

The Use of Nanoparticles for Enhanced Heavy Crude Oil Recovery

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I. INTRODUCTION

1.1 Background of the Study

Heavy crude is a type of crude oil possessing a high viscosity and density. It is usually produced from oil sands, and as the name suggests, it is heavy and hard to extract. It is referred to as “heavy” because it has a higher specific gravity and is also much denser when compared with conventional (light) crude. Although some variations still exist, heavy oil is classified as crude with API gravity less than 20⁰. Light crude oil primarily produces fuels such as gasoline, diesel and aviation fuels, heavy crude (which also yields these transportation fuels) also provides feed stock for plastics, petrochemicals and road surfacing to name a few, therefore it is safe to say adequate heavy crude oil investment is necessary for the security of the oil and gas industry. Compared to its lighter counterpart, there is more unexploited heavy crude oil reserves around the world with several reasons responsible, most of which are associated with the difficulty encountered in recovering these heavy crude oils.

From all current projections, petroleum and liquid fuels will maintain their dominance over other renewable alternatives in the global transportation sector. By 2019, petrol and distillate fuel oil accounted for a shocking 84% of all energy consumed by the transportation sector (EIA, 2020). In terms of locational distribution, the United States alone accounts for 17.34% of the total primary energy consumption in the world (Energy Information Administration, 2020). Vast proven reserves, a hydrocarbon yield that strongly rivals conventional reservoirs and growing energy demand are factors driving commercial interest in heavy crude oil investment (Ding *et al.* 2019). Recent studies show the availability of tremendous heavy oil and bitumen resources in Saskatchewan and Alberta located in the western region of Canada. Due to a constantly growing

demand for renewable energy, oil and gas, there is a real need to focus even more attention on the exploration of heavy crude, its production and most importantly how its recovery can be advanced to maximum profitable levels (Canadian Association of Petroleum producers, 2022). Heavy oils are found in many places around the world. The biggest heavy crude oil manufacturers in the world, the United States, has its largest reserve in California, where the San Joaquin Valley is home to the largest oil field in the country with approximately 36 billion barrels of heavy oil reserves (Energy Information Administration, 2020). Canada on the other hand has the most extensive reserves for production. Canada has the world's fourth-largest oil reserves, with the majority of it being heavy oil, counting billions of barrels in oil reserves. Approximately 170 billion barrels of bitumen (a type of heavy hydrocarbon) are in the oil sands of Northern Alberta. This is the largest heavy hydrocarbon reserve on the planet, with 1.7 trillion barrels of heavy crude oil in place, covering an area of approximately 140,000 square kilometers (Canadian Association of Petroleum producers, 2022). Canada is clearly a stand out destination for heavy crude oil exploration and investment. Such amount of available hydrocarbon deposits shows that the future of hydrocarbon investment is in good condition and it also opens up a variety of opportunities for other industries as well.

Although Canada is a special destination for research, the challenges associated with extracting and processing heavy oil from the oil sands are tremendous because the extraction processes require specialized technology and infrastructure, leading to the application of several techniques. Canada has a long history of heavy oil production, and the industry has been a significant contributor to the country's economy. The Canadian government has also been supportive of heavy oil research and development,

with significant investments in research and technology aimed at improving the efficiency and sustainability of heavy crude oil production. Additionally, its proximity to the United States, which is the largest market for heavy oil, makes it an attractive destination for heavy oil research and investment.

1.2 Statement of the Research Problem

- i. The current methods used for heavy crude oil recovery are highly steam dependent. However, the high cost of generating the steam needed for such injection processes and large volume of water required are vital issues faced.
- ii. Another problem with steam injection techniques is the excessive heat loss into the atmosphere which occurs with natural gas emission harmful to the environment.
- iii. The release of sulfur to the surrounding is another major challenge faced with current methods.

1.3 Objectives of the Study

The main objective of this research was to use nanoparticles for recovery of heavy crude oil.

The specific objectives of the study were to;

- i. construct a core flooding system prototype that will be used to carry out the experiments;
- ii. generate or obtain core samples for the experiments;
- iii. determine the petro-physical properties; permeability and porosity of the core samples;
- iv. use water as an injection fluid in the system;
- v. use a Nanoparticle mixture as an injection fluid in the system; and
- vi. evaluate incremental oil recovery from both injection processes.

1.4 Significance of the Study

- i. The introduction of Nanotechnology through the use of polymeric nanoparticles in this research is important at a time where constant improvement to oil recovery methods is necessary.
- ii. Applying such an innovation to EOR shows that even the petroleum industry can grow and adapt in various aspects to avoid being left behind.

- iii. Maximizing recovery from heavy hydrocarbon reservoirs proved a major issue for many decades but with the introduction of Nano-technology to EOR, expectations are high, resulting from their potential to break through oils in special ways and address major recovery challenges faced both in heavy and conventional reservoirs as well.

1.5 Scope and Limitations of the Study

Conducted in a region predominantly richer in light crude, easy access to the required heavy crude oil for this work stood as a great challenge to the completion of the work. Bitumen was used, mixed with Automotive Gas Oil (A.G.O) this was necessary to achieve a lighter form. The absence of a standard core flooding system was another problem encountered in the course of this study.

II. REVIEW OF RELATED LITERATURE

2.1 Heavy Crude Oil

The use of conventional reservoirs has covered a very high oil and gas demand spanning over decades. However, with their numbers depleting, to meet the ever-growing demand for crude oil and its products alternatives are being sort after leading to more gravitation towards heavy crude oil reservoirs to meet this demand. With constant spiking in prices of crude oil products, such as premium motor spirit (P.M.S), automotive gas oil (A.G.O) and several others, and there is likelihood that this migration will only increase over time. Therefore, it is important that something is done quickly to avoid the arousal of even greater problems.

Heavy crude oils are mainly classified by their high viscosity, very dense natures and the strong interfacial tensions they exhibit. All these are factors that cause the difficulties encountered during production. Globally, there is an estimated 80 million barrels of oil produced daily, out of which 11 million barrels are classified as heavy hydrocarbons. There is a depleting number of light crude oil reservoirs and heavy crude oil reservoirs are replacing them in the pool of crude oil feedstock in refineries. These crude oils are processed into various value-added products such as LPG, gasoline, diesel etc. According to Gounder

(2019) the current contribution of heavy hydrocarbons in the crude oil pool is 10% but it is projected to increase in a few years. Tremendous deposits of heavy crude oil can be found in different places around the world; actively producing countries include: Venezuela, Ecuador, Canada, Chad, Mexico, Russia, Indonesia, Saudi Arabia, China, Colombia, Iraq, Brazil, Kuwait, United States and Angola. Heavy hydrocarbons are an important energy resource requiring a high level of effort and expertise to produce and process economically. With growing energy demands, the economics of heavy crude oil production and processing will improve. Reaching up to six times the proven reserves of conventional oil, most reservoirs are unconventional, in the form of oil

sands, heavy oil, extra-heavy oil, tar sands, oil shale, bitumen (Carillo and Corredor, 2013). Various organizations such as the American Petroleum Institute (API), United Nations Institute for Training and Research (UNITAR)/World Petroleum Congress (WPC), Canadian Centre for Energy (CCE), Alberta Energy Resources Conservation Board (AERCB), and the US Geological Survey (USGS) have defined the term heavy oil based on API gravity (which is specific gravity related) and viscosity. Table 2.1 below shows various organizations responsible for defining American Petroleum index (API) gravity and their standards.

