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Application of Thermal Methods for Heavy Oil Recovery: Phase One

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ABSTRACT

In this study, an integrated research review is conducted to figure out the possibility of applying thermal methods for heavy oil recovery since plentiful heavy oil reserves and increasing demands for energy have encouraged more and more interest in the exploitation of heavy oil mostly found with in thin pay zones (less than 10 m) in the world, often found in fractured carbonate reservoirs. The whole recovery of heavy oil is demanding due to its high viscosity, different Enhanced Oil Recovery (EOR) methods should be considered and implemented appropriately. The conventional thermal recovery process widely used to reduce the viscosity and increase the mobility of heavy oil includes but not limited to Cyclical Steam Stimulation (CSS) or Huff and-Puff, in situ combustion (ISC), Steam Solvent Hybrid Steam drive process, steam-assisted gravity drainage (SAGD), Expanding Solvent-Steam Assisted Gravity Drainage (ES-SAGD), Steam injection(Steam Flood) and Vapor Extraction (VAPEX) used with the intention of reducing the high oil viscosity and, as a consequence, improving phase mobility in porous media so as to obtain a more efficient drainage up to the producing well. Vapor extraction (VAPEX) has gained considerable attention because it is energy effective and environmentally friendly. Other emerging Recovery Technologies (Non-Steam) VAPEX (Vapor Extraction) inclusive are JIVE (Joint Implementation of Vapor Extraction), N-Solvent, THAI (Toe to Heel Air Injection), ET-DSP (Electro-Thermal Dynamic Stripping Process) and ESEIEH (Enhanced Solvent Extraction Incorporating Electromagnetic Heating). Thermal Recovery Technology for Heavy Oil has been successfully applied in many parts of the world like Shengli, Henan and Jilin and other heavy oil producing areas of China, and also in heavy oil producing countries of Sudan, Kazakhstan and Venezuela. Conventional thermal recovery techniques are not cost-effective for many heavy oil reservoirs, due to unnecessary heat loss through the overburden which can be reduced through non-conventional thermal methods of either; controlled heating of the pay zone by introducing heat to the reservoir in a controlled manner or Hybrid SAGD and warm VAPEX studied combining the effects of heat conduction and solvent dissolution to be discussed in the next phase of this study.

Keywords: Heavy Oil; Thermal EOR; SAGD; VAPEX ; Steam Flooding; In-Situ Combustion; Cyclical Steam Stimulation; JIVE ; N-Solv; THAI; ET-DSP ; ESEIEH.

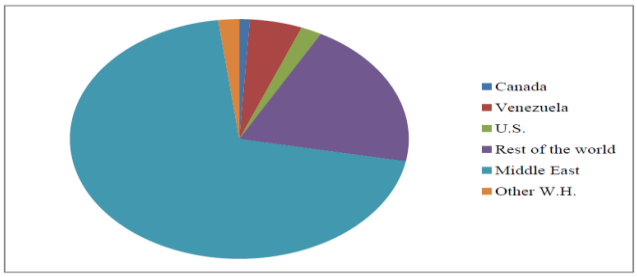
1. INTRODUCTION

1.1. Definition of Heavy Oil

Heavy crude oil is a kind of formation oil which does not run easily in the reservoir due to its higher density and viscosity compared with light oil, also the heavy oil is characterized as its heavier composition and molecular weight. Heavy crude oil is defined as any kind of liquid petroleum with gravity less than 20°API, and a reservoir viscosity range of 50–5,000 centipoises. Although there is no consensus, crudes having a viscosity above 10 cp up to 10000 cp is also classified as a heavy oil. World Energy Council classifies crude with gravity below 22.3 °API or density above 0.920 as heavy oil. The lower border is 10 °API, oil having less than 10° API designated as extra-heavy oil. In addition to high viscosity and high specific gravity, heavy oils typically have low hydrogen-to-carbon ratios, high contents of asphaltenes, high carbon residues, sulfur, nitrogen, and heavy-metal content, as well as higher acid numbers. Heavy oil and bitumen reservoirs are formed by microbial degradation of conventional light crude oil reservoirs over geological timescales [2, 3, and 4].

Occasionally, in the oil and gas industry, some petroleum geologists classify bitumen from oil sands as extra heavy crude oil although due to the API gravity less than 10°API. Others, however, categorize this heavy oil as bitumen, differentiating it from extra-heavy oil. Heavy oil and bitumen differ in the degree by which they have been degraded from the original crude oil by bacteria and erosion in the long geologic time. The largest heavy oil reserves in the world are located north of the Orinoco River in Venezuela,

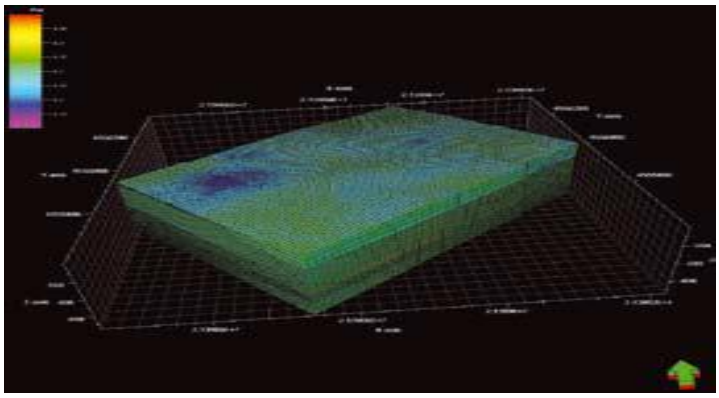
with a heavy oil amount equal to Saudi Arabia's conventional oil reserves [3]. Figure 1 shows the worldwide conventional and heavy oil distribution.



(a) Conventional crude oil

Figure 1: Worldwide distributions of conventional crude oil and heavy hydrocarbons [3].

During the thermal recovery of heavy oil, researches should be conducted to cope with different types of oil reservoirs and specific features of different development stages. Accordingly, physical simulation, numerical simulation, economic assessment and other technologies should be applied on the basis of the reservoir description and in-house experiment. Development methods for the heavy oil reservoirs should be based on the latest technologies with economic efficiency and recovery factor as main objectives to cope with the specific reservoir conditions and properties of the contained oil [6].



CNPC (China National Petroleum Corporation) has prepared and implemented the development programs for 15 blocks with a reserve of over 25 million tons in each block. Conformity between implementation outcomes and designed indexes is over 95%.

Table-1: Screening criteria of development mode for heavy oil in CNPC [8].

