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Enhanced Oil Recovery in Post-CHOPS Cold Heavy Oil Production with Sand Heavy Oil Reservoirs of Alberta and Saskatchewan Part 1: Field Piloting of Mild Heating Technologies

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Abstract

Lloydminster area that straddles Alberta and Saskatchewan border contains vast amounts of heavy oil deposits in thin unconsolidated formations. It is believed that the heavy oil resource volume is in the 50 to 70 billion bbl range which makes it a world class resource. This work briefly summarizes the reservoir properties of these formations and provides an overview of the primary CHOPS recovery mechanism which only recovers on average 8% of the original oil in place. Therefore, the target for Enhanced Oil Recovery (EOR) processes are substantial. For instance, if an additional 2% (25% of the primary) oil can be recovered, this means an additional 1 to 1.5 billion bbls of oil production which can sustain the oil industry for many years in this area providing jobs and contributing significantly to government royalties.

A number of EOR processes are reviewed in this study from the conventional water flooding technologies to more state of the art processes such as Horizontal well Hot Oil Circulation. It is shown that part of the resource with viscosities less than 5,000 to 10,000 cp can be a target for water/polymer flooding.

While steam injection in heavy oil reservoirs can be very successful, more than 95% of the resource in Lloydminster is less than 10 m thick and, thus, is not amenable to steam injection due to excessive heat losses to the surrounding formations. However, EOR processes involving mild heating or no heating can be feasible in these thinner formations. A number of mild heating technologies are discussed. Two of these technologies have been piloted in the field: Hot Water Vapour Process and Horizontal Well Hot Oil Circulation. Field results from these pilots are presented and discussed in this paper. It appears that these technologies can offer significant commercial potential in post-CHOPS reservoirs as well as in areas where CHOPS or horizontal primary production wells have not been successful.

Heavy Oil Resource in Lloydminster

Lloydminster area that straddles Alberta and Saskatchewan border contains vast amounts of heavy oil deposits in thin unconsolidated formations. While there are estimates of the amount of heavy oil in place in the order of 5.2 E9 m3 (33 billion bbl) (Brice and Renouf, 2008), it is believed that the actual number is higher more in the range of 8 to 11 E9 m3 (50 to 70 billion bbl) (Adams, 1982). The oil is found in multiple zones of thin unconsolidated aerially continuous sandstone formations and in some areas thicker channel sands with high oil saturations mostly found at a depth of 400–600 m. Most of the oil is found in the Lower Cretaceous Mannville Formation. "Cyclic bedding typically includes coal capped, upward coarsening units that grade from basal shale through sandy mudstone to sandstone, and upward fining units that grade from basal sandstone to mudstone and shale" (Coskuner, et al., 2015). The formation names in the Lloydminster area change in various locations, but the major sand units for the channel deposits and marine sands are called the Colony, McLaren, Waseca, Sparky, GP, etc. as shown in Figure 1.

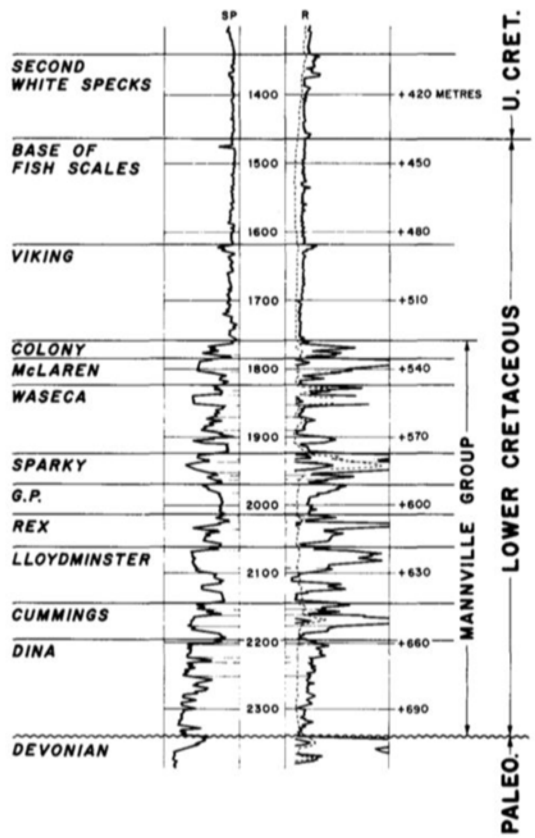

Figure 1—Stratigraphic Nomenclature of Lloydminster Area (Adams, 1982)

Maximum bedding thickness in the offshore and shoreline deposits of the Mannville Formation is about 20 m (Christopher, 2002). However, more than 80% of the oil is found in formations less than 5 m thick (Adams, 1982). It has been observed that these reservoirs are fine to very fine grained quartose sand zones with porosities in the neighbourhood of 30%, average connate water saturation of around 25% and permeabilities between 0.5 to 10 Darcy. Most reservoirs have an average permeability of 1 to 4 Darcy (Dusseault, 2002). Oil viscosity varies between 500 to 50,000+ cp and the oil gravity is in the 10 to 16 °API range. Reservoirs are typically under pressured at initial pressures of 3000 to 4000 kPa and the reservoir temperature ranges from 20 to 30 °C (Carlson et al., 1995). Most reservoirs are thought to be at the bubble point; and many initial gas caps have been found.

Cold Heavy Oil Production with Sand (CHOPS)

The target of CHOPS technology is mainly this Heavy Oil Belt. Where CHOPS is not possible and oil viscosity is moderate horizontal wells (i.e. manmade wormholes) are used both for primary recovery and also for water/polymer flooding (Wiebe, et al, 1999; Huang et al. 1998; Delamaide, 2018)

It has been recognized for a long time that the recovery of oil from an unconsolidated formations is directly dependent on the recovery of the sand itself (Kobbe, 1917). However, CHOPS was not widely implemented with commercial success until advanced pumping systems that can handle slurries with sand were developed in the late 1980's.

"Cold Heavy Oil Production with Sand (CHOPS) has been successfully implemented in many of these reservoirs, particularly since late 1980's with the large scale implementation of progressing cavity pumps with which continuous sand production is encouraged. CHOPS comprises the deliberate initiation of sand influx during the completion procedure, maintenance of sand influx during the productive life of the well without any sand exclusion devices such as screens or liners. High permeability channels called wormholes are created as a result which provide a conduit for the flow. Foamy oil behaviour, where solution gas stays as bubbles and a continuous gas phase does not form, contributes to flow enhancement (Sawatzky et al., 2002) Because of these unique characteristics of unconsolidated heavy oil reservoirs, well productivity may be 10–20 times higher in CHOPS wells than predicted by conventional Darcy's law flow equations (Smith, 1988; Han et al., 2007). Therefore, commercial production rates can be attained through this process" (Coskuner, et al., 2015). The mechanisms responsible for the enhanced production rate in CHOPS are (Dusseault and El-Sayed, 1999):

- Porosity and permeability are enhanced as sand is removed from the formation, along with any mechanical skin that may have developed;
- The oil flow velocity relative to fixed coordinates is increased if the matrix is partially mobilized. Therefore, production rate increases compared to that predicted from Darcy's law;
- Foamy oil behaviour, where solution gas stays as bubbles and a continuous gas phase does not form, contributes to flow enhancement;
- Increased compressibility and porosity dilation occur, leading to easier formation compression and compaction drive; and,
- Sand removal leads to vertical stress concentrations and lateral stress reductions, causing shear dilation, continued sand destabilization and plastic extrusion of sand to the wellbore.

Experimental evidence indicates that the first two mechanisms alone could increase the oil flow rate by as much as 5 to 50 times (Vaziri et al, 2000). Newly drilled wells typically have a sand cut of 10 to 15%, which decreases over a 6-month period and then stabilizes at 0 to 1% during the life of the well. The high viscosity, sand production, and low GOR result in numerous production problems. These have required development and application of specialized completion techniques to ensure efficient and profitable operation (Gurel, 1979)

During the first 6 to 12 month production period, a large volume of sand usually is produced (Figures 2a, 2b). A peak productivity commonly is obtained that is an order of magnitude larger than would be predicted from the radial flow semi steady-state calculation. Because most reservoirs are less than 5 m thick and closure is 15 to 30 m, most Lloydminster reservoirs probably produce from transition zones, and a mobile water phase could be present under initial conditions even in the more permeable sands. Early primary production data from many fields indicates producing water cuts of 10 to 30 %.