Table 2.1: Definitions of heavy crude oil by various organizations

Organization	API (⁰)	Viscosity (mPa.s)
API	<22.3	>10
UNITAR/WPC	10 to 20	10 ² to 10 ⁵
CCE	>10	< 10 ⁵
AERCB	10 to 19	10 ² to 10 ⁵
USGS	<22	>10 ²

The API gravity proposed by the American Petroleum Institute is the most widely used definition heavy crude oil classification is based on, but the range elected to define and classify the oils has not been standardized. For instance, WPC classifies oils having below 22.3 0API gravity as heavy. The API defines heavy as those having an API index equal to or smaller than 200. Heavy crude oil processing is a complex process that involves a range of technologies and techniques to extract and refine the oil. Since the cost of investing in new oil reserves has been rising continuously. Over the last two decades, the North American heavy oil fields became a primary gold rush for energy firms, instead of hunting for brand-new reservoirs, engineers shifted their budgets toward squeezing more volume out of the sites they already controlled. The United States Bureau of Mines estimates over 150 billion barrels of oil categorized with a gravity of less than 25° API in known reservoirs (Szasz and Thomas, 1965), most of them have over 1000 bbl/ft; about half of which are located at depths of less than 3000 ft. Compared to an estimated ultimate recovery of 30 percent from conventional fields, recovery from these heavy crude reservoirs is

estimated at about 11%. This brings a special attraction to heavy hydrocarbons despite their having significant low oil mobility. Highly ranked in the world production index, Canada is considered a standout location for heavy crude investments aside the US, ranking as one of the top countries for natural gas production also, it is obvious why it has become a place of interest for investors over time. Putting aside the difficulties that come with heavy crude oil recovery and placing the focus on its up-sides shows the potential it has to address major energy problems. Nevertheless, a lot of work still needs to be done to take the industry to the next level and benefit safely from all that these reserves have to offer. A very important fact to recognize is that the problems of heavy crude recovery are really not new; they have been encountered before in conventional reservoirs. In heavy oil reservoirs, however, we find them on an exaggerated scale. But the potential reserves in such systems make every attempt to surmount these problems worthwhile. A tabular representation of the top oil producing and distributing countries in the world is represented in Table 2.2.

Table 2.2: List of top oil producing countries in the world

Rank	Oil prod (MMB/d)	Percentage contribution to world demand
KUWAIT	3.0	3%
BRAZIL	3.1	3%
IRAN	3.8	4%
UAE	4.0	4%
CHINA	4.1	4%
IRAQ	4.5	5%
CANADA	5.6	6%
RUSSIA	11.2	12%
SAUDI ARABIA	12.1	13%
UNITED STATES	17.8	18%

2.2 Heavy Crude Oil Recovery

Before we delve into heavy crude oil EOR and what it entails, it is important that like light crude, heavy crude oil must go through the various initial stages for maximum recovery to be achieved, although this is typically harder with heavy crude oil. Typically, conventional oil recovery is above 30% but for heavy crude oil the recovery factor is within the range of 5-10% (Gounder, 2019). This is because heavy crude oil is often found in reservoirs that are more difficult to access. Crude oil recovery takes place in 3 stages; primary, secondary and tertiary recovery also called enhanced oil recovery (EOR).

2.2.1 Primary Recovery

This takes place first or as the initial stage in the oil production process. It involves placing increased pressure on the wells in order to move the oil to the surface, in other words, primary recovery depends heavily on the pressure difference naturally existing between the surface and the underground reservoir. As oil gets produced out of the reservoir, gradually underground pressure decreases slowly, thereby causing the oil production rate to decrease. During this stage, only a small portion of the hydrocarbon is recovered, usually around 5-15%, depending on the properties of the reservoir (Mohammad et al. 2024). Residual oil remains trapped underground. Primary recovery methods rely very much on the natural drive in the reservoir to force oil to the surface. Several challenges are associated with primary oil recovery. One of the main challenges is the declining natural pressure in the reservoir over time. As the oil is produced, the pressure in the well decreases, leading to a reduction in rate of oil produced over time and

eventually to the well running dry. Finally, primary recovery is not always effective, particularly in reservoirs with low permeability or high viscosity in such cases, secondary and tertiary recovery methods may be required to recover additional oil from the well.

2.2.2 Secondary Recovery

The second stage of recovery in oil production is Secondary recovery. Here additional oil is recovered from the well that was not recovered during primary recovery. Primary recovery methods typically recover only a small amount of the residual hydrocarbon, therefore secondary techniques are employed to increase hydrocarbon production. Secondary methods involve fluid injection into the well increasing oil pressure forcing flow to the surface. Water flooding is the most commonly used method of secondary recovery; it involves injecting water into the reservoir through an injection well, which is typically located near the producing well. Displacement of the oil in the well is done by the injected water which pushes it towards the producing well. Maintenance of reservoir pressure is a major effect of water flooding; it also helps in oil viscosity reduction causing easier oil flow through the reservoir. In situations where water injection may be ineffective, gas injection is employed. This involves injecting gas into a well to help with pressure maintenance in the reservoir, pushing oil towards the producing well. Gas injection is effective because it can also cause viscosity reduction making for easier oil flow through the reservoir. Natural gas and carbon dioxide (CO₂) are the most commonly used gases for injection.

2.2.3 Tertiary Recovery

In situations where both primary and secondary recovery methods prove insufficient, tertiary recovery techniques will be employed to recover additional oil that is still trapped they have both been exhausted. Unlike the prior methods which rely on natural pressure or fluid injection to drive hydrocarbon to the surface, tertiary recovery methods involve more complex and expensive techniques to produce the remaining hydrocarbon in the reservoir (Jason, 2022). Several methods have been developed for the recovery of unconventional feedstock. There are several challenges associated with tertiary oil recovery. One of the main challenges is the cost of the recovery methods, particularly if large volumes of fluids or chemicals are required. Tertiary recovery methods can also cause environmental damage if the fluids or chemicals are not properly managed.

Injected fluids or chemicals can cause formation damage, reducing the permeability of the reservoir and affecting the rate of oil production. To curb this, careful planning and monitoring of the injection process is required. Despite these challenges, heavy crude oil remains an important source of energy for many countries around the world, and the demand for this type of oil is likely to grow in the years to come. Although EOR is the final stage of oil production for extracting more oil from the well that was not recovered while natural and secondary techniques were employed, it is worth mentioning that these EOR techniques can still be improved further to fully maximize the potential of available reservoirs, especially in the heavy crude oil industry. In recent years, there has been a growing interest in heavy hydrocarbon processing due to an increasing demand for crude oil products and the declining availability of new conventional reservoirs. As a result, many companies are looking for new technologies to invest in and techniques which can improve the efficiency and effectiveness of heavy crude oil processing. EOR techniques can be thermal (10%), chemical (67%), gaseous (10%), and miscellaneous (3%) (Mokheimer et al. 2019). Thermal recovery is one of the most commonly used methods of tertiary recovery, particularly in heavy oil reservoirs. According to Demirbas et al. (2015) thermal method has accounted for over 70% of the world's EOR. It involves viscosity

reduction and increase of mobility ratio by injection of heated fluids into the reservoir. The most commonly used fluids for thermal recovery are steam and hot water. Thermal recovery is effective because it can increase the amount of oil that can be recovered from the reservoir, particularly in heavy oil reservoirs. However, thermal recovery can be expensive, particularly if large volumes of fluids are required; it can also be environment some damage if the fluids are not properly managed.

In chemical recovery, chemicals are injected into the reservoir to improve oil mobility. Polymers, surfactants and alkaline materials are commonly used chemicals. Gaya (2021) provides insights on deep or thin oil patches reserves where thermal techniques cannot be applied and a chemical boost is needed to get the oil mobile. While mono-chemical methods like a basic polymer (P), alkaline (A), CO₂ solvent or surfactant (S) wash can be applied, they rarely hold a candle to blended setups. Combining these agents into dual or triple systems, like an AS or ASP is exactly what makes the process commercially viable in the real world. In chemical EOR, chemical agents are applied for improvement in sweep efficiency without influencing the chemical properties of the oil. Interactions involving reservoir minerals and recovery additives (surfactant, and polymer) may happen, although this depends on the reservoir rocks geology, this can affect interfacial properties like wettability and surface charge (Mokheimer et al., 2019). These interactions are still being studied for several additives. Consequently, the criteria for choosing any given EOR method is dependent on the formation being explored. The emergence of several new chemical formations has resulted from combining heavy hydrocarbon recovery with several upgrading methods to overcome refining, logistical and cost challenges (Brown et al., 2016).

2.3 Nanotechnology, Nanofluids and Nanoparticles (NPs)

Nanoparticles are perfect for subsurface applications as a result of their minute size below 100 nm. They also exhibit high specific surface area, making it easy for them to pass through the pore throats of porous media without blocking them while enhancing oil recovery at relatively low volume concentrations this

happens through wettability alteration (Rockey et al. 2018). Nanofluids are base substances engineered with nanoparticles to give them unique properties that make them highly effective in oil recovery. Although more and more attention has been gained recently, the application of Nanotechnology in the oil and gas industry has been open for decades. Over the years various types of Nanofluids have been engineered for the purpose of improving oil recovery at the final stage. Their effects on the IFT, reservoir rheological properties and wettability alteration are very vital to these mechanisms.

