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Enhanced Oil Recovery

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Abstract: Enhanced oil recovery procedures, which are part of improved oil recovery, are used to recover the leftover oil include Steam injection, Polymer flooding, Gas injection and Water injection. Only a small percentage of the total hydrocarbons in the reservoir can be recovered using standard oil recovery technologies. Even if normal recovery procedures are implemented, almost 2 trillion barrels of conventional oil and 5 trillion barrels of heavy oil will remain in reservoirs around the world. Many factors, both economic and technological, influence the strategy chosen and the projected recovery. The study evaluates the EOR approaches that are currently in use in the field.

The current EOR technologies are put into context, with the technical reasons for their failure highlighted. Recovering additional oil is difficult and expensive, and it has only been done successfully in a few cases under strict conditions. Despite this, EOR will continue to play a significant role in oil production due to rising energy demand and constrained supply. It is estimated that a significant amount of research is required to develop new technologies for recovering almost two-thirds of the oil that remains unrecoverable in the reservoir. New methods of enhanced oil recovery improves the efficiency of existing processes and reduce demand for new reserves in the longer term. This paper represents the new technologies evolved in the petroleum industry for Enhanced oil recovery.

Keywords: Enhanced Oil recovery, Water injection, Gas injection, Polymer flooding, production

I. INTRODUCTION

Enhanced oil recovery (EOR), also known as tertiary recovery, is the process of extracting crude oil from an oil field that would otherwise be impossible to remove. In comparison to primary and secondary recovery, EOR can extract 30% to 60% or more of a reservoir's oil. Carbon dioxide and water are injected, along with some EOR procedures such as thermal injection, gas injection, chemical injection, and other approaches, according to the US Department of Energy. Quaternary recovery refers to more advanced, speculative EOR procedures.

The hydrocarbons that naturally rise to the surface or those that require artificial lift devices like pump jacks are eligible for primary oil recovery. Water and gas injection are used in secondary recovery to dispense with the oil and drive it to the surface. Using these two ways of extraction, up to 75% of the oil can be left in the well. EOR is the tertiary recovery method to increase oil production. It can elevate oil production by 75%.

EOR is used in fields with heavy oil, poor permeability, and uneven fault lines, and it involves modifying the hydrocarbons' real characteristics, which sets it apart from secondary recovery. While the secondary recovery method uses water flooding and gas injection to force the oil down the well, EOR uses steam or gas to modify the makeup of the reservoir. EOR restores formation pressure and increases oil displacement in the reservoir, whether it is utilised after both primary and secondary recovery have been depleted or at the start of production.

In general, the development of oil and gas field is classified into the following three phases

1) *Primary Recovery:* Crude oil flows out due to the pressure of the reservoir
2) *Secondary Recovery:* Water or gas is injected into the reservoir to push out the crude oil, or pumped out crude oil mechanically by a pump installed in the well
3) *Tertiary Recovery:* The physical and chemical properties of rocks and formation fluids are altered to recover the crude oil remaining underground

The recovery factor at the primary recovery in generally said to be no more than 30% of the total amount of crude oil in the ground Although secondary recovery increases the recovery factor to about 40% there is still 60% to 70% of the crude oil left underground. To further increase the recovery factor the tertiary recovery, called Enhanced Oil Recovery (EOR) is used. Many research institutes and oil development companies have been developing technologies to change the physical and chemical properties of rocks and formation fluids and to recover the hydrocarbon reserves trapped in the reservoirs.