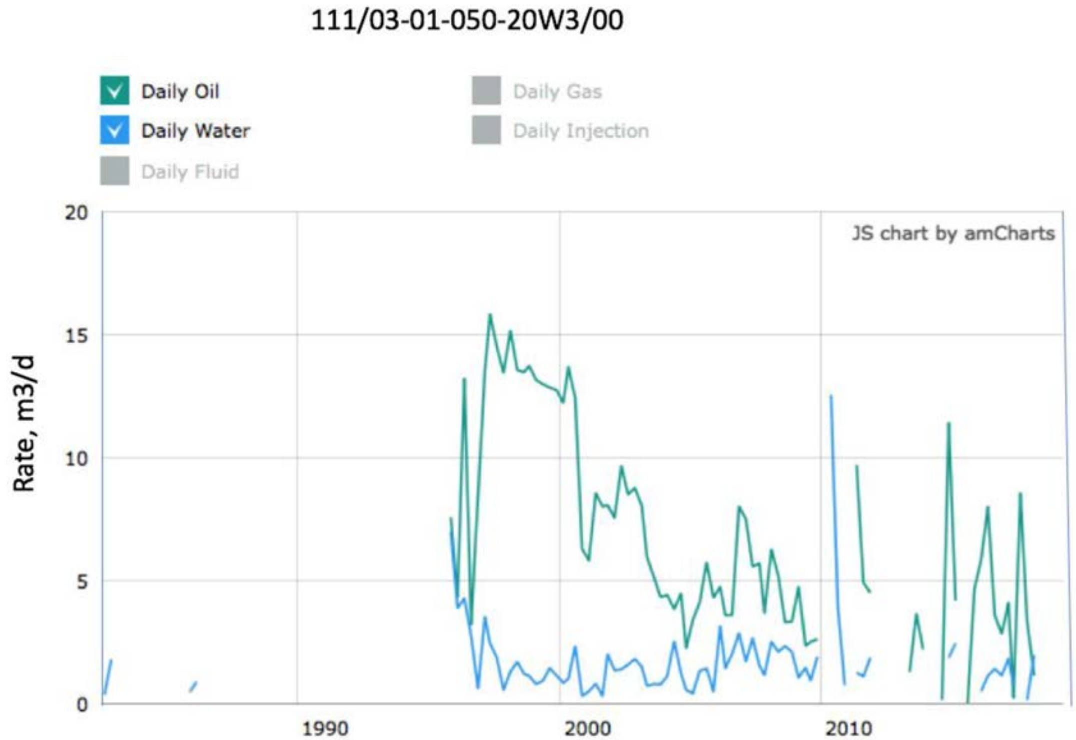

Figure 2a—A Typical CHOPS wells drilled in early 1980's before the implementation of PCP's in Lloydminster. A PCP was installed in 1995 and the production behaviour is typical of CHOPS wells. Later life includes response to CO2 injection (public data base).

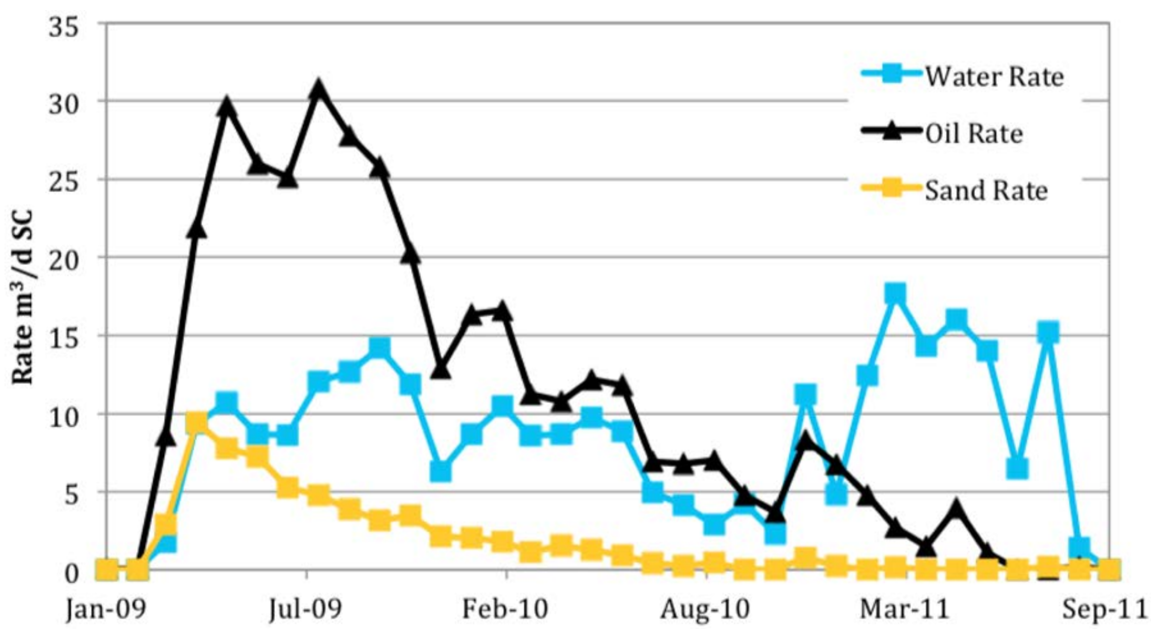

Figure 2b—Example of a Typical CHOPS Well (Lindbergh Area)

Figure 2a shows a typical CHOPS well drilled in early 1980's before the implementation of PCP's in Lloydminster. The initial oil rates of around 1 m3/d were not economic. A PCP was installed in 1995 and sand production was encouraged, wormholes were generated. The result is the production behaviour shown which is typical of CHOPS wells. It appears that there were initially some sand production/inflow issues and the oil rate peaked in 1.5 years and gradually declined over the next 12 years. This well produced approximately 40,000 m3 of oil over this time which is an excellent performance. Later life includes response to CO2 injection.

Primary reservoir drive energy for Lloydminster heavy oil reservoirs is provided by solution gas drive, rock compaction, and possibly limited edge water drive. The low initial solution GOR of 8 - 10 sm3/m3 provides little energy. Pore compressibility values indicate that for a reservoir pressure drop of 3000 kPa, rock compaction could account for up to 30 % of the primary drive energy in these reservoirs (Adams, 1982).

Therefore, high heavy oil viscosity, low solution gas oil ratio and low initial reservoir pressures result in primary recovery efficiencies that are typically below 10% (Dusseault, 2002; Gutiérrez et al., 2011). After operating in Lloydminster area for almost 70 years, Industry's experience for the primary CHOPS recovery on average is 8% of the original oil in place (Coskuner et al., 2015). This means that at the end of the primary recovery process, there will still be a very significant amount of oil left behind.

As shown in Figure 3, less than 5% of the OOIP is found in thicker (>10 m) sands in the Lloydminster area (Miller, 1987). Where there are channel sands thicker than 10 m, steam injection methods (mostly SAGD) are quite feasible and result in quite high recoveries. Many SAGD projects are successfully being implemented in Lloydminster area (JWN, 2016 and 2019; Oil Sands Magazine, 2018). However, new EOR technologies are needed for the remainder of the 97% of the resource (Coskuner, 2015). Some of the more promising technologies of water/polymer flooding and mild heating will be reviewed in this paper.

The second part of the paper will review the implementation of Cyclic Solvent Injection in Lloydmister (Coskuner and Huang, 2020)

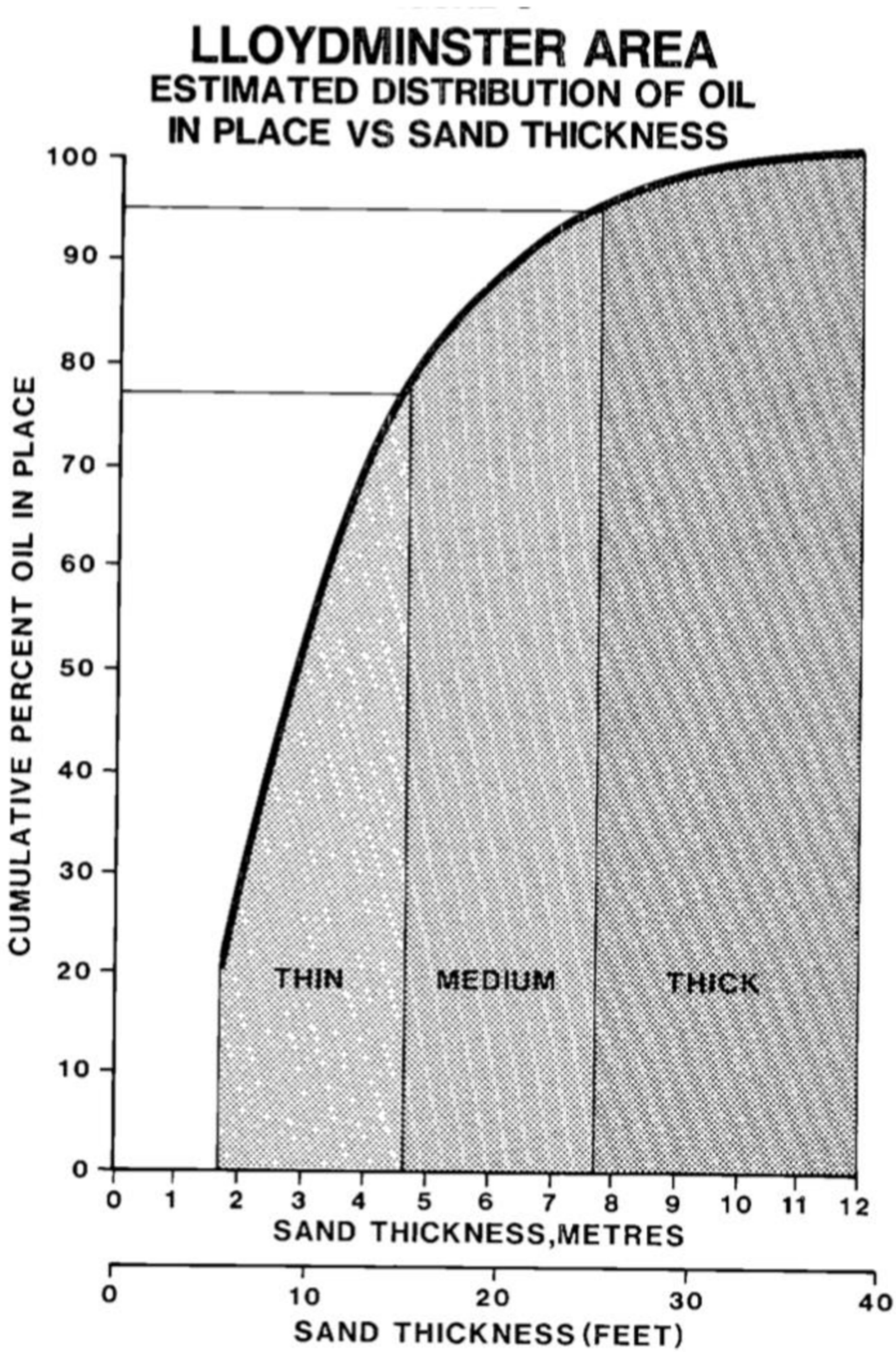

Figure 3—Lloydminster Heavy Oil OOIP vs Sand Thickness (Miller, 1987)

Waterflooding of Heavy Oil Reservoirs

Waterflooding is sometimes dismissed as an ineffective process for heavy oil fields, with development plans focused on more exotic and expensive recovery mechanisms such as chemical or thermal processes.