Development mode	Steam Stimulation	Steam Flooding	SAGD
Buried depth of reservoir (m)	≤1,800	≤1,400	≤1,000
Thickness of oil zone (m)	≥10	7-10	≥10
Net-Total thickness ratio	≥0.35	≥0.4	≥0.5
Effective porosity (%)	≥20	≥20	≥20
Permeability (milidarcy)	≤400,00	≤10,000	≤400,00
Crude oil viscosity (mpa.s)	≥55	≥45	≥50
Permeability variation coefficient (decimal fraction		≤0.65	≤0.65

Reservoirs act differently due to varying range of both rock and fluid properties and thus must be treated uniquely. During production, reservoirs are allowed to naturally produce their hydrocarbons until when production rates are mostly not economically viable then other support systems are used. Primary recovery is the natural stage of the reservoir to be able to produce without support thus depending on reservoir's internal energy. There are different drive mechanisms known in the earlier life of the production but can be seen from production data with time. The knowledge about the reservoir's drive mechanism can help improve reserves recovery and supervision during its middle and later life. The important drive mechanisms include: Rock and liquid expansion drive, solution gas/ depletion drive, Gas cap drive, Water drive, Combination drive and Gravity drainage drive [1].
Improved oil recovery methods appear from the need of increasing the producing life of a reservoir, augmenting the profitability of the process. They are more frequently used when recovery from conventional methods is less profitable. These processes involve an external agent that can help to reduce the oil viscosity, to improve the porous channels, to reduce the interfacial tension among the fluids, or to increase the mobility of the oil that will be produced. Thermal methods (steam injection or *in situ* combustions),

chemical methods (surfactants injection, Alkali-Surfactant- Polymer injection, or polymer injection) or miscible methods (CO2 injection) may be cited as examples of such processes. If the injected fluid has a lower viscosity than that of the reservoir oil, it is possible that the displacing fluid moves easier within the porous media, finding preferential channels or "fingers" towards the producing wells. In this case, the oil is left behind because of poor sweep efficiency. When high interfacial tensions are observed, the capacity of the injected fluid to displace the oil out of the pores of the rock is very low, leaving high residual oil saturations in the areas that already had contact with the injected fluid which defines a method to be used to improve oil recovery. The recovery methods can be divided into three categories: Miscible Methods, Chemical Methods and Thermal Methods, Figure 2 below shows example of the heating effect on oil viscosity [9].

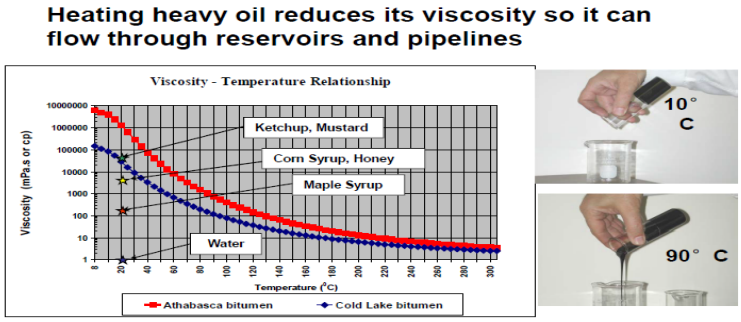


Figure -2: effect of heat on heavy oil production [10].

Furthermore, this research particularly focused on thermal processes, in that they provide a decrease in oil viscosity contained in the reservoir, leading to an increase in its mobility in the porous medium. Thermal methods (steam injection or in-situ combustion) and non-thermal methods (VAPEX) may be cited as examples of such processes [7].

Horizontal wells have shown high efficiency in terms of oil recovery, due to intrinsically larger reservoir contact areas. However, they are still more expensive than vertical wells. An example of the technologies that use horizontal wells is: steam assisted gravity drainage (SAGD), expanded solvent with gravity drainage (ES-SAGD) and vapor extraction (VAPEX) [7].

These technologies improve the fluid contact area in the reservoir, the sweep efficiencies, and oil production. Thermal methods have proven to be successful in most applications. The chosen method should be carefully evaluated and the analysis should consider physical reservoir parameters, results from similar reservoirs, teamwork experience and reservoir simulations [11].

All thermal methods tend to reduce the flow resistance by reducing the viscosity of the fluid. Of all these processes, steam assisted gravity drainage (SAGD) is an effective method of producing heavy oil and bitumen. In a typical SAGD approach, steam is injected into a horizontal well located directly above a horizontal producer. A steam chamber grows around the injection well and helps displace heated oil toward the production well, as shown in figure 3. At the steam chamber boundary, steam condenses to water as heat is transferred to the oil. Condensed water and hot oil flow along the steam chamber to the production well [6, 17, 18]. It is concluded that the effect of steam distillation, gas-drive and solvent extraction contributed to more oil recovery during steam injection as depicted by the following stages.

