Closed-loop Extraction Method for the Recovery of Heavy Oils and Bitumens Underlain by Aquifers: the Vapex Process

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Abstract

In previous papers(1,2,3) the authors described the results of injecting saturated ethane or propane vapours into a scaled two-dimensional model to recover heavy oils and bitumen at or slightly above the reservoir temperature. The results were encouraging. Although the scaled oil production rates were lower than those obtained with SAGD(4), they showed that it may be possible to recover heavy oils and bitumens economically using this method in conjunction with long horizontal wells. Apart from the low heat requirement inherent in the use of saturated propane, additional advantages derived from vapex are a partial in situ deasphalting and a reduction in the content of heavy metals. The resulting oil can be lighter, of a higher quality and better suited for a direct refining.

In this paper these ideas are expanded further: a development of a closed-loop extraction is described and a technique for spreading the hydrocarbon vapour underneath the oil bearing payzone is proposed to simulate the performance of a planar well. Using this concept the vapour-oil contact is greatly increased and improved production rates are obtained.

The paper discusses scaled physical model results for Peace River bitumen and Lloydminster heavy oil. The mechanism involved is believed to be similar to that which was described earlier on rising fingers of liquid solvent(5). Experiments are presented that show that the rate of mobilization is a function of the areal distribution of the solvent vapour. The results demonstrate that oil production rates exceed those of the SAGD in spite of the fact that no extraneous heat is injected into the reservoir. This strategy may permit the economic production of marginal heavy oil and bitumen reservoirs.

Introduction

Many heavy oil reservoirs in Alberta and Saskatchewan are thin and underlain by extensive aquifers. Bottom water frequently limits the performance of primary and thermal recovery methods. Primary production is often hampered by rapid water coning, and economic recoveries are limited to about 1 to 5% of the original-oil-in-place. Thermal methods can be inefficient and uneconomical due to excessive vertical heat losses, thin pay zones, high water cuts and steam condensation in bottom water zones.

Underlying zones of high water saturation are also common in bitumen reservoirs in Peace River. In Cold Lake, reservoirs fluids tend to migrate through the path of least resistance, i.e., via the bottom water zone, resulting in low recoveries and poor sweep efficiencies. Pilot or commercial thermal recovery operations in these reservoirs are either considered unsuitable or their location is chosen to maximize net pay thickness and to minimize bottom water thickness. As a result, until now reservoirs with an underlying aquifer have been of a lower commercial value to operators because of low productivities and high water cuts.

It is believed that when employing a saturated hydrocarbon vapour (typically ethane or propane) in conjunction with horizontal wells to mobilize and recover viscous oils and bitumens from formations, the bottom water zone can serve as a means for providing initial injectivity. Since the vapour is injected at reservoir temperature and since it is essentially insoluble in water—while strongly soluble in oil —there are no heat or material losses to the water layer. Furthermore, the mobile water layer will underride the lighter diluted oil and assist in moving it towards the production well.

The injection of hydrocarbon vapour into bottom water reservoirs is a cost effective solution that improves chances for an economic return. What is a disadvantage for steam injection becomes an advantage for hydrocarbon vapour.

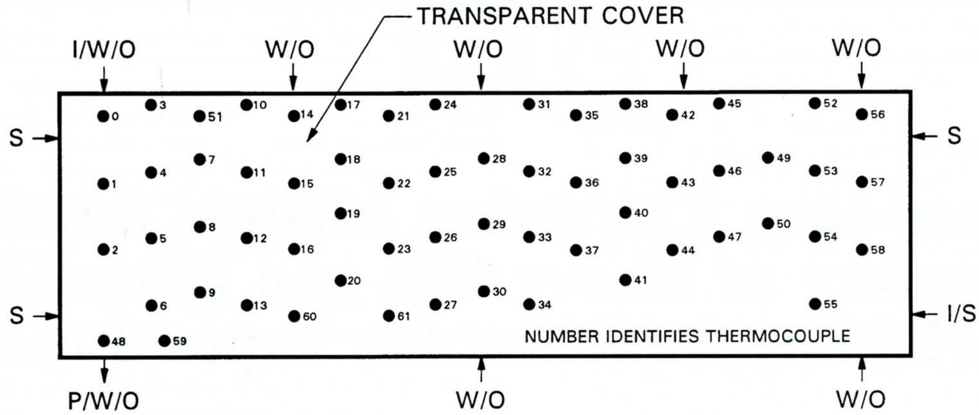
Another advantage of the vapex approach is that heat losses to the reservoir rock and overburden are negligible. This makes the process attractive for low porosity and/or thin reservoirs as well as for thicker, higher porosity reservoirs. Operation in fractured, low porosity rocks could be of interest.

Experimental Work

Closed-loop Extraction: Method and Apparatus

The experimental work utilized a scaled, vertical, two-dimensional physical model that was confined in a pressure vessel. A diagram of the cell is given in Figure 1 and the apparatus in Figure 2. The scaled model cell was made of reinforced phenolic resin sheets and was vibro-packed with 1 mm glass beads or Ottawa sand (20 – 30 mesh or 30 – 50 mesh). The injector was initially positioned above the production well (experiments without aquifer, Figure 2) or later at the bottom and across the cell (experiments with underlying aquifer). The cell represents a vertical cross-section through a reservoir payzone with horizontal injector and horizontal producer. The cell was equipped with 62 thermocouples to obtain temperature distribution as the heat front due to the dissolution of propane in oil was created and dissipated(2). A transparent cell wall made it possible to examine and photograph the undisturbed reservoir at the end of the experiment without opening the cell.

The apparatus for a closed-loop propane extraction without an aquifer is presented in Figure 2. The essential parts of the system are the gas recycle loop and the propane make-up line. The main element of the recycle loop is the propane stripper which heats up



INSIDE HEIGHT = 21.70 cm
INSIDE WIDTH = 69.80 cm
INSIDE DEPTH = 3.4 to 3.5 cm
CELL VOLUME = 5.15 Litres
PORE VOLUME = 1.8 to 2.0 Litres
THERMOCOUPLES PROTRUDE 17 mm INTO THE CELL

S = SAND FILL-UP PORT
W/O = WATER OR OIL FILL-UP PORT
P/W/O = PRODUCER OR FILL-UP PORT
I/W/O = INJECTOR OR FILL-UP PORT
I/S = INJECTOR OR FILL-UP PORT

FIGURE 1: Vapex cell with 62 thermocouples.

the propane-oil solution, boils off and recycles the saturated vapour and produces oil containing small amounts of solution gas. The solution gas separates from the dead oil and is collected above water in an inverted cylinder. A small gear pump was used in the recycle loop to move the drained oil from the well to the stripper.

Load cell readings for propane (and water in some experiments) as well as thermocouple temperatures were displayed on a monitor at predetermined time intervals and recorded on a computer disk file. The temperature readings were accurate within a degree celsius and the load cell readings within a gram.

