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Comparing Venezuelan and Canadian Heavy Oil and Tar Sands

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ABSTRACT

The world's two largest oil deposits are the heavy and extra heavy oil deposits of Venezuela and Canada. These deposits have many similarities and some differences; however, the general similarity in geological disposition and history, in reservoir and fluid parameters, and in other factors, is striking.

Extensive technological developments in Canada in the period 1985-2000 have resulted in several new heavy oil exploitation technologies, and new ideas continue to be generated. This innovative thrust has developed in part because of the great exploitation difficulties experienced in Canada and the greater maturity of the sedimentary basin: to maintain oil production, it was necessary to move toward heavy oil and oil sand development sooner than in Venezuela. The technologies of SAGD, CHOPS and PPT have been the major directions of technical activity in Canada, whereas in Venezuela, more favorable reservoir conditions allowed the use of multilateral horizontal wells.

The article reviews technical developments and deposit properties in the two countries, and points to a vast potential in the application of technologies developed and perfected in Canada to the vast resources in Venezuela. Not only will this be of value in specific projects and areas, it will also benefit and stabilize world oil supplies in the long term.

INTRODUCTION

There are vast heavy oil deposits (defined herein to be all the liquid petroleum resource less than 20°API gravity) in Venezuela and Canada. In both cases, these resources are found largely in unconsolidated sandstones with roughly similar geomechanical and petrophysical properties. This article will attempt a comparison of the Faja del Orinoco deposits in Venezuela (Figure 1) with the Heavy Oil Belt and Oil Sands deposits in Alberta and Saskatchewan (Figure 2).

The term “unconsolidated” is used to describe the high porosity sandstone reservoirs in both Canada and Venezuela. It is analogous to the term “cohesionless” in the soils or rock mechanics sense: it is meant to convey the fact that these sandstones have no significant grain-to-grain cementation, and that the tensile strength is close to zero. This turns out to be an important attribute in technology assessments.

The magnitude of the resources in the two countries is vast, probably on the order of 3.5-4 trillion barrels of oil in place (bbl OOIP), but its scale deserves a few comments. Conservation authorities, through the use of geophysical logs and cores to analyze and examine the oil-bearing strata, determine a “total resource in place”. This depends substantially upon a choice of “lower cut-off” criteria, below which an individual stratum is not included in the resource base. For example, any bed less than 1.0 m thick may be excluded from resource calculations, no matter where it is found. If a thin bed (e.g. 1.5 m) is separated by more than several m from superjacent or subjacent oil saturated beds, i.e. if it is “iolated”, it may be excluded from the resource base, no matter what value of oil saturation (S_o) it possesses. Furthermore, any bed with a low oil saturation, such as $S_o < 0.4$, may be excluded.

The resource in place is not linked to current or future extraction technologies, and the definition of what is a resource may vary from country to country. Without entering into a detailed comparison as to how specific values are chosen in the two countries, it is reasonable to state that each country has total in place heavy oil reserves of ~200-400×10^9 m^3, or 1.2-2.5×10^{12} bbl. Of all the liquid oil of all types delineated worldwide to date, 70% of it is in the category of <20°API oil in unconsolidated sandstone reservoirs less than 1000 m deep. Approximately 15% is 10-20°API oil, and 55% is <10°API, often called extra-heavy oil or bitumen. Of the world’s known <20°API oil, the large deposits of Canada and Venezuela together may account for about 55-65%.

Magnitude of the Resource

The resource figures given above can be placed into a more understandable context by comparison to world production and other resource bases. Here, world consumption is compared to the conventional recoverable oil in Saudi Arabia and the heavy oil resource bases in Canada and Venezuela. As can be seen, both countries have a heavy oil resource base (total OOIP) about an order of magnitude larger than Saudi Arabia.

Comparison basis	Barrels of oil
Daily world oil consumption:	77,000,000
Yearly oil consumption:	28,000,000,000
Saudi Arabia recoverable oil:	~250,000,000,000
Venezuelan oil in place:	~1,200,000,000,000[1]
Canadian oil in place:	~2,200,000,000,000

A total in-place reserve is not a recoverable reserve. Furthermore, the amount that can be recovered depends on technology evolution; therefore, recoverable oil values change with time, generally becoming an ever and ever higher percentage of the OOIP. For example, the Alberta government, based on current proven technologies, claims that approximately 10% of OOIP of <20°API can now be considered recoverable, giving a recoverable resource base of ~200,000,000,000 bbl, similar to Saudi Arabian claimed reserves in place. Also, the BITOR s.a. website states that there are economically recoverable reserves in the Faja del Orinoco of about 267,000,000,000 bbl. Although the source of this figure is not known, one may suppose that it is based on assessments similar to those carried out in Canada.

To place the Canadian resource into context, it can be compared to the daily consumption in the United States and Canada, approximately 21,000,000 bbl/d in 2001.

Assumed eventual recovery factor	Years of oil at current rates
10% of Heavy OOIP	27 years
30% of Heavy OOIP	81 years
50% of Heavy OOIP	135 years

[1] This figure, published in Kopper et al, 2001, is approximately half the figure of over two trillion barrels that the Venezuelan government was using a decade ago.

In other words, if an ultimate extraction efficacy of ~25% of the known <20°API oil resource in place in Canada is eventually achieved, with all known and future technologies, it comprises approximately 68 years of oil at current consumption rates.

Eventual Recovery Factors and Energy Futures

What ultimate recovery factors can be expected? In order to borrow from a financial institution, it may be necessary to specify a value of expected oil recovery with 90-95% certainty, using proven technology. Currently, the only proven technologies in Canada, by the harsh standards of lenders, are open-pit mines with hot water extraction for near-surface deposits, and CHOPS[2] for oil <20,000 cP viscosity (usually >11°API in typical Canadian reservoirs at temperatures of 16-35°C). Lenders would be justifiably loth to advance financing based on novel technologies that to some degree remain in a state of development or optimization, yet resource managers in oil companies must do so systematically, and must also try out many new ideas to develop the optimum long-term exploitation strategy. (New technologies will be discussed in more detail in the next section.)

The writer has conducted an informal survey of engineers in Canada working in heavy oil and oil sands, posing the question: "What probability would you affix to an ultimate extraction of XX%, accounting for current and future technologies, whatever they may be?" No one suggested any figure less than 20-25%, and although the responses generally were optimistic, some claiming eventual 65-70% recovery, the following figures appear to be reasonable estimates of their assessment:

Percent ultimate OOIP recovery	Probability estimate by Canadian engineers
20%	P > 95%
35%	P ≈ 50%
50%	P ≈ 5%

[2] CHOPS is an acronym for Cold Heavy Oil Production with Sand, to differentiate it from Cold Production, which is non-thermal heavy oil production, often from long horizontal wells.

Recent Developments

The magnitude of Canadian and Venezuelan deposits has been known since at least the middle 1970's. Canadian commercial development began with the Suncor Mine in the 1960's, followed by Imperial Oil Ltd. Cold Lake Project (cyclic steam injection) in the early 1970's, the Syncrude mine in the late 1970's, and accelerated heavy oil development of >10°API oil in the Heavy Oil Belt (Figure 2) using CHOPS in the late 1980's and 1990's. The latter resulted in the building of the Regional Upgrader (Husky Oil) in Lloydminster, which is currently producing over 130,000 bbl/d of synthetic crude oil from a feedstock that probably averages 14-15°API.

No significant development of their extra heavy crudes was undertaken in Venezuela before 2000 except for the BITOR s.a. operation, where somewhat less than 100,000 bbl/d of 9°API oil are produced by primary production and mostly shipped as an emulsion (Orimulsion™) of 70% oil and 30% H_2O for direct combustion in thermal power plants.

The development of Canadian and Venezuelan heavy oil deposits has accelerated significantly in the last five years, pushed by several factors, the most important of which is the gradually emerging consensus that the peak in world conventional oil (>20°API) production will occur within the next 10 years. This should have the effect of stabilizing heavy oil process at a price high enough to warrant the large capital investments required.

At the present time, the major developments in Canada include an expansion at Suncor, a new mine and expansion at Syncrude, a new mine by Shell Canada and an upgrader in Scotsford, a new mine by Canadian Natural Resources Ltd., three large SAGD (Steam Assisted Gravity Drainage) projects: Foster Creek by Alberta Energy Company Ltd. (AEC), Surmont by Gulf Canada Ltd., and MacKay River by Petro-Canada Ltd.. Furthermore, Imperial Oil Limited has announced a significant expansion in their Cold lake CSS (Cyclic Steam Stimulation) project, and a number of other smaller developments are occurring.

These developments in Canada should increase heavy oil and oil sands production by at least 800,000 bbl/d of synthetic crude oil by 2006, perhaps even more if the price of oil stays above USA$20.00/bbl indefinitely. Currently, the limitation on CHOPS production in Alberta and Saskatchewan is not production technology, but restricted upgrading capacity in Canada and the USA. There is little doubt that CHOPS production could jump from its current value of ~350,000 bbl/d to 800,000 bbl/d within 3-4 years if the rate of return was acceptable and if the upgrading capacity were available. The two are linked of course: a restricted upgrading capacity keeps the heavy-light differential price high, reducing rates of return to the producers. Hopefully, this will soon result in greater upgrading capacity.

The oil production history of Canada remains unique in the world: it is the only country to have gone through a sharp peak in oil production, followed by a trough, then a continued growth top production values substantially in excess of the peak. This is because of the slow but steady heavy oil production increase over the last 35 years, currently responsible for more than 1.2×10^6 bbl/d of production. Canada exported 1.37×10^6 bbl/d to the USA in January 2001 (60% of which is heavy oil), and in the next few years, it is likely that Canada will supplant Venezuela, Mexico, and Saudi Arabia as the number one exporter to the USA (in fairness, Canada also imports oil on the East Coast).

In Venezuela, the major developments are the four Orinoco projects, all partnered with PDVSA (Petroleos de Venezuela, s.a.). From east to west, they are:

- Cerro Negro Project, operated by Exxon-Mobil;
- Ameriven Project (Hamaca), operated by Phillips and Texaco;
- Petrozuata Project, operated by Conoco
- Sincor Project, co-operated by TotalFinaElf, Statoil and PDVSA.

These four projects, representing an investment of about USA$14 billion, each with their own upgrading facilities, will produce approximately 700,000 bbl/d of synthetic crude oil by the year 2006. One may also expect that there will be an additional 100,000 – 200,000 bbl/d production from BITOR and a few other smaller projects in the northern part of the Faja del Orinoco.

