DEÜ FMD 24(71), 437-445, 2022

Dokuz Eylül Üniversitesi Mühendislik Fakültesi Fen ve Mühendislik Dergisi
Dokuz Eylul University Faculty of Engineering Journal of Science and Engineering

Basılı/Printed ISSN: 1302-9304. Elektronik/Online ISSN: 2547-958X

Agir Petrol Birikimlerinin Su ile Otelenmesi

Waterflooding of Heavy Oil Reservoirs

Gökhan Coşkuner

Independent Consultant, Calgary, Alberta, Canada

gokhan.coskuner@gmail.com

Geliş Tarihi / Received: 03.05.2021 *Araştırma Makalesi/Research Article*
Kabul Tarihi / Accepted: 07.11.2021 *DOI:10.21205/deufmd.2022247110*
Atıf şekli/ How to cite: COSKUNER,G. (2022). Waterflooding of Heavy Oil Reservoirs. DEUFMD, 24(71), 437-445.

Öz

Petrolü su veya polimer katılmış su ile oteleme genellikle ağir petrol sahalari için etkin olmayan bir yöntem olarak kabul edilir ve onların yerine daha cazip görünen kimyasal ya da ısıl gelişmiş petrol kazanımı yöntemleri tercih edilir. Halbuki ağır petrolun su yada polimer ile otelenmesi esnasında öne çıkan özgün bazı mekanizmalar bulunmaktadır. Bu özgün mekanızmalar dolayısı ile 10,000 cp yada daha yüksek viskositedeki ağır petrolün başarılı bir şekilde su ya da polimer ile ötelenmesi mümkündür. Bu çalismada ağır petrolün su yada polimer ile ötelenmesi esnasinda etkin olan özgün mekanizmalar ayrıntılı olarak incelenmiş ve başarılı bir uygulama için gerekli adımlar açıklanmıştır. Ulaşılan sonuçlar Kanada'nın ağır petrol sahalarındaki başarılı su, polimer ve su+polimer ile öteleme uygulamalarının sonuçlarıyla temellendirilmiştir. Umulur ki bu başarılı deneyimleri dünyanın ve Türkiye'nin ağır petrol sahalarına da aktarabiliriz.
Anahtar Kelimeler: *Agir Petrol, Su ile Oteleme, Polimer ile Oteleme*

Abstract

Waterflooding or polymer flooding 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. There are a number of unique mechanisms that operate in heavy oil fields under water and polymer flood. It is, therefore, possible to succesfully flood heavy oil reservoirs with viscosities up to and beyond 10,000 cp oil viscosity. This work elaborates on the unique mechanisms operating in heavy oil water and polymer floods, presents a workflow for successfull implementation and supports its conclusions with a number of case studies, namely, actual successful field examples from Canadian heavy oil fields. The hope is that, this experience can be translated to heavy oil fields in other parts of the world including Turkey.
Keywords: *Heavy Oil, Waterflooding, Polymer Flooding*

1. Introduction

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. For instance, widely used screening criteria in the oil industry limits successful application of polymer flooding to oil viscosities less than 150 cp [1,2]. This is because, the extremenly adverse mobility ratios encountered in heavy oil reservoirs are believed to cause significant viscous fingering which when coupled with gravity effects will result in very low recovery factors. 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.

2. Waterflooding of Heavy Oil Reservoirs

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 [3].

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 [3]. 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 1 and 2 [4].

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.

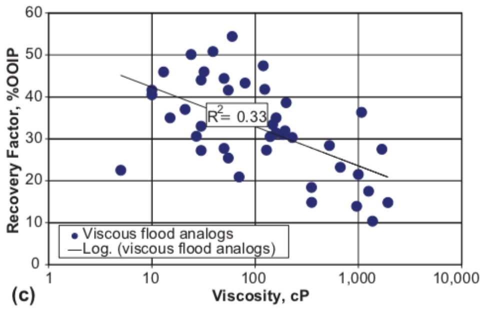

Figure 1. Heavy Oil Waterflood Recovery versus Oil Viscosity [4]

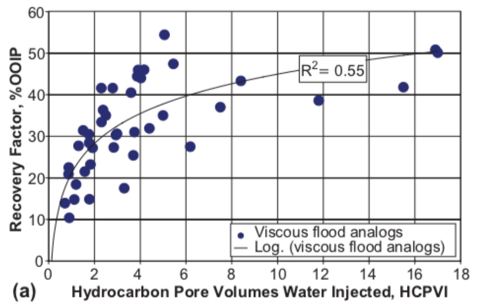

Figure 2. Heavy Oil Waterflood Recovery versus HCPV Injected [4]

Furthermore, there are quite a few steam injection projects in the Lloydminster region. 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 (Cold Heavy Oil Production with Sand) 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 [3,4], 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 [5]. 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 (Region III in Figure 3). In this region an emulsified oil bank with relatively low water content is being produced in the form of water in oil emulsion. This emulsion 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.