The heat into the thermally insulated propane container was supplied by means of two electric heaters: a booster heater for a sudden increase in propane temperature (as required during the start-up) and a small heater for pressure maintenance once the required cell conditions were reached. The power consumption was determined at any given time from voltmeter and ammeter readings. Since there were heat losses to the surroundings, the supplied current was somewhat higher than that required to vapourize the propane. The line for the make-up propane to the pressure vessel formed a flexible loop to improve the load cell accuracy.

The initial communication path in experiments without an aquifer was achieved by means of an electric heater coil strung between the injector and producer well (Figure 2). Only a short interval of heating was required to achieve a communication path for Peace River bitumen and no heating was required with heavy oils. The production and propane injection lines were also equipped with electric heaters but these were used only sparingly. Experimental parameters and properties are summarized in Table 1.

The cell fill-up procedure for the experiments with aquifer

TABLE 1: Data on the cell, pressure vessel, crudes and packing.

Cell Material	Phenolic resin
Cell inside dimensions (L x W x D)	69.8 x 21.7 x 3.5 cm
Number of J-type thermocouples	62
Packing material permeability:	
1 mm glass beads	830 Darcy
20 – 30 mesh Ottawa Sand	220 Darcy
30 – 50 mesh Ottawa sand	43.5 Darcy
Porosity	0.39
Pressure vessel: max. operating pressure	8.3 MPa
typical operating pressure	0.8 – 1.0 MPa
Crude types	Tangleflags North heavy oil (Lloydminster formation) and Peace River bitumen
Oil viscosity	7,600 mPa.s at 20˚C (Lloyd) 126,000 mPa.s at 20˚C (Peace R.)
Oil density	0.979 g/ml at 15.56˚C (Lloyd) 1.0269 g/ml at 15.56˚C (Peace R.)
API gravity	12.9 (Lloyd) 6.3 (Peace R.)
Asphaltene content (70 to 80:1 pentane at 20˚C)	15.6 wt.% (Lloyd) 18.8 – 19.5 wt.% (Peace R.)
Propane (lit. data): viscosity	0.1045 mPa.s at 20˚C and 588 psia
density	0.5006 g/ml at 20˚C and 122 psia
heat of vaporization	349.2 kJ/kg at 20˚C

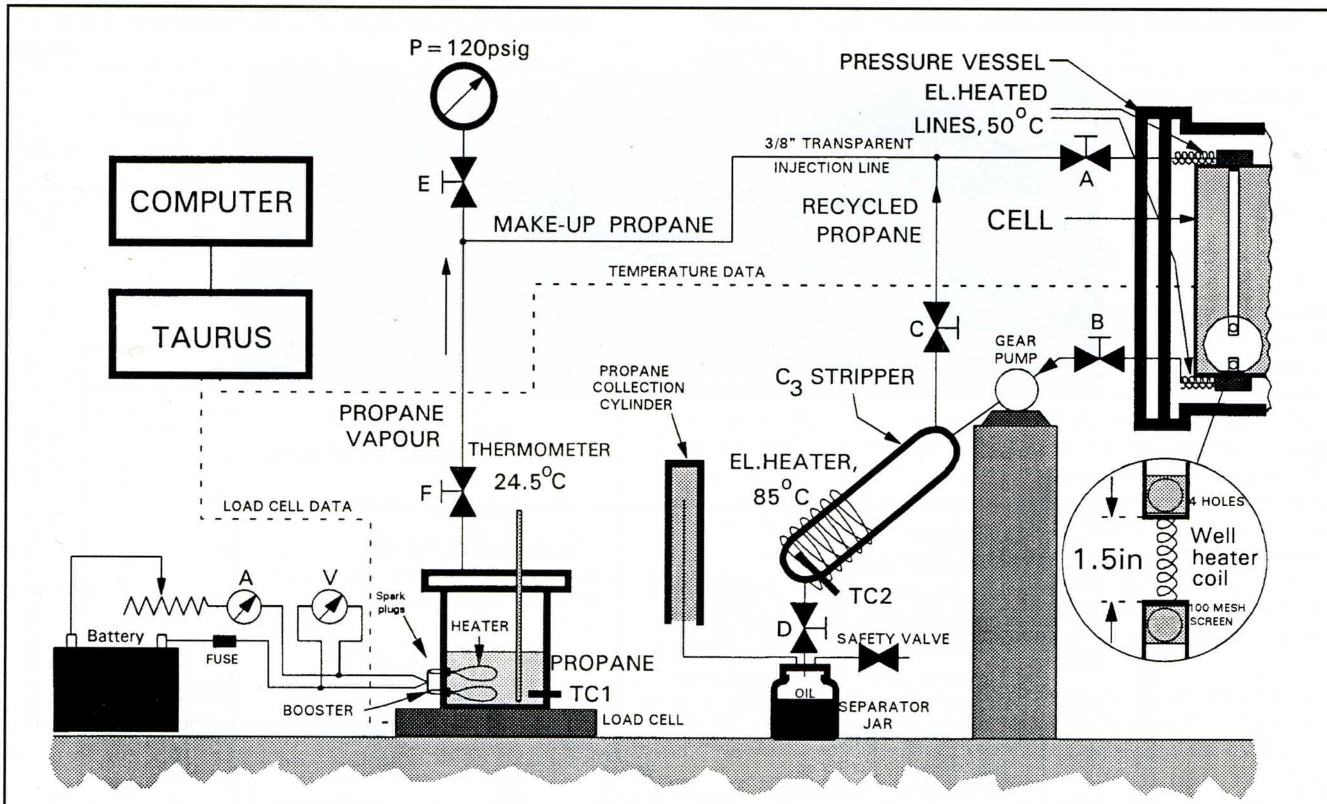


FIGURE 2: Schematic of closed-loop extraction.

involved filling up the cell with water and then partially displacing the water with oil or bitumen. A suitable water layer thickness was about one inch. In a typical filling operation the crude was warmed to 75°C and entered the cell under 3 – 5 psig pressure through several ports at the same time. This allowed the formation of almost level layers of oil and water. The densities of oil and water at the elevated temperature determined their relative position during the filling-up stage: the Lloydminster oil was filled from the top and the Peace River bitumen from the bottom. This involved turning the cell upside down for bitumen and using the same five ports (Figure 1).

In some experiments water was injected during the experiment into the aquifer at a constant rate determined by the setting of a Pulsa 7,120 diaphragm metering pump. The rate of propane injection (i.e., propane consumption) was set indirectly by the operating pressure and the rate of withdrawal of the oil and solution gas. However, in the early stages of the experiment the propane consumption usually peaked as a result of propane breakthrough, the saturation of oil with propane and the formation of an incipient vapour chamber.