Goshtasp et al. (2020) in research on Nanofluids highlighted that their ability to alter rock wettability, reduce IFT and improve reservoir rheological properties can be observed when they are applied as additives in polymer and surfactant solutions. Although the future boundaries this technology are limitless, a clear fact is that it will revolutionize and develop the oil and gas industry sector in a shorter period if applied properly. Initially, proposals advocating for the use of Nanofluids in oil recovery involved adding them to aqueous formulations which were already used in secondary recovery after which alcohols were introduced as stabilizing agents, as nanoparticles tend to be unstable. To make the process even better, researchers started mixing nanoparticles with surfactants and polymers, combinations as such created new and unique formulas for boosting oil recovery. Wasan et al. (2003) explored how adhesion behavior relevant to EOR is affected by the suspensions of Nanometer sized particles on the rock surface. Researchers from different fields of study have recently started gearing towards Nanoparticles. Enhanced oil recovery (EOR) from hydrocarbon wells is one of the main fields it is currently being applied to. EOR involves improving the amount of oil that can be extracted from reservoirs. In the past decade, core-flooding tests have been conducted to test Nanofluid performance as injecting fluids for EOR, such tests also highlight the optimum conditions for practical application.

Cheraghian et al. (2014) discovered several significant EOR benefits of adding Nanofluids to injection solutions with, advantages such a fluid property alteration, wettability alteration, improvement of the

trapped oil mobility, enhancement of the consolidation of sands and decreasing interfacial tension (IFT). Interestingly, even at high salinity and temperature in oil and gas reservoirs, nanoparticles are still very resistant to degradation. IFT reduction and wettability alteration between the fluids and rocks are major mechanisms Nanoparticles can enable on micro and Nano scales (Le et al. 2011). Applying Nanoparticle technology in the petroleum industry, is gaining more attention with passing decades. The use of Nanoparticles and Nanofluids have emerged as suitable substitutes for various chemical additives and have been seen to improve recovery better by accessing parts of the reservoir which other means are not able to. Aluminum oxide (Al_2O_3), Magnesium oxide (MgO) and Silicon oxide (SiO_2) are common nanoparticles which are used; polymeric nanoparticles such as polyacrylamides have also shown great potential to improve heavy crude oil recovery at minute quantities. Research by Bera and Belhaj (2016), revealed that some nanoparticles (NPs) will improve oil recovery by through altering of fluid properties, wettability, sand consolidation, trapped oil mobility and interfacial tension (IFT). Nanoparticles have the ability to combine effectively with thermal and other upgrading methods as well to improve their potential recoveries. The constantly evolving oil and gas industry is improving even more rapidly recently and to improve the efficiency of oil recovery, new technologies are being researched and developed. Roustaei and Bagherzadeh (2015) investigated SiO_2 nanoparticles and their effect on the wettability of carbonate reservoir rocks, where they found out that SiO_2 NPs can change the strongly oil-wet state of carbonate rocks to a strongly water-wet state.

2.3.1 Effects of Nanoparticles on IFT

In a study conducted by Rosen et al. (2005) showed that NPs can lead to a significant reduction in the interfacial tension by forming a thin layer on the surfactant distributing between oil and injected fluids. An amazing observation in this concept is the increase in the capillary number and significant decrease in capillary forces acting against flow in the reservoir. Therefore, in order for stable flow to be obtained, both nanoparticles and the surfactant must support each other and balance each other out. In addition, sedimentation stability is increased by NPs being able

to balance the surface forces and the force of gravity (Suleimanov et al., 2011). Researchers have found that nanoparticles give surfactant fluids a major boost, helping injection solutions flow much better during oil recovery. When the nanoparticle concentration is kept low, they work beautifully to cause absorption and drop surface tension. But when there is an overload of too many nanoparticles, they end up hogging everything, practically draining the surfactant right out of the main water solution (Ravera et al. 2006). To figure out exactly how surfactants and nanoparticles change interfacial tension, Barati et al. (2014) experimented with an anionic surfactant called sodium dodecyl sulfate, pairing it with both slightly hydrophobic and hydrophilic silica nanoparticles for enhanced oil recovery. They discovered that the critical micelle concentration (CMC) number helps pin down the absolute best formula for the nano-suspension. Essentially, the interfacial tension keeps dropping as you add more nanoparticles and surfactant, but only until you hit that critical micelle concentration milestone (Barati et al. 2014). To verify these findings, another study tested fully hydrophobic silica nanoparticles in a surfactant solution using rock core samples (Zargartalebi et al. 2015). The team found that increasing the mixture concentration lowered interfacial tension.

Crucially, the nanoparticles (especially the fully hydrophobic ones) prevented the surfactant from wasting away by sticking to the reservoir rock (Zargartalebi et al. 2015). Another study by Hendraningrat and Zhang (2015) looked at how well hydrophilic TiO₂ nanoparticles stayed stable in polyvinylpyrrolidone for enhanced oil recovery. This TiO₂ nanofluid did a fantastic job changing rock wettability and easily lowering the interfacial tension between water and oil after core flooding experiments were carried out to prove its efficiency.

2.3.2 Effects of Nanoparticles on Wettability

Changing rock wettability and finding ways to apply it are easily some of the most critical and challenging parts in subsurface engineering. Kuang et al. (2019) pointed out that making a surface water-wet gives the imbibition process a major push into medium and small pores. At the same time, lowering interfacial tension helps with drainage and cuts down entry

pressures. When it comes to altering rock wettability, silica nanoparticles are easily one of the most popular go-to choices in the field. These nanoparticles do a fantastic job of freeing up trapped oil from tight pores and throats, which will ultimately boost recovery in heavy oils (Maghzi et al. 2011). Nanoparticles are a great choice for changing rock wettability during polymer flooding as they help the fluid sweep through the reservoir much easier, which means an increase in ultimate recovery.

2.3.3 Application of Nanoparticle in EOR

Nanoparticles can be used in a range of applications, including as catalysts, surfactants, and stabilizers. In tertiary oil recovery, nanoparticles can be employed to enhance the effectiveness of the fluids being injected into the reservoir. One of the main challenges with tertiary oil recovery is getting the injected fluids to penetrate deep into the reservoir and displace the remaining oil. Nanoparticles can help overcome this challenge by improving the fluid's mobility and reducing viscosity and IFT. Various NPs have been evaluated to improve oil recovery over the years. For instance, Ehtesabi et al. (2015) found that TiO₂ nanoparticles will deliver a massive 80% boost in oil recovery from oil-wet sandstone. Shah (2009) after investigating oil recovery with CuO nanoparticles realized a 71% increase in oil recovery. Kanj et al. (2011) flooded modified carbon nanoparticles and found out that carbon-based fluorescent NPs will yield over 96% increase in oil recovery. Wang et al. (2012) showed that finding the right nanoparticle concentration is a major balancing act for keeping emulsions stable. At first, adding more Na-montmorillonite nanoparticles lowered interfacial tension and altered the droplet charge, while making the interface much more elastic. But as they kept pushing the concentration higher, both the elasticity and interfacial tension actually reversed and went back up, while the droplet charge completely leveled off after 250 mg/L (Wang et al. 2012). To evaluate the true potential of hydrophilic silicon dioxide in enhanced oil recovery, Hendraningrat et al. (2015) simulated a wide range of reservoir environments. Their bench-scale research accounted for shifting thermal conditions and varying wettability (spanning oil-wet to water-wet states) while demonstrating how polymer-shielded particles use pH modifications to drive heavy oil

production. After investigating the relationship existing between the temperature, additional oil recovery and initial wettability and additional oil recovery, Nano-EOR process were instigated showing high stability and stable conditions at high temperatures and avoiding particle aggregation in porous media. Their results proved that Nanofluid are suitable for EOR purposes under a wide range of reservoir conditions. In another study, a new nano-SiO₂ polymer composite was created using free radical polymerization for polymer flooding systems. Researchers thoroughly tested how this mixture handled extreme conditions, focusing on its ability to move oil, withstand high heat and salt, and maintain its flow properties.

The trials proved that this composite works incredibly well as a chemical agent, especially when it comes to steering fluid movement, enduring hot temperatures, and keeping a stable flow during oil recovery. Across a wide variety of reservoir settings, the team found that using a balanced, one-to-one blend of nanoparticles and surfactants gives the best boost to oil recovery. Furthermore, surfactants paired with hydrophobic nanoparticles easily outperformed those mixed with hydrophilic ones (Zargartalebi et al. 2015).

