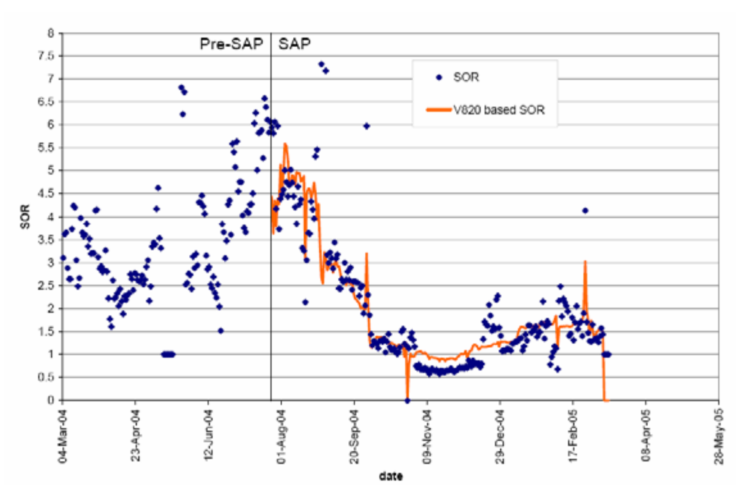


Figure 16B: EnCana's Steam-Solvent Injection Field Performance (Steam-Oil Ratio (SOR))

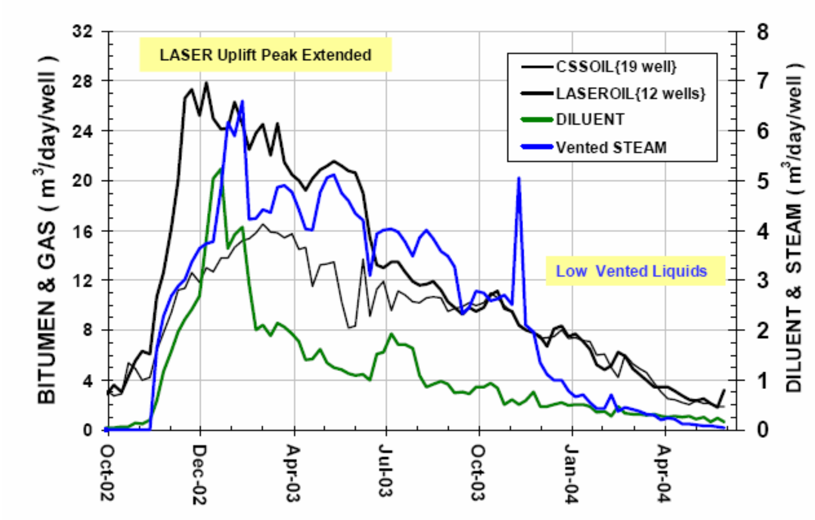


Figure 17A: LASER Field Performance (Oil, Gas and Diluent Rates)

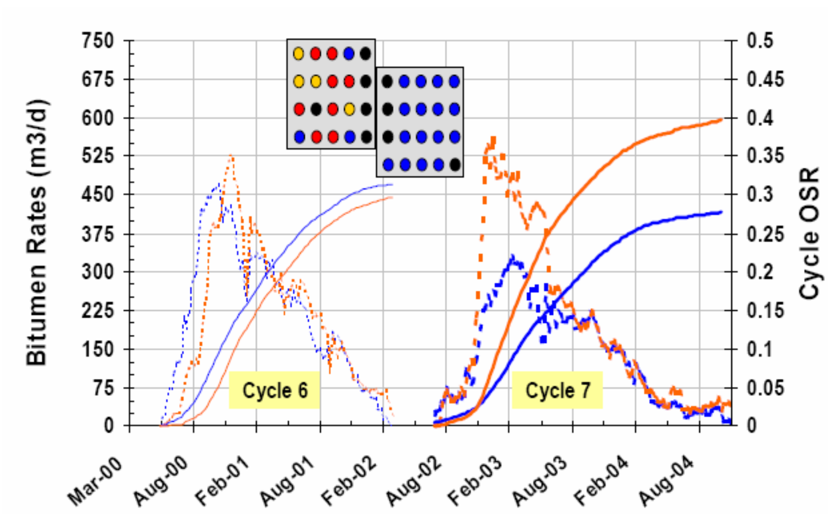


Figure 17B: LASER Field Performance - (Oil Rate and Oil-Steam Ratio (OSR))

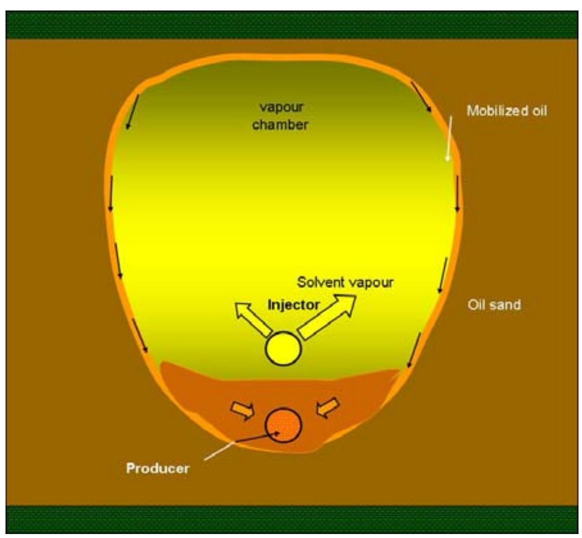


Figure 18: VAPEX Process Concept

(Courtesy T. Frauenfeld - ARC)