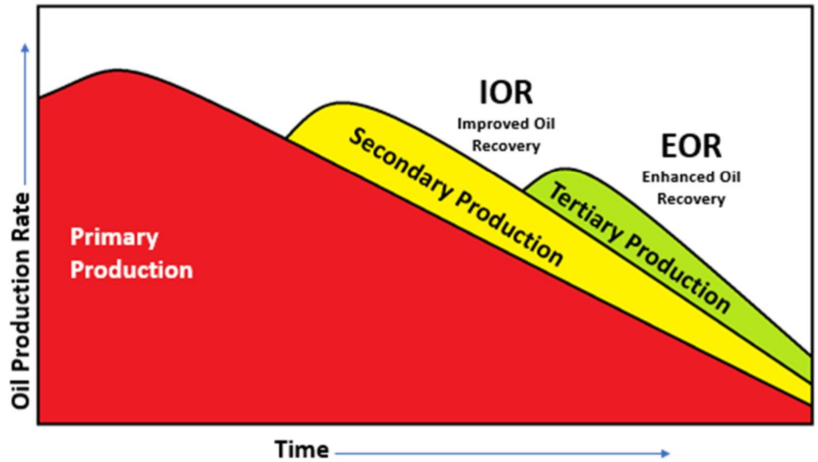

Figure 1: Graphical representation of production

At times, the terms EOR and IOR have been used interchangeably. IOR, or improved oil recovery, is a broad word that refers to any method of increasing oil recovery. Operational strategies such as infill drilling and horizontal wells, for example, improve vertical and areal sweep, resulting in higher oil recovery. The concept of enhanced oil recovery, or EOR, is more specific, and it can be thought of as a subset of IOR. Oil saturation is reduced below the residual oil saturation in EOR (Sor). Oils that are immobile or nearly immobile due to high viscosity (heavy oils and tar sands) and oils that are retained due to capillary forces (after a water flood in light oil reservoirs) can only be recovered by lowering the oil saturation below Sor. EOR methods include miscible processes, chemical floods, and steam-based methods for reducing residual oil saturation.

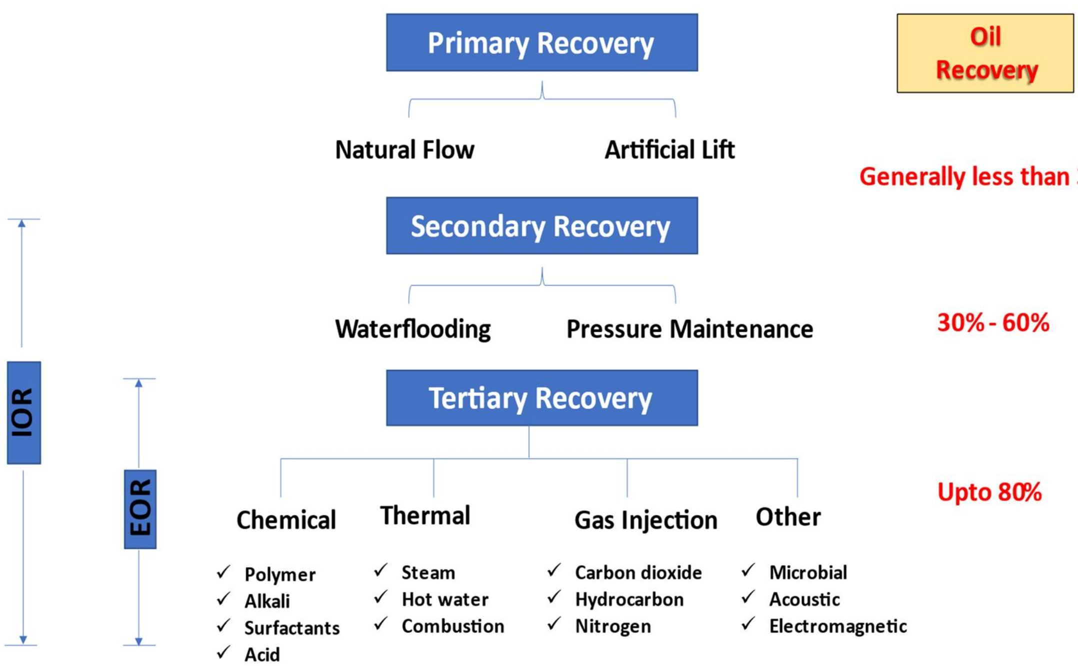

Figure 2: Flowchart for Recovery methods

II. DISCUSSION

A. *Chemical EOR Method*

The displacing fluid in chemical techniques is a chemical formulation, which causes a drop in mobility ratio and/or an increase in capillary number. In the 1980s, there were many commercial enterprises in operation, some of which were successful, but many of which were failures. Except in China, the current chemical flood activity is modest. Because of the high need for energy, as well as technological advancements, the future looks bright. The previous chemical flood initiatives have provided a wealth of knowledge and experience. The cost of commercialising chemical floods is a major impediment. It should also be mentioned that the technology is currently unavailable for reservoirs with specific features. Polymer flooding, surfactant flooding, alkaline flooding, micellar flooding, and ASP (alkali surfactant-polymer) flooding are the most common chemical flood processes. Other approaches that have been tried include emulsion, foam, and the use of microorganisms, but their impact on EOR production has yet to be determined.