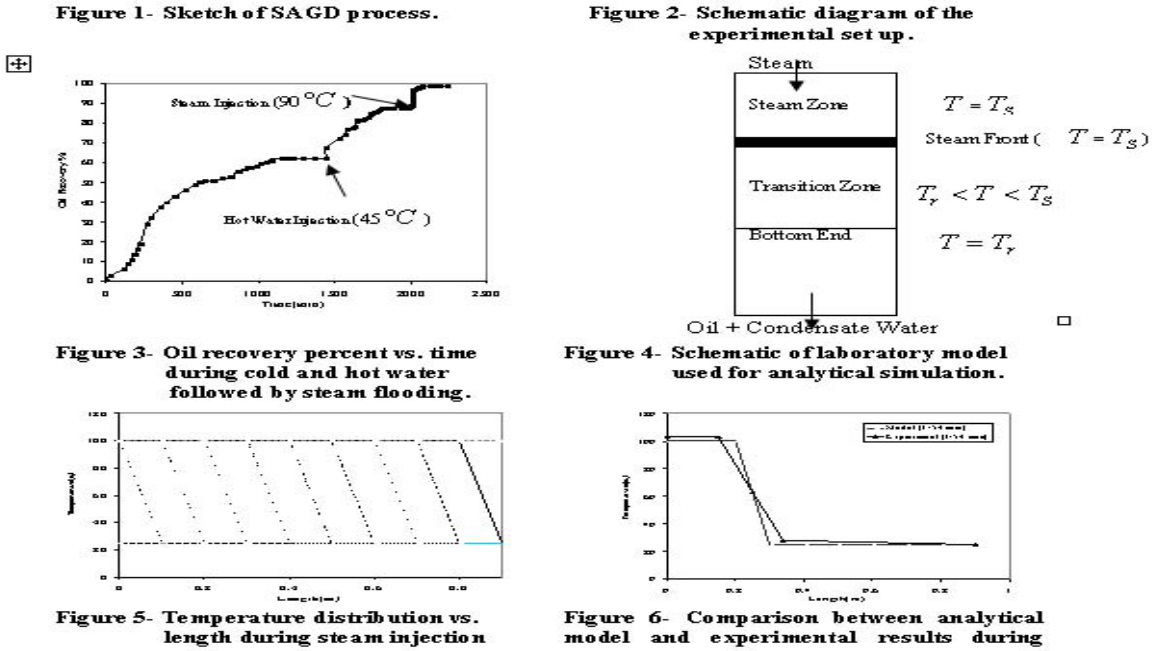
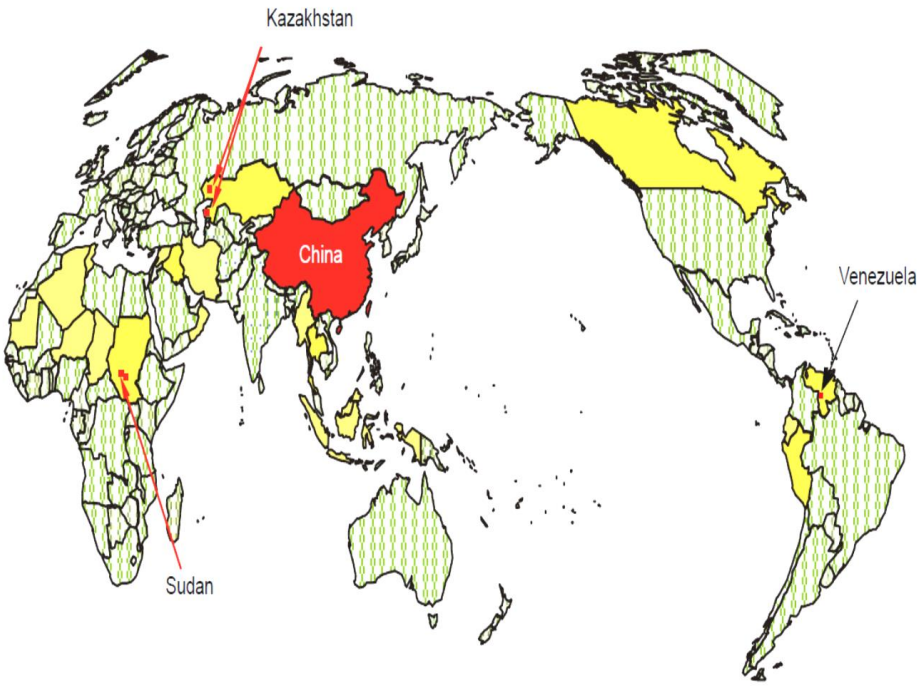


Figure-3: Steam Displacement processes [6].

Thermal Recovery Technology for Heavy Oil has been successfully applied in Liaohe, Shengli, Henan, Xinjiang Uygur Autonomous Region, Dagang and Jilin and other heavy oil producing areas of China, and also in heavy oil producing countries of Sudan, Kazakhstan and Venezuela as shown by the map below[8].



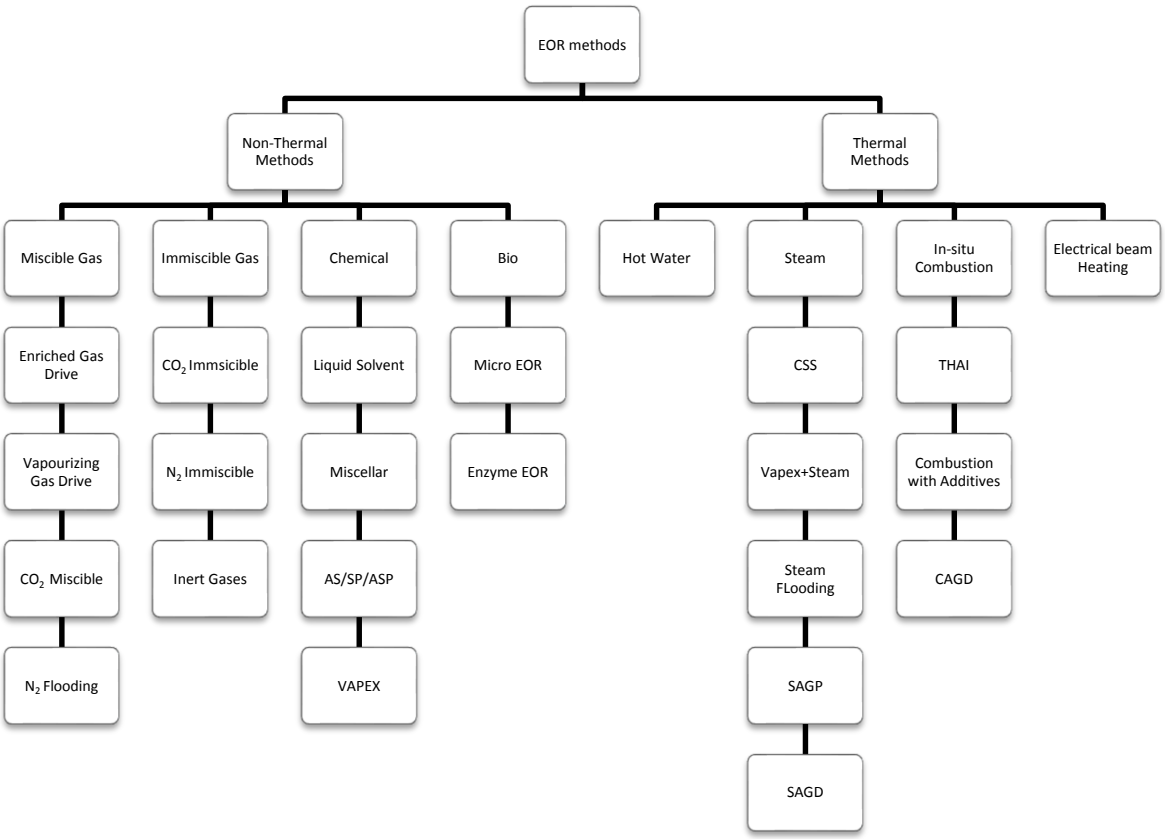


Figure-4: The classification of enhanced oil recovery method [5]

Carbonate reservoirs introduce great challenges due to their complex fabric nature (low matrix permeability, poor effective porosity, fractures) and unfavorable wettability, further displayed when combined with increased depth and low-grade oil (high density and

viscosity). It is possible to increase heavy oil recovery in some of these reservoirs with the help of enhanced oil recovery processes, thus enhancing oil field productivity and profitability [7]. Screening criteria have been proposed for all enhanced oil recovery (EOR) methods by SPE [7] for conventional reservoirs (Table 2).