However, waterflooding is a relatively inexpensive recovery technology, therefore, it should be one of the EOR choices for heavy oil reservoirs where steam-based processes are uneconomical. For instance, many Lloydminster heavy oil reservoirs are thin or segmented making them poor candidates for steam-based processes due to excessive heat losses to overburden and underburden.

Assumptions concerning mobility ratio and fractional flow values found in conventional waterflood theory do not apply to heavy oil reservoirs. Therefore, this theory should not be used to make project decisions. Sometimes one may see the words 'heavy oil' in the title of a waterflood article, however, one must be careful that some conventional oil waterflood practitioners consider oil with viscosity in the range of 3 to 10 cp to be heavy oil. This is much lower viscosity than hundreds to thousands of cp oil typically waterflooded in Western Canada.

"There is a historic connection between conventional and heavy oil waterflooding, and therefore an explanation for prior theory transfer, as early Western Canadian projects were likely initiated by those familiar with conventional waterflooding. There were good responses at selected projects for them to be continually expanded, and to sustain economic performance for up to 50 years and counting" (Miller, 2005).

"In summary, the technology of Canadian heavy oil waterflooding likely started as conventional oil waterflood theory, has evolved in a generally empirical manner, and in some ways is still more 'art' than 'science.' The mobility ratio is so adverse that the 'flood' process is likely over very quickly" (Miller, 2005). The subsequent operations that focus on production at very high water cuts show that viscous oil fields can yield reasonably good ultimate recoveries under waterflood as indicated in Figures 4 and 5 Beliveau (2009). To maximize waterflood oil recovery from a viscous oil reservoir, it is important to inject large volumes of water and to handle large volumes of produced water along with the oil. Normally, 50% or more of the ultimate oil recovery is produced at water cuts of 90% or greater. Waterflood recovery is reduced for higher oil viscosities, but this can be partially compensated by means of larger volumes of injection water and reduced well spacing.

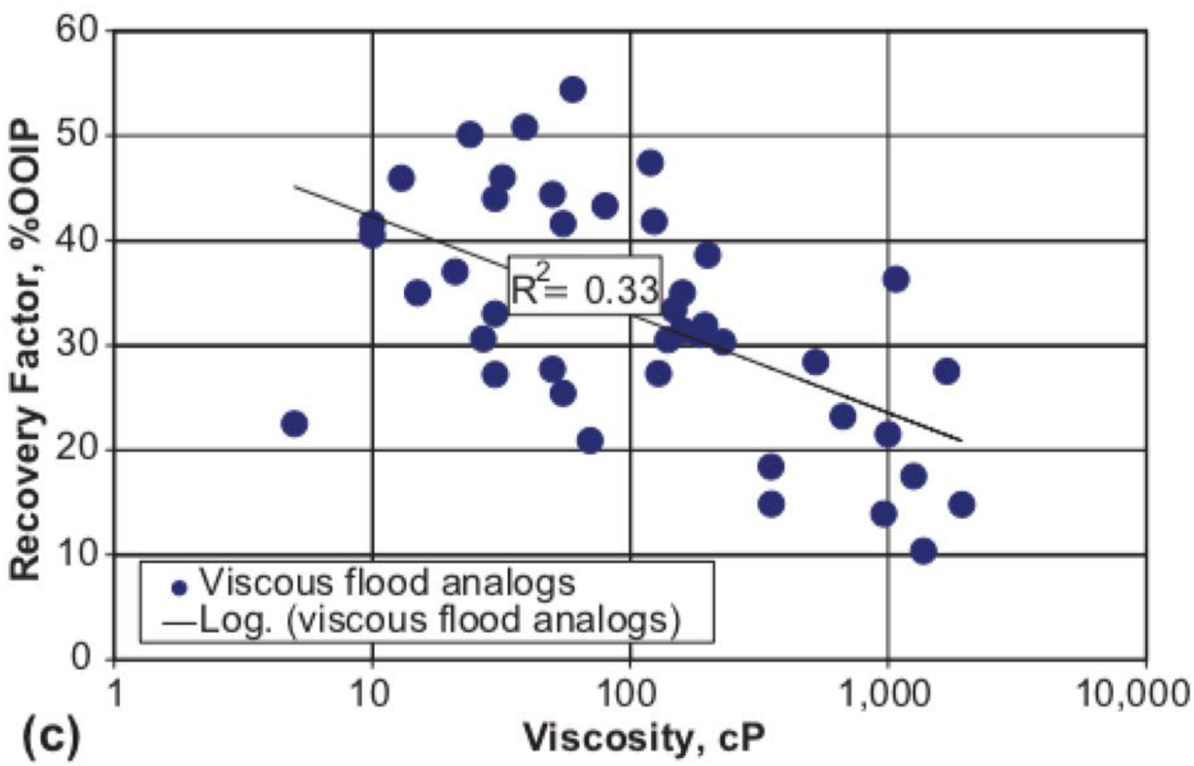

Figure 4—Heavy Oil Waterflood Recovery vs. Oil Viscosity (Beliveau, 2009)

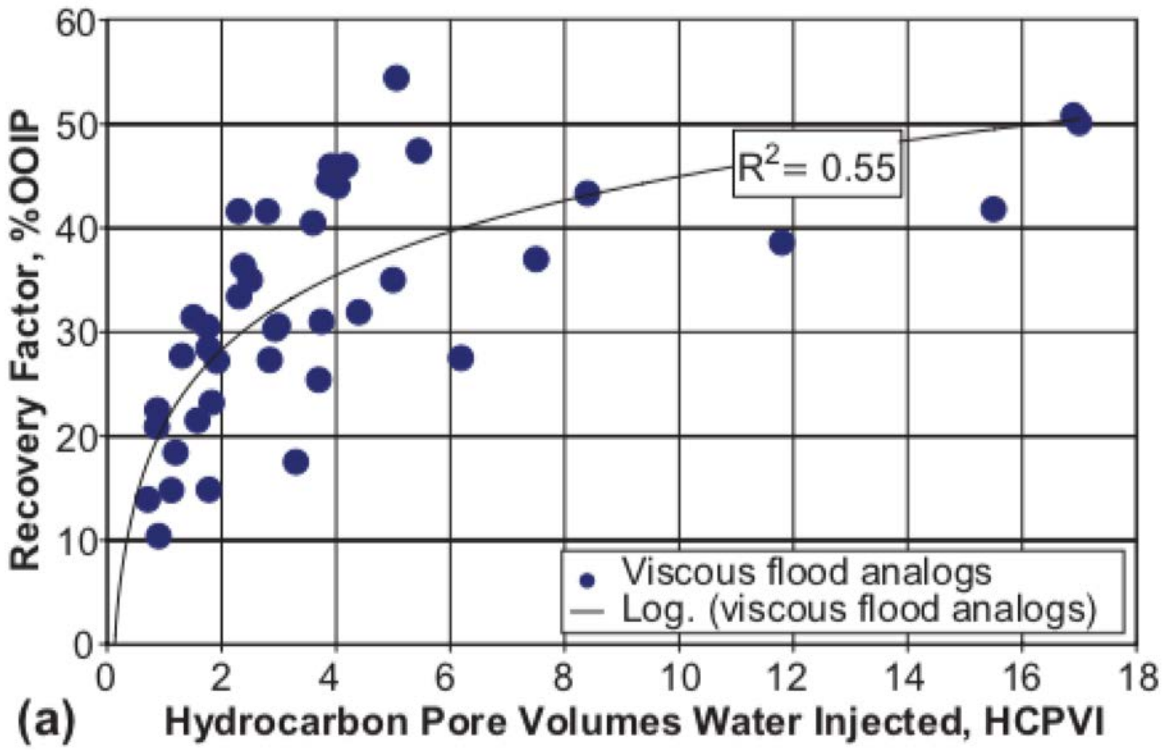

Figure 5—Heavy Oil Waterflood Recovery vs HCPV Injected (Beliveau, 2009)

Furthermore, there are quite a few steam injection projects in the Lloydminster region and this is an area of growth for the industry as mentioned above. These operations generate significant amounts of (high TDS) hot water that are disposed of usually by injecting into another zone. The hot water generated by thermal operations may present an opportunity for hot waterflooding the thinner heavy oil zones in the vicinity of these operations. Whether this process will work as post-CHOPS waterflood or as horizontal well waterflood needs to be investigated. Given the higher permeabilities in the unconsolidated sands in Lloydminster, it may be possible to inject the hot water without any treatment or with minimal treatment which would be economically attractive.

