Journal of Engineering Research and Reports

21(10): 25-40, 2021; Article no.JERR.83543
ISSN: 2582-2926

Critical Review of Polymer Flooding in Daqing Field and Pelican Field: Case Studies of the World's Largest Polymer Flooding in Light and Heavy Oil Reservoirs, Respectively

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Authors' contributions

This work was carried out in collaboration among all authors. Author OE was responsible for the conceptualization of this review with authors SSI and OA, Author OE wrote the draft manuscript under the guidance of authors 2 and 3. Author 1 wrote the final manuscript, while authors SSI and OA went through the manuscript. All authors read and approved the final manuscript.

Article Information

DOI: 10.9734/JERR/2021/v21i1017497

Open Peer Review History:
This journal follows the Advanced Open Peer Review policy. Identity of the Reviewers, Editor(s) and additional Reviewers, peer review comments, different versions of the manuscript, comments of the editors, etc are available here: https://www.sdiarticle5.com/review-history/83543

Review Article

Received 22 October 2021
Accepted 24 December 2021
Published 25 December 2021

ABSTRACT

Aim: Polymer flooding is a promising chemical enhanced oil recovery. Originally it was thought that polymer flooding was not economical. The polymer flooding in Daqing field China has proved otherwise. After that, it was thought that polymer flooding could only be successful in light oil reservoirs, but then polymer flooding was implemented in Pelican field in Canada on a large scale and recorded success.
Methodology: The methodology employed was to review polymer flooding from inception, beginning from the work of Kingsley Detling in 1944 who got a patent in the USA to late 1970's, thus early history of polymer flooding was a good insight for this paper. The mechanism of polymer flooding was also captured; improving the mobility ratio of water with a water soluble polymer is what helps for better sweep efficiency. The successful polymer flooding in Daqing field China has

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made many companies to understand this technology and go for polymer flooding. Polymer flooding of Daqing field has helped China's oil and gas industry. Polymer flooding is now used to recover heavy oil especially for deep reservoirs with thin pay zone. Pelican field in Canada has carried out the largest polymer flooding implementation in the world and has proven that polymer flooding can be used for heavy oil and given a new screening parameter for polymer flooding.
Results: This review has captured the critical aspects of polymer flooding both in light oil reservoirs-Daqing field, China and heavy oil reservoirs-Pelican field, Canada.
Conclusion: This review has proven that polymer flooding is a promising Chemical Enhanced Oil Recovery technology in both light oil and heavy oil reservoirs and it is used to increase the ultimate recovery of some fields and could help any country to remain relevant in the oil and gas sector. Using polymer flooding to recover heavy oil proves more efficient and more economical. Because, polymer flooding does not require a lot of heat as in thermal flooding, there is reduction in global green house gas effect.
Recommendation: It is recommended that companies use polymer flooding to recover their oil from light oil reservoirs and most importantly increase production and recovery in heavy oil fields.

Keywords: Daqing field; heavy oil reservoir; light oil reservoir; pelican field; polymer flooding.

ABBREVIATIONS

A	*: Alkaline*
AP	*: Alkaline-Polymer*
API	*: American Petroleum Institute*
AS	*: Alkaline-Surfactant*
ASP	*: Alkaline Surfactant Polymer*
Bbls	*: Barrels*
bbl/d	*: Barrels per Day*
bbl/d/well	*: Barrels per Day per Well*
BET surface Area	*: Brunauer-Emmett-Teller surface area*
Bopd	*: Barrels of Oil per Day*
cEOR	*: Chemical Enhanced Oil Recovery*
cP	*: Centipoise*
CPDI	*:* centralized preparation and dispersion injection
EOR	*: Enhanced Oil Recovery*
GHG	*: Green House Gas*
g/L	*: Grams per Litre*
HAPAM	*: Hydrophobically Associated Polyacrylamides*
HCHMW	*: High-Concentration-High-Molecular-Weight*
HS	*: High Salinity*
HT	*: High Temperature*
HTHS	*: High Temperature High Salinity*
HPAM	*: Hydrolyzed Polyacrylamide*
Ibs	*: pounds*
Kg/mol	*: Kilogram per Mole*
Km	*: Kilometre*
Km^2	*: Square Kilometre*
KYPAM	*: Comb Shaped Modified HPAM-A high Salinity Tolerant Polymer*
M	*: metre*
mg/g	*: milligrams per gram*
mg/L	*: milligrams per litre*
MMSTB	*: Million Stock Tank Barrels of Oil*
MPI	*: Ministry of Petroleum Industry*
OOIP	*: Original Oil In Place*
OPEX	*: Operating Expense*
P	*: Polymer*

PAM	*: Polyacrylamide*
PAIT	*: Polymer Alternating Injection Technology*
PF	*: Polymer Flooding*
pH	*: potential of hydrogen*
PPM	*: Parts Per Million*
PV/year	*: Pore Volumer per Year*
S	*: Surfactant*
SP	*: Surfactant-Polymer*
STB	*: Stock Tank Barrel*
STB/D	*: Stock Tank Barrels per Day*
T	*: metric tons*
TDS	*: Total Dissolved Solids*
USA	*: United States of America*
VRR	*: Voidage Replacement Ratio*
WF	*: Waterflooding*
WOR	*: Water Oil Ratio*
XG	*: Xanthan Gum*
µg/g	*: Microgram per gram*
µm	*: Micro Metre*

1. INTRODUCTION

1.1 Background

The quest for a better planet and the reduction of global warming have led to so much progress on renewable energy, but then oil and gas will remain the dominant sources of energy for many years to come [1-4]. In the oil and gas industry, there are three recovery mechanisms, namely, the primary recovery process, the secondary recovery process, and the tertiary recovery process. Primary recovery is the recovery by natural energy drives such as water, depletion, gas cap, rock compaction, gravity drainage, or a combination of any of these drive mechanisms whereby the differential pressure that occurs between the reservoirs and wellbore helps in oil production. In this process, no injection of fluids or heat is allowed, but gas lifts or electric submersible pumps (ESP's) could be employed. A secondary recovery process is employed when the differential pressure declines. The secondary recovery process involves the injection of an external fluid (mostly water or gas) via the injection wells for the purposes of reservoir pressure maintenance and subsequent displacing of oil into the production well. The recovery processes via primary and secondary recovery leave about two-thirds of the oil in the reservoir, and that is where the tertiary recovery process comes into the limelight [2, 5-8].