Thus, the world oil supply picture is slowly changing. Both Canada and Venezuela plan to have about an additional million barrels of oil per day in about 5 years, and this will represent about 2.6% of world oil supply. Currently, less than 5% of world supply comes from heavy oil, but this percentage will rise more rapidly as the peak in conventional oil production is encountered within the next few years. Nevertheless, because of the large reserves of conventional light oil, the Middle East will continue to dominate the supply figure for the next thirty years.

NEW PRODUCTION TECHNOLOGIES

The major new technologies that have positively affected the heavy oil industry in Canada in the last 10 years are:

- Horizontal well technology for shallow applications (<1000 m depth) involving cold production, but more-and-more combined with thermal gravity drainage approaches (e.g. SAGD); and,
- CHOPS technology, where sand production is encouraged and managed as a means of enhancing well productivity.

New Production Technologies

Method	Years	Status (2001)	Suitability
CHOPS	>10	$$$ - fully commercial	Best for 5-20 m zones,no mobile water, no water legs
SAGD	~6-8	$ profitable	Probably limited to thicker zones, > 15-20 m
PPT	2	$$$ early days	Useful with other methods (cold flow, CHOPS)
VAPEX	0	? no field trials yet	Best in >20°API cases, or as a SAGD adjunct
THAI	0	“ “	We'll see what happens soon…

These two methods have added about 250,000 bbl/d of >10°API oil to Alberta and Saskatchewan production since 1990. In addition to these proven technologies, there are two new ideas that are in early stages of commercialization:

- Thermal gravity-driven processes, particularly SAGD, using horizontal wells to establish stable gravity-assisted thermal EOR; and,
- PPT, Pressure Pulse Technology, where tailored pressure impulses are used as a flow enhancement technology, both as a reservoir-wide method and as a workover method.

PPT and SAGD are on the steep part of the learning curve for full-scale commercial applications. There are several new concepts for viscous oil that may have a substantial impact on the industry in years to come:

- VAPEX (Vapor-Assisted Petroleum Extraction), where a mxture of hydrocarbons are used to reduce viscosity in a gravity-dominated drainage regime; and,
- THAI (Toe-to-Heel Air Injection), an attempt to revitalize in situ combustion using a horizontal well concept with a short reaction zone and a short production path to avoid instabilities.

These two emerging technologies have not yet benefited from full-scale field tests. Also, these technologies are suitable for different strata conditions, different thicknesses, and different reservoir conditions, and a direct comparison can be misleading.

The oil industry in Canada pioneered shallow (<1000 m deep) **horizontal well** drilling, with cost-per-metre values now no more than about 1.2 times the cost of vertical wells. In the shallowest cases (150-200 m depth in the MacKay river Project) wells may be drilled using masts inclined at 25°-45° to reduce curvature build rates required to "turn the corner" from vertical to horizontal. Coiled tubing drilling was introduced in the last decade, further reducing costs of horizontal well drilling. Good seismic control (3-D seismics) and cuttings analysis allows precise steering in thin zones (<5 m) to place the well in the optimum position in the reservoir. In the production phase, the long drainage length of the well, >1200 m in many cases, allows much more effective production, giving higher production percentages of OOIP (original oil in place). There are many cold production horizontal wells in Canada, and in Venezuela, horizontal cold production wells are being used exclusively for development of the heavy oil at this time.

CHOPS (Cold Heavy Oil Production with Sand) is widely used as a "primary" production approach in unconsolidated sandstones; thousands of wells in Canada are now stably producing oil in this manner. Instead of blocking sand ingress by screens or gravel packs, sand is encouraged to enter the well by aggressive perforation and swabbing strategies. Note that if a screen is installed to keep out sand, oil production will drop to uneconomic levels. Productivity increases over conventional primary production as high as ×10 and ×20 have been achieved regularly (>100 b/d rather than 5-10 b/d). Also, from 12-20% of OOIP can be developed, rather than the 0-2% typical of conventional primary production (no sand) in such cases.

CHOPS wells (vertical to 45°) are operated more-and-more with rotary progressive cavity pumps, and old fields are being gradually converted to higher-rate progressing cavity pumps, giving production boosts to old wells. CHOPS increases productivity for four reasons:

- If sand can move, the basic permeability to fluids is enhanced.
- As more sand is produced, a growing zone of greater permeability is generated around the wellbore;
- Gas exsolution in heavy oil generates a bubble phase, leading to an "internal" gas drive, referred to as "foamy flow".
- Continuous sanding means that asphaltene or fines plugging of the near-wellbore environment cannot occur to inhibit oil flow.

Typically, a well placed on CHOPS will initially produce a high percentage of sand, often >25% by volume of liquids; however, this generally decays to 0.5-5% sand by volume after some weeks or months. The more viscous the oil, the higher the "stable long term" sand cut that is observed in the produced fluids. Operating costs for CHOPS have been driven down from

\$CAN12.00-13.00/BBL in 1987-91 to \$CAN5.00-7.00/BBL in 1999-2000, raising the profitability of small heavy oil projects. (The costs of sand management are approximately 20% of OPEX.) These massive cost reductions have been implemented mainly in small companies, although now larger companies have instituted and carried out similar cost reduction programs. Interestingly, there are almost no large multinational corporations active in CHOPS production in Canada.

Figure 3 shows the history of the Luseland Field in Saskatchewan that was converted to CHOPS production in the period 1994-1998. At present, approximately the same number of wells produce on the order of five times the amount of oil compared to the pre-CHOPS period. It should also be noted that in this field, and in a number of other fields in Canada, cold production from horizontal wells has not proven to be economically feasible.

SAGD (Steam-Assisted Gravity Drainage) is most suitable for reservoirs where the heavy oil is essentially immobile. SAGD involves drilling one or two horizontal wells at the bottom of a thick unconsolidated sandstone reservoir, injecting steam slowly and developing a "steam chamber". The heat and steam rise, whereas condensed water and mobilized oil flow downward through the porous medium by counter-current, gravity-driven flow (Figure 4). Injection pressures are much lower than the fracture gradient, which means that the chances of breaking into a thief zone are essentially zero (something which plagues massive CSS and all other processes based on high-pressure injection of fluids).

SAGD is extremely stable because the chamber grows only by upward and lateral gravity segregation and there are no pressure-driven instabilities (channeling, coning, fracturing), providing that the wells are properly operated with modest pressure gradients. Failure of attempts to economically execute single well SAGD in Alberta are likely attributable to excessive enthusiasm on the part of the engineers to increase production, and the high pressure gradients attempted de-stabilized the process.

SAGD seems also to be insensitive to the presence of shale streaks and horizontal barriers to flow because as the rock is heated, differential thermal expansion causes the shales to be placed under a tensile stress, and vertical fractures are created, which serve as conduits for steam (up) and liquids (down). Essentially, the pore pressure becomes greater than the lateral stress ($p > \sigma_{hmin}$), which is the condition for vertical hydraulic fracturing. Furthermore, as high steam temperatures hit the shale, instead of expanding thermally, dehydration (loss of water) and dehydroxylation ($\text{-OH} + \text{HO-} \Rightarrow H_2O + \text{-O-}$ bonds) lead to volumetric shrinkage of the shale barriers, opening the induced vertical fractures even more (Figure 5).

Thus, the combined processes of gravity segregation and shale thermal fracturing make SAGD so efficient that recovery ratios of 50-75% are probably achievable in appropriate cases (thicker horizontal sandstone reservoirs, porous-flow dominated except for the shales).

A radically new aspect of porous media mechanics was discovered and developed into a production enhancement method in the period 1995-2001, based on theoretical developments in carried out at the University of Alberta in the period 1985-1995. **PPT** (Pressure Pulse flow enhancement Technology) is based on the discovery that large amplitude pressure pulses dominated by low-frequency wave energy generate enhanced flow rates in porous media. For example, in heavy oil reservoirs in Alberta, PPT has reduced the rate of depletion, increased the oil recovery ratio, and prolonged the life of wells. Also, it has been found that very large amplitude pressure pulses applied for 5-30 hours to a blocked producing well can re-establish economic production for many months, and even years.

The mechanism by which PPT works is to generate local liquid movement into and out of pores, through the propagation of a porosity dilation wave. As the porosity dilation wave moves through the porous medium at a velocity of about 40-80 m/s, the small expansion and contraction of the pores with the passage of each packet of wave energy helps unblock pore throats, increase the velocity of liquid flow, overcome part of the effects of capillary blockage, and reduce some of the negative effects of advective instabilities such as viscous fingering, coning, and permeability streak channeling. Although very new (dating only since 1999), PPT promises to be a major adjunct to a number of oil production processes. It will be useful in conventional oil production technologies as well.

Several new technologies have been developed in the period 1995-2000 but have not achieved full-scale field testing by April 2001. **VAPEX** (Vapor-Assisted Petroleum EXtraction) uses a mixture of condensable and non-condensable gases (e.g. CH_4 to C_4H_{10}) to dissolve into and thin the viscous oil so that it will flow to horizontal production wells. The VAPEX principle is general, and it can be "added" to SAGD projects, used in a warm situation (some electrical heating for example), and in a vast number of combinations.

In situ combustion may make a comeback with a new concept. **THAI** (Toe-to-Heel Air Injection), based on a geometry involving horizontal wells, promises to solve the instability problems that have always plagued in situ combustion. The well geometry enforces a short flow path so that the instabilities associated with conventional combustion methods are avoided or reduced (Figure 6).

The potential advantages of a fully *in situ* combustion method are tremendous: if a method of *in situ* upgrading is developed that leaves behind (or burns) the carbon residue, as well as the heavy metals and the sand, and yet achieves an extraction ratio that is reasonable, the heavy oil industry worldwide will be revolutionized again. Current laboratory experiments using THAI are promising, with a typical oil upgrading from 11.5° to 18-20°API achieved as a result of the process.

Finally, development of the Faja del Orinoco in Venezuela has been based on drilling long horizontal wells with a large number of multi-lateral branches, resulting in large-scale oil production through **Cold Flow** or **Cold Production** (i.e. non-thermal heavy oil production with minimal sand influx). The mother well and the daughter branches are carefully located in the best sections of the reservoirs, using a combination of geophysical log data, seismic data, and measurements while drilling (Figure 7). The longest of these wells in Venezuela is on the order of 12,000 m, and such a well, placed in the right horizons, can achieve production rates of 1500-2500 bbl/d. Although this may be regarded as simply a minor development on existing technology, one should keep in mind that the integration of the different data sources to optimize trajectory in a dynamic drilling condition is nothing short of revolutionary. Furthermore, there is excellent reason to believe that the investment in horizontal wells for cold flow will also lead to the implementation of one or more of the Canadian technologies in the future to enhance the value from these wells.

