AN OVERVIEW OF THE LOW AND HIGH TEMPERATURE WATER-OIL RELATIVE PERMEABILITY FOR OIL SANDS FROM DIFFERENT FORMATIONS IN WESTERN CANADA

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ABSTRACT
Relative permeability is a dominant factor controlling the multiphase flow in porous media and strongly affects the ultimate economics of production operations. Although a variety of correlations to predict relative permeability are available, the experimental results provide the most accurate method of relative permeability determination. Specific thermal processes have best application in certain types of geological settings, net and gross pay conditions, vertical permeability condition and for rock and fluid with certain characteristics. Accurate determination of relative permeability is a key factor for reservoir simulation.

Canada ranks third in the world in terms of oil reserves most of which in oil sands. As deposits of conventional oil and availability of better quality oil sands continue to decline, the industry is moving towards development of more challenging reservoirs, including lower quality oil sands. The paper presents an overview of the low and high temperature water-oil relative permeability data for oil sands from different formations in Western Canada collected during the period of 30 years.

INTRODUCTION
Heavy oil and bitumen account for more than double the resources of conventional oil in the world. In Canada, most of oil reserves are in oil sands. Oil sands contain 176.8 bln barrels of extra heavy oil and bitumen (Alberta Government, 2014). Extra heavy oil and bitumen in oil sands have on average 5 - 10^o API gravity and viscosity at reservoir conditions of 1 MM cP or even higher (AOSTRA, 1989). Cyclic Steam Stimulation (CSS) and Steam Assisted Gravity Drainage (SAGD) are the main in-situ thermal recovery methods in oil sands in Canada.

The multiphase flow interference effects associated with steam, steam condensate and bitumen moving concurrently through the pore system is represented by relative permeability curves. These curves play an important role in determining the speed, efficiency and ultimate economics of a thermal recovery process and the future of a particular project. As conventional oil and availability of better quality oil sands continue to decline, the industry is moving towards development of more challenging reservoirs, including lower quality oil sands. Lower quality oil reservoirs are characterized by lower oil saturation, lower permeability, lower total recovery and higher potential of thermal formation damage. Relative permeability curves for lower quality oil sands differ from that for better quality oil sands. Results of relative permeability and steamflood studies for on oil sands from different formations in Western Canada are reported presented elsewhere (Bennion et al, 2002, 2006, 2007). The paper provides an overview of such studies and some new data and observations.

EXPERIMENTAL

The Effect of Oil Sand Characteristics on Oil Recovery by Steam Injection

Canadian oil sands are located in the Western Sedimentary Basin in the Peace River, Cold Lake and Athabasca areas. Oil sands contain bitumen in the McMurray, Wabiskaw, Clearwater and Grand Rapids formations of the Lower Cretaceous period. The McMurray formation consists of uncemented quartz sand with a very uniform, mature mineralogy and little clay content, primarily kaolinite and illite. Compared to the McMurray oil sand, oil sand deposits in these three formations are more challenging. The Wabiskaw formation is typically a finer sand. In addition to kaolinite and illite, the Grand Rapids and Clearwater deposits have chlorite and smectite what increases sensitivity of such oil sands to formation damage due to steam injection.

Formation damage in thermal heavy oil and bitumen productions operations includes a variety of processes such as fines migration, mineral alterations, scale formation, wettability changes, formation of stable emulsions, etc. A better understanding of thermal formation damage related to both reservoir characteristics and operational practices is needed.

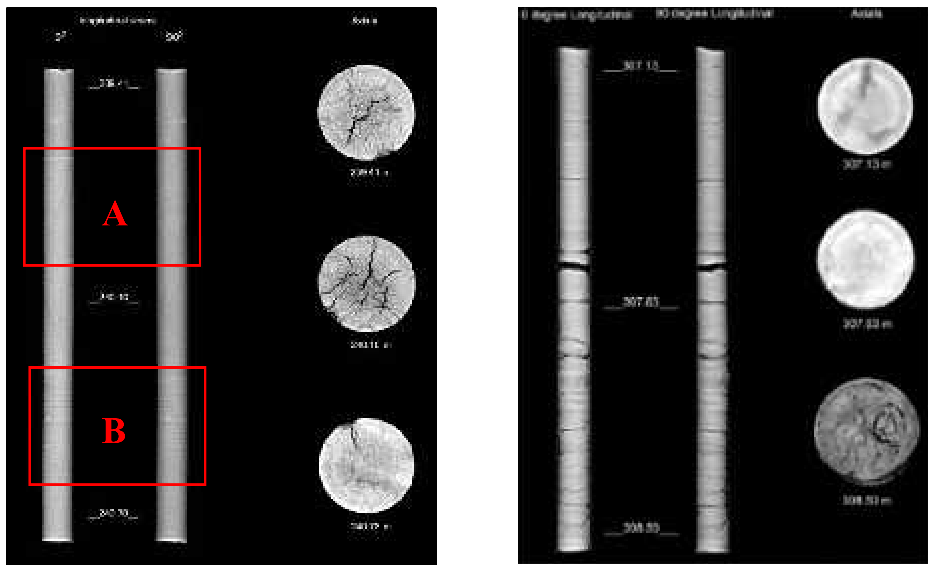
Core Preservation

Oil sand core needs to be preserved on side and kept frozen (-27^{o}C) in sealed tubes. It is important to run tests on fresh core. While being stored, even in the frozen state, the oil sand core loses formation water and becomes more oil-wet while bitumen loses light ends which leads to the higher viscosity and lower API gravity of bitumen.