Past experience indicates that optimal heavy oil waterflood management differs from that of light oils. While it has been suggested that a Voidage Replacement Ratios (VRR) of close to 1 should be aimed for heavy oil waterfloods (Miller, 2005; Beliveau, 2009), in Alaskan heavy oil reservoirs it was suggested that the optimal (VRR) is likely less than one early in the life of a waterflood when the displacement fronts are being developed, (Vittoratos and West, 2010). The observation that, in Alaska heavy oil reservoirs, there is an extended period in the life of the waterflood where the Water Oil Ratio (WOR) ~ 1 is likely a flag for in-situ emulsion multiphase flow (see Figure 6). It can be initiated by a variety of conditions particularly the chemistry of the oil and water, shear due to high flow rates, particulates, and the shear of gas exsolution when VRR < 1. For the Alaska heavy oil reservoirs, this is observed empirically as the VRR's of several different pools, operated to maximize oil recovery, converge to the same optimum VRR of 0.7. It is not clear if the same approach would apply to polymer floods.

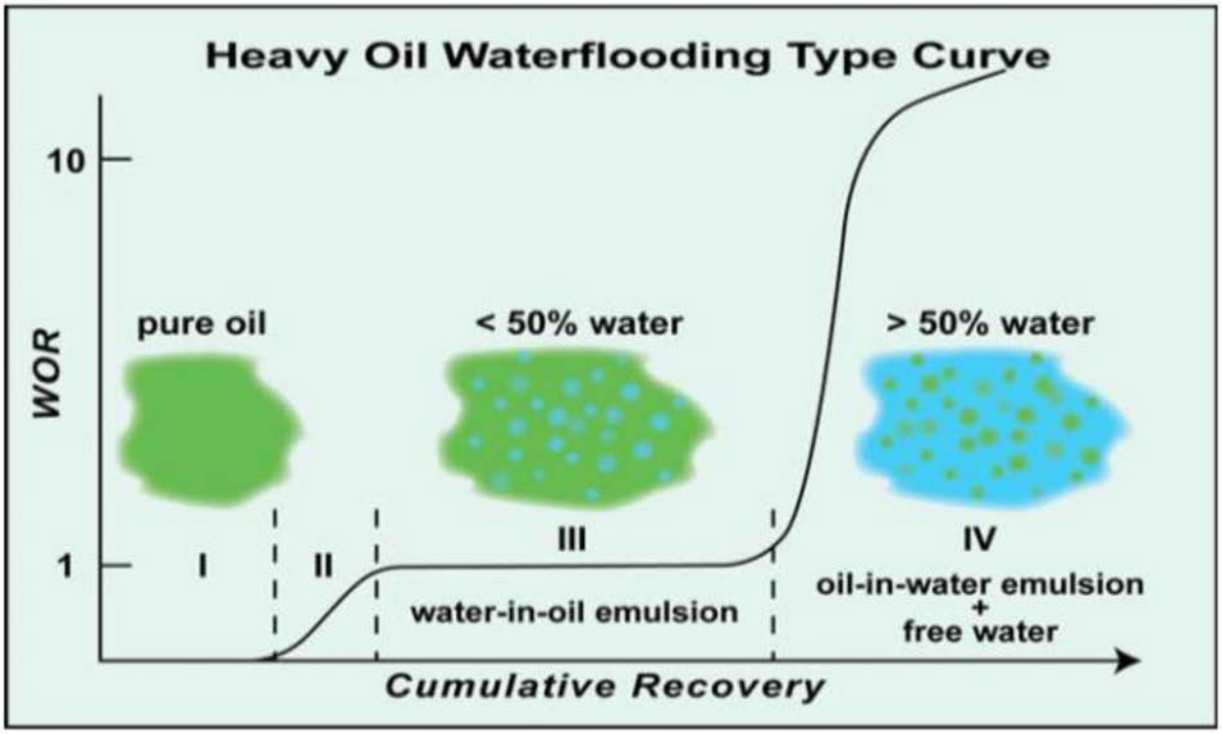

Figure 6—Proposed Heavy Oil Waterflooding Type Curve (Vittoratos and West, 2010)

The successful application of waterflooding heavy oil reservoirs are attributed to a number of production mechanisms (Smith, 1992; Miller, 2005; Alvarez et al., 2014):

- dragging or emulsification of oil at a water channel/oil boundary
- pressure support of a continuous oil phase
- formation and flow of 'bubbly oil,'
- elongation of solution gas drive by prevention of gas bubble coalescence
- imbibition of water into the reservoir matrix and oil flow out in a manner similar to fractured reservoir behavior
- higher pressures outside the water channel forcing oil into the channel
- pore scale reactions
- improved relative permeability at high water cuts
- gravity drainage

Polymer Flooding of Heavy Oil Reservoirs

The unfavourable mobility ratios in waterflooding may be improved on by the use of polymer in the injection water. Most screening criteria put the maximum viscosity for a polymer flood at 200 cp. However, there are polymer floods in reservoirs with much higher oil viscosities: 500 cp and higher. This is the result of merging polymer flooding with horizontal well technology. The upper limit for the oil viscosity for a chemical flood may be in the 5,000 to 10,000 cp range, i.e., if the oil can be produced without the addition of heat, it can be polymer flooded. (ERCB, 2012; Saboorian-Jooybari, et al. 2016; Paskvan, et al. 2016).

This contention is also consistent with observations at Pelican Lake (or Brintnell) in Wabasca area in Alberta which is the first successful application of commercial scale polymer flood in a heavy oil reservoir

(Delamaide et al., 2014). Polymer injection began in May 2005, with the first production response noted in March 2006. Average water cuts have increased but are generally less than 60 percent. This behaviour conforms to the theory where rapid water breakthrough is expected, but production continues at a moderate and constant water cut for an extended period of time. The range of oil viscosity in the polymer flooded areas is wide, with most areas below 5,000 cp (ERCB, 2012).

Long periods of up to several years of production at a Water Oil Ratio (WOR) at or close to 1 have been observed in water and polymer floods in heavy oil reservoirs in Western Canada and Alaska. (Delamaide, 2018; Vittoratos and West, 2010). This would impact the economics of the process positively. Such long periods of WOR stability at low values, with very unfavorable Mobility Ratios, are not expected from theory and this is an active area of investigation currently. For instance, polymer floods in Pelican Lake and Cactus Lake and ASP flood in Mooney have exhibited this behavior (ERCB, 2012). There is some evidence that this period can be controlled through operational practices.

The estimations of recovery vary depending on the area of the field, and they have been updated several times since the project began in Pelican Lake. The most recent ones for CNRL are an estimated ultimate recovery of between 15 and 21% of OOIP (CNRL 2012) for most of their lands and between 27 and 31% of OOIP for a small portion; Cenovus estimates recoveries of 3 to 32% of OOIP at 1 PV injection (Cenovus 2012). Most of those areas have not been waterflooded before polymer injection, and that primary recovery was expected to reach between 5 and 10% of OOIP.

EOR Processes Involving Mild Heating

Because of heat costs and losses, a thickness of greater than 15 m is desirable for steam processes (Edmunds and Chhina, 2001). In the thickness range of 8-15 m, steam may be viable if conditions are favorable, such as a high permeability or if the oil is of moderate viscosity. Therefore, steam injection into heavy oil reservoirs at thicknesses less than ~10 m result in too much heat loss into the overlying and underlying formations and, therefore, is uneconomic. Unfortunately, this constitutes 97% of the resource in Lloydminster (Figure 3). However, processes that involve oil viscosity reduction with mild heat can offer promise as the heat loss is directly proportional to the temperature difference between the reservoir and the surrounding formations (Coskuner, 2015). That is, under mild heating conditions, both the heat losses and the oil viscosity will be reduced.

Hot Water Vapour Process (HWVP)

The core idea of HWVP technology is the injection of a non-condensable gas (NCG) together with hot water vapour (in other words relatively low temperature and pressure steam) into heavy oil formations (SPRI, 2014). Hot water vapour is generated in an in-line heater at the surface and is carried into the formation with NCG. HWVP technology in a CHOPS well takes advantage of the existing wormholes in the reservoir to more efficiently deliver the hot vapour deeper into the reservoir. HWVP is, therefore, a thermal stimulation technology that can be used as post-CHOPS EOR method in heavy oil reservoirs partially depleted by primary recovery. The thermal energy is conveyed to the reservoir by the enthalpy of evaporation of the water vapour. This thermal energy raises the temperature of the stimulated zone and reduces the heavy oil viscosity.

A non-condensable gas is required to carry the water vapour as the temperature/pressure operating envelope is outside the steam envelope. The non-condensable gas has the added benefit of raising the currently depleted reservoir pressure towards initial reservoir conditions. The injection fluid will provide incremental oil as this technology can be used in wells which have no remaining primary reserves.