Closed-loop Extraction Without Aquifer

Several experiments were carried out using Tangleflags oil and 1 mm glass beads packing with the injector at the top of the pay-zone, directly above the production well. An example of such a run is experiment 3.25 given in Figure 3. This experiment was carried out at propane pressure of 115 psig and initial temperature of 20°C. The experiment duration was eight and a half hours, during which time about 50% of the initial oil was recovered. This time corresponds to about four years in the field. The scaled stabilized drainage rate was constant at 343 bbl/d (for a 5 Darcy reservoir) until the end of the experiment.

The produced oil was moderately deasphalted at this pressure and its viscosity was lowered to about a half of its original value. The change in viscosity of the produced oil was however not uniform. After about one and a half hours of model time the viscosity reached a value higher than that of the original oil and then it sharply dropped to below 2,000 mPa.s. This type of behaviour has been observed before at lower propane pressures and is associated with local variations in drainage paths of the propane swelled oil caused by this particular well configuration.

The initial 15% of oil production is the result of a rapid displacement by propane vapour as it pushes the oil out without dissolving in it uniformly. This creates local regions of high propane concentration leading to high amounts of precipitated asphaltenes, that are swept along randomly by the vigorous movement of the oil. This results in irregular viscosity values for the samples withdrawn during and shortly after the gas displacement phase (higher than the original viscosity at 12 – 15% production followed by a sudden dip, see Figure 3). After a recovery of about 20%, the gravity drainage interface has become sufficiently established to stabilize the drainage flow and effluent viscosity. This can be seen in the production curve and viscosity curve in Figure 3.

For most Vapex experiments without the propane stripper and the recycle loop, the cumulative injected or produced gas-to-oil ratio at the end of the run reached typically a value of about 0.5 by weight, i.e., one half of a kilogram of propane was required to recover one kilogram of oil. On a volume basis, one bbl of liquid propane was needed for each bbl of recovered oil. By comparison, the steam requirement in a typical SAGD project is about 3 bbl of steam per 1 bbl of recovered oil. As apparent from the inset in Figure 3, the G/O ratio is decreased from 0.5 to about 0.13 when propane recycling is employed. The stripper thus eliminates free gas, decreases the amount of solution gas in the effluent and, as a result, lowers the propane requirement by about 74%. The purpose of the make-up gas is mainly to fill the space of the growing solvent chamber (that is devoid of oil) with saturated propane vapour. In laboratory experiments virtually all propane is recovered during a blow-down and similarly in most reservoirs the injected propane can be, to a large extent, recovered at the end of the project. Blowdown at the end of run 3.25 recovered 65% of the injected propane. The losses were the solution gas that was not collected. However, in subsequent experiments the apparatus was modified to include gas collection and the recovery was usually 99%.

The opened cell (Figure 3) revealed a large solvent vapour chamber spreading over about a half of the cell. The propane-diluted oil from the chamber was completely drained and there

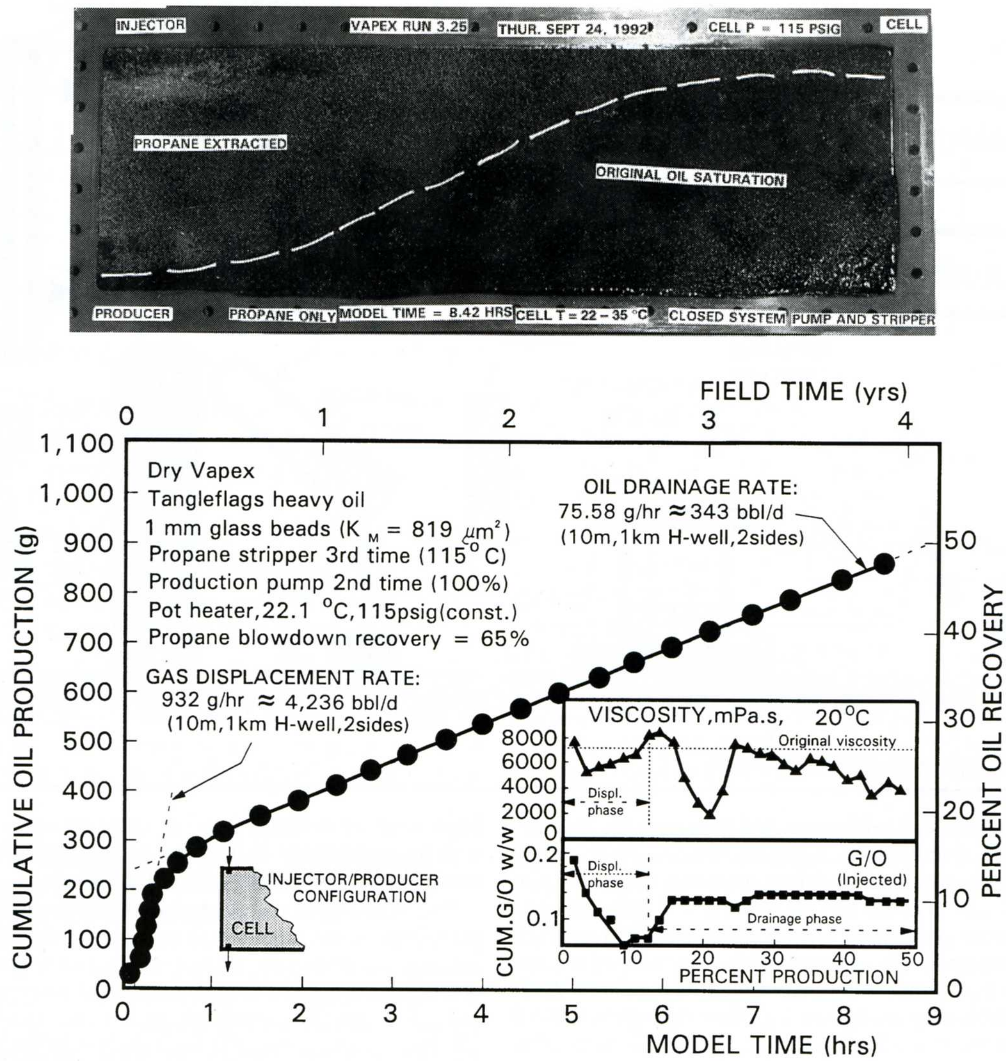


FIGURE 3: Closed-loop extraction run 3.25.

was a distinct S-shaped interface along the top boundary of the oil saturated area (highlighted with pieces of a string in the photograph). The extracted sand was dark as a result of asphaltene deposition. The residual oil saturation in this region was determined to be 3.3% but most of this 'oil' consisted of heavy fractions of asphaltenes. It is important to note that the chamber spread laterally all the way to the limit imposed on it by the size of the cell.