1) *Polymer Flooding*

Polymers that are water soluble, such as polyacrylamides and polysaccharides, are excellent for increasing mobility ratios and decreasing permeability contrast. Polymer flooding is usually done as a slug process (20-40% PV) with dilute brine as the driving fluid. The concentration of polymers varies between rock and fluids. 200-2000 parts per million. Many polymer floods have occurred in the past, although most recoveries were less than 10%. Loss of polymer to the porous medium, polymer degradation, and, in some situations, injectivity loss are the main drawbacks. In the past, one of the most prevalent reasons for polymer flood failure was that it was introduced too late in the water flood, when the mobile oil saturation was low. When used early in a water flood, such as at water breakthrough, when the oil saturation is higher than the residual oil saturation, the method will be more effective.

2) *Alkaline Flooding*

Alkaline flooding involves injecting a slug of an aqueous solution of an alkaline chemical, such as sodium hydroxide, carbonate, or orthosilicate of sodium. In situ, the alkaline chemical reacts with the crude oil's acid components to produce the surfactant. The fundamental mechanism is IFT lowering. It's also possible that emulsification will happen on its own. Depending on the type of emulsion formed, drop entrainment or drop entrapment may occur, which can improve or hinder recovery. Changes in wettability can be caused by alkalis; however, wettability changes require high concentrations. The outcomes in the field have been discouraging (RF 0-3 % OIP). Because of the various reactions that occur between the alkaline chemical and the reservoir rock and fluids, the process is difficult to design.

3) *Surfactant Flooding*

Surfactants are useful for reducing the tension between oil and water. Surfactants such as petroleum sulfonates or other commercial surfactants are frequently employed. Aqueous surfactant slug is followed by a polymer slug, with both chemical slugs being propelled by brine. Surfactant floods have occurred in the past, but they were mostly ineffectual due to high surfactant loss to the porous medium. In some circumstances, surfactant adsorption and interactions with rock minerals were severe. Emulsion treatment and disposal were also a source of concern.

4) *Micellar Flooding*

Micellar flooding has outperformed other chemical flooding techniques in the field. A micro emulsion slug (also known as a micellar slug) and a polymer slug are the two major components of this approach. The brine is used to propel these two slugs. Surfactant-stabilized oil-water dispersions with small drop size distributions are known as micro emulsions (10-4 to 10-6 mm). Both reservoir oil and water can be "miscible" with micro emulsions. During the majority of the displacement, the two chemical slugs are constructed with ultra-low IFT (10-2 mN/m or below) and a favourable mobility ratio. The technology has been proven successful in banking and producing residual oil remaining after a water flood in 45 field projects. In field projects, recovery factors ranged from 35 to 50 percent OIP. However, the expensive cost of chemicals, the demand for small well spacing, the high initial cost, and the significant delay in response made the economics unappealing. Furthermore, many candidate reservoirs' geology and characteristics (high salinity, temperature, and clay content) are unsuitable for micellar flooding. Under the current economic conditions, the procedure has potential and ought to be re-evaluated. Micellar flooding has been given a scaling group, which is a useful tool for laboratory testing to lessen the chance of the procedure being used in the field.

5) ASP Flooding

Alkaline-Surfactant-Polymer flooding is a relatively new concept that is being investigated in both the lab and in the field. Alkali, surfactant, and polymer solutions are the major chemical formulations used in the process. The chemical slugs could be injected in order or, more often, as a single premixed slug. The main mechanisms are a drop in IFT and an increase in mobility ratio. The preliminary findings are promising (RF 25-30 percent OIP). The technique can both bank and produce leftover oil. The approach has promise, but the mechanics aren't completely understood. At best, economics is marginal.