In order to minimize cost as much as possible there is a large incentive to use existing wellbores for an EOR process instead of incurring the cost of drilling new ones. Existing wellbores have not typically been thermally completed and are therefore not suitable for standard applications of high temperature and pressure steam. However, HWVP can be tailored so that the temperatures employed preserve the wellbore integrity.

In HWVP, the thermal fluid injected into the reservoir is not steam but hot water vapour. Steam is a fluid entirely composed of water in the vapour state. Hot water vapour is water in the vapour state but carried by another gas. That is, HWVP involves the injection of a hot non-condensable gas (e.g. methane or nitrogen) saturated with water vapour. Steam and hot water vapour are chemically and thermodynamically identical and will carry the same amount of thermal energy into the reservoir.

The use of hot water vapour instead of steam reduces the temperature and pressure of the injection fluid. Therefore, hot water vapour can be injected under milder temperature and pressure conditions, allowing the use of existing wellbores and avoiding breakouts and excessive heat losses in the reservoir. It is possible to generate water vapour at temperatures up to 140°C and injection pressures not exceeding average initial reservoir pressure of 3500 kPa without any damage to a standard CHOPS wellbore (SPRI, 2014). Note that the in-line heater has to be set at a higher temperature to take into account various heat losses in the lines, valves and vessels.

Figure 7 illustrates the difference between steam and hot water vapour. If the operating limit of thermal injection into CHOPS wells is assumed at 140°C and pressure between 500 and 3,000 kPa, it is seen that the steam curve does not pass through these conditions. That is, the injected fluid would be just hot water at these conditions which is not an efficient thermal fluid because most of the latent heat is associated with vaporization into a steam. Similarly, hot dry gas on its own is an inefficient thermal fluid as the heat carrying capacity will be low. The mixing of steam with an NCG shifts the effective steam curve to the left and allows it to pass through the operating envelope. Thus, with HWVP, it is possible to inject water in a vapour state at mild conditions and carry the latent heat of vaporization into the reservoir.

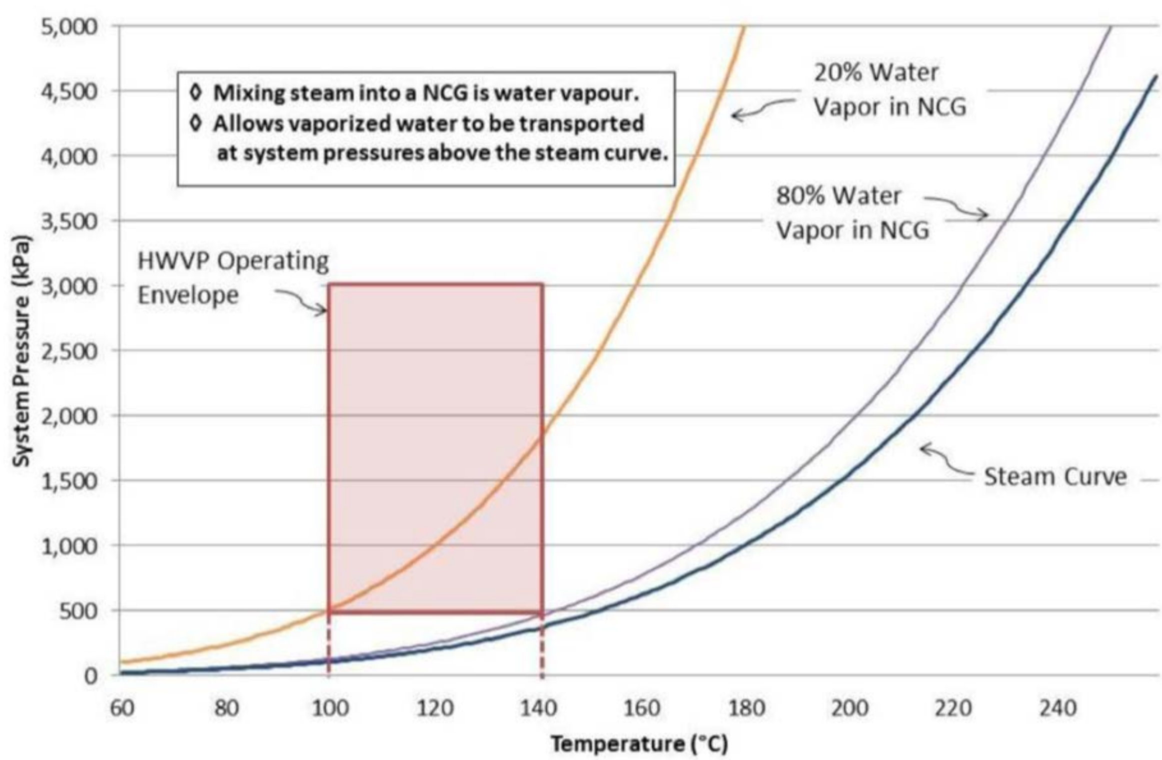

Figure 7—Comparison of Hot Water Vapour and Steam

For example, injection of 12,300 sm3/day (435,370 scf/day) of dry gas at 140°C and 1,000 kPa will carry 1.9 GJ per day. Saturating this gas with water vapour will increase its thermal carrying capacity to 16.4 GJ per day. The additional energy is contained in the 5.3 tonnes per day of water vapour carried by the gas. The amount of water vapour that can be carried by a hot gas depends primarily on pressure. Less water vapour is carried at higher pressures. In the above example, if the gas pressure is doubled to 2,000 kPa, 7.6 GJ per day would be carried by the hot gas (2.1 tonnes per day of water vapour). While it will be desirable to operate at low pressures, injection pressure will be controlled by reservoir injectivity. Injection pressure will likely start low and increase during the course of an injection cycle.

At the end of the CHOPS process, the reservoir pressure is depleted. The co-injection of the NCG with hot water vapour will increase reservoir pressure and provide added energy for oil production. While heating the oil reduces its viscosity, increasing the pressure with the help of NCG injection provides the energy to produce the heated oil.

HWVP was field piloted by Husky in Big Gully well 10-4-50-24W3 in the lower McLaren formation with a dead oil viscosity of ~ 8000 cp at initial reservoir temperature of 20°C and 550 cp at 50°C (SPRI, 2014). In July 2001, 11/10-04-050-24W3 was completed in the McLaren formation. Initial rates from the McLaren were: 8.4 m3/d oil and 0.9 m3/d water. 10-04 continued to produce from the McLaren formation until December 2004. The well was then shut-in after cumulative production of 7,185 m3 oil and 1,314 m3 water from the McLaren. Final rates (3 month average) at shut-in were 2.2 m3/d oil and 0.4 m3/d water. A plot of the primary production rates for the McLaren is shown in Figure 8.

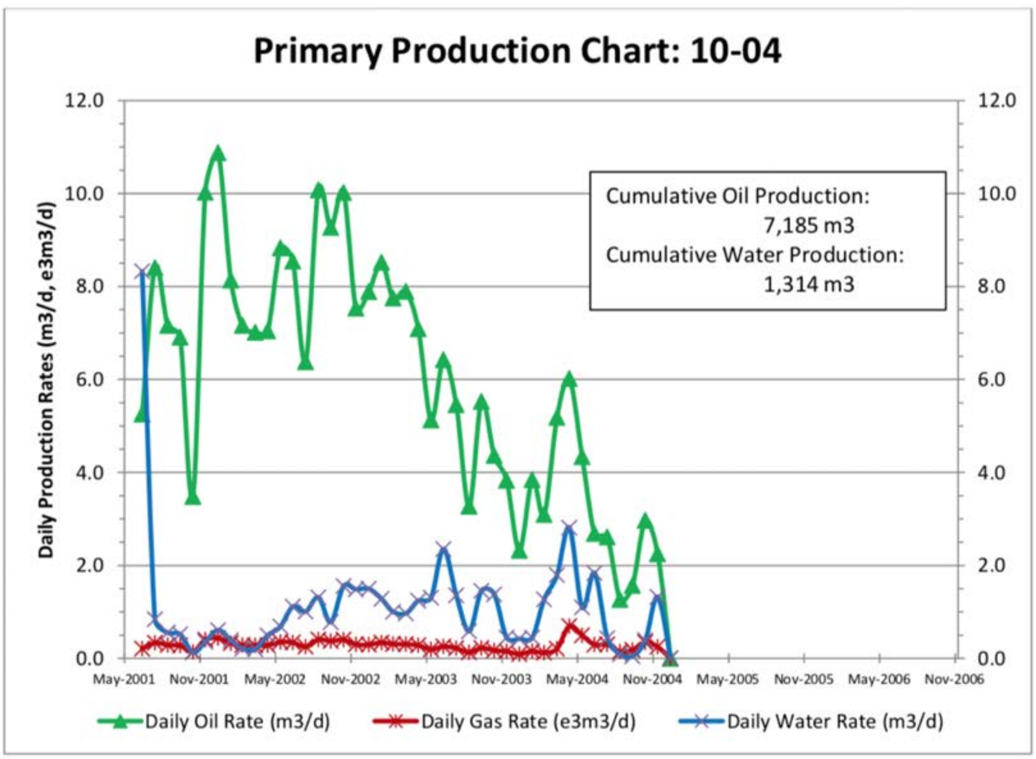

Figure 8—Primary Production 11/10-04-050-24W3

Two injection and production cycles were carried out. Nitrogen was used as NCG and the injection period was approximately one month during which reservoir pressures climbed close to initial pressure of 3500 kPa. The bottom hole temperatures reached 130-140°C range. Modest amounts of nitrogen (500-600 e3m3) and water vapour (85 m3 cold water equivalent) was injected during this period. The production initially was quite encouraging with oil rates climbing close to primary rates. Unfortunately, many inflow issues were experienced which caused the temperature and the pressure in the reservoir to dissipate during the workovers. A total of ~3000 bbl oil was produced which was uneconomic.