The tertiary recovery process is also known as enhanced oil recovery (EOR). EOR targets about two-thirds of the original oil in place (OOIP) in the reservoir. This quantity is too enormous to be ignored or left unattended. EOR: The oil displacement efficiency is enhanced by reducing the oil viscosity and/or by reducing the interfacial tension, while the volumetric sweep efficiency improves by developing a favorable mobility ratio between the displacing fluid and the remaining oil. EOR is therefore a viable method to recover both the bypassed and residual oil in the reservoir. Heavy oil reservoirs, low permeability reservoirs, or heterogeneous reservoirs, respond poorly to secondary recovery processes, i.e., water or gas flooding. In tertiary recovery processes, or EOR, a substance not found in the reservoir is introduced. EOR processes can be classified into four categories:

- Miscible flooding processes
- Chemical flooding processes
- Thermal flooding processes
- Microbial flooding processes

The thermal flooding process is good for viscous oil, but it is expensive and poses a lot of green house gas (GHG) effects on the atmosphere because of the heat involved. Thermal EOR is not feasible for oil that is located in a deep reservoir or in reservoirs that have thin pay [4-5,7,9-11].

Chemical enhanced oil recovery (cEOR) has received considerable attention and is used for EOR purposes. The three chemicals used are polymers (P), surfactants (S), and alkaline (A). They can be used individually or in combination to harness the advantages of each of the individual chemicals. cEOR reduces the residual oil saturation by lowering water-oil interfacial tension using surfactant and or alkaline and increases the volumetric sweep efficiency by reducing the water-oil mobility ratio using polymer. Nanoparticles are also part of cEOR. Thus, cEOR could be polymer flooding, surfactant flooding, alkaline-surfactant (AS) flooding, alkaline-polymer (AP) flooding, surfactant-polymer (SP), alkaline-surfactant-polymer (ASP) flooding and nanoparticle flooding [4].

Fig. 1 shows the oil production mechanism from discovery through primary, secondary and tertiary recovery production mechanism [12].

Amongst the chemical enhanced oil recovery (cEOR) methods, polymer flooding is a proven chemical enhanced oil recovery (cEOR) method used to recover residual oil, especially in heavy oil where waterflooding is not effective due to viscous fingering [13–15]. In the oil and gas industry, two types of polymers are mostly used: synthetic polymers like hydrolyzed polyacrylamide (HPAM) and its derivatives, and biologically produced biopolymers like xanthan gum (XG) and cellulose [15,16,17]. HPAM has been deployed for the majority of the field polymer flooding. The reason for this is that it is readily available and it is not as expensive as XG. Because of their high cost and plugging tendencies, biopolymers like xanthan gum have been used in very few fields. HPAM has been known to be unstable in high temperature and high salinity (HTHS) reservoirs and suffers from polymer degradation. xanthan gum, on the other hand, withstands high temperatures and high salinity reservoirs [18–21]. But nowadays, there are HPAM derivatives that have been synthesized from HPAM to overcome high salinity or high temperature, like hydrophobically associated polyacrylamides (HAPAM) and comb shaped modified HPAM, that is salinity tolerant and it is called KYPAM [22,23].

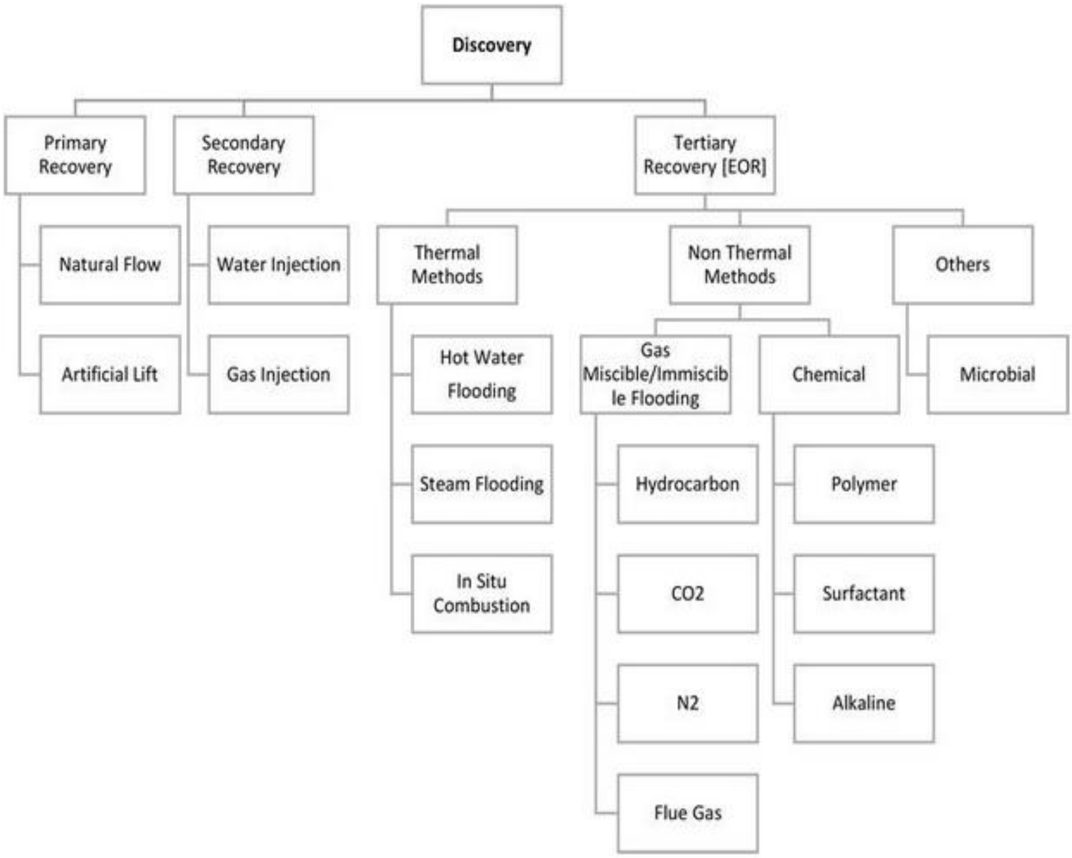

Fig. 1. Oil Production Mechanisms (Source, Ragab et al, [12])