Energy Considerations

Figure 4 shows the propane and power usage for run 3.25. The initial propane consumption was higher due to the oil displacement by propane and the formation of a saturated vapour chamber. The initial power usage was also correspondingly higher. The propane consumption for the stabilized drainage flow was 9.1 g/hr. which should require 0.88 watts of power to evaporate the propane at 20°C and form saturated vapour. The measured power supplied into the propane container was 1.8 watts (Figure 4), the discrepancy being largely due to heat losses to the environment. The total power requirement for propane vapour injection during the experiment was 23 W.hr/865 g of produced oil. This corresponds to about 0.015 GJ/bbl of oil. This compares very favourably with 3 bbl of steam (1.3 GJ of energy) that are used to produce a barrel of oil in SAGD.

Permeability Effect

In our earlier work on sideways leaching of bitumen[6] with liquid solvents a drainage equation for flow of diluted oil was derived, i.e.,

$$Q = 2\sqrt{2kg\phi\Delta S_o H N_s} \quad \text{(1)}$$

where k is the permeability, g is the gravity, ϕ is the porosity, ΔS_o

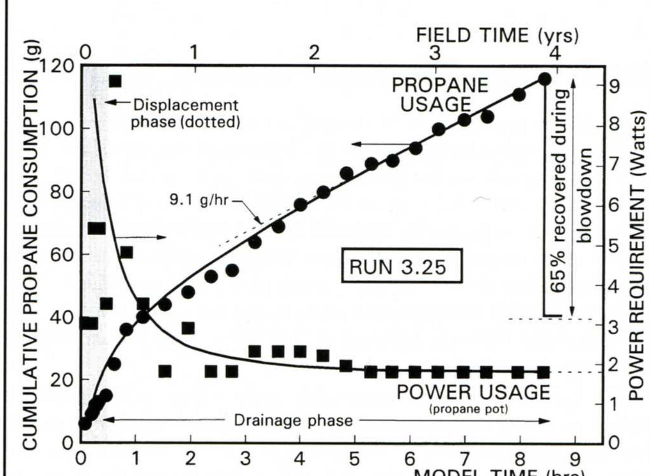


FIGURE 4: Propane and power consumption.

TABLE 2: Experimental and predicted oil drainage rates.

Run #	Model Permeability k (Darcy)	Experimental rate (g/h)	Predicted rate (g/h)
3.26	830	45.1	—
3.28	220	12.8	11.9
3.29	43.5	2.43	2.38

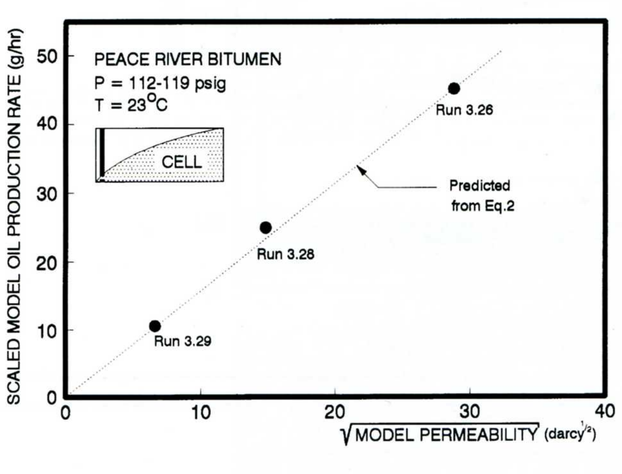


FIGURE 5: Effect of packing permeability on rate.

is the change in oil saturation, H is the drainage height and N_s is a solvent number (a function of intrinsic diffusivity, densities, solvent concentration and bitumen solution viscosity). For the same bitumen-solvent system in our scaled model with injector positioned above the producer, the solvent number, height, change in saturation and porosity may be assumed constant, so that the ratio of the drainage equations for different packing permeabilities gives

$$\frac{Q_1}{Q_2} = \sqrt{\frac{k_1}{k_2}} \quad \text{......(2)}$$

Equation (2) relates rates to permeabilities and makes it possible to predict oil drainage rates for different permeabilities.

Experiments with Peace River Crude

A series of three runs was carried out with Peace River bitumen and with cell packing permeabilities ranging from 43.5 to 830 Darcies. Using Equation (2) and the rate obtained in run 3.26, rates for the remaining runs were predicted. The results are summarized in Table 2 and plotted in Figure 5.

Propane was injected at 112 – 119 psig and 23° C. The propane dew point at 23°C and p_{bar} = 12.75 psia is 118.6 psig. The rates were determined at 10 – 15% oil production when the vapour chamber was formed and the drainage slope had stabilized. The pressure in run 3.26 was later raised to about 132 psig and the experiment continued until the rate decreased due to an intentional partial plugging of the matrix with precipitated asphaltenes.

Results in Table 2 and Figure 5 indicate that the experimentally determined oil drainage rates are 2 – 8% higher than would be expected from predictions based on Equation (2) for lower permeabilities. This result dispels the notion that finer sands are more prone to developing flow restrictions from asphaltene precipitation. On the contrary, it shows that finer sands promote mixing of fluids by providing a larger contact area for interaction between the saturated vapour and oil. The lower drainage flow is caused entirely by the sand permeability and is less than anticipated.

TABLE 3: Experimental and predicted rates of interface rise.

Run #	Interface Rise cm/hr	Predicted/Observed Interface Rise
3.39 (Peace R.)	2.5	2.9
3.40 (Lloyd)	2.6	3.3

Closed-loop Extraction with Aquifer

An active aquifer at the bottom of the reservoir creates a natural, 3D communication path that can be utilized to inject and distribute saturated hydrocarbon vapour underneath the oil formation to mobilize the oil. In the presence of an aquifer, in situ mixing of propane and oil may be further enhanced by the stirring action of water oozing through the porous sand. By injecting the saturated vapour below the oil sand, i.e., within the underlying aquifer, advantage is taken of both the percolation of the water that carries along the saturated vapour and of the gravity segregation of the lighter hydrocarbon which tends to form rising solvent chambers in the underbelly of the oil sand payzone thus diluting, draining, in situ upgrading and demetallizing the bitumen and recovering at a high production rate an oil that is lighter and of higher quality; its refining is simpler.

If there is no pre-existing aquifer underlying the main reservoir, under some conditions, an aquifer might be created at the base of the hydrocarbon deposit by hydraulic fracturing of the rock.

As opposed to spreading solvent chambers(6), where the oil production rate decreases when a no flow boundary has been reached, the vertical rise of solvent chambers occurs at a constant rate and was studied experimentally and described theoretically in our earlier work on leaching with liquid solvents(5). The presence of an aquifer is therefore beneficial as it promotes the formation of a continuous blanket of rising solvent chambers which results in a more complete contact of propane (or other hydrocarbon vapour) with the oil deposits, in a faster and more steady production rate and in a higher ultimate recovery.