The pilot project proved that the HWVP concept was worthwhile. Unfortunately, the potential for oil production is still an unanswered question because of the production issues experienced by the pilot. The potential for HWVP as a post-CHOPS recovery process for Lloydminster reservoirs remains to be seen.

Horizontal Well Hot Oil Treatment (HOWHOT) Process

One of the more promising ways of delivering mild heat to the formation can be achieved by means of circulating a hot fluid in a horizontal well and heating the formation by conduction. Such a process was not possible until the development of vacuum insulated coiled tubing (Marchal, 2006a, 2006b; Blonz and Ollier, 2009). This technology requires very high performance insulation materials to avoid thermal losses between the heat source above ground and the downhole production zone. Heating the oil reduces its viscosity, consequently reducing the pressure drop due to flow in the formation. Therefore, increased productivity can be achieved for the same pressure drop if a sufficient temperature increment is maintained at the wellbore. The aim is to provide an efficient way of heating reservoirs which still have some reasonable pressure by conduction in order to decrease heavy oil viscosity.

Figure 9 shows the typical set up for the HOWHOT process. The vertical section is completed with a conventional production tubing and downhole pump. Part of the production goes to a holding tank. The other part goes to the production facilities. From the holding tank, a pump sends it to a heater and further into an insulated coiled tubing which is run to the toe of the horizontal well. This coil tubing is a pipe-in-pipe with the insulating material under vacuum in the space between the two pipes (Figure 10). Consequently, there is little heat loss between the surface and the toe. Once the heated fluid/oil leaves the coil tubing at the toe and starts flowing towards the heel in the annulus, this fluid exchanges heat with the formation by conduction. There is no intention of liquid injection into the formation as it would imply less fluid coming from the formation. The temperature differential between the hot fluid and the reservoir is essential as the efficiency of conductive heating is driven by it and that is why the insulation capacity of the coiled tubing is very important.

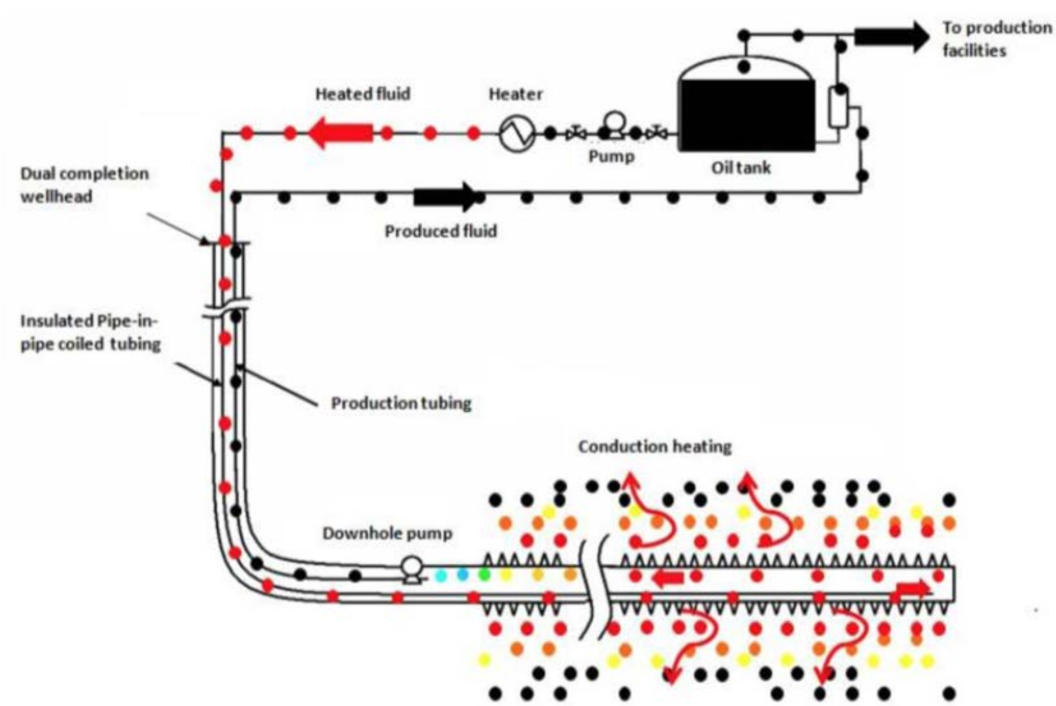

Figure 9—HOWHOT process

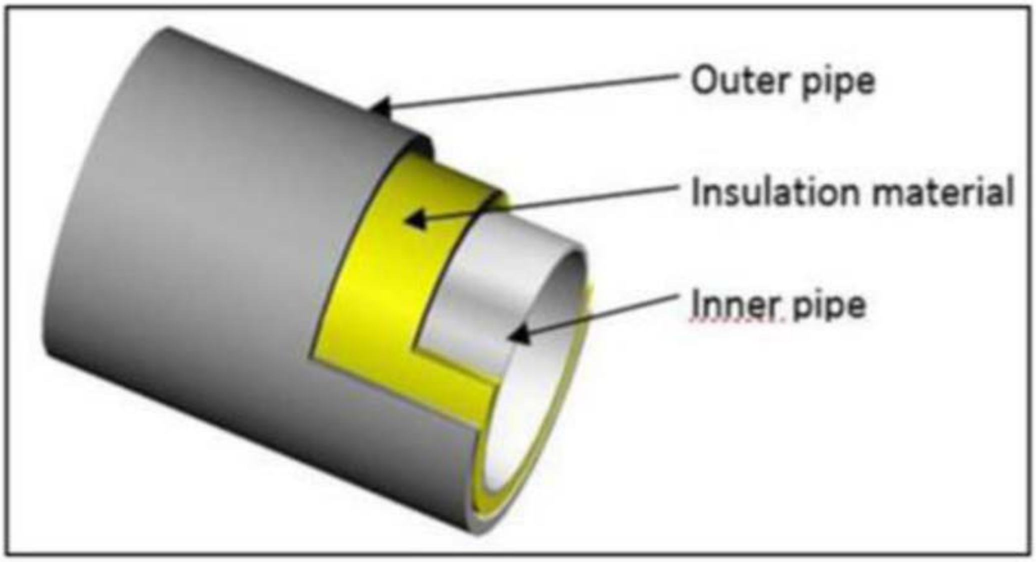

Figure 10—Pipe-in-pipe coil tubing configuration

Therefore, this technology requires the use of a highly insulated coiled tubing. This pipe-in-pipe coiled tubing is designed to support temperatures up to 240°C. There is no limitation in diameter except the coiled tubing units' standard dimensions which are generally limited to 2"3/8 tubing due to transportation limitations. The insulation is preferably made of Izoflex which has been extensively used in the offshore industry within pipe-in-pipes, it provides the best thermal performances and was qualified for use in reeled pipelines. The technology was used to circulate hot oil in Oman (Blonz and Ollier, 2009) and hot water in Pelican Lake (Duval et al., 2015).

HOWHOT technology was tested in a horizontal well in Aberfeldy HZ 1D14-21-1C15-20-049-26W3 (91/15-20-049-26W3/0) in the GP zone that was 5 m thick and contained oil with a viscosity of 6000 cp at 20C and 500 cp at 50C (SPRI, 2016). The primary production of this well is shown in Figure 11, the well was shut in due to low inflow in 2004 and was put back on production after clean out in 2007. The decline trend after 2007 indicates that this well would have stopped producing sometime during mid-2013.

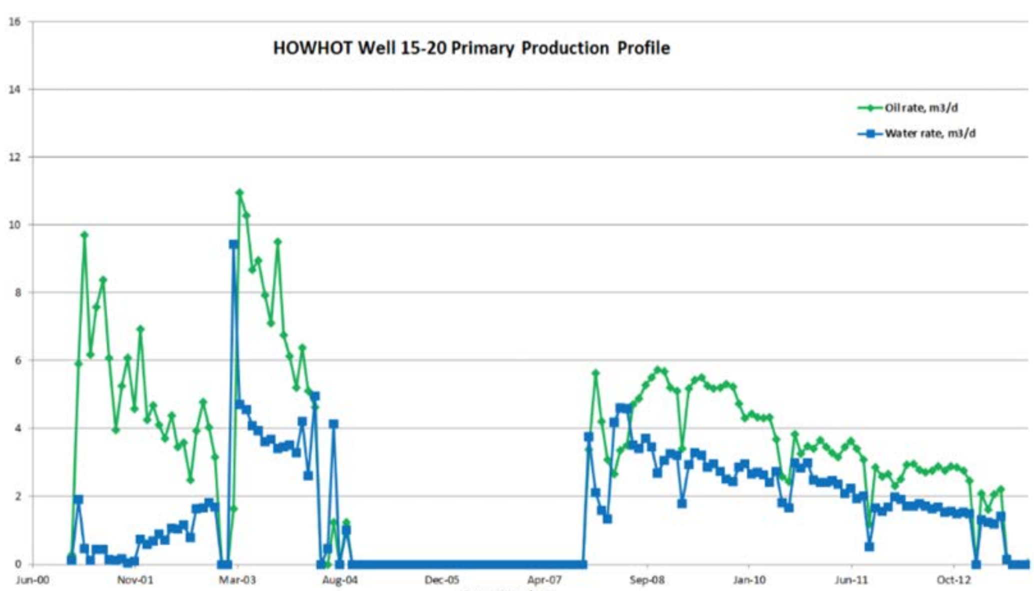

Figure 11—Primary Production of Aberfeldy HOWHOT horizontal well

One of the objectives of the test was to keep the pump and production casing temperature below 50°C to maintain casing and pump integrity and this objective was achieved. That is, there is enough heat losses along the wellbore between the toe and the heel that the temperature at the pump and the intermediate casing stayed below 40°C. Although no specific observation wells were used for this project, offsetting production was monitored for increases in production rate and/or increases in casing pressure to determine if the hot oil circulation has affected other wells. Offset wells were not affected by this project.