Hybrid approaches that involve the simultaneous use of several of these technologies are evolving and will see great applications in the future. For example, a period of primary exploitation using CHOPS or Cold Production to horizontal wells (as in Venezuela) can be substantially extended, giving more oil faster, using PPT (Figure 8). Then, after the primary phase is essentially complete, a period of gravity drainage, aided by inert gas injection and steam injection, could be used once some reservoir pressure is re-established. Different exploitation phases and the use of hybrid approaches may well allow the production of as much as 30-50% of the heavy oil in reasonable quality reservoirs. Furthermore, the technologies developed for heavy oil will also be useful for conventional oil.

GEOLOGICAL FACTORS

General Basin Disposition

The WCSB (Western Canadian Sedimentary Basin) is a compressional basin ($\sigma_v = \sigma_3$ in all shallow rocks near the mountains) characterized by significant thrust fault structure on the southwestern boundary, and a synclinal axis that parallels the mountains about 50 km east of the last major thrust fault. From this deep axis with thick sedimentary sequences, the WCSB becomes progressively thinner to the northeast, pinching out against the Canadian Shield igneous rocks. The heavy oil deposits were sourced from greater depth (generally pre-Cretaceous shales) and moved up-dip through hydrodynamic transport at a time when the oil viscosity was much lower than at present, and when the entire basin was more deeply buried. A major conduit for northeast directed fluid migration was the pre-Cretaceous unconformity, a complex karstic surface that has had a major effect on basin hydrodynamics. The heavy oil deposits were emplaced in stratigraphic traps with small structural components in some cases, and it appears that loss of light-weight HC materials and massive biodegradation at shallow depths led to a condition of high viscosity and permanent immobilization.

The eastern Venezuelan Basin has a synclinal and geometric structure similar to the WCSB, but at a reduced scale: the distance from the syncline to the Faja del Orinoco is 200-300 km, whereas in Canada the distance is closer to 500-700 km. The deep synclinal basin lies north of the Faja in front of the Sierra Orientale, a mountain front that has a tectonic structure based on a combination of thrust and strike-slip faulting (likely $\sigma_v = \sigma_2$ in most shallow areas). From the deep syncline axis, approximately east-west, the basin progressively shallows and pinches out to the south against the igneous rocks of the Guyana Shield. There are many minor unconformity surfaces, although there is not the striking carbonate-related karstic erosion surface that characterizes the WCSB. The general hydrodynamic conditions were similar: source rocks buried deep in the syncline generated hydrocarbons that moved updip under the general southward gradients, becoming emplaced when the moving hydrocarbons began to undergo biodegradation that consumed the lighter HC fractions.

In Canada, the presence of an ancient salt solution front at depth in the Prairie Evaporites (Devonian) provided a bit of structural control for the accumulation of oil, and the high permeability of the collapsed zone, plus its hydraulic connection to far-field hydrostatic pressures, means that pore pressure conditions at present are almost always somewhat less than hydrostatic. The Venezuelan deposits are not underlain by a thick sequence of carbonates and evaporites; in fact, the igneous shield rock is quite close to the base of the arenites sequence, with no significant underlying carbonate strata.

In Alberta, in addition to the large deposit in unconsolidated sands, there are heavy oil deposits on the order of 100-200 billion barrels in carbonates that lie below the karstic erosional surface (Figure 2), but no such carbonate heavy oil zone exists in Venezuela.

In general, the Canadian deposits are found over a much wider area, with a broader range of properties, a broader range of burial depths, a broader range of reservoir types, and so on. Nevertheless, the general basin dispositions are similar.

Geological Stress History and Erosion

Canadian heavy oil deposits are almost all Middle Cretaceous in age (~115 MYBP), and are found in the Mannville Group of sand-silt-shale arenites and overlain regionally by thick, regionally continuous shales. (One exception is the heavy oil found in the Bakken Formation, an unconsolidated sand of Permian-Carboniferous age, but these strata comprise a small fraction of the entire resource.) The Faja del Orinoco deposits are early Tertiary (Miocene) in age (~50-60 MYBP), and are found in the Oficina Formation, a sand-silt-shale arenite sequence overlain by regionally continuous thick shales.

The Canadian oil sands have very few faulting structures of any consequence, except a few short-throw normal faults in the region of salt solution where collapse of the overlying beds generated some mild structure. The Venezuelan reservoirs also have few faults, although in the eastern Faja there are a number of short-throw normal faults arising largely from differential compaction effects arising from burial of lithostratigraphically different sedimentary bodies. Neither group of deposits has experienced any strong tectonic activity, therefore large-scale through-going faults or regional folding is absent.

The largest "single" Canadian reservoir, the Athabasca oil sands in the McMurray Formation, centered around the town of Ft McMurray, is at the surface (zero burial depth 50 km north of Ft McMurray to 400 m burial depth south-southeast of Ft McMurray). The remainder of the reservoirs lie between 350 m and 900 m deep, dispersed around the province and into Saskatchewan. Note that Saskatchewan has no massive deposits of "tar sands", only reservoirs with heavy oil >10°API. In Venezuela, the rich heavy oil reservoirs of the Faja del Orinoco range from 350 to about 1000 m in burial depth, and no outcrops exist. The deposit is about 500 km long and 50-60 km in north-south extent, much less than the combined area covered by the Canadian deposits.

About 400-600 m of sediments have been stripped from the Canadian deposits since the period of deepest burial, reflecting a vertical effective stress change of about 6-8 MPa, whereas the Venezuelan deposits have experienced about 300 m of erosion, a vertical effective stress of about 4 MPa. In both cases, the effect has been to over-compact the reservoir, exposing the granular materials to effective stresses substantially larger than those that exist at present. This has affected the deformation behavior of the deposits, making them stiffer than other similar deposits that have not experienced erosion (e.g. Lago de Maracaibo deposits in Venezuela).

In Canada, even though the distance from the mountains is substantial, the direction of σ_{HMAX} is toward the mountain front, governed by the compressive nature of the mountain building. Below depths of 300 m, hydraulically induced fractures tend to be vertical and point toward the mountains. The fracture gradient is rarely less than 85% of the overburden stress σ_v. Above 300 m, induced fractures tend to be horizontal because the slow unloading and rebound from the ~500 m of erosion has led to a condition of $\sigma_v = \sigma_3$. In the Faja, all initial fractures appear to be vertical, and a reasonable estimate of the fracture gradient is that it is between 80 and 90% of σ_v. It is not known what the generally preferred vertical fracture orientation is.

Lithostratigraphy

The Oficina Formation is a fluvial and marine-margin deposit. Apparently, there were a number of large estuarine accretion plain and deltaic complexes (at least four) formed by rivers that drained the Guyana Shield to the south, and the focal area of deposition changed as the sea level changed in response to the sedimentation, the formation of the mountains to the north, and the subsidence of the eastern Venezuelan Basin. The deposit is a unitary sequence of strata with general east-west continuity. Individual sand bodies range in thickness up to 40-45 m, although the majority of "discrete" oil bearing beds are 8-12 m thick, with sharp lower boundaries from lateral erosional migration of channels, and more gradational upper boundaries. Good permeability interconnectivity is evidenced by a high oil saturation state in the vertical sequence of strata. Some sand bodies are thick channel sands of almost uniform properties over many metres, others contain multiple laminae of silt and have poor vertical flow properties. In general, the upper beds are of lower quality than the lower beds.

The Canadian deposits represent a much broader range of sedimentary environments. The deepest deposits are sediment-filled valleys with lag gravels and typical river deposits incised in the karstic limestone terrain. As one moves up in the stratigraphic sequence, and depending on location, the depositional conditions changed from incised valleys to estuarine accretion plains in broad valleys (Athabasca) to deltaic (Cold Lake), to blanket sands, offshore bars, seacoast dune sands and channel sands in the deposits of the Heavy Oil Belt.

Thick beds that are laterally continuous and well saturated with viscous oil are found in the Athabasca deposit (gross pay up to 65 m with net pay of 50-55 m in the central part) and the Cold Lake deposit (gross pay up to 40 m with net pay of 40 m in the richest central part of the deposit). The less viscous oils farther south in the Heavy Oil Belt are generally in beds from several metres to perhaps 20 metres thick, and most reservoirs being exploited in the Lloydminster region are 8-12 m thick. In this area, if a bed is a blanket sand, it will have excellent lateral continuity for many kilometres, whereas the channel sands tend to be narrow and sinuous, and there are few channels that have coalesced with others to form the typical thick estuarine plain typical of the Faja area. The areal continuity of the heavy oil deposits in the Heavy Oil Belt is sparse, and channels dominate the southern half of the area.

In Canada, depending on location, there may be several reservoirs 5-25 m thick encountered in a single borehole, and these reservoirs will usually be separated by many metres (15 to 80 m) of silts and clayey silts. In general, the net pay in the Canadian strata is perhaps 30-35 m, varying from the thick Athabasca zones to the thin zones southwest of the Cold Lake deposit. In the Faja, the series of stacked channels and other sand bodies is much more compact vertically, usually having a net-to-gross of 60% over a vertical extent of 100-150 m, giving a net pay approaching 110 m in some areas. The oil may be found in up to 6-7 separate zones, the thickest ones usually 20-25 m thick.

There are only a few genuine shales (>50% clay minerals) in either deposit; the oil-free strata separating the oil zones are dominantly silts to clayey sands and silty clays in texture. Both deposits are overlain by thick shallow marine clay shales of high porosity.

Mineralogy and Diagenetic Fabric

There is a wider variety of mineralogical composition in the Canadian heavy oil deposits. The Athabasca deposit is a dominantly quartzose sandstone (>90% SiO_2), whereas the Cold Lake deposit is arkosic in make-up, with siliceous volcanic shards, feldspar grains, and lithic fragments comprising perhaps 20-35% of all particles, the rest being quartz. In the Heavy Oil Belt south of Cold Lake, the individual strata vary from highly quartzose and coarse-grained basal Mannville sands to clayey, arkosic sands that are very fine-grained ($D_{50} \sim 80$ μm). The provenance of the arenaceous material changed over the Mannville sedimentation episode from the east (igneous shield) to the southwest and south, and the mineralogy reflects this change. Most reservoirs being exploited by CHOPS have clay content of perhaps 3-5%, occasionally more.

The Faja deposit is substantially more quartzose and less clayey than the Canadian strata in general, although quite similar to the Athabasca deposit. This reflects the source rocks to the south in the Guyana Shield, and also suggests that there was a long period of reworking of the sand bodies in the estuarine plain as the Oficina Formation was gradually laid down.