1.2 Mechanism of Polymer Flooding (PF)

Adding water-soluble polymers will increase the viscosity of the water, hence improving mobility control and at the same time could also decrease relative permeability compared to oil. The advantages of polymer flooding are:

*Increasing vertical and areal sweep efficiencies
*Increasing mobility of injected fluid
*Polymer flooding requires lesser volume of injected water than waterflooding alone
*Cost of operating polymer flooding is lesser than surfactant and or alkaline flooding
*Lower operational cost for surface facilities because of reduced watercut etc.

When waterflooding is carried out, especially in heterogeneous reservoirs, the low viscosity of water been injected travels much faster than the oil being swept. This phenomenon is called viscous fingering and this is what polymer when added to water can control. Hence, understanding mobility and mobility ratio help in polymer flooding projects [24-26].

Mobility control is important in EOR processes, especially for polymer flooding. Mobility (λ), is defined as the effective permeability (k) divided by the viscosity (µ) of the phase.

$$\lambda = \frac{k}{\mu} \qquad 1$$

From the formula, λ relates to amount of resistance to flow through a reservoir rock that a fluid possesses at any given saturation of that fluid. Also from the position of µ in the equation, crude with low API ° will have low mobility.

Mobility Ratio (M), is defined as the mobility of displacing fluid (water) divided by the mobility of the displaced fluid (oil).

$$M = \frac{\lambda_w}{\lambda_o} \qquad 2$$

Substituting equation 1 into equation 2, and considering relative permeabilities because of two phase,

$$M = \frac{K_w/\mu_w}{K_o/\mu_o} \qquad 3$$

This can be solved as

$$M = \frac{K_w}{\mu_w} * \frac{\mu_o}{K_o} \;=\; M = \frac{\mu_o\, K_w}{\mu_w\, K_o} \qquad 4$$

The mobility ratio has served as one of the routine screening parameters for reservoir analysis and it represents the effects of relative permeability and viscosity of water and oil at a fractional flow rate based on the famous Darcy's law, which is expressed as,

$$f_o = \frac{1}{1+M} = \frac{1}{1+\frac{\mu_o\, K_w}{\mu_w\, K_o}} \qquad 5$$

Where f_o is the fractional flow of oil [6].

During the waterflooding process, as water is injected into heavy oil or into heterogeneous reservoirs, the water seeks the path of least resistance (usually layers of high permeability) to the lower pressure region of the offset producing wells. This causes uneven flooding or viscous fingering as mentioned earlier. Nevertheless, with the addition of water-soluble polymers, the viscosified water corrects the mobility ratio experienced during the water flooding, thereby increasing the volumetric sweep efficiency of the water-flooded reservoir.

The values of mobility ratio, M, mean a lot during polymer flooding.

When M > 1 unfavorable front, when M = 1, Piston-Like displacement and when M < 1 favorable front [4,23].

Fig. 2 shows how polymer flooding can achieve better oil recovery [23].

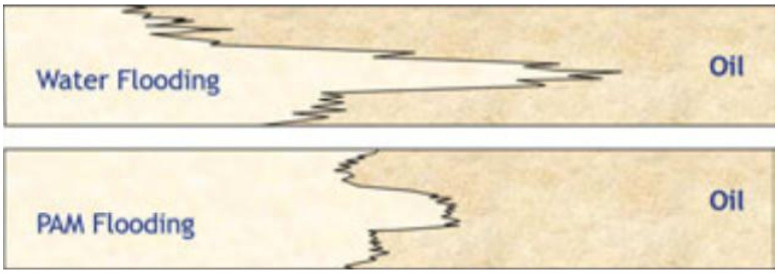

Fig. 2. Water breakthrough delayed and improved sweep efficiency by Polyacrylamide (PAM) polymers (Source, Thomas, [23])

1.3 Early History of Polymer Flooding

Polymer flooding has been around for about 60 years. There has been progress and research geared towards this cEOR method. Much scientific progress has been made and this is an active research area. Researchers and scientists are working hard to develop high-performance polymers for applicability in high-temperature, high-salinity (HTHS) onshore and offshore environments, etc.

Kingsley Detling implemented a polymer-based EOR, or rather cEOR. A patent was granted to Kingsley Detling in 1944 under USA Patent 2,341,500. In the experiment, a flooding process for the recovery of oil from depleted oil sands was conducted, comprising the steps of first injecting into an input well a viscous liquid consisting of an aqueous solution of sodium oleate and phenol, then injecting water into the injection well and forcing the liquid through the depleted oil sand towards the production wells. In addition, an aqueous solution of fatty acid soap and a hydroxyl-aromatic compound were injected. In another experiment, an aqueous solution of alkali metal soap with a higher fatty acid and a hydroxyl-aromatic compound was prepared [27]

Muskat first, in 1949, recognized that fluid mobility would affect waterflood performance. This was a success, and the sequel to it was a textbook published in 1981 [28-30].

In August 1961, small slugs of HPAM were injected during waterflooding into the West Cat Canyon field in Santa Barbara County, California, USA for 3 days in one of the tests. This early polymer pilot test improved the recovery of oil from West Cat Canyon from 100 STB/D to 300 STB/D. The crude oil is viscous and heavy, with an API gravity of 11 to 23° API and an average viscosity of 110 cP. As of September 1963, the total incremental oil recovery was estimated to be 95,000 STB for 2,600 *ibs* of injected polymer addition. More pilots were performed, but with larger polymer slugs, with promising results if applied to larger sections. Sandiford's studies conducted on cores in the laboratory before the pilot tests have shown that polymer solutions (HPAM) may lead to an increase in oil recovery over waterflooding by either improving sweep efficiency or improving microscopic displacement efficiency or both [31,32].