The pilot well was not tied into a natural gas system and ran on propane heating. Therefore, the operating costs were high as this was a trial of a new technology, future applications of the HOWHOT technology are expected to have reduced costs by using natural gas. The maximum design injection rate for the pilot was expected to be 50 m3/d heated to a maximum temperature of 250°C at the surface.

The project experienced significant amount of surface facility issues until 2015. These issues were remedied and there was less downtime after May 2015. The maximum injection rate achieved was 25 m3/d which is half of the facility design value with the maximum production rate of 33 m3/d in December 2015. The toe temperature history is shown in Figure 12. This is the temperature when the injected fluid first contacts the reservoir. Therefore, it is the maximum temperature that reservoir sees, and it is ~140°C. If the maximum design injection temperature is 250°C, then the heat loss in the coiled tubing and the surface equipment is 44% which is unlikely given the manufacturer's claim about the heat losses. It is more likely that the problems experienced at the surface (heat transfer fluid issues, heater size, etc.) limited the injection temperatures below the maximum design temperature. If one assumes 10 to 20% heat loss, it appears that injection temperatures at the surface were in the range of 155 to 170°C which are significantly below the maximum design value of 250°C. That is, the heat input to the well was significantly less than designed at half the maximum design rate and 35% below the maximum design temperature.

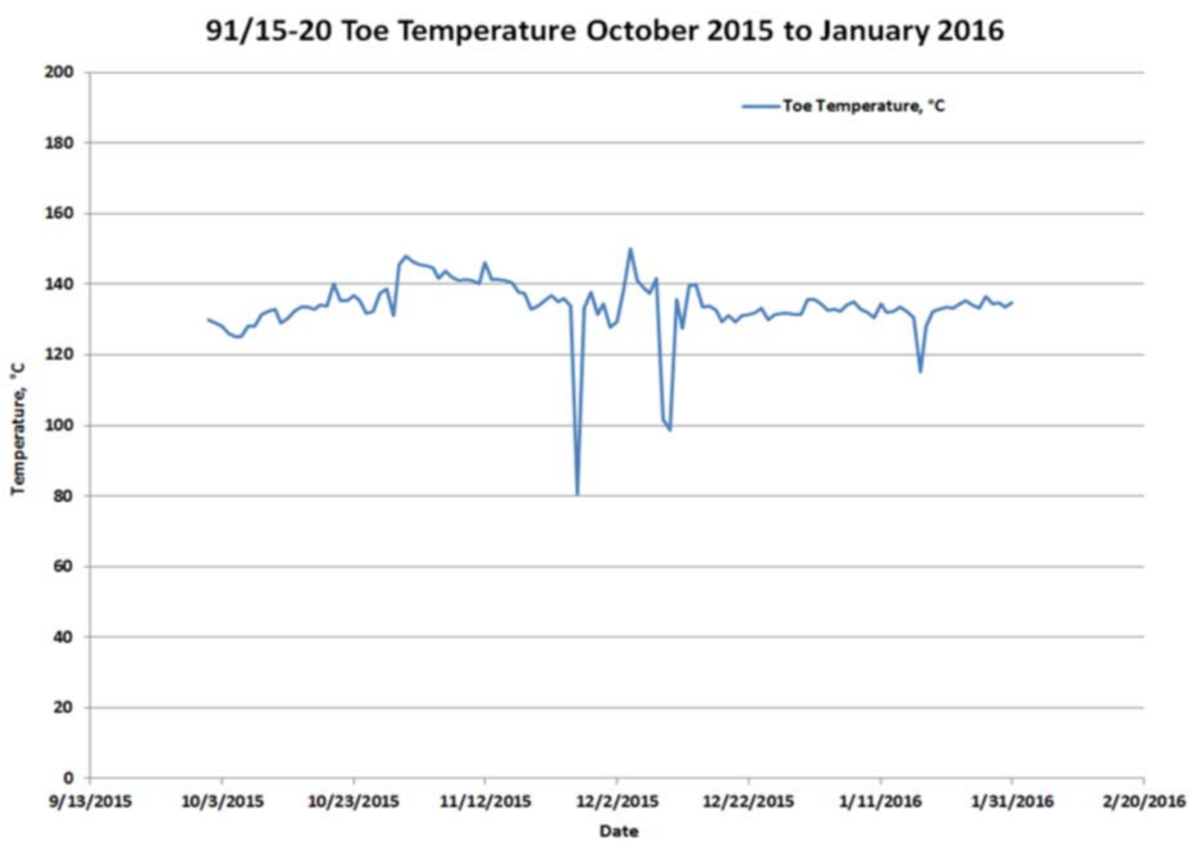

Figure 12—HOWHOT Well Toe Temperature History

The production profile is shown in Figures 13a and 13b. From December 2013 to January 2016, the well has produced 770 m3 oil and 330 m3 water. It appears that the oil production beyond the report period hovered around 2 to 3 m3/d for a couple of years. The oil production not surprisingly was below the expectations and uneconomic. However, the operator believed that there may be potential in developing this technology with continued innovation and refinement.