Oil Sand Characterization and Sample Selection

Computer tomography (CT scan) is a very useful tool to select representative core samples for testing and it needs to be performed on preserved (frozen) core kept in tubes. Longitudinal CT scans at 0 degrees and 90 degrees and three axial scans per a 75 cm – 1m interval are recommended. CT scan images of oil sand core suitable for testing and not suitable for testing are shown in Figure 1a and Figure 1b, respectively. Figure 1a shows a better quality (massive, higher permeability and porosity) oil sand (sample A) and a lower quality (laminated, lower permeability and porosity oil sand (sample B). The upper part of the core in Figure 1b is non-reservoir. The lower part of the core is too fractured to obtain reliable coreflood data.

Petrographic analyses (thin sections, X-ray diffraction - XRD and scanning electron microscopy - SEM are recommended on the pre test core samples to characterize lithological facies. Such analysis is also useful to characterize post test core.



a) b)

Figure 1. Longitudinal and axial CT scan images of oil sand core suitable for testing: A - better quality; B – lower quality (a) and oil sand non suitable for testing (b)

Water-Oil Relative Permeability and Steamflood Test Procedure

The following procedure to obtain the low and high temperature water-oil relative permeability and steamflood data on heavy oil core has been developed:

1. Mount a full diameter core or a composite stack of native state core plugs of approximately 30 cm length (a schematic of the steamflood test apparatus is presented in Figure 2);
2. Heat the sample to the bitumen mobilization temperature (T_1) and determine baseline permeability to degassed reservoir oil at full reservoir conditions;
3. Conduct an unsteady state waterflood with formation brine to endpoint at T_1; measure oil production to water at the mobilization temperature; then conduct a “hot water” flood at increasing temperature (T_2, T_3 , T_4);
4. Switch injection fluid from formation brine to fresh steam condensate; drop backpressure slightly to generate saturated/superheated steam in the system; steamflood the sample at maximum steam temperature (T_4);
5. Increase backpressure to obtain liquid phase water again at max steam pressure and re-measure water perm to note the effect of steamflood at T_4;

6. Deplete and cool stack to the ambient conditions; dismantle stack and proceed with post-test Dean Stark for material balance;
7. Regress data to determine full low temperature water-oil relative permeability curves at temperature T_1 by using Sendra^{TM}.

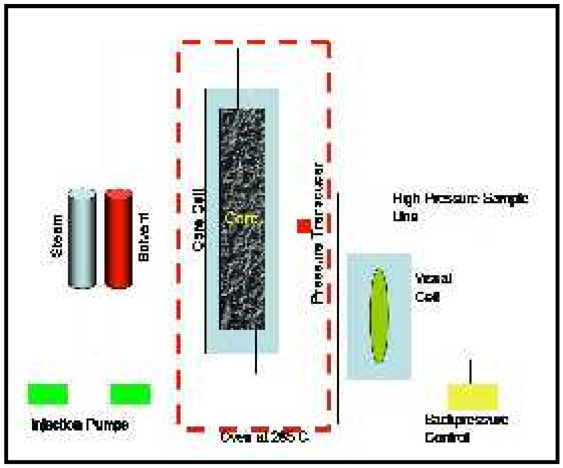


Figure 2. A schematic of steamflood experiematal set up

DISCUSSION

Oil Sand Relative Permeability Database

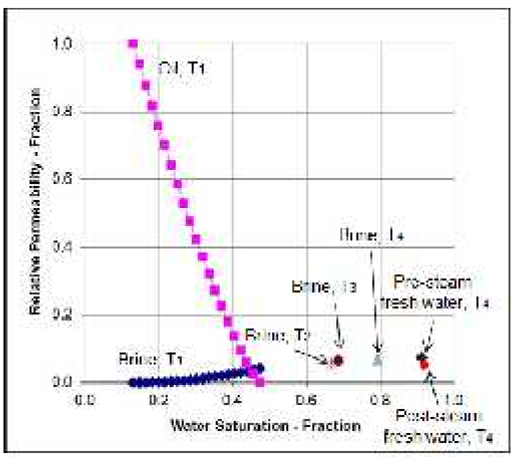
A database of the low and high temperature water-oil relative permeability and steamflood data for the Canadian oil sand from different formations has been built. A few correlations and general trends have been established. They should be used for indicative purposes only and are not meant to replace specific laboratory measurements for a particular reservoir and a specific production method.