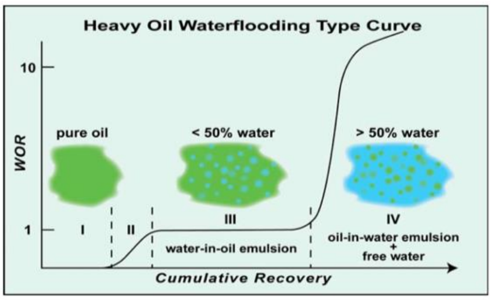

Figure 3. Heavy Oil Waterflooding Type Curve [5]

Once the oil bank is produced, the water breakthrough occurs and the water content of the proiduced fluids increase rapidly. The fluids are produced either as oil in water emulsion or free water in this region (Region IV in Figure 3). These flow regines are preceeded by convential water free oil bank production (Region I in Figure 3) followed by the transition zone (Region II in Figure 3).

The successful application of waterflooding heavy oil reservoirs are attributed to a number of production mechanisms [3,6,7]:

- 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

3. 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 [1,2]. 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 [8-10].

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 [11]. The reservoir is thin (less than 5 m) with high oil viscosity (800–80,000-plus cp). The reservoir has generally excellent petrophysical properties, with 28–32% porosity and a permeability that varies between 300 and 5,000-plus md. 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 [8].

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 [12,13]. 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 [8]. There is some evidence that this period can be controlled through operational practices.

4. Case Study: Pelican Lake, Alberta, Canada

Initial production in the Pelican Lake heavy oil field in northern Alberta utilizing conventional vertical wells was poor because of the thin reservoir formation and high oil viscosity. The original oil in place estimate (OOIP) is 4.1 billion bbl on Canadian Natural Resources Limited (CNRL) lands and 2.3 billion bbl on Cenovus lands. The primary recovery is estimated at 5–10% OOIP which presents a significant target for EOR. But it is also a challenging reservoir with high-viscosity oil in a thin formation [14].

The reservoir formation, the Wabiskaw A sand, is composed of unconsolidated sands that consist mainly of quartz and chert. The reservoir has generally excellent petrophysical properties, with 28–32% porosity and a permeability that varies between 300 and 5,000+ md.

The reservoir depletion mechanism is solution-gas drive, but initial reservoir pressure was low and there is very little dissolved gas (4–6 m3 gas/m3 oil), so there is little energy in the reservoir. This combined with high oil viscosities result in low primary recovery of approximately 5–10% of OOIP. In addition, the reservoir is thin (1–9 m, average 5 m), and as a result the first wells drilled in 1980–81 were not economic: low rates (less than 5 m3/d, usually declining rapidly to less than 2 m3/d) and low cumulative productions (an average of 4,500 m3 per well).

The field began to reach its full potential with the introduction of horizontal drilling and later multilaterals, and was one of the first fields worldwide to be developed with horizontal wells. However, with primary recovery at less than 10% and 6.4 billion bbl of OOIP, the prize for enhanced oil recovery (EOR) is large.

Initially, both waterflooding and polymer flooding was piloted and later implemented at commercial scale. . Some of the waterfloods continue to this day while some of them have been converted to polymer floods. In some areas, primary production was directly followed by polymer flooding. As an example, the well configuration in the Cenovus area is shown in Figure 4. Normally, the well spacing between the two producers is 400 m (i.e. 200 m between injector and producer) except in the infilled areas shown by red. The well spacing in these areas (200m, 133m, etc.) are also shown in this figure.

The CNRL area waterflood performance is shown in Figure 5 for all the pads that have been under waterflood since early 2000's. Initially a small portion was under waterflood which was later expanded to a larger area in 2003 with an immediate response in oil rate. Because water oil mobility ratios is quite adverse (in the 300+ range), the watercut increases quickly due to severe viscous fingering and triples to 60% within one year. However, one can see that the behaviour described in Figure 3 is observed for a couple of years while the WOR <1 (i.e. water cur < 50%). Watercut gradually climbs to 85% within the next 4 years and stays there for the remainder of the life of the flood.