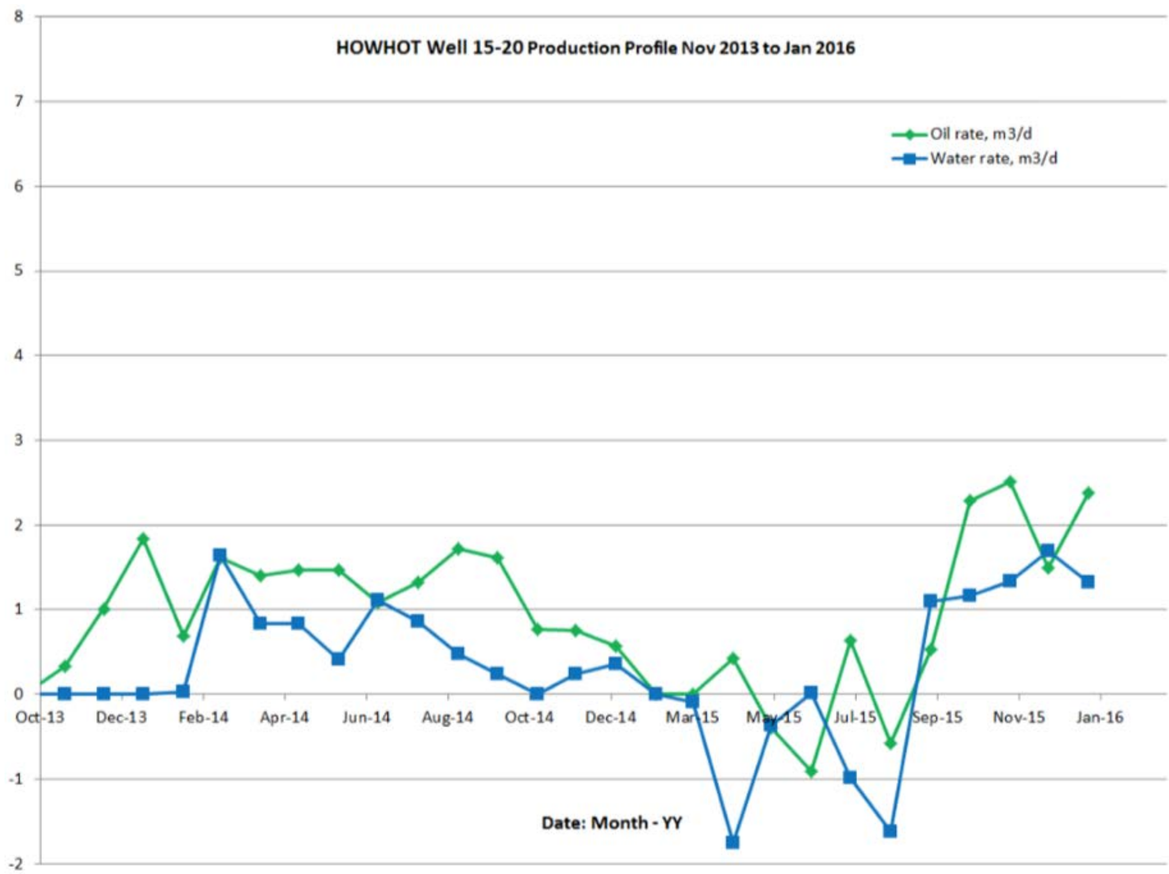

Figure 13a—HOWHOT Performance

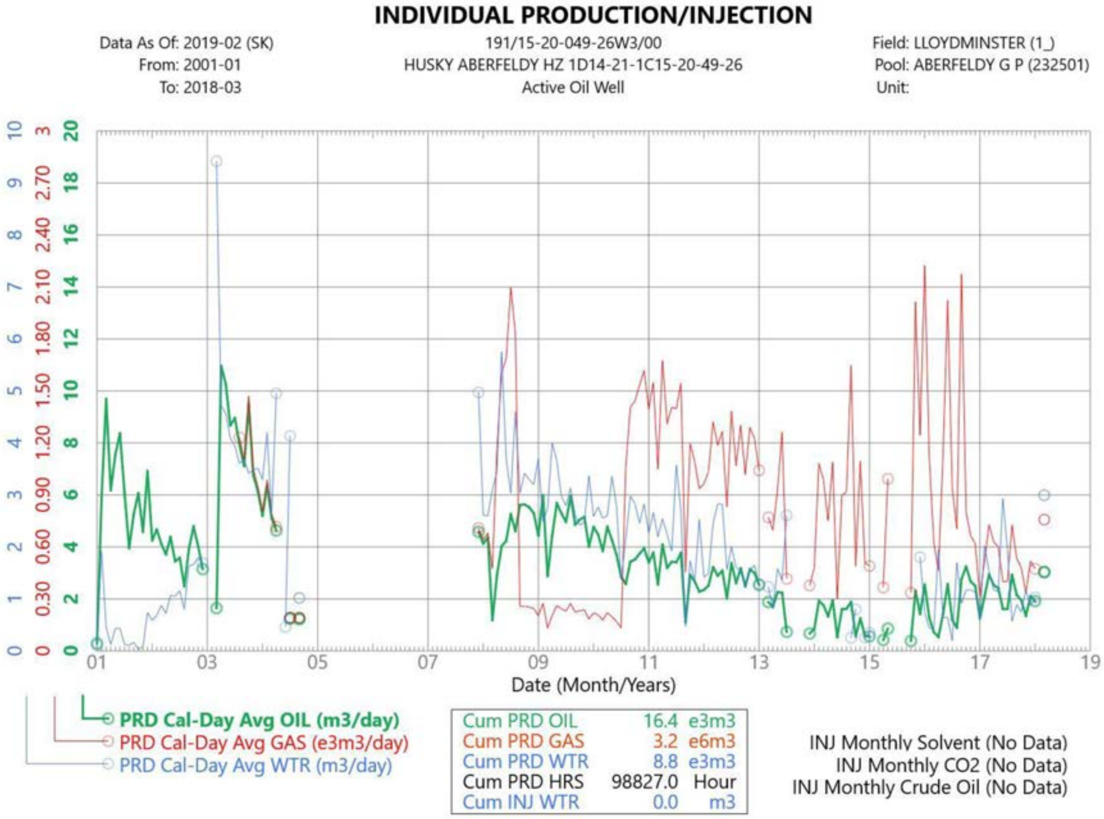

Figure 13b—HOWHOT Performance Cont'd

Given the data available from the pilot performance, it would be worthwhile to numerically simulate this process first to history match the pilot performance and then optimize the performance within the envelope of the equipment and wellbore limitations. The analysis can further be conducted to find out reservoirs that are ideally suited to this process. Further analysis can be conducted to see if it can be used to develop the stranded resources that are too high in viscosity, too thin for steam injection and where CHOPS technology was inefficient in recovering significant resources. The targets should include existing horizontal wells with poor performance as well as possibility of drilling new horizontal wells.

However, one should keep in mind the complexities of such a numerical simulation study. The fluid dynamics and heat exchange behaviour must be solved in order to predict the rate at which heat is transferred to various parts of the formation along the length of the well. The rate of heat transfer and fluid convection into the reservoir formation determine how communication is established along the length of the horizontal well. Between the tubing and annulus, heat transfer occurs via convection from the fluid in the inner tubing, conduction from the inner tubing wall to outer tubing wall and then via convection to the fluid in the annulus. Heat transfer from the well to the formation consists of convective heat transfer from the fluid in the annulus to liner wall, conduction through the liner and conduction from outer surface of the liner to the formation (Yuan and McFarlane, 2009). Furthermore, fluids inside the coil tubing and within the annulus flow in the counter-current direction to each other. Numerical simulation of this process is non-trivial and requires fully discretized wellbore within a fully implicit reservoir simulator (Ayala and Gates, 2018). Most reliable solutions may even require finite element analysis instead of finite difference analysis.

It is anticipated that this alternative thermal technology can add very significant reserves to Lloydminster heavy oil reservoirs. A number of horizontal wells can be drilled from the same pad and thus can allow for centralized injection and production facilities to be installed. Such centralized facilities are expected to reduce the capital costs per well significantly.

Hot Water and Solvent Injection

"Steam and solvent injection in fractured reservoirs is a recently proposed method which consists of alternate injection of steam and hydrocarbon solvents to improve oil recovery compared to steam injection alone (Al-Bahlani and Babadagli 2009). Initial tests were done with hot water instead of steam and liquid solvents for simplicity. However, it was found that even at these relatively low temperatures compared to steam injection significant oil recoveries were obtained. An added advantage of this methodology is that a final injection stage of hot water tends to recover solvent in the reservoir fairly rapidly along with additional oil" (Coskuner, et al., 2013).

"It was surmised that wormholes generated during the CHOPS process can act as conduits, similar to fractures in carbonates, to distribute injected fluids into the reservoir and to produce the mobilized oil in return. Therefore, similar experiments with preserved, unconsolidated heavy oil cores were carried out to see if the hot water and solvent injection can be a viable process in the Lloydminster heavy oil reservoirs" (Coskuner, et al., 2013). It was found that the oil recovery ranged between 42 to 88 % which was encouraging.

The tests carried out with heptane as the solvent phase yielded good results. "In Lloydminster, a distillate from Husky's heavy oil upgrader is used to reduce the viscosity of the produced heavy oil so that it the oil can be transported to the upgrader through pipelines. Considering the availability and relatively lower cost of the distillate compared to liquid alkane solvents, experiments were also carried out with distillate as the solvent phase. In general, oil recovery with distillate was found to be better than that obtained by heptane. This is not unexpected as higher molecular weight aromatic distillate (C11+) should be more miscible with heavier ends even though the diffusion rate is slower than the lower carbon number heptane (C7)" (Coskuner, et al., 2013).

"The solvent recovery is economically a critical part of the process. This was the main objective of the final hot water phase of the process. The solvent was recovered fairly quickly during this final hot water phase of the process through boiling off of the solvent from the core as well as imbibition of the hot water into the core" (Coskuner, et al., 2013). While this study found that the solvent recovery was in the 50% range, there were some significant sources of error for this calculation. In a separate series of similar experiments conducted with carbonate cores solvent recoveries of 60 to 80% were observed (Naderi, et.al., 2013). Therefore, it could be assumed that similar recoveries should be obtained in heavy oil cores as well.

Hot water available from thermal operations in the area combined with distillate locally available from the heavy oil upgrader in Lloydminster may present an economic opportunity to apply this technology as a viable post-CHOPS process.

Electromagnetic Heating

Resistive electrical heating of wellbore was tested in Lloydminster (Davidson, 1991). It was thought that the application of heat significantly reduces the viscosity of the oil, improves the oil/water flow characteristics, and overcomes some forms of formation damage. The end result should be an improved pressure profile in the near wellbore region and a corresponding increase in the oil production rate. The process was tested in two wells where the productivity index improvements of 1.3 to 3.7 were observed. However, this was observed for a very brief period as there were significant operational problems and tests were stopped prematurely after a short time.

Summary

Lloydminster area that straddles Alberta and Saskatchewan border contains 50 to 70 billiob bbl of heavy oil in the thin unconsolidated Mannville formations. Industry's experience for the primary CHOPS recovery on average is 8% of the original oil in place which presents a vast remaining oil target for potential EOR methods. Where there are channel sands thicker than 10 m, steam injection methods are quite feasible and result in quite high recoveries. However, non-steam EOR technologies are needed for the remainder of the 97% of the resource.

The waterflood operations that focus on production at very high water cuts show that viscous oil fields can yield reasonably good ultimate recoveries under waterflood. It is important to inject large volumes of water and to handle large volumes of produced water along with the oil where more than 50% of the ultimate oil recovery is produced at water cuts of 90% or greater. The unfavourable mobility ratios in waterflooding may be improved on by the use of polymer in the injection water. The combination of polymer flooding with horizontal wells can be successfully applied to reservoirs with oil viscosities in the 5,000 to 10,000 cp range.

EOR processes involving mild heating can also be feasible in thinner heavy oil formations. Two of these technologies have been piloted in the field. Hot Water Vapour Process where injection of NCG with low temperature and low pressure steam can yield additional oil recovery and the process can be applied on a well by well basis. While the field results showed that HWVP was a prospective technology, the potential for wide scale application remains to be investigated.

One of the more promising ways of delivering mild heat to the formation can be achieved by means of circulating a hot fluid in a horizontal well and heating the formation by conduction. Field piloting indicates that HOWHOT technology can offer significant commercial potential in post-CHOPS reservoirs as well as in areas where CHOPS or horizontal primary production wells have not been successful.

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