Acting as surfactants, nanoparticles can alter the interfacial tension existing between the reservoir rock and the fluid. This in turn, helps the fluid penetrate deeper into the reservoir and displace more oil. Another way nanoparticles can improve tertiary oil recovery is by acting as catalysts to improve oil recovery. They are used to catalyze chemical reactions that can improve the effectiveness of the injected fluids, for instance, SiO₂ can be used to speed up the oxidation of heavy crude oil, improving its mobility and make it easier to extract. This is important because injected fluids can often become unstable and break down, which reduce their effectiveness. By adding nanoparticles to the fluids, they can help stabilize the fluid and prevent it from breaking down, thus improving the effectiveness of the tertiary recovery process.

2.3.4 Advantages and Disadvantages of Applying Nanoparticles in Oil Recovery

Although the application of Nanoparticle technology to Enhanced Oil Recovery comes with several advantages, there are several challenges associated with using this technology in tertiary oil recovery. One of the main challenges is ensuring that the nanoparticles are stable and do not clump together. This can be achieved by using appropriate stabilizers and surfactants and making sure the concentration used is balanced with the fluid it is being mixed with. Another is that the nanoparticles used must be compatible with the reservoir rock otherwise it can cause damage to the formation. The cost of purchasing these nanoparticles especially if they are required in large quantities, is another challenge. Despite these challenges, the potential benefits they bring to oil recovery are enormous. With great possibilities to address even the most complex difficulties experienced in recovering heavy oils, nanoparticles can be used to reduce the viscosity of heavy oil, making it easier to extract from the reservoir. By improving the efficiency of the tertiary recovery process, nanoparticles can help extract more oil from existing reservoirs. While there are several challenges associated with using nanoparticle technology in tertiary oil recovery, the potential benefits are significant. As such, it is likely that nanoparticle technology will continue to gain attention and be developed further in the oil industry in the years to come.

2.4 Hydrolyzed Polyacrylamide (HPAM)

A lot of Nanoparticles are unstable in nature and although this can be a major disadvantage, it is one of their most attractive selling points because it means they possess an ability to react in indefinite patterns creating an unlimited boundary to what they can be used to achieve in heavy hydrocarbon recovery. Nanoparticle stabilization is divided into two main categories: chemical and physical methods (Wu et al. 2011). The physical method involves suspension of the nanoparticles by application of a mechanical force while chemical methods involve the addition of chemical agents like polymers, acids, surfactants, etc. (Wu et al. 2011). However, this research involves the use of Hydrolyzed Polyacrylamide (HPAM) Nanoparticle (NPs) which will be tested in a

laboratory to see how they can affect heavy oil recovery. Linking hydrophobic groups to partially hydrolyzed polyacrylamide nanoparticles is a clever trick to help water-soluble polymers survive tough environments. It gives them the extra backbone they need to work properly in reservoirs with extreme heat and high salt levels. For more than five decades polymer flooding has been a widely applied EOR approach. Polymeric nanoparticles are used for EOR. These nanoparticles are made up of long chain polymers that are engineered to have unique properties which make them highly effective in EOR. For example, some polymeric nanoparticles have been designed to be highly stable in high salinity environments, making them highly effective in offshore oil production. Several laboratory studies have shown that the use of polymeric nanoparticles can lead to a significant increase in oil recovery. Polyacrylamides are the most used polymers for nanoparticle EOR, they are slimy, thick and transparent fluids rich in SiO₂ making them some of the most effective Nano fluids for recovery of heavy oils.

Typically, polyacrylamides exist in two forms, traditionally as a complex structured chemical Xanthan although this is not popular. The more commonly known form is the cheaper and more soluble, partially hydrolyzed polyacrylamide (HPAM), whose main deficiency is its salinity intolerance in that it can still function under saline conditions but its effectiveness is highly altered (Gaya, 2021).

III. MATERIALS AND METHODS

Experiments in this research are confined to bitumen as the main hydrocarbon, having a gravity of 20° API or less suiting what is present in my region. Viscosities associated with such crudes generally range anywhere from 100 to several thousand centipoises. Such high viscosities give rise to the major problems of heavy oil recovery. Gas or water drive is inefficient because of extremely unfavorable viscosity ratios. This results in

low primary recovery by solution gas drive or natural water encroachment. Similarly, secondary recovery by fluid drive soon becomes uneconomical because of excessive channeling, early breakthrough and high driving fluid-oil ratio. Also, the rates at which heavy oils can be produced are very low because of high reservoir flow resistance. Consequently, even if the ultimate recovery is acceptable, it is achieved only over an extremely long period, which makes the pay-out time economically prohibitive.

3.1 Materials

The materials used for this research include: Water, bitumen, diesel, salt, Hydrolyzed polyacrylamide and cement cores.

3.1.1 Equipment

Several equipment was employed to ensure completion, they include:

A core flooding system prototype, calipers, porosimeter, hydraulic pump, core holder, Oven, beakers, meter rule, electric cooker, measuring cylinder, pressure gauges and a weighing balance.

3.2 Methods

Bitumen obtained from a road construction company here in Uyo, Nigeria was used.

It was mixed with automotive gas oil (A.G.O) known as diesel to form the hydrocarbon sample for this research. This mixing process was carried out to form a slightly lighter form for better recovery and easier absorption by the cores. The cores used on the other hand, were created from a mixture of cement, sand and stones. The mixture was put in cylindrical plastic pipes of varying lengths and same diameter and allowed to dry for several days; the solid and permeable rock samples derived from this process served as cores used in the experiments. Several cores were used to carried out the core flooding experiment. These cores were made from a mixture of cement, stone and sand. The weights of these cores were determined by putting them on the weighing balance. Figure 3.1 shows a Core sample on a weighing balance.

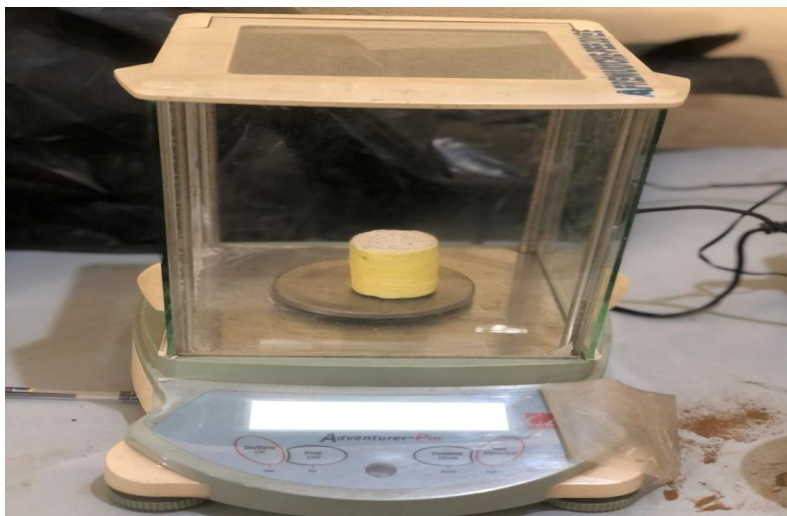


Figure 3.1: A Core sample on a weighing balance
Source: Researcher (2026)

3.2.1 Procedure for Modeling the Laboratory Experiment

The bitumen was heated above its boiling point, while three core samples namely: Alex, Benson and Carson were immersed in it for a period of one hour. An increase in their individual weights after dissolution indicated absorption. The core flooding model consisted of a 26000 cm³ inlet storage tank filled with water across all experiments. This was connected through a horizontal pipe to the hydraulic pump. The pump was then linked directly into the core holder with a pressure gauge mounted on each side to determine inlet and outlet pressures and the system was closed by an outlet tank for product reception. Core Alex weighed 61.56 g after dissolution; it was subject to flooding at initial pressure as high as 70 psi. A Nanoparticle volume of 1.5 cm³ was used. Incremental recovery was very high. Core Benson was used to test salinity effects on HPAM with salt introduced into the drilling fluid at 52 g. This was done to mimic offshore conditions. A nanoparticle volume of 1.5 cm³ was maintained. Core Carson employed the use of a lesser composition of 0.5 cm³ of the hydrolyzed polyacrylamide. Each experiment was carried out with an outlet pressure of 50psi to maintain a steady flow across all and after flooding was complete, the recovered fluid in the outlet chamber allowed to settle for 2 days before oil was extracted.

This was done to ensure that the total volume of oil produced can be properly accounted for.