In 1962, Barnes noticed that waterflooding was inefficient because some of the reservoirs were partially invaded by bottom water. The oil was of high viscosity, hence it would finger through without producing good enough oil. The investigation was carried out on a model representing a 20-acre spot with one set of reservoir conditions. 10% and 25% of viscous water slug were used to displace viscous oil, and there was an increment in volumetric sweep. The 10% viscous water slug displacement would produce, depending on the injection rate, 65 to 90% as much fluid as a straight water displacement would produce, and the 25% viscous water slug displacement would produce, depending on injection rate, 70 to 75% as much fluid as a straight water displacement. There was a 16% increase in volumetric sweep for all viscous water displacement over conventional flooding at a water oil ratio (WOR) of 20:1. An increase in injection rate resulted in an increase in volumetric sweep for all types of displacement. Some limitations noted included a homogeneous reservoir that was completely liquid saturated, no residual gas saturation prior to the start of flooding, equal residual oil saturation of the flooded out portion and the bottom water zone, a single set of field conditions, and finally constant displacement [33]

The Niagara field near Henderson City, Kentucky, initiated a waterflooding pilot in 1954 to help the recovery of its 16 cP viscosity oil. The relative permeability of water at a residual oil of 0.09 resulted in an unfavourable mobility ratio and poor sweep efficiency. But in 1959, a 1.35 cP polymer solution was injected in a continuous manner for 33 months into the four-spot polymer pilot. This polymer injection exhibited a resistance factor of 8 in the reservoir rock, which made the mobility ration more favorable and resulted in better sweep efficiency [34].

The Albrecht Oil Field is located in Texas, USA. It is a heavy oil with an average viscosity of 130 cP. The high viscosity resulted in a water-oil mobility ratio of about 40. In 1964, Pye published an article in SPE-845 with the title "Improved Secondary Recovery by Control of Water Mobility." He pointed out that a polymer pilot test in a small 4-acre reservoir was about 7 net ft of 600 md sand at a depth of 85 ft. The polymer pilot test recovered 2 times what waterflooding would have recovered because of improved sweep efficiency and oil gain [34].

In 1966, Mungal used two different types of polymers (Polyethelyene Oxide and Polyacrylamide (PAM)) of different molecular weights to augment water flooding and thus was able to study the adsorption of polymers, transport rheology, and oil recovery. He achieved a reduction in the mobility ratio of the water during injection with a polymer concentration of 0.05% by weight, and concluded that polymer type, molecular weight, salinity and pH of the water, crude oil, and capillary properties of the porous medium are all important for effective polymer flooding. Also, there was a slight reduction in residual oil saturation and improved volumetric sweep efficiency. PF requires careful design and profitability analysis. [35].

In 1969, Necmettin Mungan, in an article titled "Rheology & Adsorption of Aqueous Polymer Solutions," used two HPAMs called Nos. 500 and 700 to determine the rheological and adsorptive properties of the polymer solutions while varying their temperatures and salinities. Viscosity and its shear rate dependence are reduced as NaCl is added to the HPAM solutions. He concluded that the viscosity of the polymer solutions is dependent on the shear rate, the salinity, the pH, and the molecular weight. Thermal degradation of HPAM solutions occurs between 135 and 150 degrees Celsius. Adsorption on unconsolidated sandstone and silica sand ranged from 30 to 880 µg/g. In consolidated porous media exhibiting the same BET surface area, adsorption was significantly less, the maximum being 160 µg/g [36].

In 1970, Smith reported in a paper titled "The Behavior of Partially Hydrolyzed Polyacrylamide Solutions in Porous Media" his experiment on the use of three HPAM polymers supplied by the same commercial supplier. All three of the polymers were linear but of different molecular weights.

The experimental results show that the extent of polymer adsorption solution could be high if the solution has a high salinity or is in contact with carbonate rock. The experimental results also suggest that flow rate, polymer molecular weight, solution salinity and rock pore size greatly influence the reduction of mobility and permeability by polymer solutions.

From the experiments, the following conclusions were drawn:

- Different mineral surfaces have different polymer adsorption rates. Adsorption is more noted in carbonate reservoirs than in sandstone reservoirs.
- Polymer adsorption increases with salt concentration. It is more in divalent ions of calcium than in monovalent ions of sodium.
- Polymer flooding effectiveness is favored in low salinity reservoirs and when using high molecular polymers.
- At very high fluid velocities, mechanical degradation begins.
- The mobility of polymer solutions in porous media decreases markedly as the flow rate increases.
- Increasing temperatures appear to have little effect on polymer mobility reduction within their thermal stability range..

This experiment was a good breakthrough in polymer flooding [37].

In 1975, two scientists, Szabo and Maerker, reported their different experiments with HPAM. Szabo’s experiment was reported in a paper titled “Some Aspects of Polymer Retention in Porous Media Using a C^{14}-Tagged Hydrolyzed polyacrylamide,” and Maerker reported his own experiment in a paper titled “Shear degradation of partially hydrolyzed polyacrylamide solutions”. In Szabo’s experiment, the effect of slug size, polymer concentration, salinity, and type of porous medium on polymer retention was studied. The experiment had the following outcome.

Table 1. Properties of Three Different Polymers used (Source, Smith, [37]).

S/No	Polymer Type	Avg. Molecular Weight	Degree of Hydrolysis
1.	HPAM Type H	3 and 10 million	High Degree
2.	HPAM Type M	About 3 million	High Degree
3.	HPAM Type L	Very Low	Very Low Degree

- In low surface area sands, the mechanism of polymer retention by mechanical entrapment is felt greatly.
- The HPAM used exhibited a partial reversible adsorption on the silica surface.
- The distribution of retained polymer decreases exponentially with distance.
- Polymer retention by physical adsorption is more dominant than mechanical entrapment in medium permeability Berea cores.
- During polymer flooding in both consolidated and unconsolidated sandstones, an inaccessible pore volume exists.