		Oil Properties			Reservoir Characteristics					
Detail Table in Ref. 16	EOR Method	Gravity (°API)	Viscosity (cp)	Composition	Oil Saturation (%PV)	Formation Type	Net Thickness (ft)	Average Permeability (md)	Depth (ft)	Temperature (°F)
Gas Injection Methods (Miscible)										
1	Nitrogen and flue gas	>35↗48↗	>0.4↘0.2↘	High percent of C_1 to C_7	>40↗75↗	Sandstone or carbonate	Thin unless dipping	NC	>6,000	NC
2	Hydrocarbon	>23↗41↗	<3↘0.5↘	High percent of C_2 to C_7	>30↗80↗	Sandstone or carbonate	Thin unless dipping	NC	>4,000	NC
3	CO_2	>22↗36↗[a]	<10↘1.5↘	High percent of C_5 to C_{12}	>20↗55↗	Sandstone or carbonate	Wide range	NC	>2,500[a]	NC
1-3	Immiscible gases	>12	<600	NC	>35↗70↗	NC	NC if dipping and/or good vertical permeability	NC	>1,800	NC
(Enhanced) Waterflooding										
4	Micellar/Polymer, ASP and Alkaline Flooding	>20↗35↗	<35↘13↘	Light, intermediate, some organic acids for alkaline floods	>35↗53↗	Sandstone preferred	NC	>10↗450↗	>9,000↘3,250	>200↘80
5	Polymer Flooding	>15	<150>10	NC	>50↗80↗	Sandstone preferred	NC	>10↗800↗[b]	>9,000	>200↘140
Thermal/Mechanical										
6	Combustion	>10↗16→?	<5,000 ↓ 1,200	Some asphaltic component	>50↗72↗	High-porosity sand/sandstone	>10	>50[c]	<11,500 ↘3,500	>100↗135
7	Steam	>8 to 13.5→?	<200,000 ↓ 4,700	NC	>40↗66↗	High-porosity sand/sandstone	>20	>200↗2,540↗[d]	<4,500 ↘1,500	NC
-	Surface mining	7 to 11	Zero cold flow	NC	>8 wt% sand	Mineable tar sand	>10[e]	NC	>3:1 overburden to sand ratio	NC

Table-2: EOR screening criteria for conventional reservoirs [7].

The most proven approach to producing heavy oil reservoirs is through thermal methods. Thus oil recovery from this type of reservoir becomes a real challenge and classic thermal application theories fail to define the process. Main drive mechanisms in fractured reservoirs are shown in Figure 5 [7].

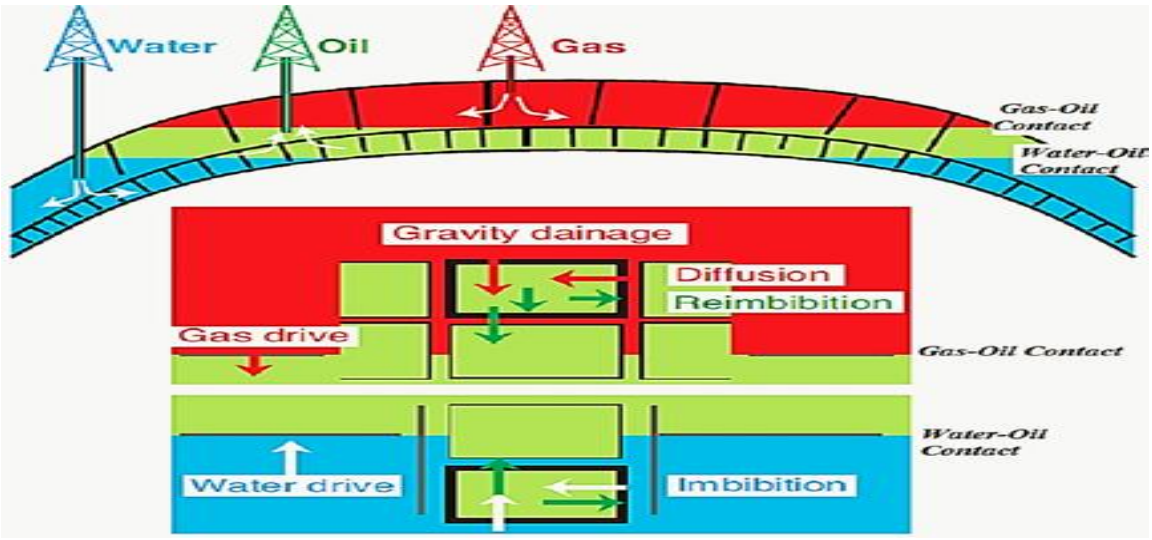


Figure-5: Main drive mechanisms in fractured reservoirs [7].

The energy gap, caused by declining conventional oil production has to be filled by expanding production of other sources. Heavy oil is one of the options for filling this gap as the world has a significant amount of heavy oil reserves. In fact, according to the report of IEA, the heavy and extra heavy oils constitute 40 % of the world oil reserves while some resources claims that it is as high as 70 % like in Herriot Watt Institute of Petroleum Engineering. In some cases, change of EOR method is required within the production period. In shallow reservoirs where the reservoir pressure is too low to maintain a steam drive, deep reservoirs where heat losses to overburden become excessive, in reservoirs having low in-situ water and gas saturation or the permeability is too low to permit injection of steam, reservoirs having thin pay zones. For such, electrical heating methods are more suitable in terms of depth and controllable heat loss to the overburden. Low-frequency heating is provided by using two neighboring producing oil wells as one anode and one cathode. By applying a potential difference between the two electrodes the reservoir is heated. In inductive heating, production casing is used as an inductively heated element to conduct heat into the production zone. While in microwave heating the microwaves act on water molecules and the water molecule is heated while this heat is then transferred to the formation [2].

Also, an analytical model is developed by the combination of Maxwell and heat equations and the analytical result is correlated with the data obtained from the experiments [2] as shown in figure 6.