3.2.2 Core Flooding Experiment

The core flooding system used in this research was a prototype design due to unavailability of a standard core flooding system. It was made up mainly of four parts; the inlet tank, a pump, the flooding chamber and outlet tank. The inlet tank was the storage container holding the flooding fluid (nanoparticle-water mixture); it had a total volume of 30,000 cm³ out of which 26,000 cm³ was used to carry out the experiments. The pump used had a capacity of 1HP and gave rise to a maximum pressure of 70 psi. The flooding chamber consists of the inlet pressure gauge with a maximum capacity of 350 psi and a 250 psi pressure gauge to record outlet pressure. Inlet and outlet valves responsible for controlling pressure and fluid flow in and out of the system were installed. One of the main components of this prototype is the core holder, responsible for housing the core samples throughout the flooding process. The final part of the system was the outlet tank where product was received after flooding. Similar in dimensions with the inlet tank, it was transparent so that separation due to density can be seen when the recovered oil was taken. Figure 3.2 shows a picture of the core flooding system prototype.



Figure 3.2: Core flooding system prototype
Source: Researcher (2026)

A core flooding experiment is a widely used technique in the oil and gas industry to evaluate the performance of various enhanced oil recovery (EOR) techniques. This technique involves injecting a fluid into a core sample under controlled conditions to simulate the reservoir conditions and to determine the effectiveness of the EOR method. During a core flooding experiment, a cylindrical rock sample, typically 1-2 inches in diameter and up to several inches in length, is placed in a high-pressure chamber. The sample is then saturated with crude oil or another suitable liquid, which represents the reservoir oil. The core is then subjected to a series of injections of the EOR fluid under controlled conditions, usually at a constant rate and pressure. The EOR fluid can be any fluid that can improve the displacement efficiency of the crude oil in the reservoir. Core flooding experiment is an essential tool for evaluating the effectiveness of EOR techniques in the oil and gas industry, it allows for precise control and monitoring of the various parameters that affect the displacement efficiency of the EOR fluid, and can provide valuable insights into the evolution of EOR techniques in the field.

3.3 Laboratory Measurement Procedures

3.3.1 Procedure for Determining Permeability

The permeability of the cores was obtained with a simple laboratory experiment, using A.G.O as the

reservoir fluid passing through the cores. The core flooding prototype system was employed for this showing its versatility. The procedure was as follows:

- i. The distance between the pressure points P1 and P2 in the equipment was measured.
- ii. The inlet tank was filled with A.G.O to a given dimension and the pump started to allow fluid flow into the system. The inlet valve was opened while the outlet valve left closed to allow pressure build up.
- iii. The outlet valve was opened to ensure that the pressures, P1 and P2 were stabilized.
- iv. The outlet tap was gently opened at 10 psi pressure intervals and the quantity of fluid flowing into the measuring cylinder was recorded at intervals of 10 seconds.
- v. A graph of Flow rate against Change in pressure was plotted and its slope, m used in Darcy's equation to calculate each core's permeability.

3.3.2 Procedure for Determining Porosity

Below is diagram of a porosimeter. This device is used to measure porosity of various material. The porosity of the core samples used during the course of this work was determined using this laboratory apparatus.



Figure 3.3: A Porosimeter
Source: Researcher (2026)

The major parameters required to calculate porosity are the bulk volume (V_b) obtained with a caliper and grain volume (V_g) which was gotten using the porosimeter. The procedure was as follows:

- i. All valves were placed in vertical position before starting the experiment and the regulator in the front plane rotated fully counter-clockwise.
- ii. The unit was turned on and allowed to warm for 5 to 10 minutes.
- iii. The length and diameter of the cores were measured with the caliper included with the unit.
- iv. The sample holder was unscrewed and the core specimen inserted, and it was screwed back just until it stops.
- v. The "P2 TEST" valve was turned to the "OFF" position.
- vi. The regulator was rotated clockwise until the pressure read approximately 180psi.
- vii. The "P1 LOCK-IN" valve was turned to the "OFF" position.
- viii. P1 was allowed to stabilize and the value recorded.
- ix. The three-way valve was then set in the "TEST" position.

- x. Gas was allowed to expand into the test chamber by turning the "P2 TEST" valve to the vertical position.
- xi. P2 was allowed to stabilize and its value recorded.
- xii. The three-way valve was turned to "VENT" and the sample removed.

Once the unit has been set up, it is easier to test numerous samples. To test numerous specimens, the following procedures were followed. It is recommended to label and measure each core before performing a test.

- i. The new specimen was placed in the sample holder which was screwed in just until it stops.
- ii. The three-way valve was set into the "TEST" position.
- iii. The "P2 TEST" valve was returned to the "OFF" position.
- iv. The "P1 LOCK-IN" valve was turned to the vertical position for a few seconds and returned to the "OFF" position. The pressure was allowed to stabilize and recorded as P1.
- v. The gas was allowed to expand into the test chamber by turning "P2 TEST" valve to the vertical position and P2 recorded after it stabilized.

- vi. The three-way valve was set into the “VENT” position and the core specimen removed.
- vii. The same steps were repeated for all specimens to be tested.

The constants V1 and V2 have been calculated for each new porosimeter and are located at the nameplate attached to the back of the porosimeter.

3.4 Ethical Issues

In addition to the insight regarding technical and economic benefits, several ethical issues are unavoidably inherent and they revolve around environmental safety, laboratory health, and the broader impact of prolonged fossil fuel extraction.

3.4.1 Environmental Non-maleficence (Avoiding Harm)

- i. Toxic Byproducts: Ethically, researchers must consider the long-term effects of the chemicals they inject into the earth, while HPAM itself is relatively stable, its natural or chemical degradation can produce acrylamide, a known group 2A carcinogen, neurotoxin, and mutagen which has a long-term effect on the environment.
- ii. Nanoparticle Eco-toxicity: Nanoparticle usage is basically uncharted territory and as a result, the fate of the environment is subject to conditions still largely unknown. There is an ethical responsibility to evaluate if these particles will accumulate in the soil, transfer to underground water sources or potentially affect biodiversity.

3.4.2 Occupational Health and Safety

- i. Researcher Exposure: Nanoparticles pose unique health risks. Their ability to be inhaled directly into the respiratory system due to their small size is a major one of these challenges. Their size also allows them to easily cross the blood-brain barrier or penetrate the skin. Basically, they have the ability to enter the human body with ease if proper protective measures are not taken. Therefore, in a laboratory setting, it is an ethical obligation to ensure that all participants are fully informed of these risks and that rigorous safety protocols

are strictly followed to prevent accidental ingestion or inhalation.

3.4.3 Sustainability and "The Carbon Dilemma"

- i. Prolonging Fossil Fuel Reliance: An overarching ethical debate in EOR research is the "dilemma of more". While your work makes extraction more efficient, it also extends the global reliance on fossil fuels, contributing to greenhouse gas emissions and climate change.
- ii. Resource Intensity: EOR operations are often energy-intensive and require massive volumes of water. Ethically, researchers must weigh the benefit of increased oil yield against the consumption of these finite natural resources.

The primary ethical issues in my work involve the long-term environmental toxicity of HPAM degradation, the unknown health risks to researchers handling nanoparticles, and the broader responsibility of developing technologies that prolong fossil fuel extraction at the cost of global sustainability goals.

IV. RESULTS AND DISCUSSION

4.1 Results

All results obtained during the research are tabled and documented for easier understanding. It is important to understand that although the results were obtained via nanoparticle flooding, water flooding was first carried out to observe how much bitumen will be recovered. The observation from water flooding is that because bitumen is so heavy, for flooding carried out at normal atmospheric temperature it yielded no recovery at all, making the volumes recovered by the Nanoparticle fluid under same conditions even more impressive.

Table 4.1 shows the various parameters measured and obtained from the permeability experiment used in plotting the graph from which the permeability, k of core Alex was derived. Where V is the total volume of fluid recovered, P_1 is the initial pressure recorded, P_2 is the final pressure, ΔP is the change in pressure, T is the time interval maintained throughout the experiment and Q is the flowrate.

4.1.1 Permeability Results

Table 4.1: Permeability experiment results for Core Alex

V (cm ³)	P ₁ (psi)	P ₂ (psi)	Δ P (psi)	T (s)	Q ($\frac{m^3}{s}$)
400	70	60	10	10	40
860	70	50	20	10	86
1060	70	40	30	10	106
1200	70	30	40	10	120
1600	70	20	50	10	160
1900	70	10	60	10	190

Figure 4.1 shows the permeability plot for core Alex. It is a graph of flowrate, Q against change in pressure, Δ P where permeability, k is the slope of the graph.