HPAM experiences degradation during injection in the process of its water mobility reduction during polymer flooding. The degradation is dependent on the rock’s permeability. In Maerker’s experiment, degradation is investigated by forcing polymer solutions, prepared in brines of various salinities, through consolidated sandstone plugs differing in length and permeability, over a wide range of flow rates. The experiment had the following outcome:

- Porous-medium-induced mechanical degradation of partially hydrolyzed polyacrylamide solutions is caused by large viscoelastic normal stresses generated by primarily elongational flow fields.
- Mechanical degradation appears to be nearly independent of polyacrylamide concentration between 300 and 600 ppm in brines of 3.0 to 3.3 % of total dissolved solids (TDS).
- Mechanical degradation becomes more severe with larger fluxes, longer dimensionless flow distances, and lower brine permeabilities at the wellbore.
- A propped, hydraulic fracture at the injection wellbore will not eliminate the degradation problem.
- Based on laboratory data and a set of fairly favorable injection conditions, a computer-simulated, hypothetical polymer flood recovered 24.6 % less incremental oil because of mechanical degradation.
- Application of the new pseudos to increase the lengths of computing blocks used in a 'two-dimensional areal model, as compared with the consistent simple increase in ionic strength. 'Implications are that softening injection water may reduce degradation significantly.
- Loss of mobility control in a formation caused by mechanical degradation at the wellbore is more severe with lower formation permeability. Isolated examples contradict this general conclusion, possibly because of different pore-size distributions. It could also occur as a result of residual oil saturations [38,39].

In 1977, two staff members of Marathon Oil Company carried out research with two different heavy oils and molecular weight commercial polymers and two developmental materials with higher molecular weights to determine the applicability of the heavy molecular weight of the polymer on heavy oil recovery. The Ottawa sand packs represented the cores of Ottawa. The absolute permeability of the front section and rear section ranges between 4,600 md and 5,000 md and 3,700 md and 6,000 md, respectively. Two heavy oils were used in the experiment; one crude from Wyoming with a viscosity of 220 cP and a 19.8° API, while the other was a refined crude with a viscosity of 1,140 cP. The front section mobility of the 220 cP oil ranged between 19.4 and 25.2, while the rear section mobility ranged between 19.0 and 25.0. The front section mobility of the 1,140 cP oil ranged between 4.6 and 4.7, while the rear section mobility ranged between 4.8 and 5.0. The mobility ratio during waterflooding was up to 30, but PF reduced the mobility ratio to 0.34 and 3.2 in the 220 cP and 1,140 cP oils, respectively. Tertiary recovery ranged from 19% to 31% for polymers. This research showed that polymer flooding is better than water flooding and that new higher molecular polymers can recover viscous oil at up to 1,140 cP [40,41].

2. DAQING FIELD, CHINA

The Daqing field is the largest oil field in the People’s Republic of China and one of the few super large sandstone oilfields in the world. It is located in the mid-western part of Heilongjiang Province and the northern part of the Songhuajiang-Nenjiang Plain and consists of 52 oil and gas fields such as Saertu, Xingshugang, Lamadian, and Chaoyanggou across an area of 6,000 km^2. Because of the time in China’s history that it was discovered, Daqing is associated with big or great celebrations. The field was discovered on September 26th, 1959, with a commercial oil flow from Songji-3 in the south of the central depression in the Songliao Basin. This well was drilled by the Ministry of Petroleum Industry (MPI). The source bed in the Daqing Oilfield is mainly Mesozoic Cretaceous sandstone of continental facies, and it is about 900–1,200 meters underground, with a porosity of 25–30% and a permeability of 500–1,000 md. The crude oil is paraffin based and characterized by a high wax content (20%-30%), a high freezing point (25°C-30°C), high viscosity (ground viscosity of 35 cP), gravity between 0.83 and 0.86, API gravity ranges between 33° to 39°, and a low sulphur content (about 0.11%). This field is remarkable because it is the largest polymer flood in a light oil reservoir and, unarguably, the largest in the world [42-44].

In March 1960, the development and productivity of the Daqing Oilfield began. In 1964, the Daqing oilfield produced almost half of China's oil and made the country self-sufficient in oil. In 1976, the oilfield's annual crude production exceeded 50 million tons for the first time, making it one of the world's most famous giant oilfields. It maintained annual crude production of 50 million tons for 27 years from then. In the late 1980s, most oil fields in the Daqing area entered the late stage of development with a total water cut of up to 90%. However, Daqing managed to stabilize its annual production. The primary recovery process in Daqing field yielded about 7–8% of OOIP. The production stabilization was because of the comprehensive control of water flooding, accelerating the production boost of peripheral resource replacement areas and reinforcing tertiary oil recovery by means of polymer flooding [43].

The first laboratory studies using polymers in the Daqing field was in the 1960's, while the first polymer flooding pilot in the same field was in 1972. The first commercial field application of polymer flooding occurred in 1996, and since then it has been a success. The Daqing field has proven that the incremental oil recovery from polymer injections averages an extra 12% of the oil originally in place (OOIP). Because of its size, heterogeneity, and large reserves, the Daqing field has seen a lot of research and field polymer testing, even after the commercial polymer flooding [46]. Many scientists and researchers in the Daqing Oilfield have documented the progress of polymer flooding at various times, including surfactant polymer (SP) flooding and alkaline-surfactant-polymer (ASP) flooding [46-53].