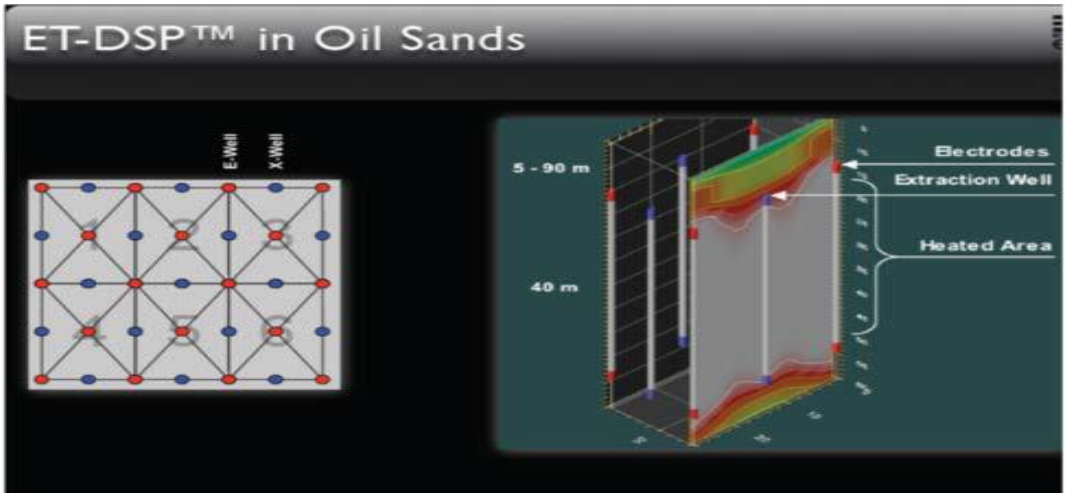


Figure- 6: Electrical Heating [10].

Today, numerical reservoir simulation is regularly used as a valuable tool in determining commerciality, optimizing field development plans and initiating secondary and enhanced oil recovery methods on major oil and gas projects [1].

2.0 CONVENTIONAL THERMAL METHODS OF HEAVY OIL RECOVERY

The main purpose in thermal methods is to add heat to the reservoir to reduce oil viscosity so that oil flow easily during production. Steam flood, cyclic steam injection, in situ combustions (fire flood), SAGD (Steam Assisted Gravity Drainage) are the main conventional thermal methods in use [2].

2.1 Cyclic Steam Injection

Alternating injection of steam and production of oil from the same well is called cyclic steam injection, steam soak, or "huff & puff" was accidentally discovered in Eastern Venezuela in 1959. In cyclic steam injection, the three-stage process involved as illustrated in Figure 2 and 3 respectively. In the first stage, high-pressure steam is injected under high pressure and temperature into the pay zone deliver the thermal energy to mobilize the oil and build up reservoir pressure. The steam injection period could last for up to a month into a producing well at very high rates (millions of kilograms). In the second stage, also called soak stage, the well is shut in to allow distribution of injected heat to the reservoir for a soak period of three to six days. After the soak stage, the well is put on production. The initial production rates are typically very high for short period of time and then decline gradually over several months. After depletion of reservoir pressure which results in very low production rate, further production is no longer economic, the well will be put on steam injection stage again and the whole process repeats for another injection-soak-production cycle (Figure 2.1). Steam stimulation is also used to stimulate the producers and to clean up the formation around the wellbore. CSS processes typically have short payback periods. At a later stage, due to the higher steam-oil-ratio, the CSS processes are typically converted into steam flooding processes [2, 4, 7].

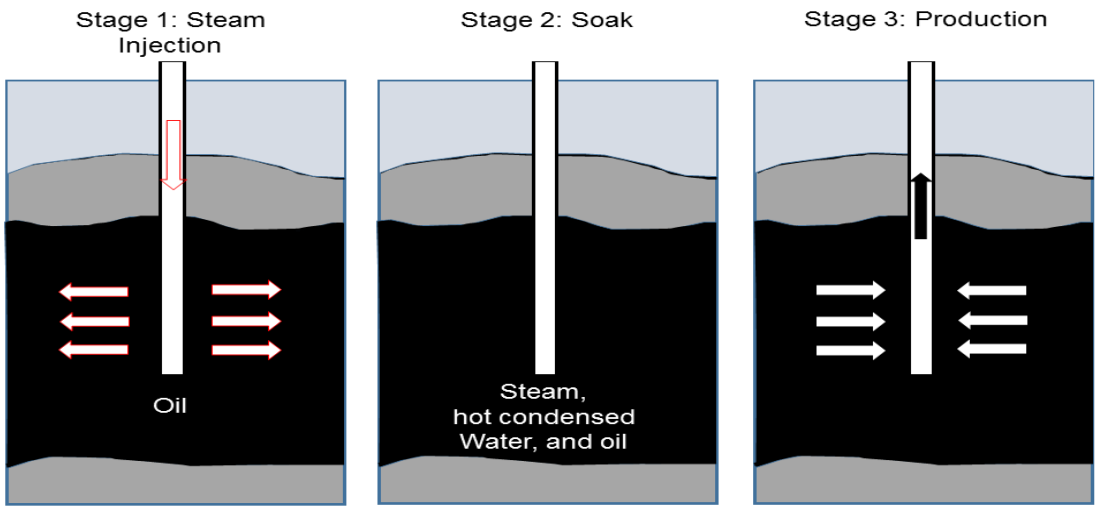


Figure-2.1: Illustration of Cyclic Steam Stimulation (CSS) process [9].

Frequently, oil rate decreases in subsequent cycles, as can be seen in Figure 2.2 below. If the cyclical injection is to be followed by a continuous injection – as observed in recent times – it will be desirable to determine the number of cycles that will maximize the oil injection recovery for the cyclical injection and steam injection [9].

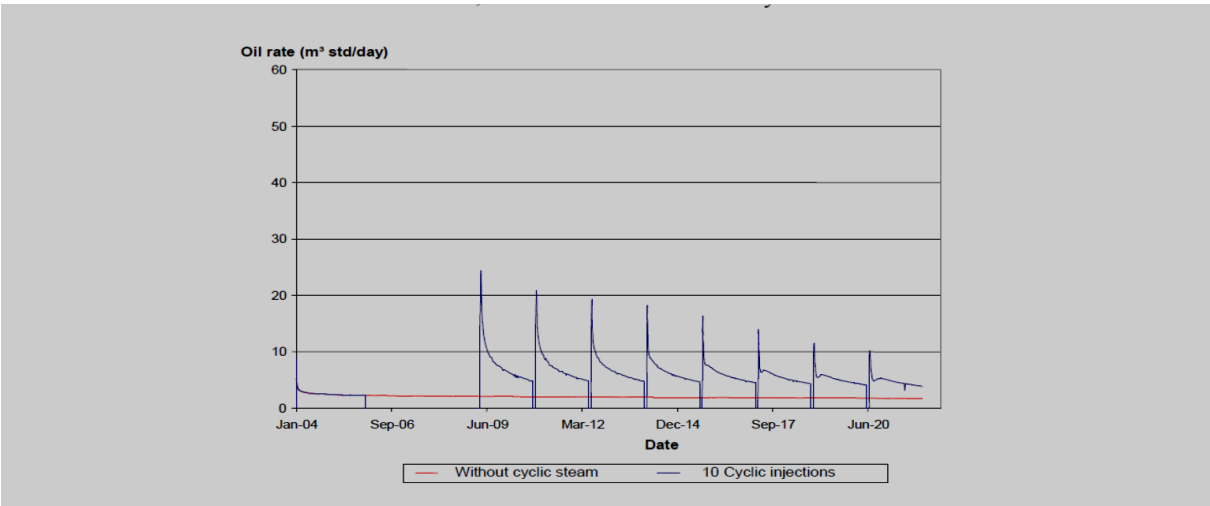


Figure-2.2: Oil rate in 20 years of production in a numerical model with and without cyclic steam injection.