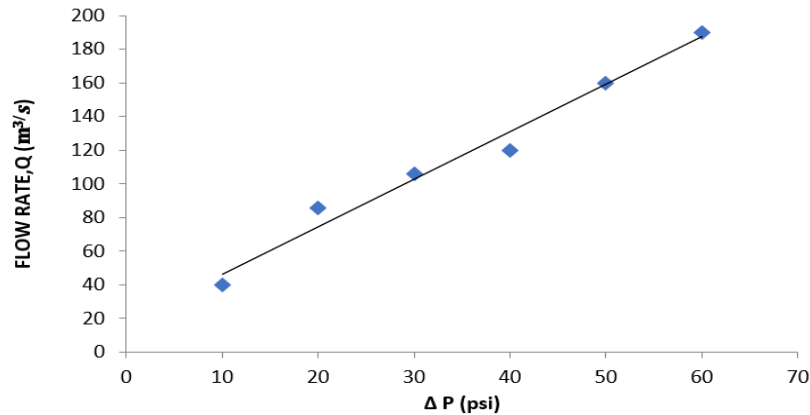


Figure 4.1: Graph of permeability for core Alex
Source: Researcher (2026)

Table 4.2 shows the various parameters from the permeability experiment used in the graph from which the permeability, k of core Benson was derived. Where V is the total volume of fluid recovered, P₁ is the

initial pressure recorded, P₂ is the final pressure, Δ P is the change in pressure, T is the time interval throughout the experiment and Q is the flowrate.

Table 4.2: Permeability experiment results for core Benson

V (cm ³)	P ₁ (psi)	P ₂ (psi)	Δ P (psi)	T (s)	Q ($\frac{m^3}{s}$)
580	70	60	10	10	58
1200	70	50	20	10	120
1500	70	40	30	10	150
2100	70	30	40	10	210
2500	70	20	50	10	250
2800	70	10	60	10	280

Figure 4.2 shows the permeability plot for core Benson. It is a graph of flowrate, Q against change in

pressure, ΔP where permeability, k is the slope of the graph.

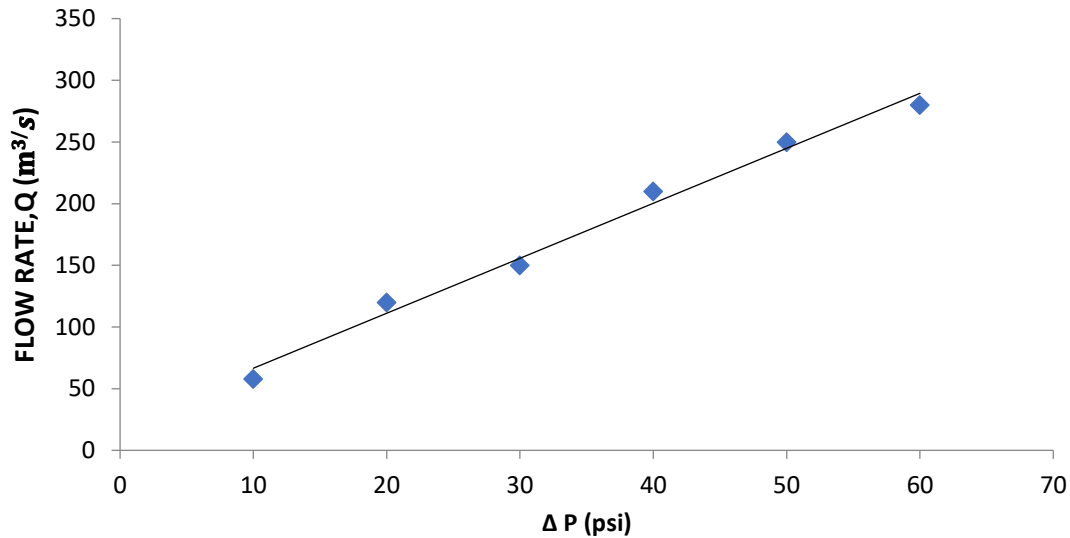


Figure 4.2: Graph of permeability for core Benson
Source: Researcher (2026)

Table 4.3 shows the various parameters from the permeability experiment used in the graph from which the permeability, k of core Benson was derived. Where V is the total volume of fluid recovered, P1 is the

initial pressure recorded, P2 is the final pressure, ΔP is the change in pressure, T is the time interval throughout the experiment and Q is the flowrate.

Table 4.3: Permeability experiment results for Core Carson

V (cm ³)	P ₁ (psi)	P ₂ (psi)	ΔP (psi)	T (s)	Q ($\frac{m^3}{s}$)
185	70	60	10	10	18.5
605	70	50	20	10	60.5
1030	70	40	30	10	130
1550	70	30	40	10	155
1850	70	20	50	10	185
2300	70	10	60	10	230

Figure 4.3 shows the permeability plot for core Carson. It is a graph of flowrate, Q against change in

pressure, ΔP where permeability, k is the slope of the graph.

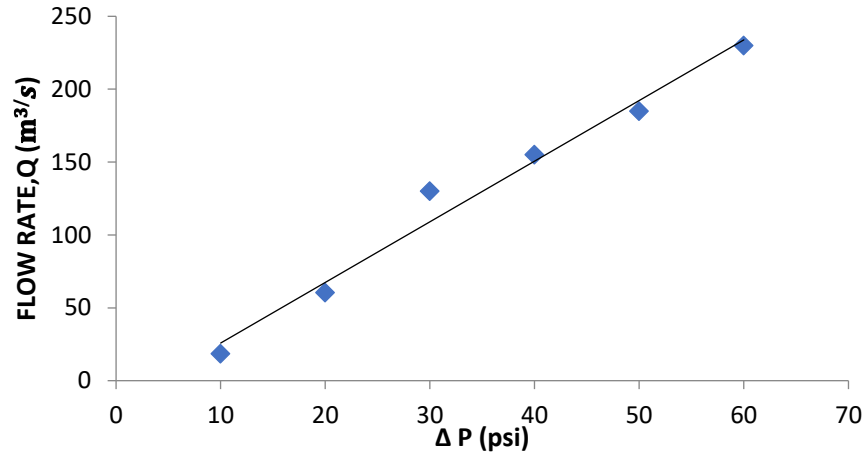


Figure 4.3: Graph of permeability for core Carson
Source: Researcher (2026)

4.1.2 Porosity Results

Table 4.4 is a representation of the porosity results for each core, as well as their corresponding lengths and diameter.

Table 4.4: Core porosity determination parameters

Core	Length (mm)	Diameter (mm)	Porosity (%)
Alex	3.1	3.6	28.45
Benson	2.4	3.6	7.65
Carson	3.0	3.6	20.05

4.1.3 Core Flooding Results

Table 4.5 shows the results obtained from the core flooding experiment and each parameter before and after the experiment. The table shows the

permeability, porosity and core flooding experimental values obtained from the recovery experiment carried out on each core sample.

Table 4.5: Parameters obtained from core flooding experiment

Core	Initial Weight Before Flooding (g)	Final Weight After Flooding (g)	Density (PPG)	OOIP (cm^3)	Total Volume Recovered (cm^3)	Incremental Recovery (%)	Salt Conc. (g)	Nano Conc. (cm^3)
Alex	61.56	63.09	7.33	8.39	7.7	91.77	-	1.5
Benson	59.6	64.20	7.33	8.13	7.3	89.79	52	1.5
Carson	65.7	67.24	7.33	8.96	7.0	78.12	-	0.5

4.2 Discussion

This discussion is based on an analysis of Nanofluid core flooding experiments performed on three core samples. The samples which were named Alex, Benson and Carson were created to efficiently evaluate the efficacy of a Nanofluid infused flooding

agent for recovering bitumen from porous media. The study specifically focuses on the performance of Hydrolyzed Polyacrylamide (HPAM) under standard and saline conditions evaluating its performance in several concentrations. In some recent research on NP performance on surfactant flooding, Zargartalebi et al.

(2015) explored mixing nanoparticles into surfactant flooding processes. They discovered that these tiny particles remain highly stable in hot environments and do not clump together inside the rock pores.