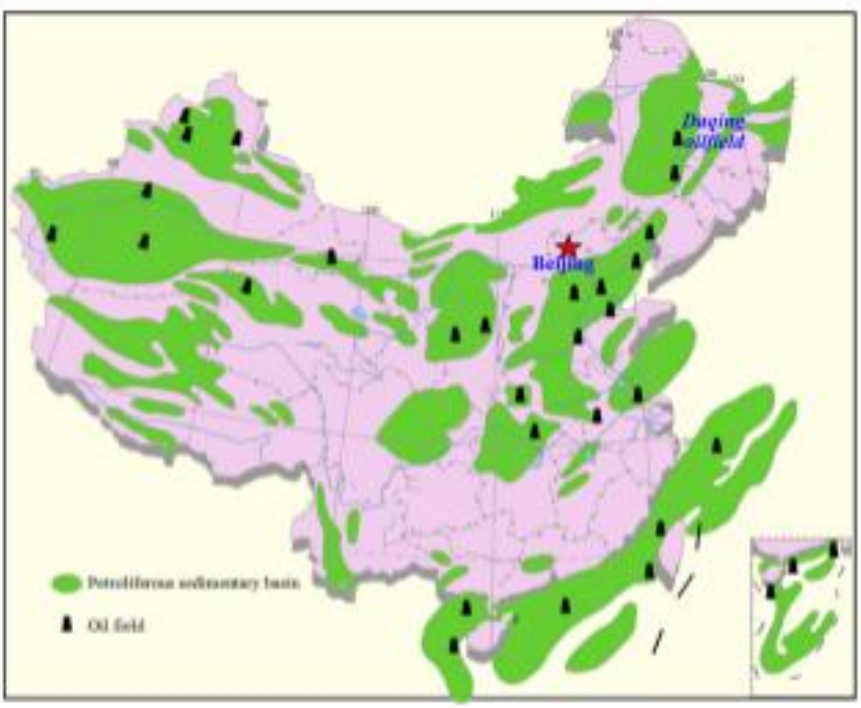

Fig. 3. Location of Daqing oilfield in China (Source, Wang et al. [45])

Until 2007, Daqing field had cumulative proven oil reserves of 42 billion barrels (5.67 billion tons) of oil and produced a cumulative crude oil total of 13 billion barrels (1.821 billion tons), about 47% of China's onshore oil production. For 27 years, the field maintained a production plateau of more than 367 million barrels (50 million tons) per year, or 1 million barrels per day, and followed this with 12 more consecutive years of stable production of 296 million barrels (40 million tons). It is dubbed "an oilfield miracle in the world's oil development history." [42].

In 2008, Wang et al. addressed the remedy for Daquin Field's high injection pressure and low injection rates in an article titled "New Development in Production Technology for Polymer Flooding." They noted some problems, like:

- Serious eccentricities on sucker and tubing have happened on a large number of pumping wells and the increase in wells with wear problems is causing high OPEX as a result of regular workovers.
- About 33% of the polymer injection wells were experiencing low injection rates, and their injection pressure was very close to the formation fracture pressure. It was observed that conventional fracturing methods can only improve injectivity for about 3 months.
- Hence, the injected polymer solutions react with the acid fluids during acid stimulation. Therefore, conventional acid stimulation cannot be used on polymer injection wells.

The above reasons challenged Daqing Oil Company and Daqing Petroleum Institute to develop some novel techniques that solved the above challenges. These included eccentric wear control, resin sand fracturing, and surfactant stimulation. because in the polymer injection wells, fracturing improved injectivity for less than 3 months [54].

As of December 2017, cumulative oil production was 0.219 x 10^9 t (1.6 x 10^9 bbl). Both polymer flooding and ASP flooding have been commercially used in Daqing, as mentioned earlier. Oil production with polymer flooding and polymer powder as used in Daqing is shown in Figs. 4 and 5, respectively [55].

Until 2019, the accumulated incremental oil production using polymer flooding and alkaline-surfactant-polymer (ASP) flooding had reached 265 million tons in Daqing Oilfield, and more than 10 million tons of oil was produced annually for a continuous period of 18 years. In 2019, the total incremental oil production by polymer and ASP flooding reached 10.4 million tons, of which polymer flooding alone represented 6.03 million tons, supporting the sustainable development of the mature Daqing Oilfield [56].

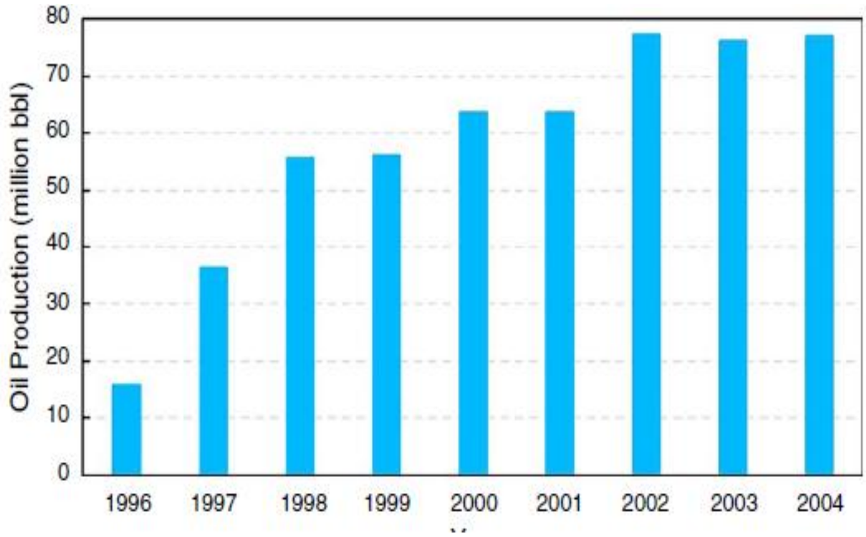

Fig. 4. Polymer flooding oil production in Daqing oilfield in China (Source, Guo et al. [55])