6) Low Salinity Water Flood

LSW Flood is one of the ways for improving oil recovery by injecting reduced water salinity, which has gotten a lot of attention since 2005, owing to its cheap facility investment, low cost, and ecologically favourable nature. In the last few decades, various researchers have proposed several LSW-based recovery methods, including one based on mixed wet clay release, PH effect, multicomponent ionic exchange, wettability alteration, and osmotic pressure. However, varied test methodologies, the complexity of mineral, crude oil, and aqueous-phase compositions, and interactions among these phases all contribute to the lack of a consistent LSW mechanism.

B. Thermal EOR Method

Thermal approaches have been tried since the 1950s, and in terms of field experience and technology, they are the most sophisticated among EOR methods. Heavy oils (10-20° API) and tar sands (≤10° API) are the best candidates. Thermal methods heat the reservoir while also evaporating some of the oil. A significant reduction in viscosity, and hence mobility ratio, is one of the key processes. Other mechanisms may be present, such as rock and fluid expansion, compaction, steam distillation, and visbreaking. Thermal approaches have proven to be quite effective in Canada, the United States, Venezuela, Indonesia, and other countries.

1) Cyclic steam stimulation (CSS)

Cyclic steam stimulation is a three-stage method that takes place in a single well. Steam infusion is continued for about a month during the early stage. The well is then sealed for a few days to allow for heat diffusion, which is indicated by the term soak. After that, the well is placed into service. The price of oil rises swiftly to a high level, stays there for a brief time, and then falls over several months. When the price of oil becomes uneconomic, cycles recur. The steam-to-oil ratio starts out low, around 1-2, and gradually rises as the number of cycles grows. CSS relies on near-wellbore geology for both heat dispersion and the capture of mobilised oil. CSS is appealing because of the speedy payoff; nevertheless, the recovery factors are poor (10-40 % OIP). CSS is administered under fracture pressure in one variation. As connectivity between wells improves, the procedure gets more complicated.

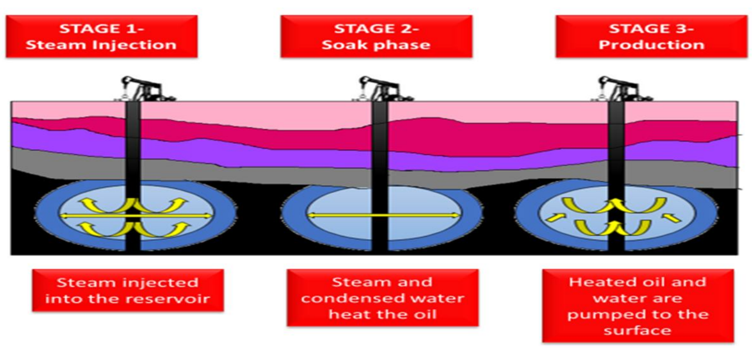

Figure 3: Schematic diagram of CSS process

2) Steam Flooding

Steam flooding, like water flooding, is a pattern drive whose performance is strongly dependent on pattern size and geology. Steam is continuously injected, forming a steam zone that moves slowly. The viscosity of the oil is reduced, allowing it to be mobilised. The swept zone's oil saturation can be as low as 10%. Recovery factors are typically in the range of 50-60% OIP. Excessive heat loss and steam override might be a concern.