Due to the unavailability of a standard core flooding system, the experiment utilized a systematic core flooding prototype designed to simulate actual reservoir displacement processes almost seamlessly. The high-capacity 26,000 cm³ inlet tank served as the reservoir for the aqueous phase, ensuring steady, constant and consistent fluid flow throughout the injection period. A 1 HP pump adequately provided the mechanical energy required to overcome the high viscosity of the bitumen and the capillary forces which existed within the core plugs. Two pressure gauges were carefully installed at inlet and outlet points to monitor the dynamics of the flood. The pressure gauge at the inlet had a capacity of 250 psi and the system recorded a maximum inlet pressure of 80psi. The outlet gauge had a maximum capacity of 350 psi. The mobility ratio and resistance to flow which was encountered as the bitumen was recovered were both critical parameters which the differential pressure (ΔP) recorded by these gauges helped in determining. In order for the bitumen to be properly sieved into the rock samples the bitumen needed to be heated over 150 degrees Celsius over a period of one hour and the samples were dissolved in it and weighed at intervals until their weights no longer increased indicating full saturation their volume was then established as the OOIP for each sample.

Core Alex was the control group for the entire flooding experiment. Very peculiar in shape and rock density, a core of considerably durable length. By introducing a negligible volume of 1.5 cm³ HPAM into the 26,000 cm³ water supply. Cheraghian and Wistuba (2020) also carried out some insightful research on Nanotechnology, according to their research, nanotechnology involves building materials, devices, and systems by working with incredibly tiny particles focusing on the nanoscale ranges—between 1 and 100 nanometers—where materials completely change and exhibit entirely new, unique properties. The viscosity of the injected fluid was increased leading to a massive improvement in the mobility ratio between the displacing water and the viscous bitumen. From the

experiments the results recorded for Core Alex are represented thus;

- i. OOIP: 8.39 cm³
- ii. Oil Recovered: 7.7 cm³
- iii. Recovery Factor: 91.77%

The high recovery factor of 91.77% suggests that HPAM successfully reduced "fingering" effects. By increasing the viscosity of the water phase, the polymer ensured a more uniform displacement front, effectively sweeping the bitumen from the pores of Core Alex.

In order to test the durability of HPAM under simulated offshore conditions Core Benson was used. Also, very peculiar in length, it had very interesting dimensions which made it the right choice for the salinity flooding as it was the smallest of the cores. The way reservoir a rock interacts with fluids is very vital to oil flows which directly dictates how much oil can actually be recovered during enhanced oil recovery (Rostami et al. 2020). The addition of 52 grams of salt created a saline environment that directly challenged the chemical stability of the Nanofluid. Recovery was obviously affected by the addition of salt as expected and recovery from the experiments were as follows:

- i. OOIP: 8.13 cm³
- ii. Oil Recovered: 7.3 cm³
- iii. Recovery Factor: 89.79%

The drop in recovery (from 91.77% to 89.79%) is attributed to a tendency referred to as "the polyelectrolyte nature of HPAM". This characteristic means that HPAM cannot withstand the presence of salts as it is made up of long polymer chains which tend to collapse or fold in the presence of electrolytes. This physical shrinkage causes the hydrodynamic volume of the polymer to reduce, leading to a drastic decrease in the viscosity of the flooding solution. As a result of this reaction, the mobility ratio of the reservoir fluid became worsened, leading to bypassed oil and lower recovery efficiency. Standard HPAM is highly sensitive to salinity, losing its magical touch as a result of the electrolytes reacting, limiting its

effectiveness in offshore or high-salinity reservoir environments.

Core Carson was the third and final core experimented on, it explored the application of Nanofluids to oil recovery using a lesser concentration while leaving other conditions standard. In order to truly test the durability and effectiveness of the nanofluid, an alteration to the volume was made, significantly reducing the concentration of HPAM to 0.5 cm³ (compared to 1.5 cm³ in previous tests). Mechanisms such as disjoining pressure, aqueous phase alteration and altering the wettability of the core to a more water-wet state are several ways which the Nano fluid achieved such high recovery. Studies also investigate solutions with NPs as Nanofluids, this will improve oil recovery even under harsh reservoir conditions (Hendraningrat et al., 2013). This therefore showed that even at lesser concentration, the performance still remained remarkably high. The results of the experiment are presented below:

- i. OOIP: 8.96 cm³
- ii. Oil Recovered: 7.0 cm³
- iii. Recovery Factor: 78.12%

A recovery of 78.12% achieved demonstrates that even at one-third of the concentration, Nano fluids can achieve near-polymer levels of efficiency. Notably, various parameters are responsible for the reduced viscosity mechanism which NPs introduce to heavy oil recovery, some of these parameters are NP concentration, type and size. The efficiency of Core Carson is an indication to two major pointers towards the growth of EOR, firstly suggesting that Nano fluids are more potent than traditionally used polymers and are also a potentially more cost-effective alternative to them.

V. SUMMARY, CONCLUSION AND RECOMMENDATIONS

5.1 Summary

5.1.1 Mechanisms of HPAM in Heavy Oil Recovery

HPAM is a water-soluble polymer capable of altering the rheological properties of several injected fluids.

Several mechanisms are primarily categorized as methods through which HPAM enhances heavy oil recovery they include:

- i. Viscosity Modification: Increasing the viscosity of the displacing water HPAM reduces the mobility difference existing between the injected fluid and the oil. This effect leads to a more uniform displacement minimizing channeling in the reservoir.
- ii. Sweep Efficiency Improvement: HPAM enhances sweep efficiency by improving the flow characteristics of water in porous media as well as the aqueous phase. The polymer creates a more stable system during the water-flooding process, allowing for better oil recovery from areas in the reservoir previously less effective.
- iii. Interfacial Tension Reduction: This one of the most effective of all mechanisms applied by HPAM Nanofluids. It has been shown to significantly lower interfacial tension between water and oil, this in turn aids in the mobilization of trapped oil droplets, thereby increasing the overall recovery.
- iv. Emulsification Effects: The creation of emulsions in certain scenarios makes HPAM a great medium for heavy crude oil recovery, these emulsions can render a portion of the oil more mobile and easier to extract.

5.1.2 Benefits of Using HPAM

Using HPAM in heavy oil recovery presents several advantages:

- i. Enhanced Recovery Rates: From several laboratory and field studies, some highlighted in this work, HPAM Nanofluids have demonstrated that their addition can significantly boost oil recovery rates as compared to conventional water flooding.
- ii. Cost-Effectiveness: Stemming from the recovery obtained even at low concentrations, it can be inferred that the subsequent increase in oil production can be resultant from even higher volume concentrations leading to favorable economic returns.
- iii. Environmental Compatibility: HPAM is generally considered to be more environmentally friendly compared to some

thermal recovery methods, as it operates at lower temperatures and does not require the burning of fossil fuels to generate steam.

5.2 Conclusion

This chapter summarizes the findings on the effectiveness of HPAM in enhancing heavy oil recovery, discussing its mechanisms, benefits, and limitations. Nine distinct outcomes of the experiment are:

- i. HPAM is highly effective in fresh-water conditions (Alex) but fails to maintain performance in saline environments (Benson).
- ii. Salinity is a detrimental factor to polymer chain extension with its effects leading to reduction of the sweep efficiency.
- iii. Nanofluids (Carson) represent the most efficient displacement mechanism per unit of volume, offering high recovery factors even at lower concentrations. These findings suggest that for offshore bitumen recovery, shifting from traditional polymers to salt-tolerant Nanofluids would optimize production and maintain high recovery factors despite harsh environmental conditions.
- iv. The drop in recovery for Core Benson is a classic case of polymer screening. HPAM is a polyelectrolyte; its molecules contain negatively charged carboxyl groups along the chain.
- v. Chain Extension: In fresh water (Core Alex), these negative charges repel each other, forcing the polymer chain to stretch out into a long, "uncoiled" string. This uncoiling is what increases the viscosity of the water, creating a thick "piston" that pushes the bitumen out.
- vi. Charge Shielding: When 52g of salt was added (Core Benson), the positive ions (Na^+) in the salt surrounded the negative charges on the polymer chain. This "shields" the charges, preventing them from repelling each other.
- vii. Coiling and Viscosity Loss: Without the internal repulsion, the HPAM molecules collapse into tight coils. This causes a drastic drop in the fluid's viscosity. The water becomes "thin" again and begins to flow around the

bitumen rather than pushing it, leading to the observed drop in recovery factor to 78.12%.

- viii. Environmental Sensitivity: The Benson experiment proves that HPAM is not "salt-tolerant," making it a poor choice for offshore bitumen recovery without prior desalination of the injection water.
- ix. Nanofluid Potential: The success of Carson suggests that nanoparticles do not rely on chain extension (viscosity) as much as they rely on interfacial tension reduction and disjoining pressure, making them more robust in various conditions.