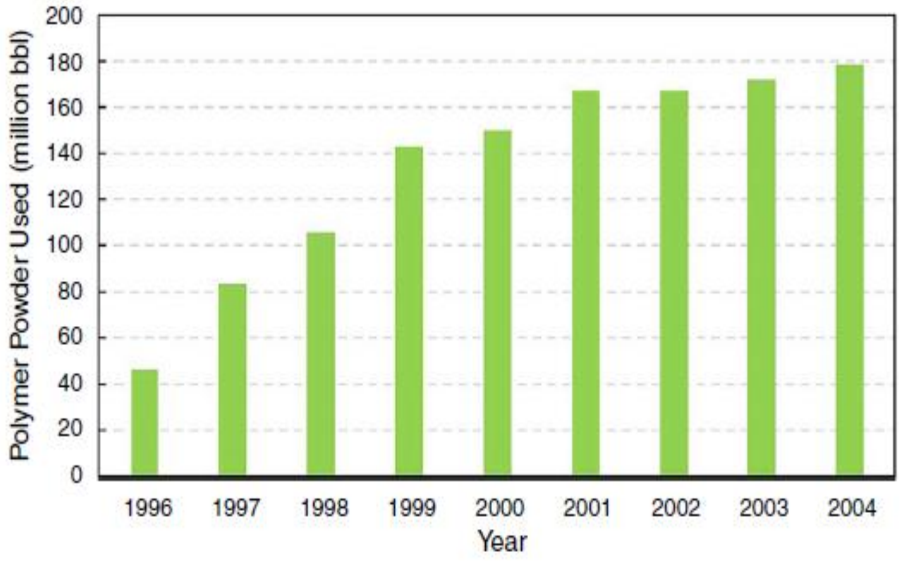

Fig. 5. Polymer powder used in Daqing oilfield in China (Source, Guo et al. [55])

3. PELICAN LAKE FIELD, CANADA

The Pelican Lake field, sometimes called Brintnell, is located approximately 250 km north of Edmonton, Alberta, Canada. The field was discovered in 1978, and production commenced in 1980. The field occupies approximately 1,770 km^2. This field is remarkable because it is the largest polymer flood in heavy oil reservoirs in the world and the largest polymer flood using horizontal wells [57].

The average net pay of the field is 5 m, and the net pay varies between 1 and 9 m. Hence, simple screening shows that it is not a good candidate for thermal recovery methods, for the estimated oil originally in place of 6,000 MMSTB. The producing formation of the Pelican Lake field is known as Wabiskaw A. From 1978 to 1987, more than 200 vertical wells were drilled in the field, but the production was not commensurate with the field's potential because of the high viscous oil and thin pay reservoir [58,59].

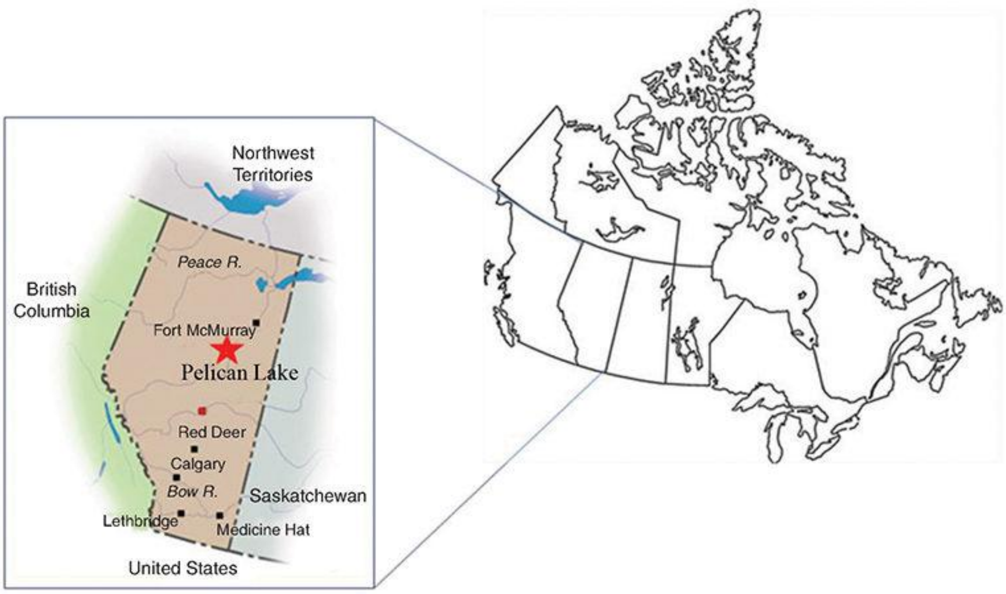

Fig. 6. Location of Pelican Lake Field (Source Dalamaide et al. [57])

Table 2. Average increase in oil rate due to polymer injection (Source, Delamaide. [60])

Phase	Oil Rate Before (bbl/d)	Oil Rate After (bbl/d)	After/Before
2005	90	130	1.4
2006	64	133	2.1
2007	25	88	3.5
2008	76	86	1.1
2009	72	86	1.2
2010	29	75	2.6
2011	24	90	3.8
2012	22	40	1.8
2013	17	44	2.6
2014	30	82	2.7

In the late 1980's, horizontal drilling was employed and this became the game changer for Pelican Lake field, though the OOIP was still low. In the early 2000's, a waterflooding pilot was initiated and this was able to produce incremental oil recovery of about 5–10% of OOIP. The heavy and viscous oil of Pelican Lake field posed some viscous fingering challenges because of the mobility of water in some sections of the field. This caused increased water cuts and reduced sweep efficiency. This was the brain child behind the polymer flooding pilot in the field in 2005. The pilot test was rated as successful, with an increment in recovery factor of about 25% [57,58].

The success of the pilot test led to the extension of polymer flooding to larger areas of the field in 2006. There was a time when 900 horizontal wells were injecting 300,000 bbl/d of polymer solution and oil production reached 65,000 bopd from polymer injection contribution. The polymer injection was done in phases because of the large number of wells and number of polymer skids involved. All the phases of polymer injection turned out to be successful.
Table 2 shows the changes in average oil rate per well from before to after the start of polymer injection, for each phase; the numbers before were taken in the year preceding the start of the injection and the after numbers correspond to the peak oil achieved after. From table 2, it is evident that all the phases of the polymer injection were successful. The 2008 phase had just a small increment of about 44%, while the 2011 phase had a significant increment of 228%. (Delamaide 2021).

One key lesson learned is that the quality of injection water during polymer flooding determines the success rate of the project. For the Pelican Lake field polymer injection, four sources of water were utilized.