The Canadian sands have a mild diagenetic fabic characteristic of sandstones that have been acted upon by pressure solution for over 100 million years. The Venezuelan sands, despite the generally higher temperatures they have been exposed to, show a milder diagenetic fabric, exhibiting a somewhat lesser degree of long grain contacts and crystal overgrowths on the free grain surfaces in the pores.

GEOMECHANICS FACTORS

The rock mechanics behavior of the reservoirs is pertinent to issues such as the compressibility, the compaction potential, the possibility for ChOPS implementation, wellbore shearing, and so on. In Canada, the presence of outcrops has allowed specimens for testing to be obtained without suffering the massive volumetric expansion that is characteristic of cored materials from both Canada and the Faja.

In the Faja del Orinoco, it is even difficult to obtain full recovery of the sands, particularly the coarse-grained, high permeability sands that are well saturated with oil. Examination of Faja cores obtained through triple-tube coring method showed incomplete (almost absent) core recovery in the zones of highest permeability, and the porosities determined from the "intact" continuous sands varied from 35 to 42%, indicative of massive irreversible damage during core recovery. All the geophysical logs indicate that the porosities of the Faja sands are from 27-28% in the deeper northern parts of the deposit, to values of 30-32% in the shallower southern section.

Strength of Unconsolidated Heavy Oil Sands

Both Venezuelan and Canadian heavy oil sands are truly unconsolidated sandstones. The tensile strength is so low as to be almost impossible to measure. Note that the tensile strength is not quite the same as the cohesion: the former is the resistance to pure tensile or pull-apart forces, whereas the latter is actually a function of how test data are plotted and fitted on a Mohr-Coulomb plot to determine a yield criterion.

A Mohr-Coloumb plot of triaxial test data from the Canadian oil sands shows a surprisingly high tangent angle of friction at low confining stresses (Figure 9). This reflects the diagenetic fabric and the over-compacted nature of the sands. There is also an important component of lithology in strength data: yield criteria from the arkosic Cold Lake deposit are much "lower" despite similar geological histories and porosities. Also, the dilational behavior is quite different: it takes a confining stress (σ_3') of 7-10 MPa to suppress the dilation of Athabasca oil sand, whereas the weaker grains in the Cold Lake oil sand will lead to a dilatancy suppression at confining stresses less than 3 MPa. (The Cold Lake and Athabasca curves shown are characteristic of outcrop samples, and different grain size specimens will have different strength criteria.)

It has not been possible to obtain sufficiently undisturbed specimens of the Venezuelan oil sands to warrant strength testing; nevertheless,

- If a well in a high-k Faja zone is perforated with large-diameter perforations and produced, it almost invariably co-produces massive amounts of sand.
- Geophysical sonic logs in the Faja give slightly lower velocities compared to Canadian strata (2.65 vs 2.8 km/s) at a depth of 400-500 m.
- Scan electron microscope examination of the Faja quartzose sands shows a somewhat milder diagenetic fabric than in the Athabasca quartzose sands.
- Porosity from geophysical log calculations is on average 1% to 1.5 % higher in the Faja sediments than in the Athabasca deposit.
- The Faja sediments are coarser-grained, more quartzose, and with smaller amounts of clay minerals than Canadian sands in general.

From these correlations, it is reasonable to assume that the strength of the Faja is only slightly less than the Athabasca Deposit, and that the sands are completely cohesionless. A tentative yield criterion is sketched on the diagram.

Deformation Parameters

Compressibility is a fundamental parameter in all flow equations. More interesting from an economic point of view is the potential for compaction drive. In Venezuela, given the massive and lucrative compaction drive that the Lago de Maracaibo shallow reservoirs evidenced (up to 8 m in Lagunillas, Bachaquero and Tia Juana over a 40 year period), there is deep interest in compaction potential. It was originally thought that the compaction potential of the Faja would be somewhat less than that of the Maracaibo sediments, but would be substantial nonetheless, and economically attractive. However, from a number of lines of argument, compaction drive can be eliminated as a significant component of the production mechanisms. The Faja strata have been over-compacted geologically, the grain structure and mineralogy are very competent (quartz with mild pressure solution at the grain contacts), there are very few cleavable (feldspar) or crushable (shale) grains, the grains are rounded to sub-rounded, and so on. In contrast, the Maracaibo sediments are much younger (only 10 million years) and are at their maximum burial depth at present. The sands are lithic to arkosic, of higher porosity (32-34% generally), and have no visible diagenetic fabric.

An explicit test of compaction potential was carried out in the Hamaca region (north of the Ameriven property) in the 1990s. Radioactive bullets shot into the formation were logged repeatedly during a history of aggressive drawdown of the well over several years, and no detectable subsidence was noted. No evidence of compaction drive has been reported from any other operations. Thus, based not only on geological and analogy arguments (in many ways the Athabasca deposit is considered an analogue of the Faja), but also on explicit field data, the compaction drive potential of the Faja can be assumed to be negligible.

What is the likely compressibility value of intact, undisturbed Faja materials? In the absence of excellent tests on high quality specimens (unavailable so far), and in the absence of a back-calculated value based on long-term reservoir behavior (difficult), the following values are recommended for use in simulations:

Deposit	Compressibility range
Athabasca Oil Sands	$0.4\text{-}0.6\times10^{-6}$ kPa^{-1}
Cold Lake Oil Sands	$1.0\text{-}2.0\times10^{-6}$ kPa^{-1}
Faja del Orinoco	$2.0\text{-}5.0\times10^{-6}$ kPa^{-1}
Maracaibo (for comparison)	$50\text{-}200\times10^{-6}$ kPa^{-1}
Lloydminster area deposits	$1.0\text{-}3.0\times10^{-6}$ kPa^{-1}

These are values for compressibility in flow equations. In the absence of shear strength testing of high quality specimens in triaxial configurations, it is difficult to give elastic modulus values and dilatancy suppression stresses for the Faja, but continuing to take the Athabasca deposit as a close analogue, the following values would be recommended:

- E (Young's Modulus) $\approx$ 3-6 GPa
- ν (Poisson's Ratio) $\approx$ 0.25
- σ_3' for dilatancy suppression $\approx$ 4-6 MPa

The conclusion reached is that the Faja sands are only slightly less stiff (i.e. slightly more compressible) than the typical Canadian sands, that the strength is probably less than the Athabasca deposit but larger than the Cold Lake deposit, and that otherwise, the geomechanical properties are very similar to Canadian Heavy Oil Belt strata (no tensile strength, dilatant at low stresses, etc.).

PETROPHYSICAL PARAMETERS

Compressibilities, porosities and geomechanical factors were discussed in previous sections.

Reservoir Fluids Behavior

The oil and water saturations of both deposits are similar, with ranges from 0.85 to 0.90 in most cases, except that in general, there is a slightly higher degree of oil saturation in the Venezuelan case (closer to S_o = 0.88-0.9) because of the coarser-grained nature of the sands. In Canada, there are some reservoirs (e.g. Luseland) that have a relatively high water saturation (0.28) and yet provide excellent long-term recovery in CHOPS applications without producing excessive amounts of water early. Such cases are not common.

The crude oil in Canada ranges from 8.5°API in the Athabasca deposit to values higher than 15°API in the southern part of the Heavy Oil Belt. In Venezuela, the shallow sands (<600 m) have oil densities of 8-9.5°API, but in the deeper parts of the Faja, north of the four large developments, higher values (lower oil densities) are noted.

The viscosity of the crude oil in Canada varies from less than 1000 cP in >15°API oil such as Pelican Lake and Amber Lake, to values in excess of 1 million cP for the surface Athabasca deposit. Many reservoirs using CHOPS in the Heavy Oil Belt have viscosities around 5000-12,000 cP (Lindburgh, Morgan, Lone Rock, Bear Trap, Lloydminster, Edam, etc.). The Cold Lake Imperial Oil Ltd. Project exploits oil of viscosity around 100,000 cP. The Gulf Surmont SAGD Project will exploit oil that is on the order of 200,000 – 400,000 cP, whereas the AEC Foster Creek SAGD Project will exploit a reservoir with viscosity of 60,000-80,000 cP. In some of the reservoirs northeast and northwest of Lloydminster, variations in viscosity within a single unitary reservoir approaching a factor of 5 or 8 have been noted (i.e. 2000 to 10,000 cP in the same producing zone), with the more viscous oil near the bottom, and usually in a reservoir with an active water leg. In reservoirs without active water legs, the viscosities appear to be far more uniform.

The range of viscosities in Venezuela is narrower because of the greater homogeneity in reservoir type, asphaltene content, burial depth, and temperature. A range of 4000-5000 cP (estimated live oil viscosity in the reservoir) for the shallower 8-9°API crudes is a reasonable estimate, and for the deeper parts of the Faja, values around 1000 cP and even lower, depending on temperature, may be assumed. The difference in viscosity of the Faja oils in a vertical dimension at a specific site has not been published.

In Canada, the asphaltene content of the heavy crude oil seems to be higher in general than in Venezuela, with values approaching 15% for oil of a similar gravity to the Faja (lighter oils generally have less asphaltene of course, therefore the 14-15°API heavy oils in Canada have less than the 8-9°API Faja crude oil. This may account for the anomalous fact that, once all parameters (T, p, μ, k, t) have been corrected for as much as possible, Venezuelan Faja oil appears to be substantially more mobile than the Canadian oil.

In Canada and in Venezuela, the formation waters in the reservoirs and surrounding rocks is not highly saline, values of 20,000-60,000 ppm NaCl are typical, depending on depth and location with respect to the local groundwater flow regimes. The Faja has a distinct oil/water contact such that the lower one to two sand bodies in the Oficina Formation are water bearing. In Canada, some reservoirs have active bottom water, many do not. This is an important factor in technology choice: CHOPS cannot be successful if there is active bottom water because rapid coning occurs under the high Δp associated with this technique. Similarly, horizontal well placement in the Faja strata is controlled by the location of the oil-water contact.

The composition of the solution gas (and any small gas caps that might exist) is about 95% CH_4 and 5% CO_2, both in Canada and Venezuela. In Canada, some of the reservoirs have small gas caps, apparently of limited extent, but such gas caps appear to be less frequent in the Faja.

Temperature, Pressure, Bubble Point

The great difference in formation temperature of course accounts for the fact that the denser Venezuelan crude oils have viscosities in ranges similar to lighter Canadian deposits. For example, the Luseland field has a viscosity of ~1400 at a gravity of 11.5-13°API, whereas the Faja oil has approximately the same viscosity at a density of 8.5-9.5°API. Canadian heavy oil deposit ground temperatures range from 4°C in the near-surface Athabasca Oil Sands to a high of 38°C at 850 m deep in southeastern Saskatchewan. In the Heavy Oil Belt, values generally range from 16°C in 350 m deep strata, to 36°C in the deeper Bakken Formation sands in Saskatchewan.