Scaled Model Results

Several runs with and without water injection into the underlying bottom water sand were carried out in the scaled model packed with sand having a permeability of 43.5 Darcy using Lloydminster oil and also Peace River bitumen. Two representative experiments summarize the results. Run 3.39 with Peace River bitumen is given in Figure 6 and run 3.40 with Lloydminster oil in Figure 7. The photograph of the cell in Figure 8 shows a typical oil sand underlain by aquifer before the experiment.

In both runs propane was injected into a wide water channel created at the bottom of the cell during the fill-up procedure described earlier. The vertical thickness of this aquifer was typically about 20% (Figure 8) of the payzone. There was no water injection with the propane in the two runs and therefore water was produced only in the first two or three samples as diluted oil collected in the water sand displacing most of the water from it. After the oil breakthrough water production ceased.

The oil breakthrough in run 3.39 was delayed by four hours as a result of a slow build-up of propane pressure to the working pressure of 120 psig. About a half of the total propane consumption for the run occurred during the first hour to form the incipient saturated vapour chamber. This high initial propane consumption is characteristic of the aquifer process and does not occur with other well configurations. The resulting cooling of the propane container allowed the cell pressure to fall below the target value. Although a slower pressure build-up was desirable to avoid possible liquid condensation in the cell as pressurized propane expanded into it, the time to a breakthrough for this experiment was longer than that found in run 3.40 with Lloydminster oil.

In Situ Upgrading: Viscosity Reduction vs.

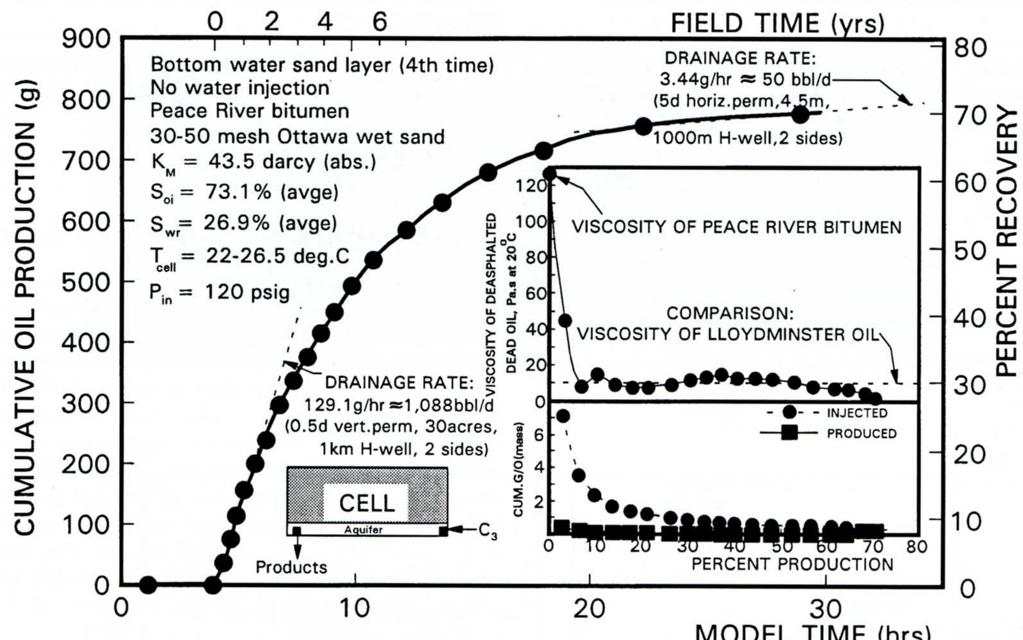


FIGURE 6: Vapex run 3.39 – Peace River bitumen.

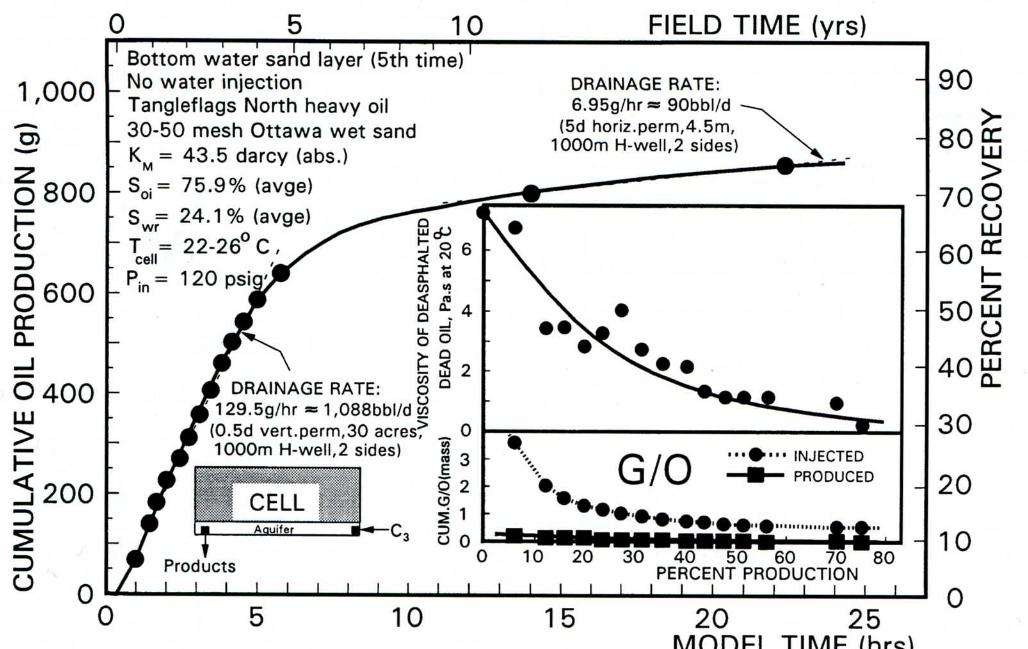


FIGURE 7: Vapex run 3.40 – Lloydminster oil.

Emulsions

After an initial period during which the propane spread underneath the oil sand establishing an initial areal contact with bitumen and displacing some water from the water sand, the production rate for run 3.39 averaged initially 129.1 g/hr. (1,088 bbl/d), declining to 3.4 g/hr. (≈ 50 bbl/d) at the end of the experiment. The viscosity of the dead deasphalted bitumen decreased from an initial value of 126,000 mPa.s at 20°C to 1,900 mPa.s at the end, i.e., the produced dead bitumen was more fluid than Lloydminster heavy oil (inset in Figure 6). This should be a definite economic advantage in pipeline transport and further processing of the produced bitumen.

The result of co-injecting water with propane is the formation of high viscosity emulsified oil and, unfortunately, this effect tends to override and negate the benefits derived from the reduction of viscosity due to in situ deasphalting. In a recent experiment with conditions identical to run 3.40, water was co-injected with propane at a rate of 120 g/hr. The produced samples of the dead emulsified Lloydminster oil exhibited viscosities in the range 30 to 40,000 mPa.s for most samples with a maximum of 60,000 mPa.s and the API gravity dropped by one – two degrees. The resulting initial unscaled oil production rate diminished from 129 g/hr. (for run 40) to 108 g/hr. and the cumulative production in 12 hours reached 52% as opposed to 70% in run 40. Similar rate reductions were observed in earlier runs where water was co-injected at high rates.