1. Re-injected formation water from the Wabiskaw formation. This was good because of the low salinity content of 8 g/L for 100 mg/g of divalent content.
2. The Grand Rapids formation has a salinity 1-2 g/L and a divalent cation content of 5-10 mg/L. This formation water is regarded as non saline.
3. The Grosmont formation is a saline water source with salinity of 22-35 g/L.
4. The shallow Quaternary formation contains non saline water of 1-2 g/L but divalent cation content of about 300-500 mg/L.

Maximum injection rates have been mostly in the 500-1,500 bbl/d/well range, which corresponds to an average injection rate of 0.02-0.04 PV/year. A cumulative Voidage Replacement Ratio (VRR) of 1 has usually been targeted, though not the same in all the patterns [60].

Conclusively, this polymer injection is a huge success as the injection has increased the recovery factor to more than 20% of OOIP for the 3.0 billion bbls flooded area. A low water to oil ratio is achieved. There is varying viscosity ranges from 800-10,000 + cp, yet it is a success, but then its performance varies according to viscosity. The permeability of this field is quite high, and with good injectivity, the results came out successfully. Injecting polymer from the beginning or early enough seems to achieve a higher recovery than tertiary polymer injection [60].

4. LESSONS LEARNT

A lot of lessons have been learnt from polymer flooding operations in Daqing field, China and Pelican field, Canada. Some of the lessons are listed below, and some are contained in the review directly:

- Traditionally, PF was thought to affect only the macroscopic sweep efficiency, but researchers working in the Daqing oil field established the fact that the viscoelastic properties of polymers can also reduce interfacial tension and, hence, recovery of oil can be influenced microscopically.
- Improvement in the utilization ratio of injected water.
- Daqing oilfield polymer flooding technology has formed a step by step working procedure, and the steps are
    - Laboratory experiments
    - Pilot field tests
    - Commercial field tests
    - Commercial large scale implementation.
- Cutting edge technologies in polymer flooding viz a viz
    - Adopting the high concentration large slug injection method
    - Conducting separate layer polymer injection process
    - Utilizing in depth profile modification
- Polymers can be modified, especially HPAM, to withstand high temperature (HT) or high salinity (HS) reservoirs, as the case maybe. KYPAM is a salinity tolerant HPAM which is produced by Beijing Hengju, China and it was used in polymer flooding in the Daqing field.
- The Daqing field has proven that the incremental oil recovery from polymer injections averages an extra 12% of the oil originally in place (OOIP).
- Using centralized preparation and dispersion injection (CPDI) saves a lot of cost during PF as compared to combined preparation and injection.
- Improved technology in lifting for PF relative to WF has been recorded. Polymer Alternating Injection Technology (PAIT) has been proposed for High-Concentration-High-Molecular-Weight (HCHMW) because it helps to increase the lower permeability layer fluid intake compared with traditional injection scheme that uses only one slug.
- The Pelican field in Canada has changed the screening criteria for polymer flooding. It was originally believed that PF was applicable to reservoirs with viscosity of less than 100 cP, but this has belonged to the old school of thought as Pelican field has very high viscosities.
- The Pelican field has shown the synergy of using horizontal wells in heavy oil reservoirs during implementation of PF.
- The Pelican field has demonstrated that timing is very instrumental to the success of any PF project. PF should be initiated as early as possible during the life of a reservoir, especially in heavy oil reservoir where primary recovery is low due to viscous fingering.
- The Pelican field has also demonstrated that even in heavy oil, recovery factor (RF), could get to 20% of OOIP in regions of very high permeabilities.
- PF has demonstrated that low WOR is achieved, low water cut and good injectivities also achieved.
- Conclusively, the injection water during polymer flooding determines the success rate of the project. For the Pelican Lake field polymer injection, four sources of water was utilized,

    - Re-injected formation water from Wabiskaw formation. This was good because of low salinity content of 8 g/L for 100 mg/g of divalent content.
    - The Grand Rapids formation of salinity 1-2 g/L and 5-10 mg/L of divalent cations. Thie formation water is regarded as non saline.
    - The Grosmont formation which is sline water source with salinity of 22-35 g/L.
    - The shallow Quaternary formation which contains non saline water of 1-2 g/L but divalent cations content of about 300-500 mg/L.

The lessons learnt from history of early polymer flooding made it possible for all the achievements' recorded in today's polymer flooding.

5. CONCLUSIONS AND RECOMMENDATION

5.1 Conclusions

This review has proven that polymer flooding is a promising chemical enhanced oil recovery technology in both light and heavy oil reservoirs, and it is used to increase the ultimate recovery of some fields and could help any country remain relevant in the oil and gas sector. Thanks to polymer flooding, the Daqing field in China has been a miracle field. Pelican field in Canada has also performed exceedingly well irrespective of the field's high oil viscosities. Using polymer flooding to recover heavy oil proves more efficient and more economical. Because, polymer flooding does not require a lot of heat as in thermal flooding, there is reduction in global green house gas effect.

Both Daqing field and Pelican field have proven the usefulness of polymer flooding in both light and heavy oil reservoirs. It is a way to achieve sustainable production of heavy oil, while taking into cognizance of the environment.

5.2 Recommendation

It is recommended that companies use polymer flooding to recover their oil from light oil reservoirs and most importantly increase production and recovery in heavy oil fields. Countries should adopt polymer flooding technology as it is cheaper than waterflooding, surfactant or alkaline flooding and even thermal flooding.

ACKNOWLEDGEMENTS

I acknowledge my co-authors, Professor Sunday Sunday Ikienkisimama and Professor Onyewuchi Akaranta, for their invaluable contributions and guidance.

I wish to acknowledge all the authors of the articles I consulted and cited for this work.

The authors wish to thank Eric Delamaide, a principal reservoir engineer and EOR expert, who has dedicated his life to researching about polymer flooding and heavy oil reservoirs. Your papers have been a great guide so far.

COMPETING INTERESTS

Authors have declared that no competing interests exist.

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Peer-review history:
The peer review history for this paper can be accessed here:
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