The oil rate peaks within one year of the start of significant injection and stays there for 4 years before gradually declines as expected. Injection into some of the high watercut wells is constrained later on and therefore the watercut slightly decreases later in the life of the flood. It is important to note that the conventional fractional flow theory and the screening criteria would definitely rule out Pelican Lake as a waterflooding candidate. However, the unique mechanisms mentioned above act to make this a successful flood. The waterflood performance can be improved upon with polymer injection which lowers the mobility ratio by a factor of approximately 20.

The performance of the polymer flood on an area where it was implemented following primary production is shown in Figure 6. Similar to the waterflood performance, the oil production rate peaks within one year of injection and is maintained at these levels for 3 years following which it declines as expected. The significant difference in this case, however, is that the water cut climbs only gradually, tripling to 60% in 7 years. This is because the tendency for viscous fingering is significanly less due to improved mobility ratio with polymer.

Finally, the performance of the hybrid flood in areas where polymer flood was implemented following waterflood is shown in Figure 7 for a portion of the CNRL leases and in Figure 8 for a pad (2 injectors and 4 producers drilled from the same surface location) in the Cenovus area. The waterflood performance looks similar to the earlier discussion. However, switching to polymer injection results in lower water cuts and sustained oil rate as a results of improved mobility ratio even after many years of waterflooding.

In Pelican Lake, the estimations of recovery vary depending on the area of the field, and they have been updated several times since the project began. Operators have successfully used horizontal wells in conjuntion with waterflooding followed by polymer flooding to achieve commercail success.

For instance, the area operated by Canadian Natural Resources Limited (CNRL) has viscosities in the range of 1,000 to 50,000 cp. The most recent recovery estimates are an ultimate recovery of between 21 and 27% of OOIP [15] for most of CNRL lands and up to between 35 and 38% of OOIP for a small portion.

The area operated by Cenovus has oil viscosity in the range of 1,000 to 25,000+ cp. Cenovus estimates ultimate recoveries of 12 to 35% of OOIP [16]. Some of those areas have not been waterflooded before polymer injection, and that primary recovery was expected to reach 4% of OOIP [17].

5. Conclusions

Waterflooding and polymer flooding are sometimes dismissed as an ineffective process for heavy oil fields. However, assumptions concerning mobility ratio and fractional flow values found in conventional waterflood theory do not apply to heavy oil reservoirs. Therefore, the classical fractional flow theory should not be used to make project decisions.

There are a number of unique mechanism, such as dragging or emulsification of oil at a water channel/oil boundary, formation and flow of foamy oil and improved relative permeability at high water cuts, that operate in heavy oil fields under water and polymer flood. It is, therefore, possible to succesfully flood heavy oil reservoirs with viscosities up to and beyond 10,000 cp oil viscosity. A number of actual successful field examples from Canada as case studies have been presented to support this contention.

The fact that these fields have been expanded continually and that the operations continued is an indication of the economic success of this process.

While this paper talks about sandstone reservoirs, there may be potential applications for the carbonate Bati Raman field in Turkey. Perhaps, one can take advantage of the dominant fracture direction to flood the formation in a direction normal to this direction somewhat mimicking the horizontal well performance of Canadian heavy oil floods. The fact that Bati Raman oil is significanly less viscous than some of the fields discussed here should also help.

References

[1] Taber, J.J., Martin, F.D., Seright, R.S., 1997, EOR Screening Criteria Revisited – Part 1: Introduction to Screening Criteria and Enhanced Recovery Prtojects, SPE Reservoir Engineering, August 1997, pp. 189-198

[2] Taber, J.J., Martin, F.D., Seright, R.S., 1997, EOR Screening Criteria Revisited – Part 2: Applications and Impact of Oil Proces, August 1997, pp. 199-205

[3] Miller, K.A., State of the Art of Western Canadian Heavy Oil Water Flood Technology, Petroleum Society of Canada, PETSOC-2005-251, Canadian International Petroleum Conference, 7-9 June, 2005, Calgary, Alberta, Canada

[4] Beliveau, D., Waterflooding Viscous Oil reservoirs, SPE Reservoir Engineering, October 2005, pp. 689-701