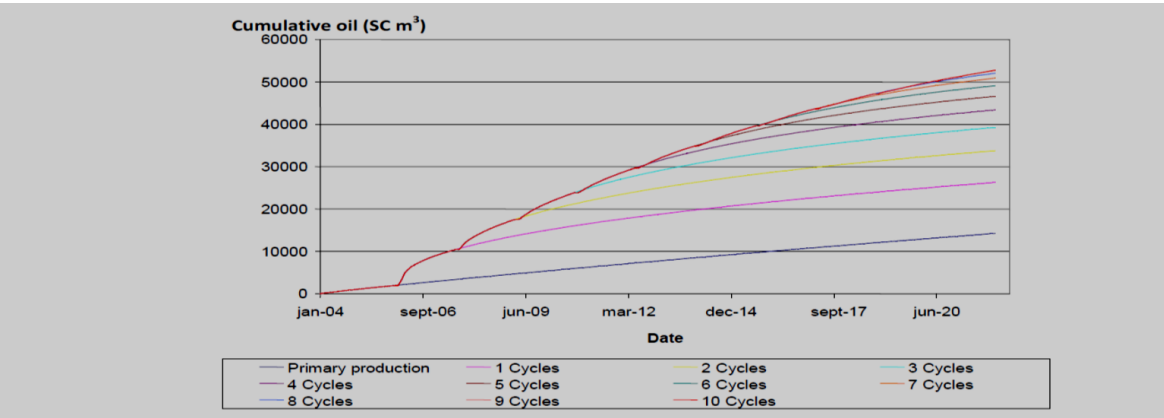


Figure-2.3: Oil rate in 20 years of production in a model with and without cyclic steam.

Figure 2.3 shows cumulative oil versus time in an optimization of the number of cycles in a cyclic steam injection. In this example the maximum cumulative oil can be obtained, with 8 or 9 cycles [9].

Regardless of the reservoir type, the cyclic injection becomes usually less efficient with increasing number of cycles. Recovery factors are low – very often found to be in the range of 10-15% of the oil-in-place. This process can be use in horizontal and vertical wells, it has been used in several oil fields with success, like in Alberta, Canada, where oil viscosity is about 100.000 cp, Dominant mechanisms in heat transfer are: conduction and forced convection during injection, conduction, and a minimum convection effect during the soaking period, and counter current of convection-conduction during the production period. For thin heavy oil reservoirs, however, no commercial success has been reported, due to the excess heat loss which makes the soak ineffective. This fact is evident in several production statistics. [7, 12].

2.1.1 Continuous steam injection

This recovery method has been used for many years in which steam is continuously injected into one or more vertical wells, and the oil is pushed away to producing wells. Since this process requires injectors and producers, a larger area inside of the reservoir is embraced, and oil recoveries higher than those provided by cyclical steam injection are obtained. Oil recovery in this process can reach up to 50% or more, but thermal efficiency is lower than in cyclical steam injection. Heating of the oil has the following effects: Thermal expansion, Viscosity reduction, Activation of solution gas drive, Distillation (thermal cracking) and potentially wettability modification [7, 13].

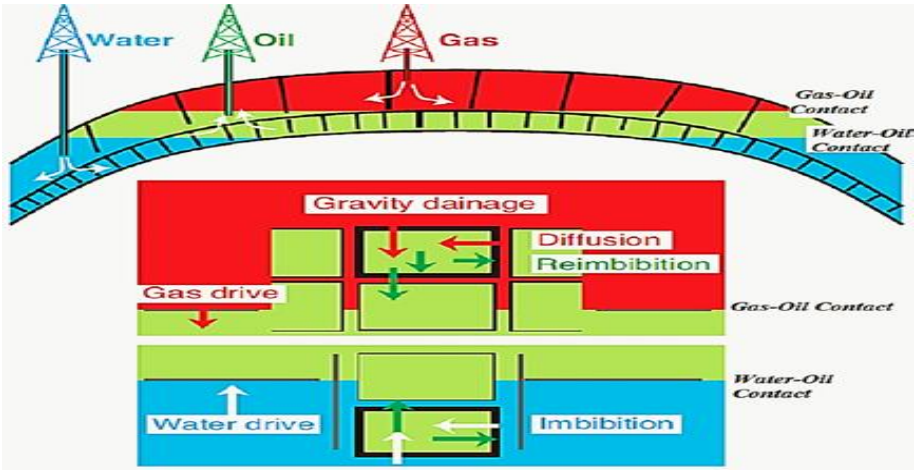


Figure-2.1.1: Main drive mechanisms in fractured reservoirs [7].

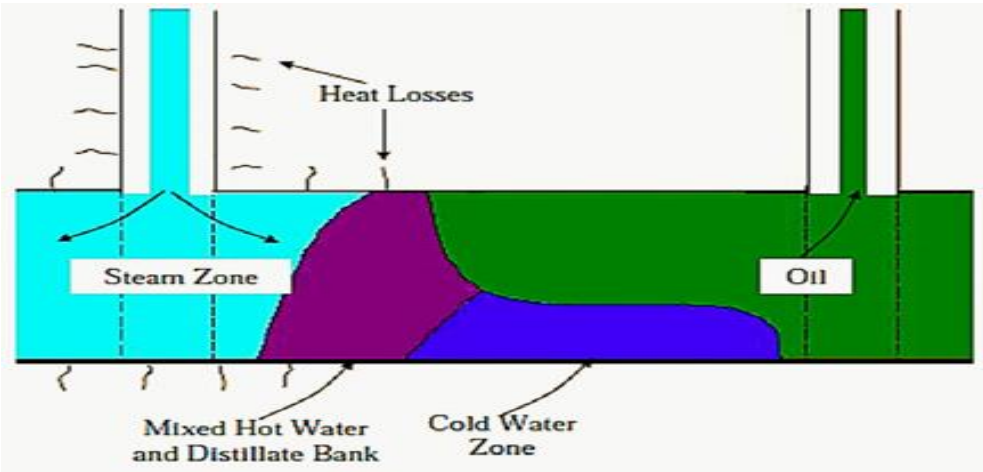


Figure-2.1.2: Steam injection scheme taking account gravity [7].