The viscosity of the draining live oil is largely determined by the solvent (liquid propane) viscosity. This can be seen for instance from the comparison of absolute (unscaled) initial rates for Peace River bitumen and Lloydminster oil (Figures 6 and 7). The rates are identical (i.e., 129 g/hr.) in spite of the fact that the bitumen is about 17 times more viscous than the heavy oil. The conclusion that solvent viscosity carries a determining effect on the rate of drainage was first observed in our earlier work with toluene solvent[5] where the rates of rise of the drainage interface were equal, although the bitumen was 1,125 times more viscous than the oil. This fact and the absence of extraneous heat makes

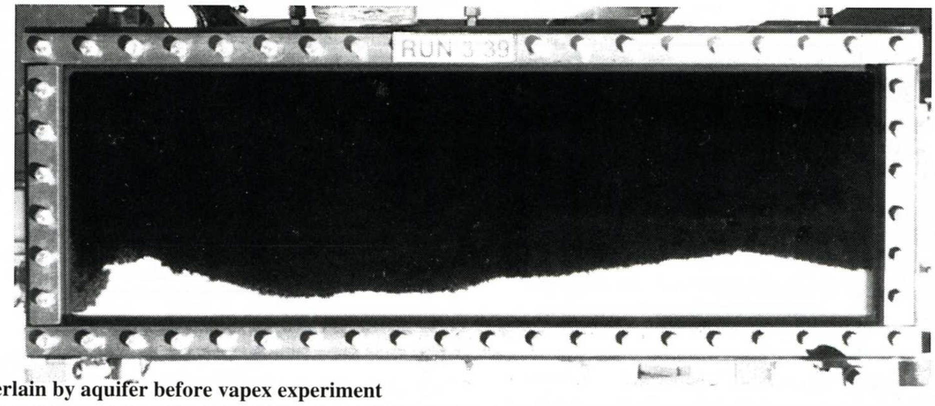


FIGURE 8: Oil Underlain by aquifer before vapex experiment

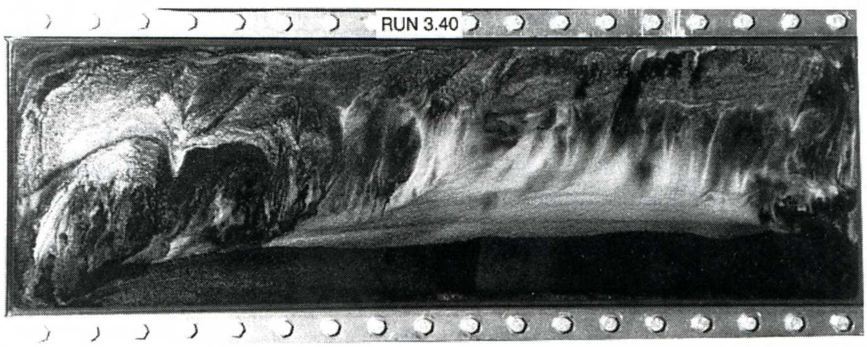


FIGURE 9: Rising solvent chambers above planer well.

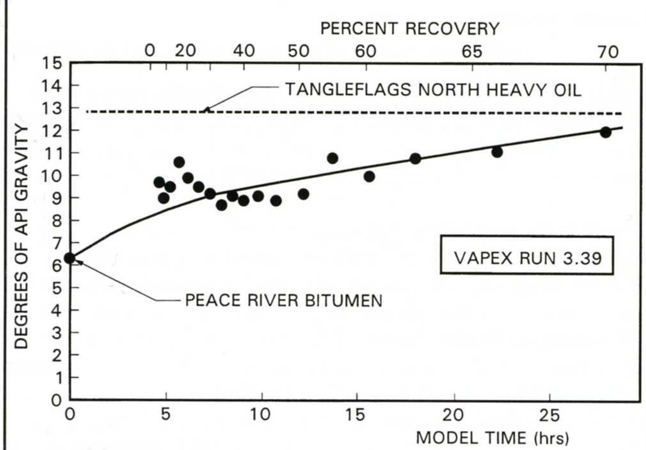


FIGURE 10: API gravity of upgraded bitumen.

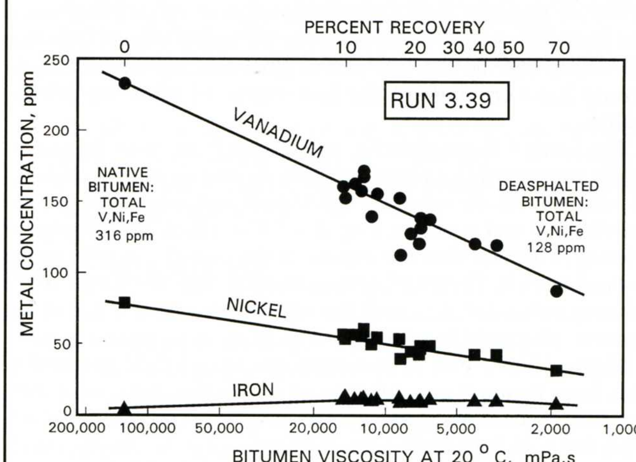


FIGURE 11: Effect of deasphalting on metal content.

the horizontal planar well process particularly attractive for the huge bitumen deposits located in northern Alberta.

The API gravity of the produced bitumen in run 3.39 showed an increase of almost six degrees over its initial value of 6.3° (Figure 10). The gravity of in situ upgraded bitumen thus approaches the gravity of Lloydminster oil. The total heavy metal content of the bitumen (V + Ni + Fe) decreased from an initial of 316 ppm to the final 128 ppm (Figure 11).

At the end of the experiment the cell displayed a band of oily material at the bottom and a yellow sand with vertical streaks of deposited asphaltenes above it. It is important to realize that although the overall bitumen recovery was 70%, the lighter fractions of oil have been recovered more completely. The remaining 30% of gooey materials left behind as deposits on the reservoir matrix have a much higher concentration of undesirable asphaltenes that contain chemically bonded heavy metals than the original crude.

Planar Well Effect

If conditions for a rapid spread of propane vapour along the aquifer (or other path such as a horizontal fracture) and a fast pressure build-up are met, the whole underbelly area of the pay-zone is contacted almost simultaneously and a horizontal planar well is formed. This situation which occurred during run 3.40 with Lloydminster crude is illustrated in Figures 7 and 12.