[5] Vittoratos E., West C.C., Optimal Heavy Oil Waterflood Management May Differ from that of Light Oils, SPE 129545, SPE EOR Conference at Oil & Gas West Asia, 11–13 April 2010, Muscat, Oman

[6] Smith, G.E., Waterflooding Heavy Oil Reservoirs, SPE 24367, SPE Rocky Mountain Regional Meeting, May 18-21, 1992, Casper, Wyoming, USA

[7] Alvarez J.M., Sawatzky R.P., and Moreno, R., Heavy-Oil Waterflooding: Back to the Future, SPE-171090-

MS, SPE Heavy and Extra Heavy Oil Conference - Latin America, 24–26 September 2014, Medellin, Colombia

[8] Energy Resources Conservation Board of Alberta, Identification of Enhanced Oil Recovery Potential in Alberta, Phase 2 Final Report for Energy Resources Conservation Board by Sproule Assoc. Ltd., March 31, 2012

[9] Saboorian-Jooybari H., Morteza Dejam and Zhangxin Chen, Heavy Oil Polymer Flooding from Laboratory Core Floods to Pilot Tests and Field Applications: Half-century of Studies, Journal of Petroleum Science and Engineering, January 2016, pp. 85-100

[10] Paskvan F., Turak J., Jerauld G., Gould T., Skinner, R., Garg, A., Alaskan Viscous Oil: EOR Opportunity, or Waterflood Sand Control First?, SPE-180463-MS, SPE Western Regional Meeting, 23–26 May 2016, Anchorage, Alaska, USA

[11] Delamaide, E., Zaitoun A., Renard G., and Tabary R., Pelican Lake Field: First Successful Application of Polymer Flooding In a Heavy-Oil Reservoir, SPE Reservoir Evaluation & Engineering, August 2014, pp.340-354

[12] Delamaide E., Investigation and Observations on the Stability of Water-Oil Ratio WOR during Chemical Floods in Heavy Oil Reservoirs, SPE-190471-MS, SPE EOR Conference at Oil and Gas West Asia, 26-28 March 2018, Muscat, Oman

[13] Vittoratos E., West C.C., Optimal Heavy Oil Waterflood Management May Differ from that of Light Oils, SPE 129545, SPE EOR Conference at Oil & Gas West Asia, 11–13 April 2010, Muscat, Oman

[14] Delamaide, E., Zaitoun, A., Renard, G., Tabar, R., Pelican Lake Field: First successful Application of Ploymer Flooding in a Heavy Oil Reservoir, SPE Reservoir Engineering, August 2014, pp. 340-354

[15] CNRL (Canadian Natural Resources Limited), Annual Performance Presentation, In Situ Oil Sands Schemes 9673 / 10147 / 10423 / 10787 / 9404, Alberta Energy Regulator, Alberta, Canada, March 2020

[16] Cenovus, Annual Performance Presentation, In Situ Oil Sands Schemes 9404W, Alberta Energy Regulator, Alberta, Canada, May 20, 2016

[17] Cenovus, Annual Performance Presentation, In Situ Oil Sands Schemes 9404W, Alberta Energy Regulator, Alberta, Canada, April 16, 2015

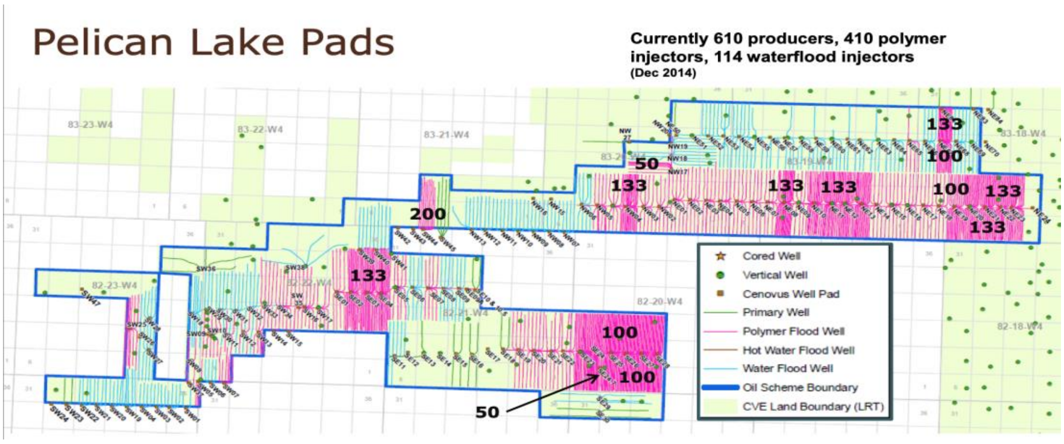

Figure 4. Pelican Lake Cenovus area well configurations. The land grid shown (squares) is based on one section (1600 m x 1600m).