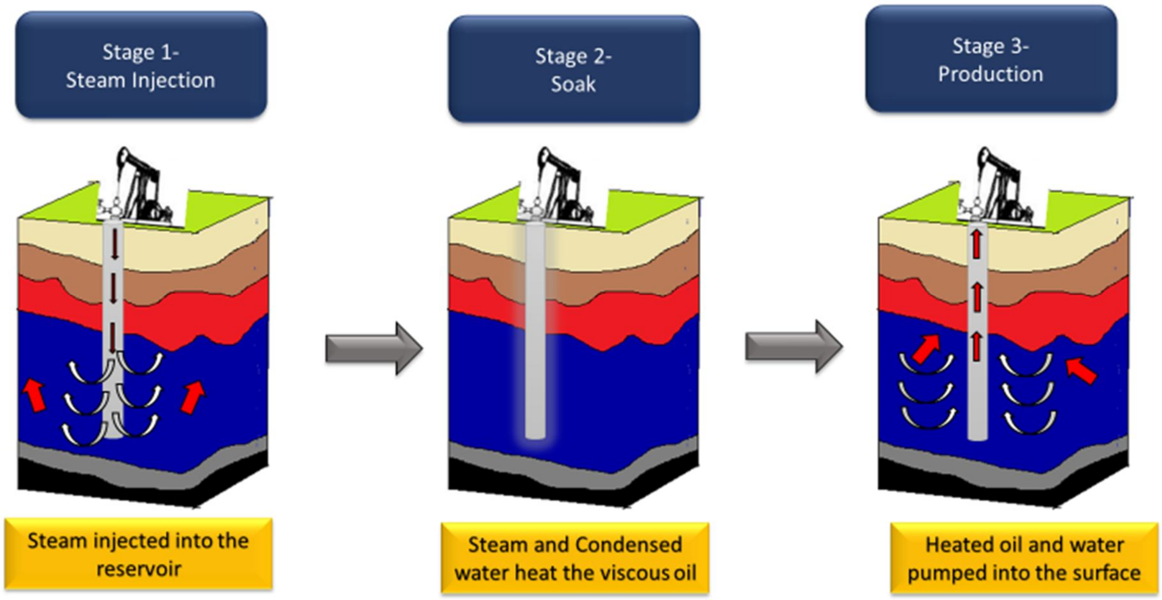

Figure 4: Schematic diagram of Steam flooding

3) In Situ Combustion

This process, also known as fire flooding, involves injecting air or oxygen into the in-place oil to burn a fraction (~10%) of it and generate heat. In a limited zone, extremely high temperatures, in the region of 450-600°C, are created. Near the combustion zone, there is a significant fall in oil viscosity. Because there is little heat loss to the overburden or under load, and no surface or wellbore heat loss, the method has a high thermal efficiency. Some additives, such as water or a gas, are used in conjunction with air to improve heat recovery. Gravity override, severe corrosion, and poisonous gas emission are all typical issues. In situ combustion has been tested in a variety of locations, but only a few projects have proven to be cost-effective, and none have progressed to commercial scale.

The main types of in situ combustion are:

- Forward combustion
- Reverse combustion
- High pressure air injection

In forward combustion, the hot zone moves in the direction of the air flow, whereas in reverse combustion, the hot zone moves in the opposite direction of the air flow. Due to the consumption of oxygen in the air before it reaches the production well, reverse combustion has not been successful in the field. The in-place oil is oxidised at a low temperature by high-pressure air injection. There is no source of ignition. In the United States, the method is being tested in a number of light oil reservoirs.

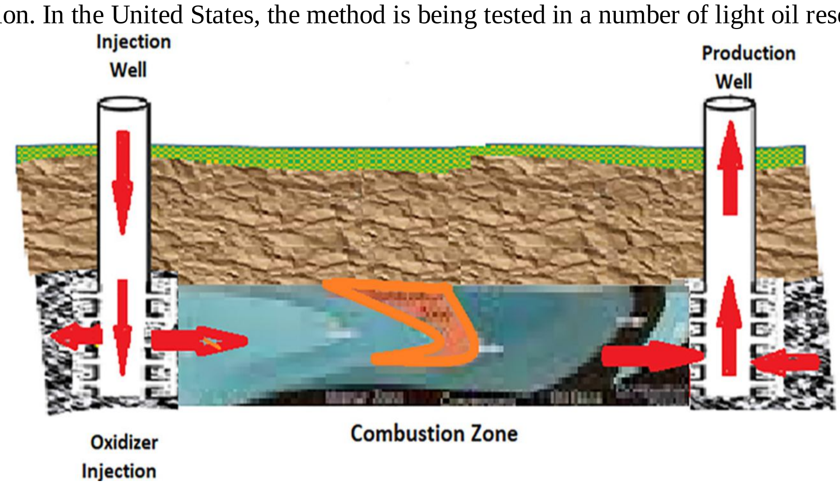

Figure 5: Schematic diagram of in situ combustion process

4) Steam Assisted Gravity Drainage (SAGD)

Butler developed SAGD for the in situ recovery of Alberta bitumen. The procedure uses a pair of parallel horizontal wells, spaced 5 metres apart (in the case of tar sands) in the same vertical plane, to separate steam by gravity. The steam injector is located at the top of the well, while the producer is located at the bottom. A steam chamber forms as steam rises to the top of the structure. The bitumen is mobilised by the high reduction in viscosity, which drains down by gravity and is captured by the producer near the reservoir's bottom. The steam chamber expands and spreads laterally in the reservoir as a result of continuous steam injection. The success of SAGD is dependent on a high vertical permeability. The procedure works better with low-mobility bitumen and oils, which are required for the development of a steam chamber, rather than steam channels. For the same reason, SAGD has been more effective in Alberta than in California and Venezuela.