Gravity drainage is one of the most important mechanisms by which oil is recovered from fractured carbonate reservoirs. Recent projects for oil recovery have proposed the combination of vertical and horizontal wells, but some technical problems still exist such as minimization of the impact of the gas cap and of water influx. The methods of continuous and cyclical steam injection are frequently combined and used, whereby wells produce oil through cyclical stimulation before the beginning of continuous steam injection. In the case of very viscous oils, stimulation prior to continuous injection is essential to obtain flow communication between injectors and producers. This communication can be established through the creation of fractures among the wells, which can be done by injecting steam at sufficiently high pressures. Oil saturations behind the steam zone can be as low as 5%. In the steam displacement experiments in fractured models, it was found that the steam enters into the fracture or the matrix depending on the steam rate [7, 14].

2.1.2. Steam injection technology.

The core of the steam injection technology is the borehole steam injection thermal insulated tubing. The thermally insulated tubing may minimize heat losses during steam injection. Steam-injection thermal insulated tubing composed of vacuum insulation pipe, extension pipe, and heat-sensitive packer. Borehole steam injection thermal insulated tubing developed by CNPC (China National Petroleum Corporation) is one of the most efficient thermal insulated tubing around the world [8].

2.1.2. Steam Stimulation Recovery Technology

Steam stimulation is also known as a periodic steam injection or cyclic steam injection method. With a simple application, quick production enhancement and high economic efficiency, steam stimulation is the most popular method for heavy oil development. Through years 'researches and development, these technologies can be divided into three series, Steam Injection Matching Technology, Uplifting Associated Technology, Enhanced Heavy Oil Steam Stimulation Recovery Technology, Which is ten major thermal injection and production technologies. [8]

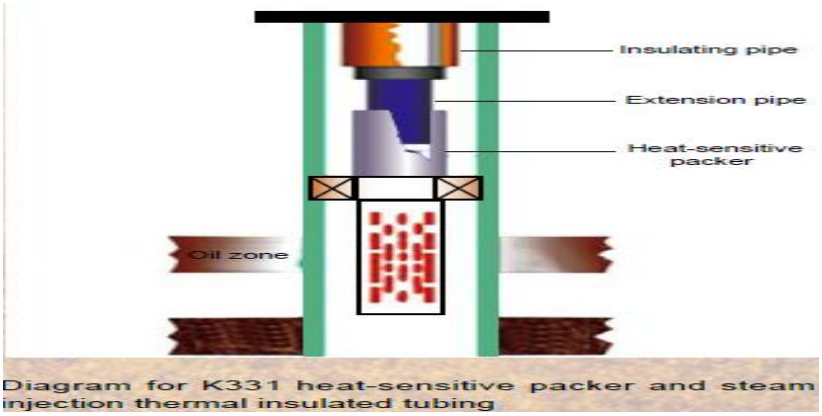


Figure-2.2: Steam flooding

The injection of steam as a recovery method for heavy oil has been used for many years in the United States, Canada, Brazil, and Venezuela. In this process, steam is continuously injected into one or more vertical wells, and the oil is pushed away to producing wells. Since this process requires injectors and producers, a larger area inside of the reservoir is embraced, and oil recoveries higher than those provided by cyclical steam injection are obtained. Oil recovery in this process can reach up to 50% or more, but thermal efficiency is lower than in cyclical steam injection [9].

Steam flooding is a process in which high-pressure steam is injected into the oil zone to supply the thermal energy to reduce the viscosity of oil which will be pushed towards to production well as in conventional fluid injection operations. The steam is primarily used as a displacing agent which is intended to displace the oil in place. To make steam flooding effective, the oil viscosity at reservoir conditions should be low enough to provide mobility, along with a high permeability of the reservoirs [4]. Under pressure gradient, as shown in Figure below, it is suggested that steam flooding methods can be applied to heavy oil reservoirs with crudes in the range 12º – 25 º API [4].

As seen in Figure2.2 below, due to density differences, the steam separates out gravitationally and overrides. This tendency favors the early breakthrough of steam into the producers. To decrease the overriding effect around the well, the perforated interval should be placed at the bottom of the formation. Before breakthrough, during the steam drive process, different zones are formed [2]:

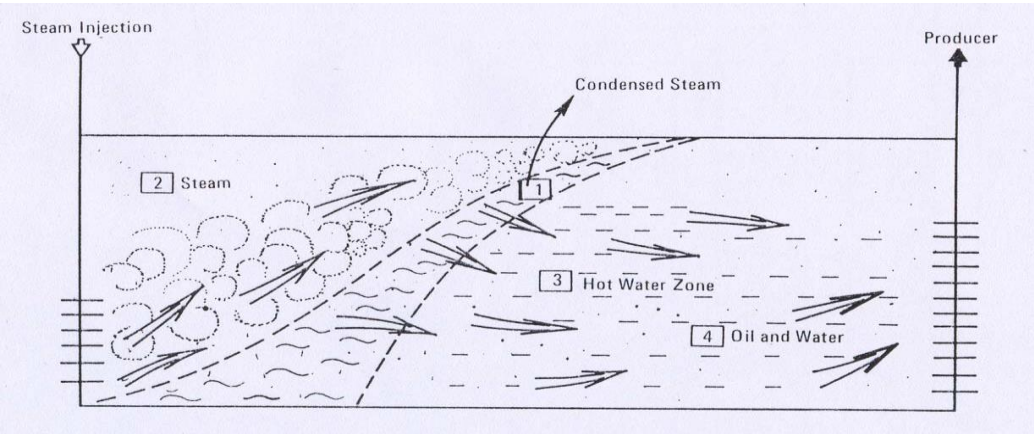
Zone 1: The condensing zone with hot water essentially at steam temperature.

Zone 2: The steam-saturated zone in which the oil saturation is reduced to less than 15 %, conditional on the viscosity of oil at reservoir temperature and on the steam temperature in the steam generator.

Zone 3: Hot water transition zone with a decreasing temperature from hot water to water near reservoir temperature.

Zone 4: Oil deposits pushed to the producers by the hot water zone.