A major highlight point of interest to a more effective completion of this work can be the use of just one Nanoparticle fluid during the course of the work in a field where several are coming up. However, among these, the use of polymeric, particularly Hydrolyzed Polyacrylamide (HPAM), has gained attention for its potential to improve the recovery efficiency of heavy oils. This chapter summarizes the findings on the effectiveness of HPAM in enhancing heavy oil recovery, discussing its mechanisms, benefits, and limitations. Nine distinct outcomes of the experiment are:

5.3 Engineering Implications of Findings

Here are the core engineering implications for implementing Hydrolyzed Poly-acrylamide (HPAM) nanofluids in heavy oil recovery:

5.3.1 Salinity Mitigation & Chemical Design

- i. Polymer Degradation Defenses: Because 52g of salt notably reduced Core Benson's recovery efficiency (from 91.77% to 89.79%), reservoir engineers must design salt-tolerant polymer matrices or introduce sacrificial pre-flushes to shield the HPAM matrix from high-salinity brine formations.
- ii. Pre-Injection Water Analysis: Rigorous chemical profiling of reservoir brine is mandatory before deployment to anticipate polymer-coil collapse and subsequent loss of viscosity control.

5.3.2 Injection Volume & Economic Optimization

- i. Volumetric Thresholds: Reducing the nanofluid volume from 1.5 cm³ to 0.5 cm³ dropped recovery by over 13% (from Alex's 91.77% to Carson's 78.12%). Engineers must calculate the precise minimum effective volume (MEV) to balance technical sweep efficiency against chemical costs.
- ii. Diminishing Returns Management: Injection strategies must be optimized via numerical simulation to find the economic inflection point where the cost of additional HPAM nanofluid outweighs the value of incremental heavy oil recovered.

5.3.3 Mobility Control & Fluid Dynamics

- i. Sweep Efficiency Improvement: The successful alteration of the mobility ratio and reduction of interfacial tension (IFT) mean that this nanofluid can be engineered to mitigate viscous fingering, a common failure mode in heavy oil displacement.
- ii. Pressure Monitoring Constraints: The inclusion of differential pressure gauges highlights the engineering need to monitor real-time pressure drops across the formation, ensuring that the enhanced viscosity does not exceed the fracture gradient of the reservoir.

5.3.4 Scale-Up & Field Implementation

- i. Pilot-Scale Translation: The massive scale gap between laboratory core flooding (using 0.5–1.5 cm³ fluid volumes) and field-scale reservoirs means engineers cannot directly extrapolate these exact rates. Intermediate pilot testing is required to model fluid shear degradation through injection pumps and long-distance reservoir propagation.

5.4 Contribution to Knowledge

With regards to the use of HPAM-based polymeric Nanofluids in heavy oil reservoirs, this research provides a detailed analytic evaluation of its performance pointing out the limits and overall providing concrete insights to the field of enhanced oil recovery (EOR):

- i. Through a detailed comparison of the recovery obtained from Core Alex (91.77% recovery at

1.5) and Core Carson (78.12% recovery at 0.5 cm³), their performance in recovery is quantified in this research by the significant drop in recovery which falls at approximately 13.65% when the Nanofluid volume is reduced by two-thirds. As a result of how unique the parameters of this work are a new baseline for categorizing how Nanofluids truly impact oil recovery was established, clearly pointing out that even with a minimum dosage of input, a maintain high-efficiency displacement can be maintained in heavy crude formations.

- ii. Assessment of Salinity Resilience in Nano-composite Polymers: This work presents a major contribution to the knowledge of salinity tolerance within the HPAM-nanoparticle matrix. From the experimental setup, despite the introduction of 52g of salt, Core Benson yielded a magnanimous recovery rate of 89.79%, suggesting that the integration of nanoparticles would provide a protective effect which can reinforce already broken polymer chains making them still effective in saline environments where traditionally HPAM typically fails.
- iii. A major defect experienced in heavy crude oil recovery stems from unaddressed viscosity driven mobility challenges. The research confirms that the use of nanoparticles can effectively address these challenges in heavy oils. The intense recovery patterns observed across all samples (ranging from a minimum 78.12% to 91.77%) further reproves the ability of Nanofluid formulations to successfully reduce interfacial tension (IFT) and improve the sweep efficiency beyond the capabilities of conventional water-flooding.
- iv. Experimental Benchmarking for Heavy Oil nEOR: Every aspect of this study introduces a unique, high-resolution data points which resulted from using a specialized core flooding setup (including a 26,000 cm³ inlet tank). This specificity of the dimensions involved in the experimental setup were tailored specially for these results and therefore serve as a new reference for researchers interested in investigating the economic and technical trade-

offs between chemical concentration, reservoir salinity and ultimate oil recovery.

Several characteristics are responsible for the varying grades at which recovery from Nanofluids yield in heavy oils. Primarily, the discovery that while HPAM-nanofluid catalysts are remarkably resilient to high salinity (producing almost a 90% recovery), they are highly affected by injection volume, whereas a 66% reduction in fluid leads to a disproportionate loss in recovery compared to saline interference. These findings will serve as a benchmark for further work done on the application of Nanoparticle technology to heavy crude oil recovery in the future. Focusing on the most vital points such as its effects on salinity will prove a handy reference for when more heavy crudes are discovered in offshore areas and maximum exploitation becomes difficult, with knowledge gathered from this research an understanding on how to approach recovery from such reservoirs can be inferred. Further work will be done by the researcher as he hopes to carry out even more extensive research on Nanotechnology and Enhanced Oil Recovery.

5.5 Recommendations

Nanoparticles are special chemicals with compositions capable of breaking down even the heaviest hydrocarbons easily, however this ability means they can influence quality of the hydrocarbons recovered changing their chemical components. How these changes affect the quality of the recovered hydrocarbon and its flashpoint should be investigated further.

5.6 Suggestion for Further Studies

Based on the limitations and variables highlighted in the research, here are targeted suggestions for further studies for its advancement:

5.6.1 Salinity Tolerance and Chemical Optimization

- i. Salt-Resistant Polymer Matrices: Investigate the performance of modified or sulfonated HPAM (such as AMPS copolymers) combined with nanoparticles to maintain viscosity and structural integrity under high-salinity conditions.

- ii. Impact of Specific Ions: Evaluate how different divalent ions (Ca^{2+} , Mg^{2+}) vs. monovalent ions (Na^{+}) uniquely affect the nanoparticle-polymer matrix, as heavy oil reservoirs often contain complex brine chemistry rather than pure salt.
- iii. Optimal Nanoparticle-to-Polymer Ratios: Conduct parametric studies to find the exact concentration threshold of nanoparticles needed to shield the HPAM chains from salinity-induced performance drops.

5.6.2 Volumetric Efficiency and Dynamic Optimization

- i. Fractional Pore Volume (PV) Sensitivity: Expand testing beyond the two discrete volumes (0.5 cm^3 and 1.5 cm^3) to map a complete recovery-versus-slug-size curve, identifying the exact thermodynamic and economic optimum.
- ii. Continuous vs. Slug Injection: Compare the efficiency of a continuous nanofluid injection against a "slug" injection strategy (alternating nanofluid slugs with water or gas flushes) to minimize chemical costs.

5.6.3 Mechanistic and Microscopic Analysis

- i. Interfacial Tension (IFT) and Pore-Scale Behavior: Utilize microfluidic "glass-on-a-chip" pore models to visually capture exactly how the HPAM nanofluid alters the mobility ratio and liberates trapped heavy oil at the pore scale.
- ii. Thermal Stability Testing: Because heavy oil reservoirs are frequently subjected to thermal recovery methods (like steam injection), study how high temperatures affect the long-term stability and degradation of the HPAM nanofluid.

5.6.4 Scalability and Transport Phenomena

- i. Core Heterogeneity Factors: Replicate the experiment using highly heterogeneous core samples or fractured cores to see if the nanofluid maintains its high sweep efficiency when path-of-least-resistance channels are present.
- ii. Nanoparticle Retention and Plugging: Quantify the rate of nanoparticle adsorption onto the

rock surface to ensure the formulation does not clog pore throats over time, which would permanently reduce reservoir permeability.

- iii. Numerical Field Simulation: Utilize the laboratory data from cores Alex, Benson, and Carson to build a reservoir simulation model, scaling up the physics from the laboratory core holder to a full-field pilot pattern.

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