SAGD is a very energy-intensive process. Steam generation necessitates large amounts of water, and natural gas use for steam generation ranges from 200 to 500 tonnes/sm3 of bitumen. Several attempts had been made to improve SAGD's economics. SAGD variations are VAPEX, ES-SAGD, and SAGP.

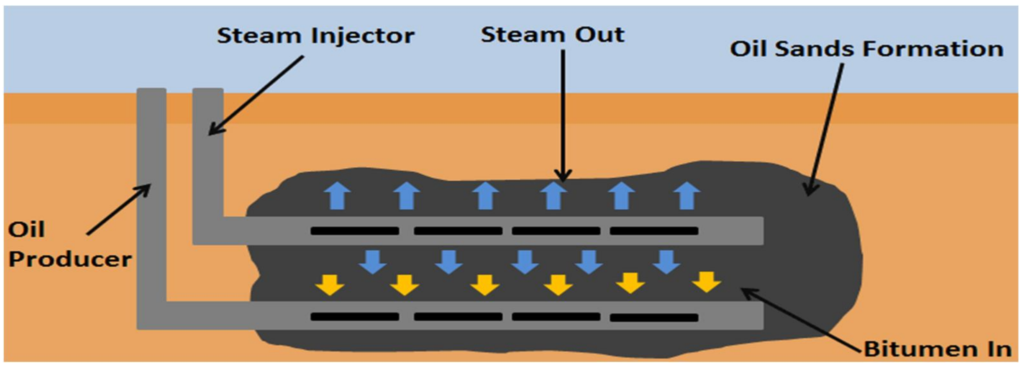

Figure 6: Schematic diagram of Steam Assisted Gravity Drainage (SAGD)

5) SAGD Variations

a) *VAPEX:* VAPEX is SAGD's non-thermal twin, and it operates on the same principles. A solvent gas, or a mixture of solvents, such as ethane, propane, and butane, is injected in place of steam, together with a carrier gas such as N2 or CO2. The reservoir pressure and temperature are used to determine which solvent to use. The dew point of the solvent gas is injected. The carrier gas raises the dew point of the solvent vapour, allowing it to stay in the vapour phase at reservoir pressure. A vapour chamber is created, which spreads laterally. The major process is the lowering of viscosity. The transfer of solvent to the bitumen for viscosity reduction relies on molecular diffusion and mechanical dispersion. Because dispersion and diffusion are inherently sluggish, they are far less effective at reducing viscosity than heat.

b) *ES-SAGD:* This process (Expanding Solvent SAGD) is another variation, where the addition of about 10% steam to the solvent mixture has been suggested to gain a 25% gain in the energy efficiency of VAPEX.

c) *SAGP:* A version is the Steam and Gas Push, in which a non-condensable gas, such as natural gas or nitrogen, is mixed with steam to lower the high demand for steam in SAGD. These methods are still in the early stages of development and have yet to be tested on a commercial basis.

C. Gas EOR Methods

1) CO_2 Miscible

In recent years, the CO2 Miscible technique has gained popularity, owing to the possibility of CO2 sequestration. Apart from environmental concerns, CO2 is a unique displacing agent due to its low minimum miscibility pressures (MMP) with a variety of crude oils. After several interactions, CO2 removes heavier fractions (C5-C30) from the reservoir oil and develops miscibility. Light and medium light oils (API >30°) in shallow reservoirs at moderate temperatures are suitable for the process. Depending on the reservoir and oil properties, CO2 requirements range from 500 to 1500 sm3/sm3 oil. This approach employs a variety of injection strategies. The WAG (Water Alternating Gas) technique, in which water and CO2 are alternated in small slugs until the requisite CO2 slug size is obtained, is particularly noteworthy (about 20 % HCPV). This method has the effect of reducing viscous instabilities. The cost and availability of CO2, as well as the requisite infrastructure, are thus important considerations in the process's feasibility. In some instances, asphaltene precipitation might be an issue. In North America, there are now 80 CO2 floods.