1. Water-oil relative permeability curves are very suppressed and end point relative permeability to water is typically in the 0.01 – 0.1 range. This is due to the high bitumen viscosity compared to the low water viscosity, even at high temperature, and unfavourable mobility ratio.
2. An attempt was made to find a correlation between initial low temperature permeability to oil and measured initial oil saturation. A large data variance was observed. However, a slight increase in permeability with increasing initial oil saturation was found.
3. Residual oil saturation decreases in steamflooding in comparison to conventional water flooding at the same temperature due to the turbulence effects associated with the vaporization of pellicular films of water underlying trapped bitumen, possible changes in interfacial tension and wettability.
4. A general increasing trend of the brine permeability with increasing temperature is observed, with the largest increase in brine permeability being noted at the temperature below <100°C.
5. Data from high temperature oilfloods conducted after waterflooding to examine hysteresis effects show that as temperature increases, “trapped” water saturation

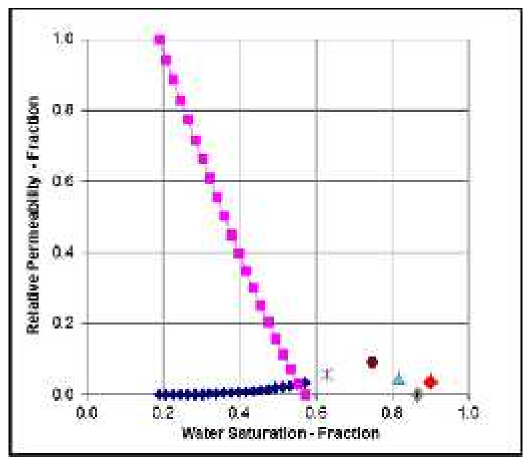
increases. That is believed to be related to a combination of poorer mobility effects and a change in rock wettability to more water-wet condition.

Examples of Relative Permeability Curves

Examples of water-oil relative permeability curves and endpoint relative permeability to brine, pre and post steam freshwater are presented in Figure 3a for “higher” quality McMurray, Figure 3b for a “lower” quality McMurray, Figure 3c for “higher quality” Grand Rapids and Figure 3d for “poorer” quality grand rapids. No formation damage, i.e. no decrease in endpoint relative permeability to water, is observed for the higher quality McMurray while there is a decrease in endpoint relative permeability to water in the test with the poorer quality core. Formation damage typically happens when the core is subjected to a hot waterflood at high temperature and is attributed to both wettability change (the core becomes more water-wet) and alterations in clay mineralogy such as kaolinite becoming smectite.



a)



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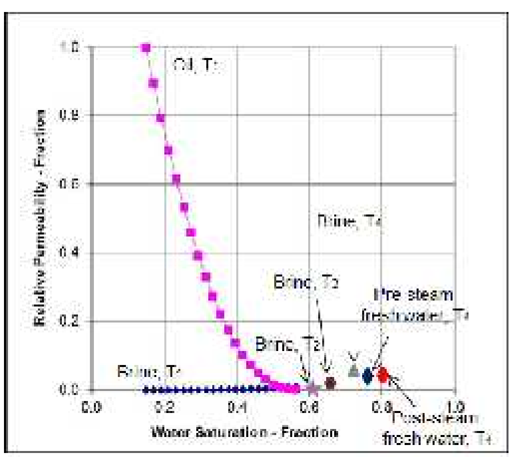
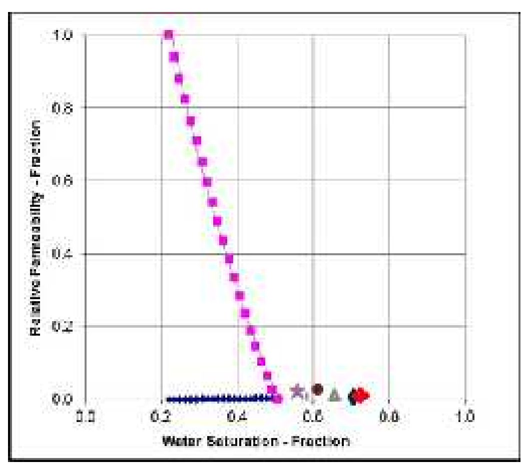


c)



d)

Figure 3. Examples of water-oil relative permeability data for McMurray oil sand, higher quality (a) and lower quality (b), and the Grand Rapids oil sand, higher quality (c) and lower quality (d)

For Grand Rapids, formation damage is observed in both cases. However, it is more significant for the poore quality core. The relative permeability curve to water is highly suppressed and goes practically to zero. That might be attributed to several factors such as (1) wettability change, (2) formation of smectite from kaolinite, (3) dissolution and re-precipitation of feldspar and some other factors.

CONCLUSIONS

1. The database of low and high temperature water-oil relative permeability for oil sands from different formations in Western Canada has been built.
2. Temperature has a strong effect on the residual oil saturation in both waterflood and steamflood and the initial water saturation in oilflood.
3. Considerable variations are observed in the dataset due to the variability in the oil sand depositional environment, reservoir quality and lithology.
4. Lower quality oil sands which typically have more reactive clay minerals, are more susceptible to thermal formation damage.
5. Thermal formation damage and permeability impairment need to be taken into account when reservoir management decisions are made.

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