It may be assumed in the Faja that the pressure in any reservoir is equal to the hydrostatic pressure of water of density ~1.02. In MPa, this converts to 1 MPa per 100 m of depth, and this value appears consistent throughout the Faja. In Canada, the conditions are far different. Some reservoirs are close to hydrostatic in pressure, but the majority of reservoirs have a pore pressure that is about 85% of the hydrostatic pressure of 10 MPa/km. Exeptionally, near deep incised river valleys or in reservoirs that overlie the collapsed zone arising from underlying salt solution, pore pressures as low as 60% of the hydrostat may be found. This means that, at an equivalent depth, Canadian reservoirs have substantially lower pressures and substantially lower amounts of gas in solution.

A similar situation occurs for the bubble point of the solution gas in the oil. In Venezuela, it appears, based on the limited public information available, that the bubble point is near the pore pressure value. In Canada, however, there are cases where the heavy oil is substantially undersaturated, with gas bubble point values that can be 70-80% of the reservoir pressure. Thus, the generally underpressured conditions and the bubble point depression mean that there is less drive energy available from gas exsolution in Canadian reservoirs.

Based on cases where the bubble point was at the pore pressure, and where accurate gas quantities were measured, the pressure solubility coefficients of CH4 in the heavy oils of Canada and Venezuela are similar, about 0.2 vol/vol/atmosphere (i.e. Henry's constant for CH_4 in heavy oil ~0.2 atm^{-1}). This converts, for example, to a value of about 50-60 scf per stock tank barrel for oil at 5 MPa pore pressure. It is interesting to note that the oils are extremely similar in terms of the amount of gas dissolved in them, once the measure is normalized using the Henry's gas solution constant approach.

There is no reason to believe that the compressibilities of the oils after all the free gas has been released is much different in Canadian and Venezuelan cases. In general, the compressibility of gas-free heavy oil is on the order of 4-5 times the compressibility of water (0.45×10^{-6} kPa^{-1}).

Permeabilities and kh/μ Values

The Venezuelan reservoirs range from 2 to 15 Darcy in permeability, whereas the Canadian reservoirs have a range of 0.5 to 5 Darcy, and most of the Heavy Oil Belt reservoirs are from 1 to 3 Darcy average permeability. Indeed, based on back-calculations from tests on wells in the northern part of the Faja, some claims of permeabilities in excess of 20 have been made. Based on granulometries and comparisons to other cases (there are no channels or vugs), it is difficult to support such high values in the absence of explicit laboratory tests on undisturbed core. Samples of Faja sand that were medium grained (D_{50} ~ 250 μm) and quite free of clay gave permeability values of less than 10 D in a state as dense as it was possible to achieve in the laboratory (ϕ ~ 34%). It is supposed by this author that there is an active foamy oil drive mechanism in these Faja wells, and that this provides an additional component of well productivity that is incompletely accounted for, and shows up as a back-fitted higher permeability than expected. It is impossible to prove this conclusively at present because of the absence of quality core, and because the well test interpretation equations in commercial software do not account for a number of non-linear effects. These effects include the presence of a strongly negative skin zone developing because of some sand production, and the consequences of a strong foamy drive because of the dissolved gas.

Nevertheless, no matter what arguments are made, the Venezuelan reservoirs in the Faja del Orinoco are of substantially higher quality than Canadian heavy oil reservoirs: they have higher permeability, slightly higher porosity and oil saturation, slightly higher formation compressibilities, higher average gas contents, lower clay content, and so on. As mentioned previously, even after correcting for all known factors, the mobility of the oil in the Venezuelan deposits appears to be from 2 to 3 times more than in the Canadian heavy oil deposits. Vertical wells in the Faja will produce substantial amounts of oil (100-200 bbl/d) even though sand is totally excluded; similar wells in Canada, albeit in somewhat lower permeability reservoirs, may produce 5-15 bbl/d.

The most common simple comparative measure of reservoir quality is the productivity measure $k \cdot h/\mu$, capturing information about the rock properties (k), the reservoir thickness (h) and the fluid properties (μ). A comparison of the Venezuelan reservoirs with the highly viscous Canadian deposits of <10°API oil is not warranted because in one case the oil is mobile, and in the other it is simply not mobile. It is more appropriate to compare the Faja deposits, with viscosities of 1000-5000 cP, to reservoirs in the Heavy Oil Belt with viscosities generally of 500-10,000 cP.

On this comparison basis, the individual beds in the Venezuelan reservoirs of the Faja del Orinoco have productivity potentials that are on the order of several times to ten times those in Canada. In units of ft·mD/cP (commonly used in Venezuela), Canadian Heavy Oil Belt reservoirs typically have values of 14-140, whereas the beds in the Faja have values on the order of 40-1000. Clearly, the production potential of the Faja reservoirs is far greater than the Canadian reservoirs.

PRESENT & FUTURE VENEZUELAN PRODUCTION APPLICATIONS

Currently, all four large Venezuelan projects are being developed by long horizontal wells with multilaterals, placed in the optimum zones (highest kh/μ). This is feasible because of the excellent reservoir conditions and because it is now technically possible to place wells in the best zones for their entire length. Such wells are expected to produce as much as 2000 bbl/d initially, and should keep producing for many years, expected to gradually decline to perhaps 200 bbl/day in 5-7 years. Operating expenses for these wells are about USD$1.00/bbl of oil; the remainder and great majority of the costs are in the development of the wells, surface facilities and transportation, and upgrading of the viscous oil.

However, on average only 40-65% (depending on the site) of the oil-bearing strata in the Faja are suitable for development using this technique. Other beds are too thin, have too low $k \cdot h/\mu$ values, have unfavorable k_v/k_h ratios because of clay laminations, and so on.

In Canada, the option of sustaining long-term production from long horizontal wells in 1000-5000 cP oil appears not to be possible. Where long horizontal wells have been successful (e.g. Cactus Lake, Pelican Lake, Amber Lake), the initial production rates have been on the order of 500-800 bbl/d, but these rates drop by as much as 35-45% per year, giving only a few years of life. Basically, the Venezuelan operating companies are using this technology because they can, thereby avoiding thermal energy expenses (SAGD), sand management expenses (CHOPS), or the uncertainties of technologies that are not yet widely accepted (PPT) or proven in the field (VAPEX and THAI).

Venezuelan conventional oil production has continued to rise until the middle of the last decade, and the perception that total oil production could not be sustained without Faja development spurred the initiation of the large projects only recently. In Canada, however, the conventional oil production peak happened about 2-3 decades ago, therefore the economic thrust to develop heavy oil resources took place about 25 years earlier (~1970), coincident with the initiation of the second large open pit mine project (Syncrude Canada Ltd.). Canadian operating companies have not had the privilege of good well productivity, therefore the thrust has been on new technologies. Within a very few years, these will become of fundamental importance to continued Faja development.

The predicted recovery ratio from the large projects in the Faja ranges from 8 to 12% of OOIP. This writer predicts that, because the capital expense of all the surface facilities (flow lines, roads, etc.) will be met by the current development scheme, the new technologies will become extremely attractive and will be adopted rapidly.

First, PPT through cheap vertical wells (many of which already exist) is directly feasible as an add-on to the existing horizontal well array after these have experienced production decline. The dynamic excitation should extend the horizontal well life and may be used in a waterflood mode, as has been demonstrated in Alberta in ~10,000 cP oil in thinner reservoirs. It is believed that this may increase the recovery ratio from the horizontal wells by a substantial amount, at least several percent and probably more, but a specific estimate is not yet possible without field trials.

Second, CHOPS is attractive for the lower permeability and finer-grained zones that generally make up from 20 to 60% of the sequence of oil-saturated beds in the sequence of stacked Faja reservoirs. Comparisons to typical Canadian cases suggest that a CHOPS well in the upper finer-grained and lower-permeability Faja strata will be on the order of twice to three times as productive as a typical Canadian CHOPS well, at a lower sand rate. This is because of the higher intrinsic permeability, the greater gas content, and other related factors. As for the PPT case, careful trials in several different horizons for prolonged periods will be required to give a quantitative estimate of the amount of extra production that CHOPS will bring, and the recovery factors that can be expected.

SAGD (and VAPEX) use horizontal wells, and the current Faja exploitation method involves 1500 m long mother wells, developed with a slotted liner. There are two options: drill a vertically offset well (above or below the mother well) within 5 m and use double-well SAGD, or attempt to initiate single-well SAGD. The writer believes that the latter is an attractive option to attempt first, and is likely to succeed if properly implemented. (Failures in the initial attempts to execute single-well SAGD in Alberta can be attributed to factors other than explicit technical difficulties with the method.)

CLOSURE (SEE TABLE 1)

There are many similarities between the large heavy oil deposits in Canada and Venezuela, suggesting that there are no barriers to the successful implementation of recently developed Canadian production technologies to the Faja del Orinoco unconsolidated sandstones. In general the Venezuelan deposits and climate present far fewer barriers to profitable exploitation. For example, the harsh winters in Canada add penalties to oil development: heavy oil is trucked, not piped, road bans restrict development in the spring, and so on. The oil in the Faja del Orinoco reservoirs is considerably more mobile than in the oil in the Canadian Heavy Oil Belt, and reservoirs are thicker with higher permeability values.

The new technologies that have been developed in Canada in the last 15 years will soon have a major impact on the Venezuelan production strategy once the period of relatively easy cold production is past. The infrastructure being developed during the current primary cold production phase will benefit the costs of these re-developments in the future.

It is reasonable to expect that 20-30% of the oil in place in both countries will eventually be produced, an amount that is approximately equal to all the oil that has been consumed in the world to date, and sufficient for about 35-40 years consumption at current rates. Likely, using the same technologies, the Venezuelan reservoirs will show higher ultimate recovery ratios than the Canadian reservoirs

Finally, it should be noted that many of the Canadian technological developments took place in small oil companies willing to take risks on new ideas. There are very few large multinational corporations that are highly active in the technology developments that have occurred. The Venezuelan development environment is geared toward large projects executed by multinational companies. Whereas this will undoubtedly be the dominant mode of development, there is great merit in encouraging small company activity in heavy oil development.