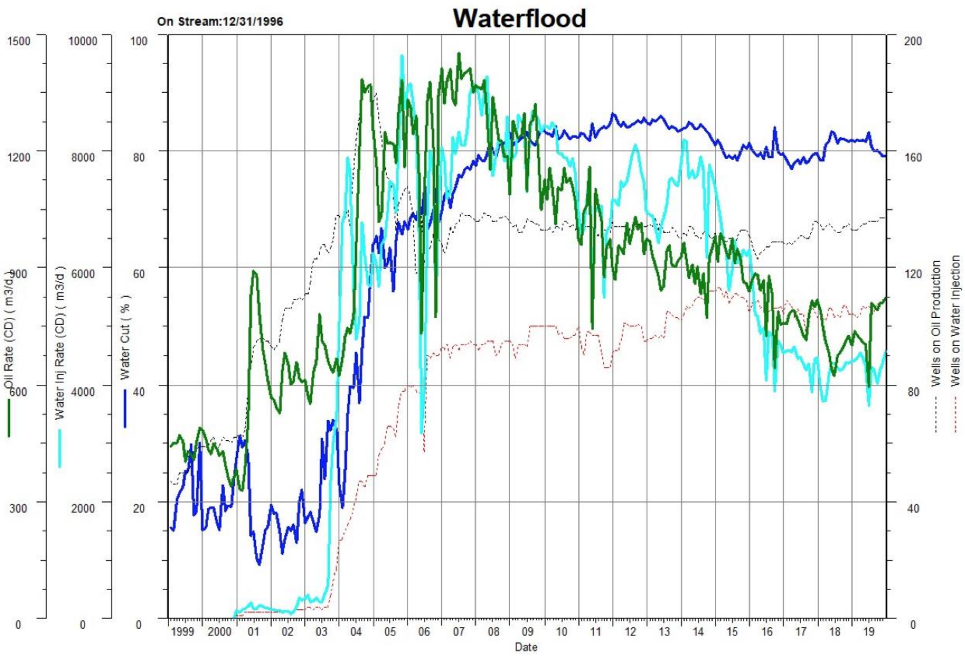

Figure 5. CNRL area waterflood performance

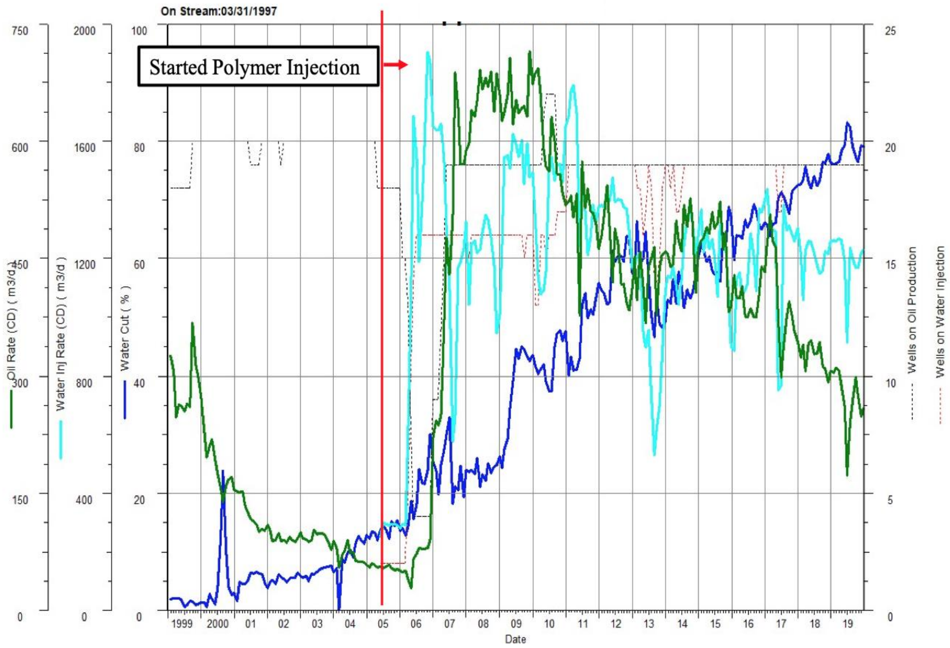

Figure 6. CNRL area polymer flood performance

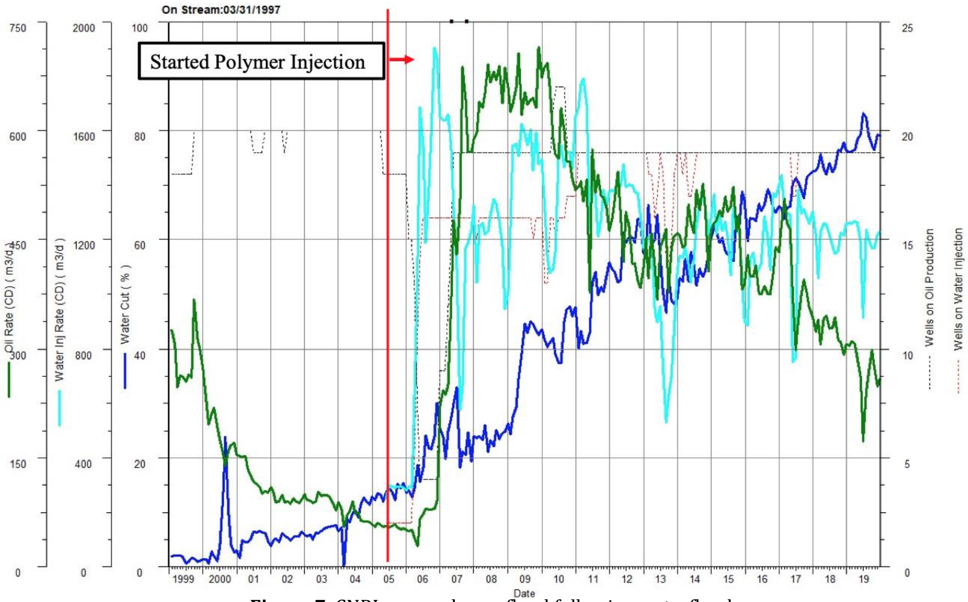