The view of the drained cell through its transparent cover is given in Figure 9. Recovery of 75% of the original heavy oil occurred in form of lighter deasphalted oil in 22 field years and this corresponds to the lighter sand area in the cell. The vertical curtain of streaks is characteristic of upwardly rising solvent chambers. The feeding of and drainage from these finger like cells occurs vertically as a result of gravity difference between lighter solvent vapour and heavier mobilized oil. Earlier studies on rising fingers in a liquid solvent/bitumen system showed the rate of rise

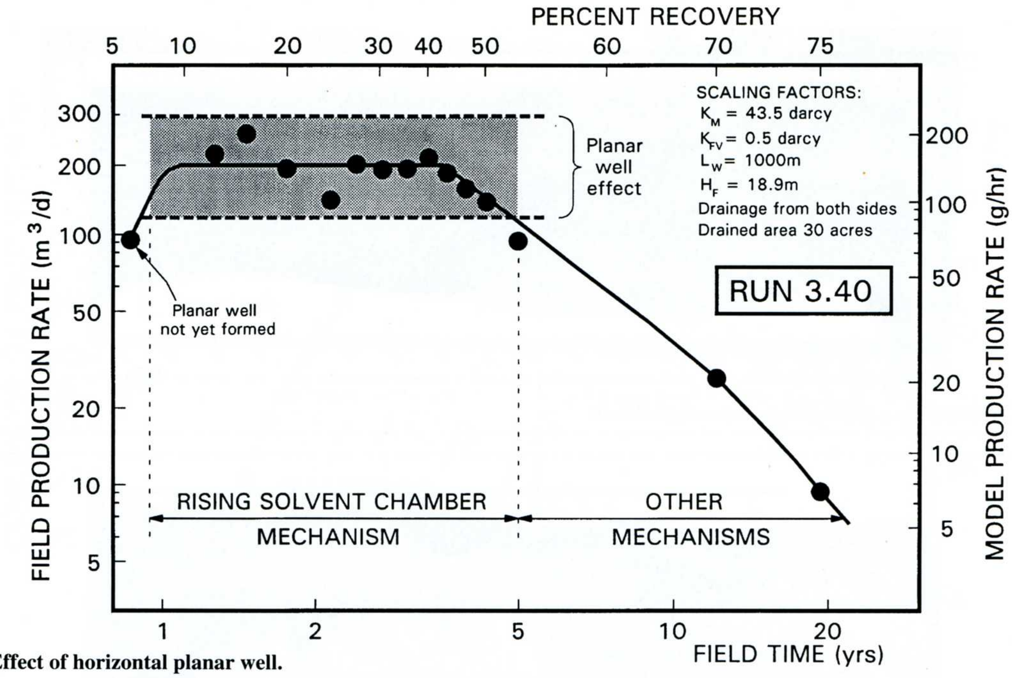


FIGURE 12: Effect of horizontal planar well.

of the interface is constant[5]. It appears that this is also true for Vapex fingers. As the interface reaches the top of the payzone, the drainage of oil slows significantly. Some of the more unusual patterns in the photograph may have been caused by the sweep of the expanding propane as the pressure was lowered during the blowdown phase at the end of the experiment.

Figure 7 shows an oil production curve characteristic of a horizontal planar well. The curve exhibits a constant high rate to about 50 – 60% recovery with a sharp transition to much lower rates. The high rate portion corresponds to the rising solvent chamber mechanism and the low rate part to other mechanisms, mostly to gravity head drainage of the last traces oil from the bottom aquifer.

The rising solvent chamber mechanism[5] involves fingers of lighter vapour rising counter currently against rivulets of draining oil solution. At the interface the vapour condenses into the oil mobilizing it and warming it up 2 – 5°C[2]. Since the oil-propane solution is heavier than the vapour, it drains under gravity to the production well. The interface rises steadily until the supply of oil has been exhausted, i.e., until the interface reaches the top of the payzone. That point is marked by a sharp break in the rate curve.

Figure 12 is a plot of instantaneous scaled field production rates from Figure 7 as a function of scaled field time (or recovery). The shaded area marks the constant rate over a period of 4.6 years for a 18.9 m thick Lloydminster reservoir, during which more than 50% of the total oil is in situ upgraded and recovered. The drained area was 30 acres and the scaled rate averages about 1,200 bbl/d for a reservoir with a vertical permeability of 0.5 Darcy. The scatter of rates can be attributed to slight variation in experimental conditions, incomplete emptying of the stripper during sample withdrawal, local heat effects in the cell and effects of asphaltene precipitation on the length of the drainage paths of the mobilized oil.

Extrapolation to the Field

The scaling of Vapex physical model results to field conditions was discussed in previous papers[1,2].

From Darcy's law it was shown that if corresponding flows are to be obtained from gravity, then

$$\left[\frac{kt}{\phi \Delta S_o H}\right]_M = \left[\frac{kt}{\phi \Delta S_o H}\right]_F \quad \text{.......(3)}$$

and, if comparable diffusion occurs in corresponding times, and the diffusivities are the same, then,

$$\left[\frac{\phi t}{H^2}\right]_M = \left[\frac{\phi t}{H^2}\right]_F \quad \text{.......(4)}$$

Equation (4) would also make thermal conduction processes similar providing that the thermal diffusivities are equal.

If ϕ and ΔS_o are the same for the model and the field, then these equations become,

$$\left[\frac{kt}{H}\right]_M = \left[\frac{kt}{H}\right]_F \quad \text{.......(5)}$$

and

$$\left[\frac{t}{H^2}\right]_M = \left[\frac{t}{H^2}\right]_F \quad \text{.......(6)}$$

Dividing (5) by (6)

$$(Hk)_M = (Hk)_f$$

or

$$\frac{k_M}{k_F} = \frac{H_F}{H_M} \quad \text{.......(7)}$$

Thus, the model should have a higher permeability than the field. However, the time scale is changed by a larger factor still. Rewriting (6) we get

$$\frac{t_F}{t_M} = \left[\frac{H_F}{H_M}\right]^2 \quad \text{.......(8)}$$

Equation (6) may be rewritten so as to relate velocities in the field to velocities in the model as,

$$\frac{(H/t)_F}{(H/t)_M} = \frac{H_M}{H_F} = \frac{k_F}{k_M} \quad \text{.......(9)}$$

These equations ignore the effects of interfacial tension and capillary pressure. These effects can be important and tend to make rates in the field higher than those predicted from laboratory models because of the increased surface area for diffusive mixing which is caused by interfacial effects in matrices of smaller pore size.

For the model experiments described here,

H_M (m):	0.217 m		
k_M (Darcy):	43.5	220	830
k_F (Darcy)	**Calculated values of H_F (m)**		
0.5	18.9	95.5	360
1.0	9.4	47.7	180
2.0	4.7	23.9	90
5.0	1.9	9.5	36

In experiments 3.39 and 3.40 a 43.5 Darcy sand was employed. In these experiments the flows were largely vertical and one would expect that the vertical permeability in the field would be the controlling factor. If the vertical field permeability is assumed to be 0.5 Darcy then, from the above table, the corresponding height of the field reservoir would be 18.9 m and the field time would be given by [Equation (8)],

$$t_F = \left[\frac{18.9}{0.217}\right]^2 t_M = 7586 t_M$$

i.e., 1 model hour = 7,586/(24 × 365) = 0.866 years. The pattern width (two sides) = 122 m.