Fig 1: Location of the Faja del Orinoco Deposits

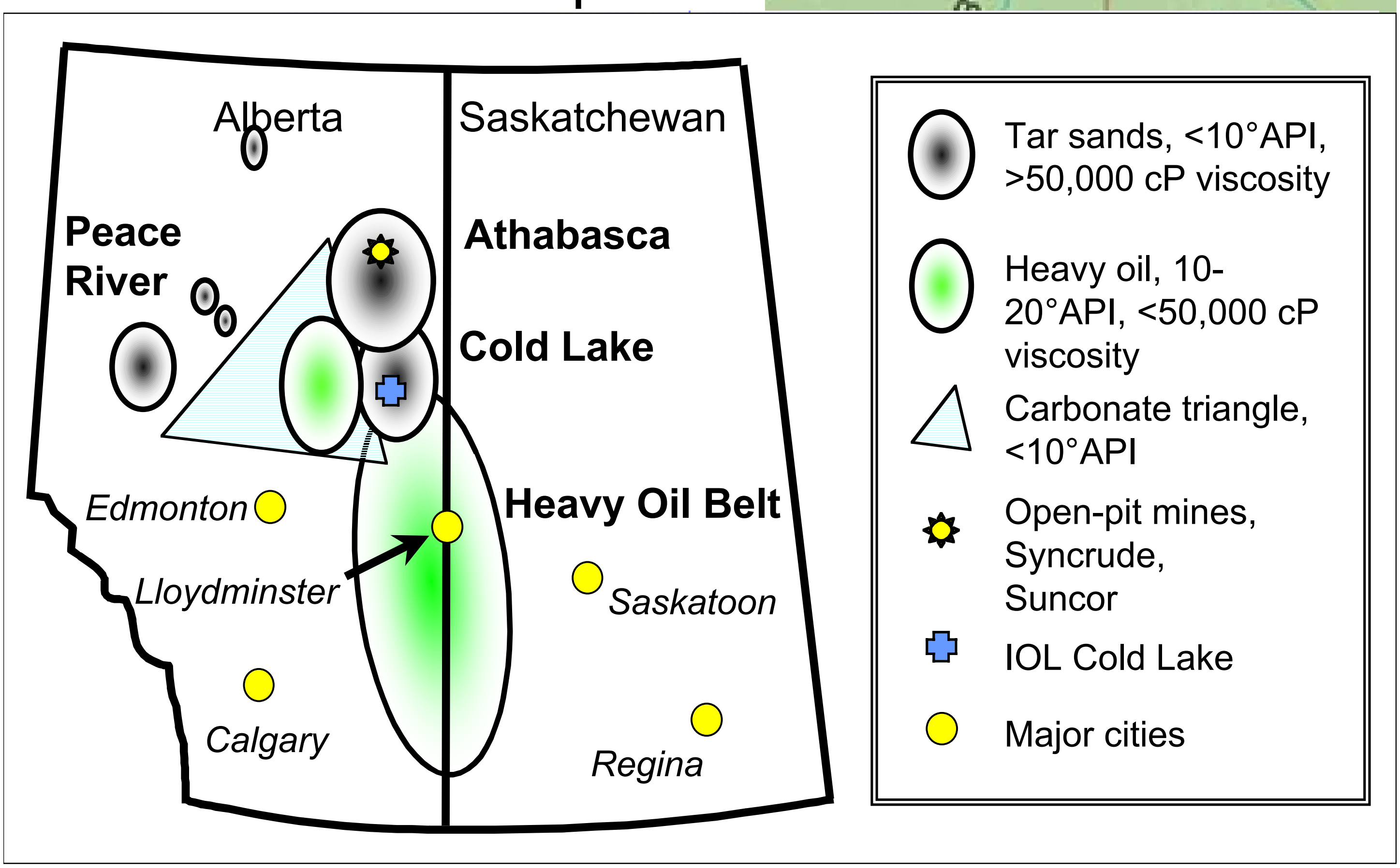

Fig 2: Location of Canadian Viscous Oil Deposits

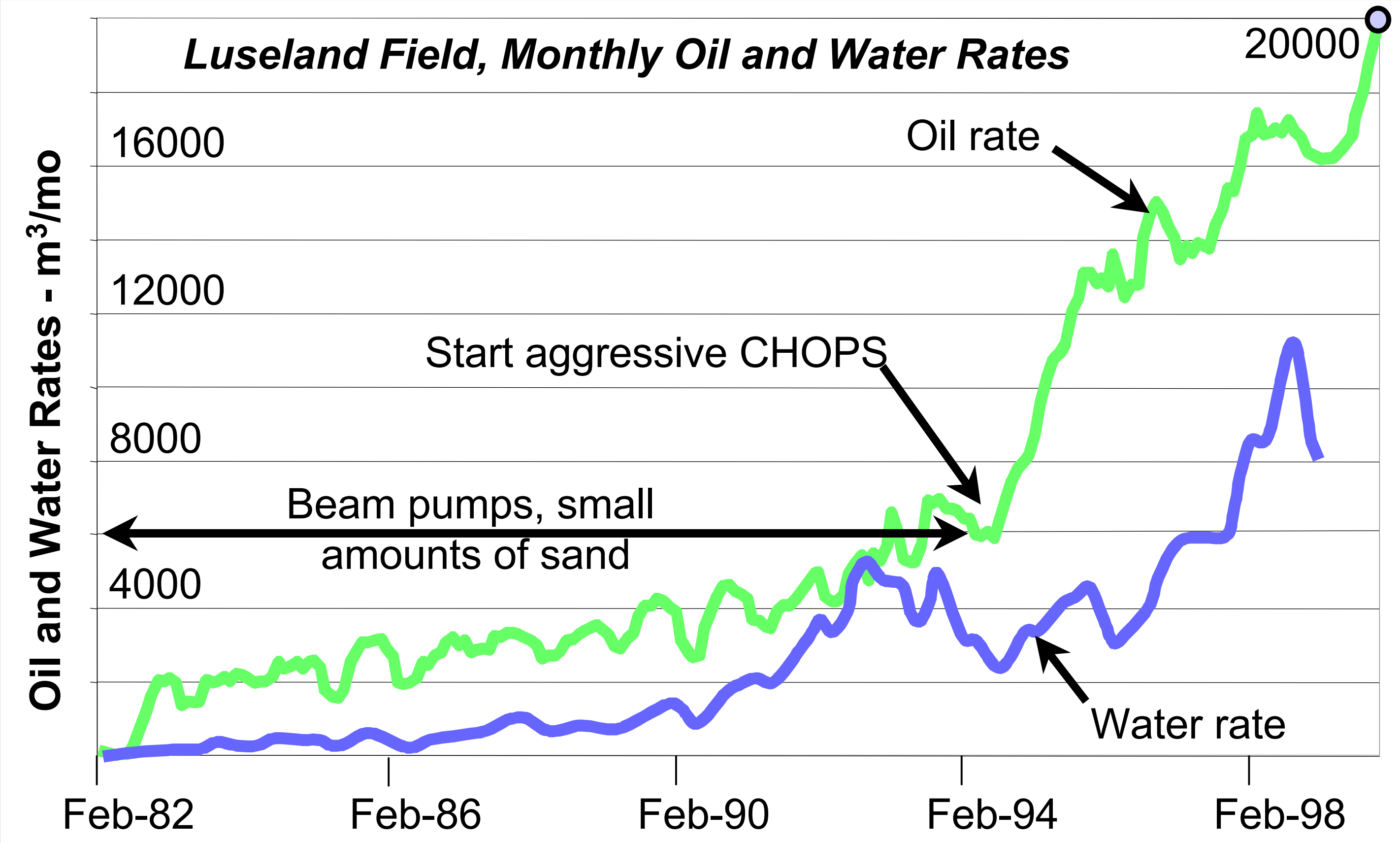

Fig 3: Field Improvement through CHOPS

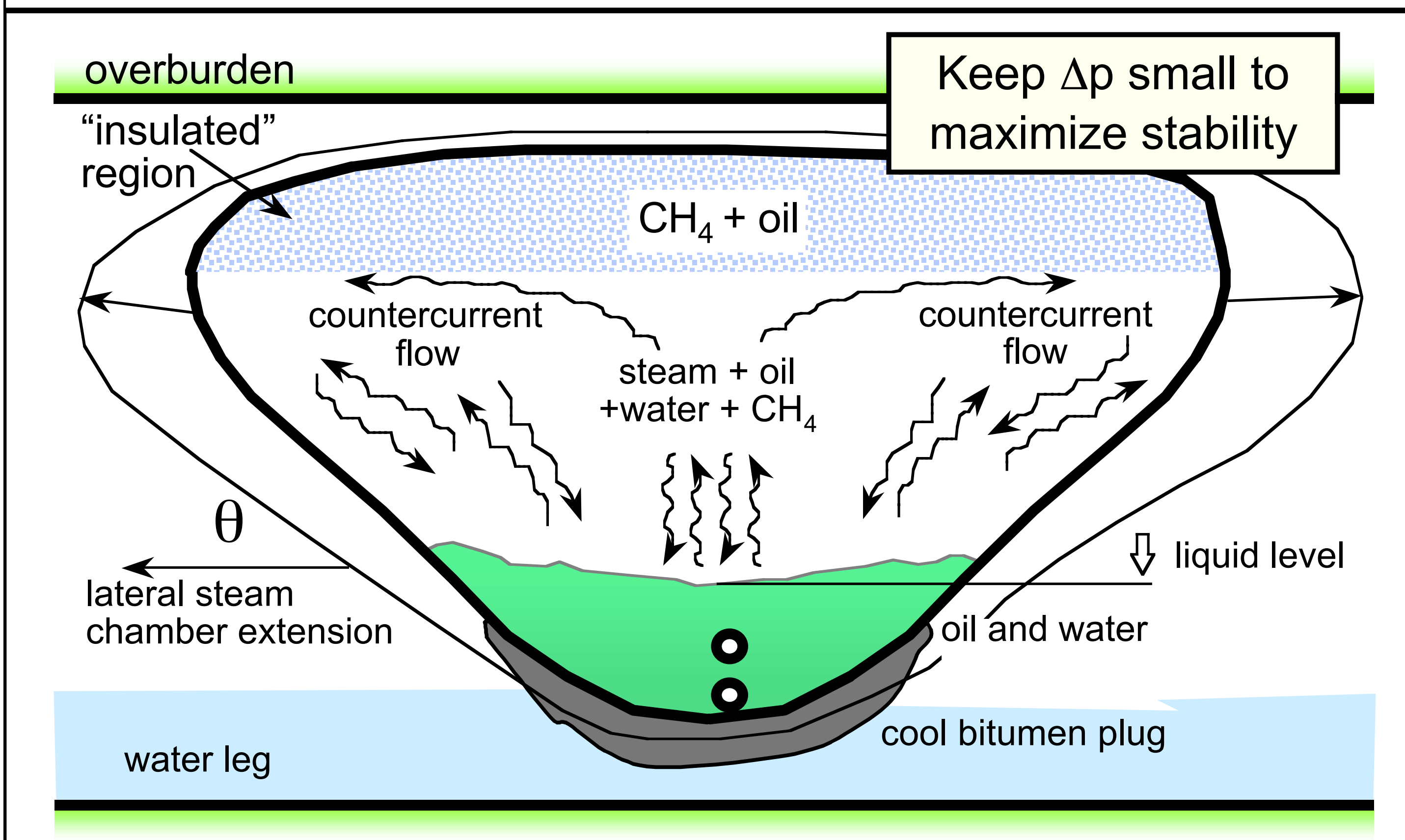

Fig 4: Basic Elements of SAGD (& VAPEX)