Figure 7. CNRL area polymer flood following waterflood

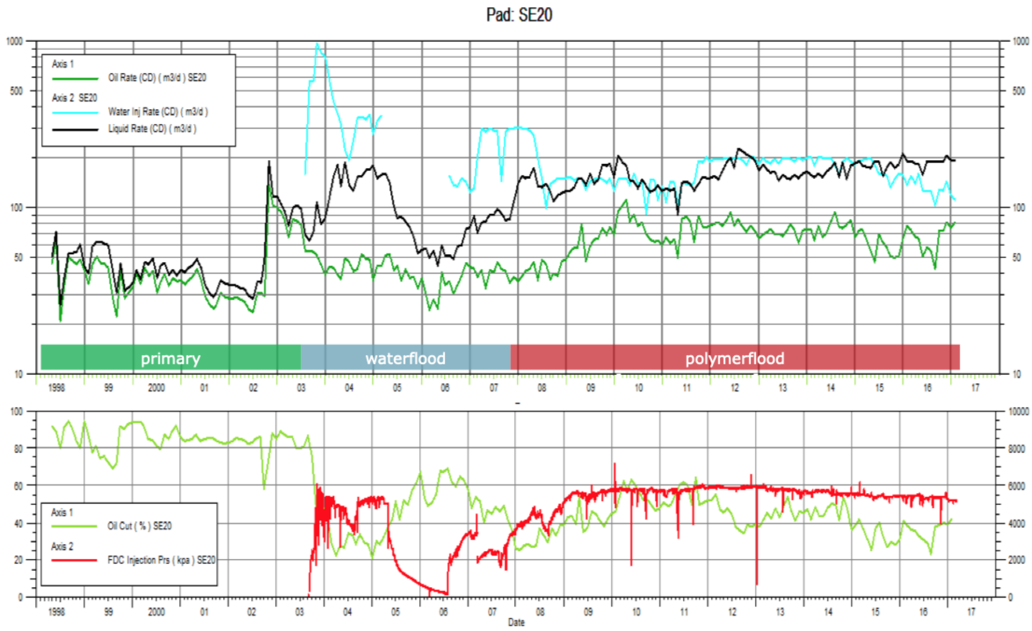

Figure 8. Cenovus area polymer flood following waterflood, this is one of the well performing pads.