2) N_2 Miscible

The principle and processes for achieving miscibility are similar to those for CO2, although N2 has a high MMP with most reservoir oils. This method can be used in deep reservoirs with moderate temperatures for light and medium light oils (API >30°). The Cantarell N2 flood project in Mexico is the world's largest of its sort, generating roughly 500 000 B/D of additional oil at the moment.

3) Enriched Gas Drive

This is a MCM process that involves the continuous injection of a gas enriched with C2-C4 components, such as natural gas, flue gas, or nitrogen. These fractions condense into the reservoir oil and form a transition zone at fairly high pressures (8-12 MPa). After several interactions between the injected gas and the reservoir oil, miscibility is attained. An increase in oil phase volume and a decrease in viscosity contrast may also contribute to improved recovery. Because of the pressure necessary for miscibility, the technique is limited to deep reservoirs (>6000 ft).

4) Vaporizing Gas Drive

This is also a MCM process, and it entails a high-pressure continuous injection of natural gas, flue gas, or nitrogen (10-15 MPa). The C2-C6 components of the oil are vaporised and injected into the gas under these circumstances. After multiple encounters, a transition zone forms, and miscibility is attained. The oil must have enough C2-C6 fractions to develop miscibility, which is a limiting condition. In order for the fractions to vaporise, the injection pressure must be lower than the reservoir saturation pressure. Only reservoirs that can tolerate high pressures are suitable.

D. Microbial EOR (MEOR)

Since the 1960s, microbial EOR has been studied. A few field experiments were also conducted in the United States and other countries. Microbes create surfactant, slimes (polymers), biomass, and gases like CH4, CO2, N2, and H2, as well as solvents and some organic acids, when they combine with a carbon source like oil. IFT reduction, emulsification, wettability alteration, better mobility ratio, selective plugging, viscosity reduction, oil swelling, and higher reservoir pressure due to the generation of gases are all oil recovery techniques used in microbial EOR. Acid formation can cause an increase in permeability. Exogenous and indigenous microbes are both possible. Exogenous microorganisms must adjust to the temperature, salinity, and hardness of the reservoir. Nutrients like molasses or ammonium nitrate are added to the reservoir to encourage microbial growth. Performance rating is pending due to insufficient field trials.

E. Foam Flooding

Since the early 1960s, foam has been studied as an EOR agent. It's a complicated non-Newtonian fluid with many variables governing its properties and characteristics. Foam is a liquid dispersion in a gas, such as CO2, air, N2, steam, or natural gas that contains a surfactant. Foam is generated in situ when a gas and a surfactant solution are injected simultaneously, or when a gas is injected into a porous material containing a surfactant solution. As fluids progress through the porous material, foam forms, breaks, and reforms in the pore throats. Because the presence of oil prevents the production of foam, it is ineffective in mobilising remaining oil. Foam has a lower mobility than gas or steam, and it behaves like a viscous fluid. In some reservoirs, foam has been utilised (with limited success) as a mobility control or blocking agent with steam and CO2.

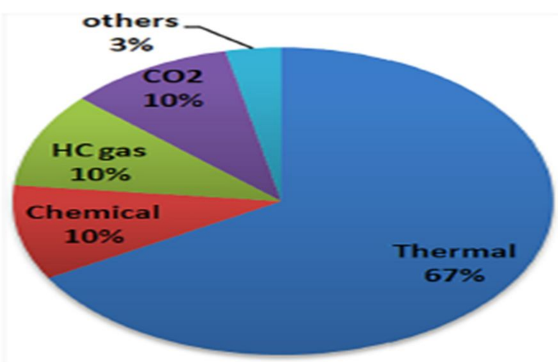

Figure 7:Ratio of different EOR methods used in projects around the world

III. CONCLUSIONS

Only a few EOR techniques have been commercially successful out of the many that have been tried. For heavy oils and tar sands, steam injection-based recovery technologies such as CSS and steam flooding have proven to be particularly effective. For light oils, miscible CO2 flooding has had a lot of success, although the economics aren't evident yet. Chemical technologies like micellar flooding and ASP have the potential to recover some of the 2 trillion barrels remaining in the world's reservoirs.

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