In the model, a 50% recovery was obtained in 4.6 hours (i.e., 3.98 field years). The cumulative quantity of oil produced at that time was 570 g (0.00058 m^3). The corresponding volume produced in the field, assuming a well 1000 m long, would be,

$$\begin{aligned} \text{Field production} &= 2 \times 0.00058 \times (H_F/H_M)^2\, L_F/L_M \\ &= 0.00116 \times (18.9/0.217)^2\, 1{,}000/0.035 \\ &= 251{,}417 \text{ m}^3 \text{ (2 sides).} \end{aligned}$$

Average rate over 3.98 years = 173 m^3/d (1,088 bbl/d).

If the field vertical permeability were different from 0.5 Darcy, then the rate can be estimated by assuming[(5)] it to be proportional to k_F, i.e., for the 18.9 m reservoir in our example, the rate would be approximately 2,176 bbl/d if the vertical permeability were 1 Darcy.

As it was shown earlier[(5)], a boundary layer flow occurs during the vertical rise of solvent chambers and the rate of interface advance is therefore unaffected by the initial viscosity of bitumen (or oil). Instead, it depends largely on the solvent viscosity and solvent intrinsic diffusivity. As a result, the unscaled initial drainage rate for Peace River bitumen in run 3.39 is almost the same as that for Lloydminster oil in run 3.40.

The vertical rise velocity of the oil-propane interface for 50% recovery in run 3.40 was about (21.7 * 0.5)/4.6 = 2.36 cm/hr which, using Equation (9) is equivalent to 2.4 m/yr$_F$. This assumes that the bottom water layer is filled with drained oil.

Thicker reservoirs will take longer than in our example for the recovery to reach 50 – 60%, extending the field project by several years. If the total drainage area is 30 acres as in the example above, the rates as calculated there will also apply. However, if the area halves, the drainage rate would halve too.

The spacing between horizontal wells can be adjusted to achieve a drainage area with a required oil production rate. Alternatively, a lower propane pressure in the reservoir may lower the oil production rate from a large area to extend the project life over a longer time interval if this is desirable. The trade-off would be a lower degree of deasphalting and lower live oil viscosity resulting in lower API gravity oil being produced than would have been the case with higher propane pressure. However, the limiting factor in spacing the wells may be the ability of propane to spread quickly and uniformly throughout the aquifer beneath the oil formation. The pressure requirement for establishing the initial communication between wells must therefore be balanced against the size of the drainage area.

Conclusions

1. The closed-loop propane extraction technique decreases the cumulative gas-to-oil ratio from 0.5 to 0.13 as a result of internal recycling of propane. Make-up propane vapour is required only to fill the growing solvent chamber to replace the drained oil.

2. The heating requirements in the Vapex process are very low. This compares very favourably with processes involving the injection of steam into a cold reservoir where the heat requirements are two orders of magnitude higher. Vapex is therefore environmentally more friendly.

3. The decrease of drainage rates as a result of lower sand permeability is less than predicted from drainage equations for sideways leaching. It is thought that finer sands promote oil-propane mixing as a result of providing a larger contact area for interaction between the components.

4. An active aquifer underlying an oil zone makes the reservoir more valuable because of the opportunity it offers for spreading a hydrocarbon vapour solvent directly underneath the oil formation increasing the vapour-oil contact extensively.

5. The formation of a planar well using horizontal injector and producer results in production rates comparable to or higher than those obtained in Steam-assisted Gravity Drainage. Rates of the order of 2,176 bbl/d are possible from a heavy oil or bitumen reservoir with a 1 Darcy vertical permeability when 30 acres are drained.

6. Since the drainage mechanism for a planar well involves rising solvent chambers, the rate is dependent on the area drained. Doubling the area will double the drainage rate. The limiting factor in determining the maximum well spacing is the pressure requirement for establishing the initial communication between the wells, the rapid spread of the hydrocarbon vapour and the pumping capacity for propane input and oil removal.

7. An additional advantage of Vapex using propane vapour is the in situ upgrading of the oil or bitumen. The recovered product is much lighter, more easily transported in pipelines and of better quality for refining.

NOMENCLATURE

- F = field
- g = acceleration due to gravity, m/sec^2
- H = reservoir height, m
- k = absolute permeability, μm^2
- k_{RV} = reservoir vertical permeability, μm^2
- L = length of horizontal well, m
- M = model
- N_s = solvent number, dimensionless
- Q = volumetric flow, m^3/d
- ΔS_o = $S_{oi} - S_{or}$, change in oil saturation, fraction
- t = time
- W = well
- ϕ = fractional porosity

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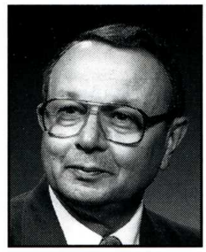
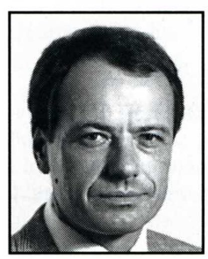
Authors' Biographies



Roger Butler occupied the endowed chair of petroleum engineering at the University of Calgary from its inception in 1983 until the end of 1995. He graduated with a Ph.D. in chemical engineering from the Imperial College of Science and Technology in 1951. For four years he taught chemical engineering at Queen's University in Kingston and then joined Imperial Oil in 1955. He worked in the petroleum industry with Imperial and Exxon in Sarnia, New York and Calgary until the end of 1982. For a year he was director of technical programs for AOSTRA until he occupied the chair at the University of Calgary. Dr. Butler's experience covers a wide range of petroleum industry research, engineering and development activities including heavy oil and tar sands production, refining, computer control and transportation. He is presently the president of GravDrain Inc., a consulting company in Calgary and a professor emeritus of the University of Calgary. During the 1987 – 1988 year, he was a distinguished lecturer for the Society of Petroleum Engineers and spoke world-wide on the subject of horizontal wells. He made a second lecture tour for the SPE in 1992 – 1993 and spoke on steam-assisted gravity drainage (SAGD) which is a process that he first described in 1978. In 1987, he was awarded the R.S. Jane Memorial Lecture award, the premium award of the Canadian Society for Chemical Engineers, and spoke on the recovery of bitumen by SAGD. He is the author or co-author of over 100 scientific papers and patents and the author of two books, *Thermal Recovery of Oil and Bitumen*, Prentice-Hall, 1991, and *Horizontal Wells for the Recovery of Oil, Gas and Bitumen,* The Petroleum Society, 1994.



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