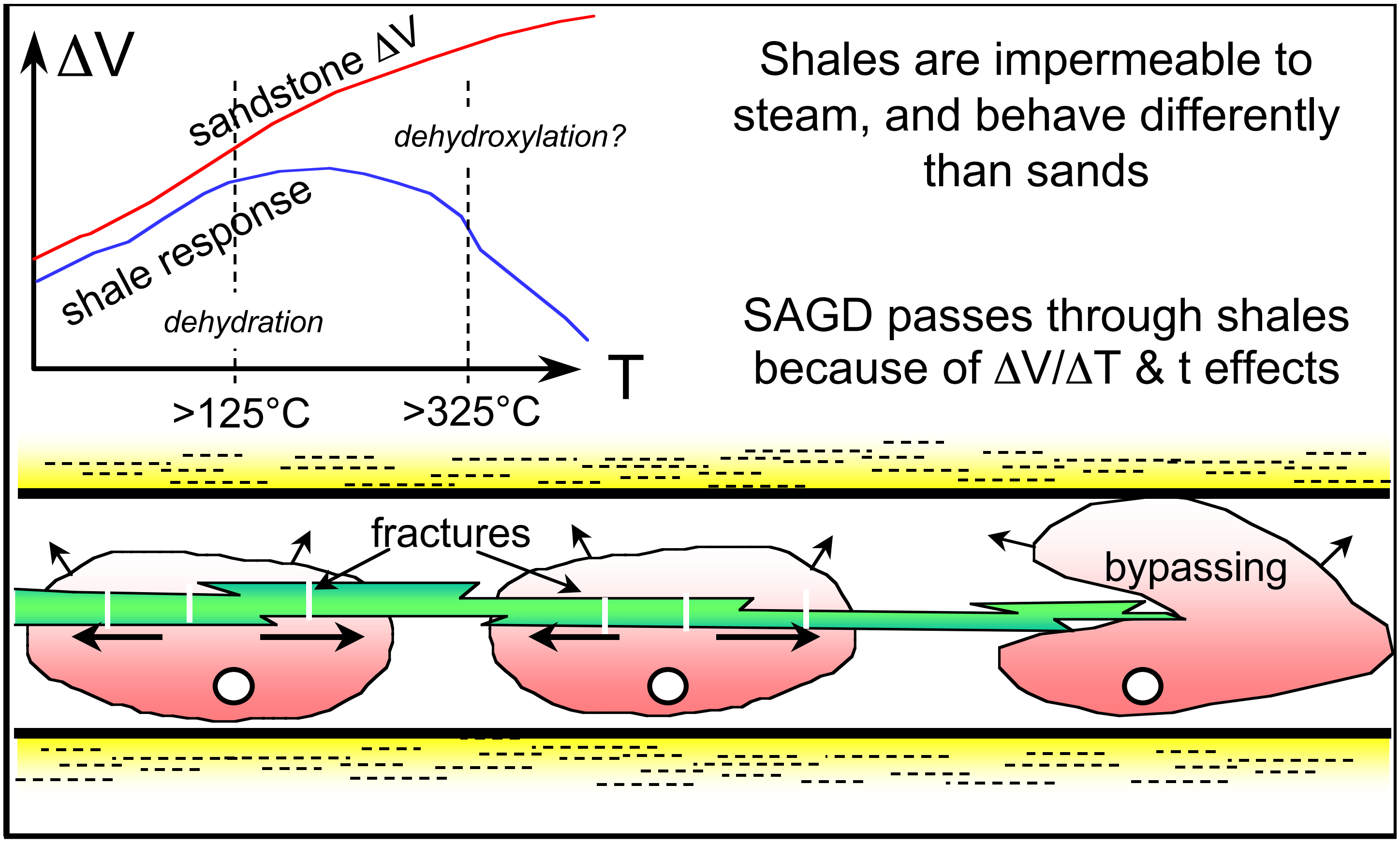

Fig 5: SAGD Passes Through Shale Beds

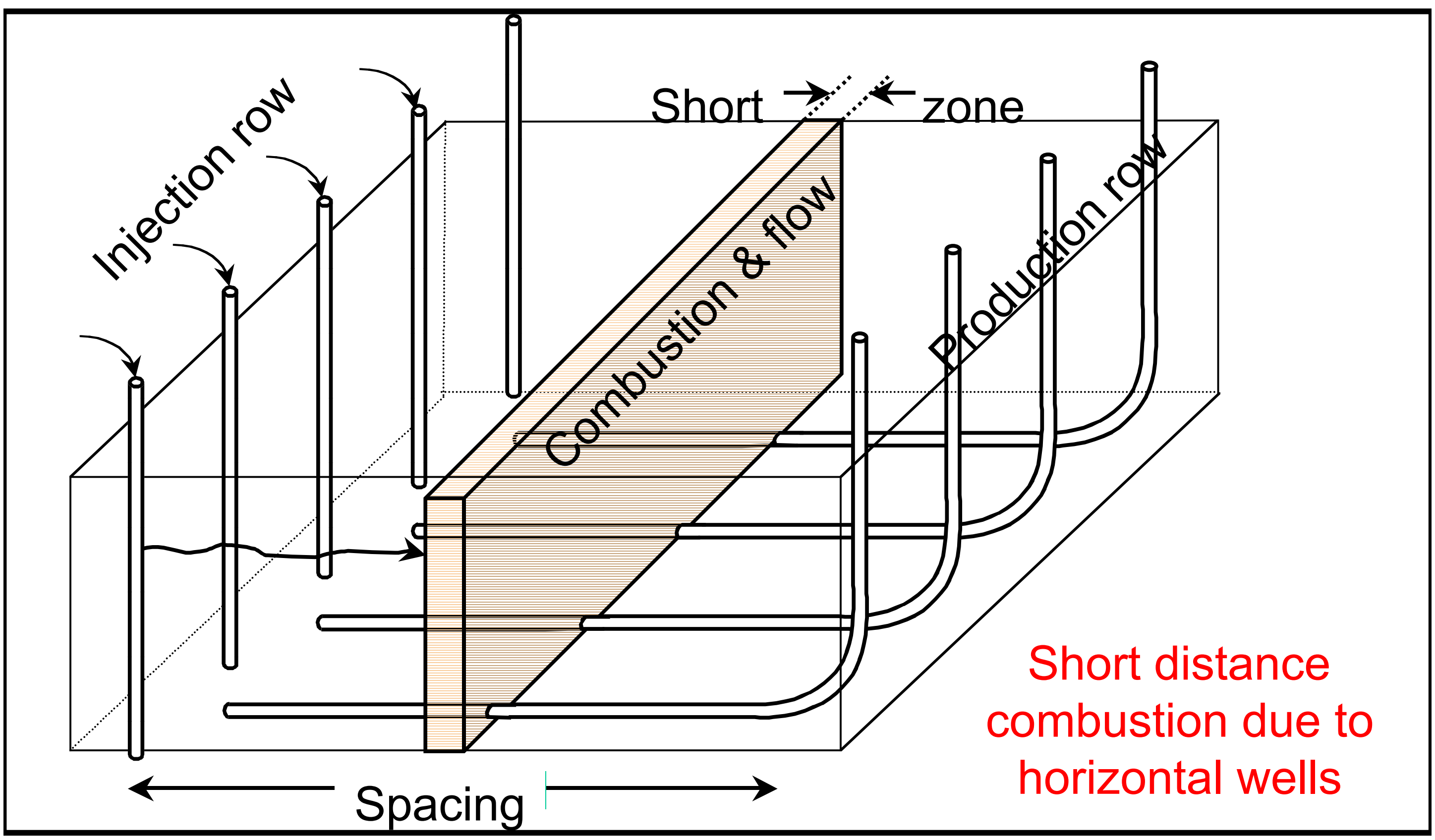

Fig 6: THAI In Situ Combustion Process

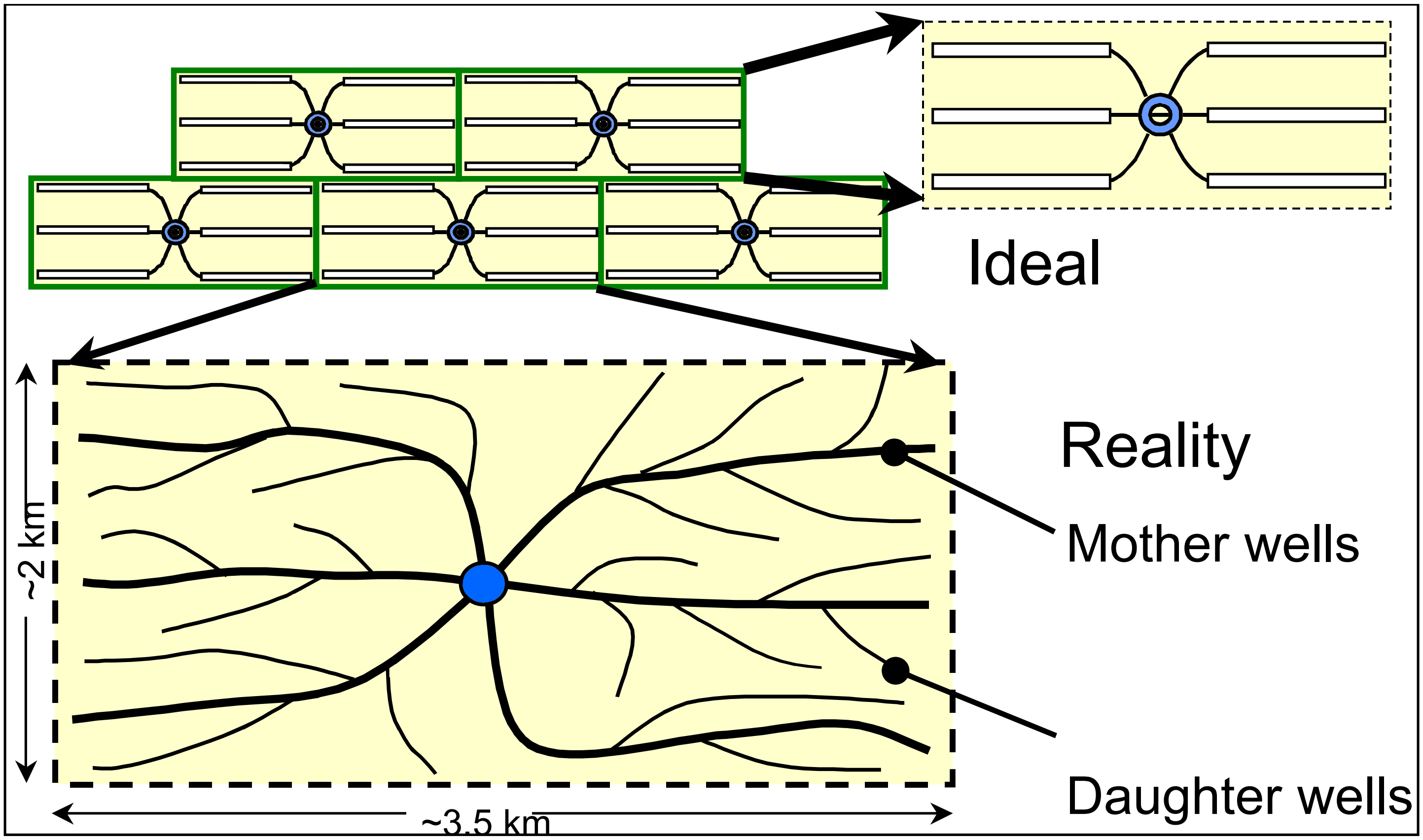

Fig 7: Multilateral Horizontal Wells

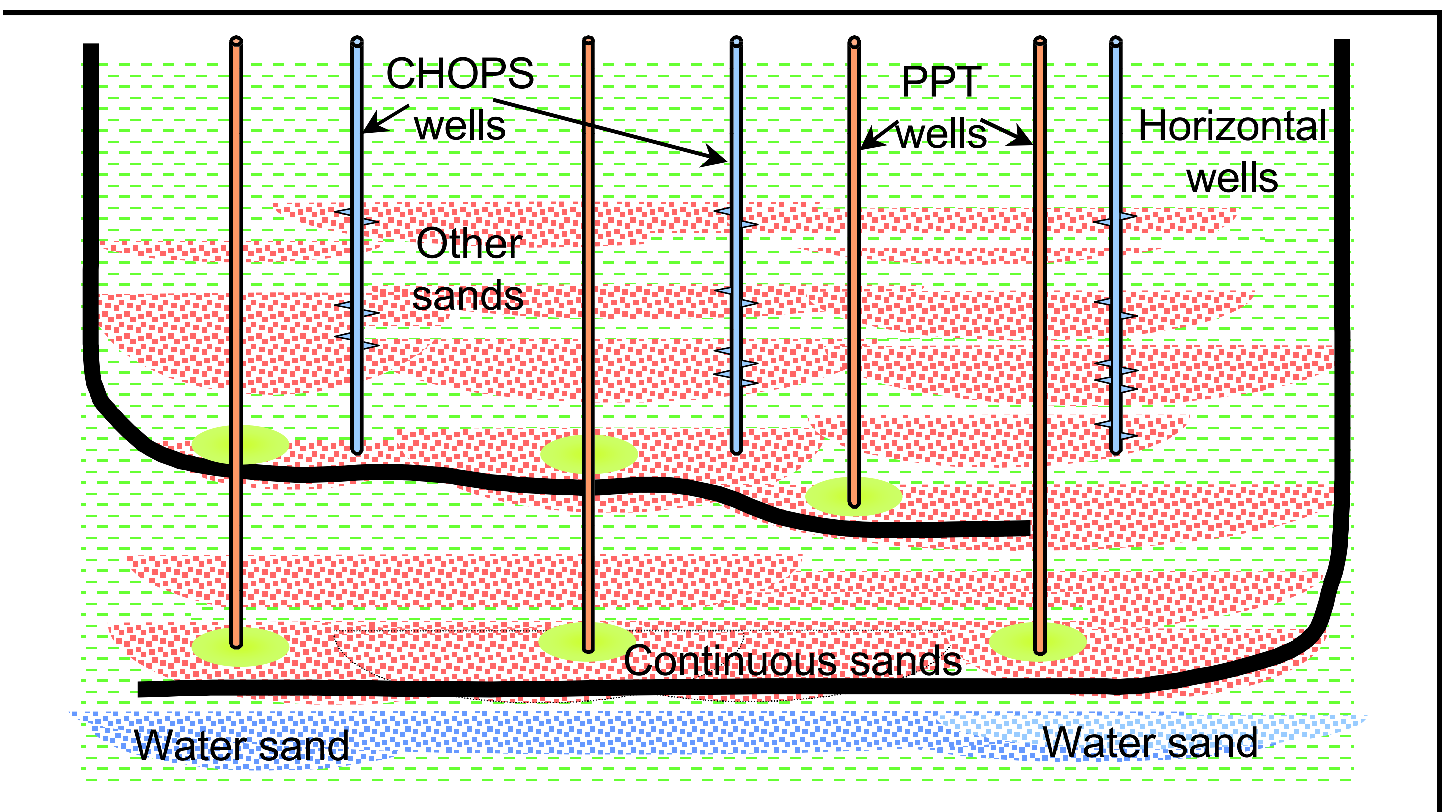

Fig 8: Mixed-Mode Development Schemes

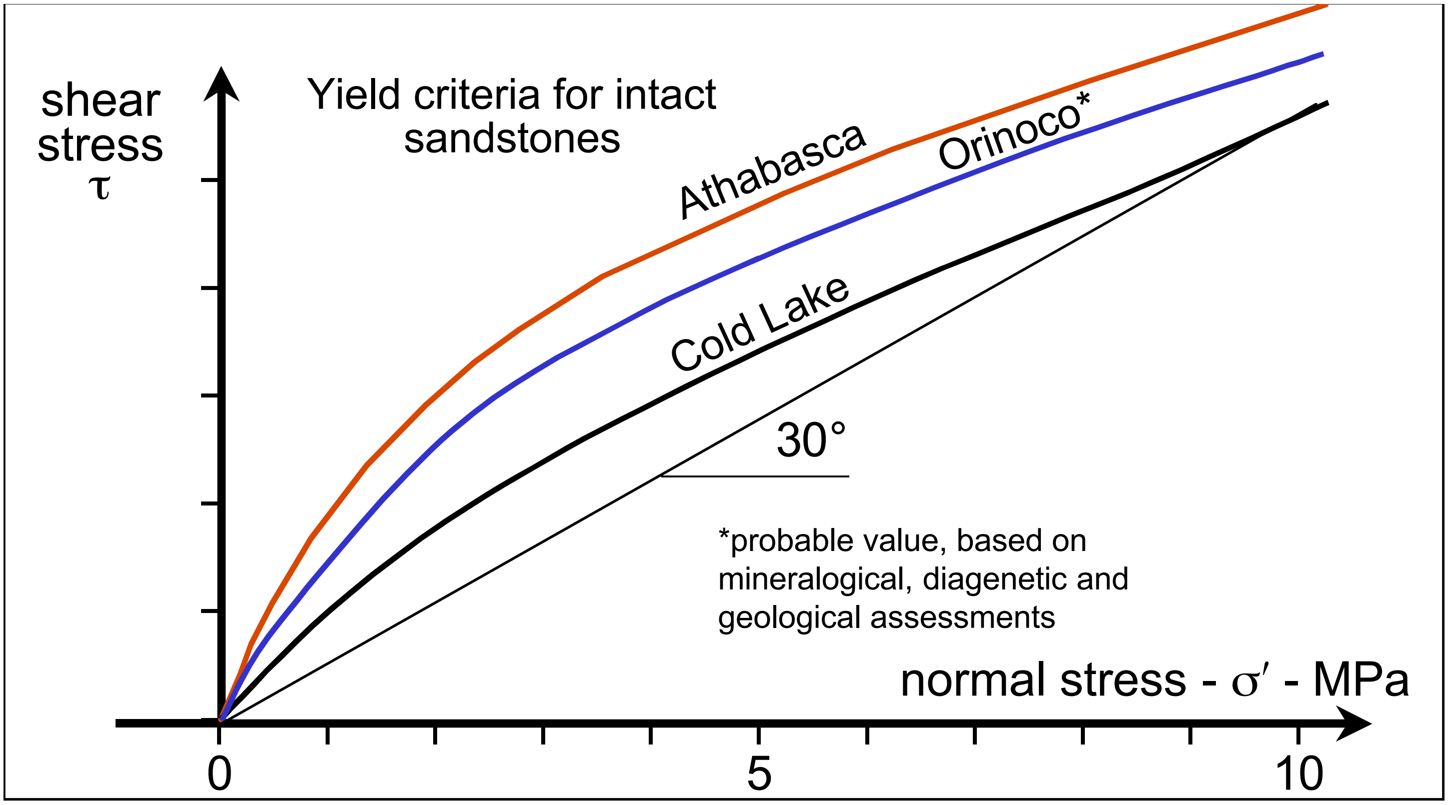

Fig 9: Comparative Strength Criteria

TABLE 1

	Units	Luseland	FAJA
Geology			
OOIP developed	E6 bbls	**90**	**100000**
Depth	m.	**730**	**450-650**
BHSP	MPa	**~6**	**4.5-6.5**
BHST	C	**30**	**60**
Avg. Porosity	%	**30%**	**31%**
Sw	%	**28% ** **	**14%**
Permeability	D	**2-4**	**5-15**
Thickness of each sand body	ft	**10-50**	**20-80**
k.h/μ	ft.md/cp	**14 – 140**	**40 – 1000**
Fluids			
API		**11-13.4**	**8-10**
Viscosity @ Pr and Tr	cP	**1400**	**1000-5000**
Rs	scf/bbl	**50 ?**	**50 - 80**
Production rates			
Spacing vertical wells	m.	**400**	**?**
Vertical wells conventional rates	bopd/sand	**2-20**	**20-250**
Wells rates	bopd	**35-350 (CHOPS)**	**1000-2000 H**
Recovery			
Primary recovery factor	%	**1-2**	**8-12 ***
Ultimate	%	**16-20**	**?**

* Horizontal wells

** Probably lower