The main purpose of steam-drive is to increase the ultimate recovery factor while for cyclic steam injection it is to stimulate the formation to produce at a higher rate. Only if the productive formation is thick, and the reservoir produces due to gravity drainage, the cyclic steam injection also increases the oil recovery.



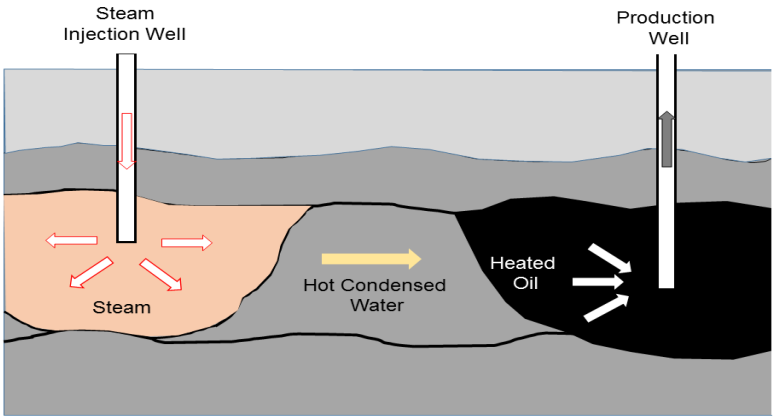
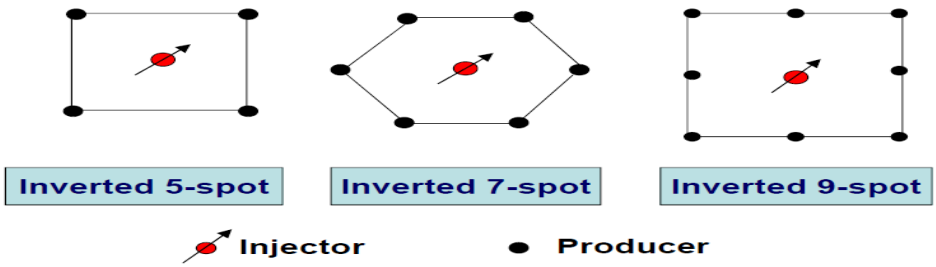


Figure-2.2.1: Illustrative mechanism of steam flooding process [4].

As shown in Figure 2.2.1 above, there is a steam zone in the vicinity of the injection well at steam temperature. Further ahead, there is hot water zone in which mixture of heated oil and hot water is pushed ahead towards production wells.
In summary, the following processes holds; [10]
• Similar to water drive in conventional oil reservoirs
• Inter-well mobility needed to inject steam at effective rates (pre-heating is usually required)
• Usually applied after huff and puff
• Poor vertical sweep due to gravity override and reservoir heterogeneities
• Recovery up to 40%.
Steam drive projects examples are; Husky Pikes Peak (Sask.), California, Indonesia (Duri Project), Maracaibo, Venezuela [10].
Examples of steam drive patterns.



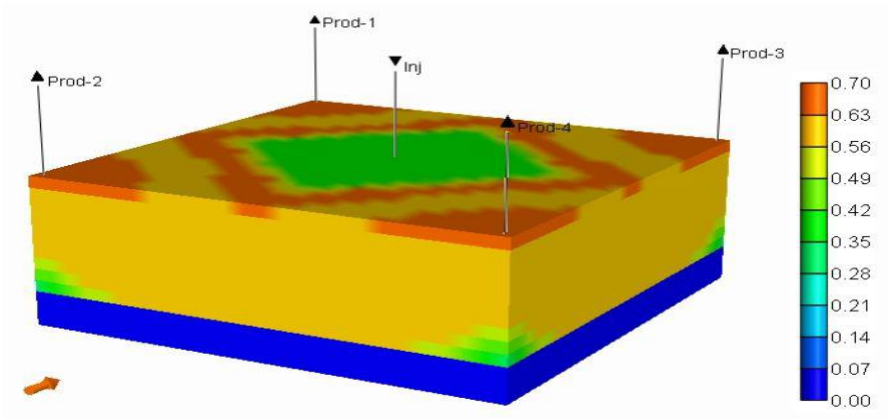


Figure-2.2.2: Steam-flooding in an inverted five-spot grid. [8]

Figure2.2.2 above shows an example of steam injection in an inverted 5-spot grid. Recent projects for oil recovery have proposed the combination of vertical and horizontal wells, but some technical problems still exist such as minimization of the impact of the gas cap and of water influx. The methods of continuous and cyclical steam injection are frequently combined and used, whereby wells produce oil through cyclical stimulation before the beginning of continuous steam injection. Figure2.2.3 below shows one example of cumulative oil and oil rate versus time with and without steam injection for an inverted 5-spot pattern.

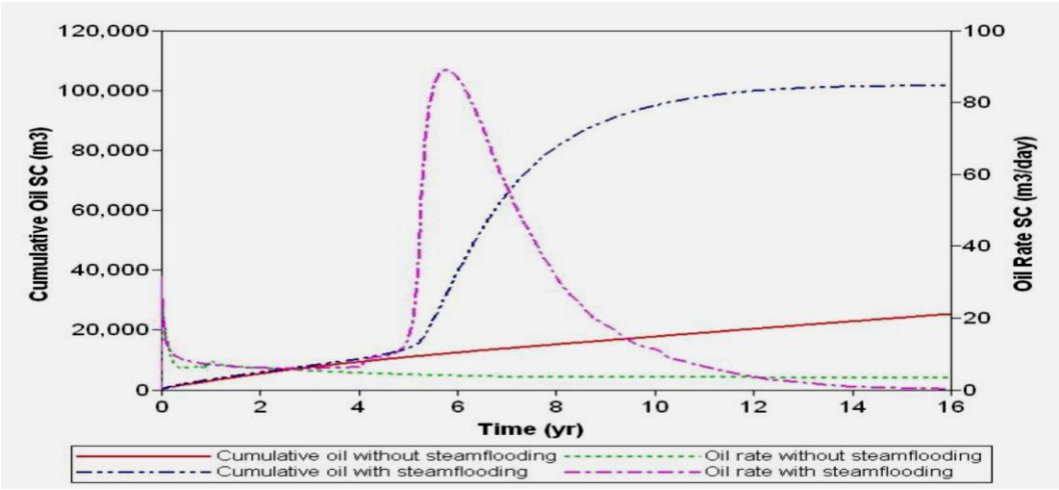


Figure-2.2.3: Cumulative oil and oil rate versus time with and without steam injection for an inverted 5-spot pattern.

It can be seen that cumulative oil after 16 years of production is much bigger (100,000 SC m3) in the case of steam injection as compared to that without steam injection (20,000 SC m3). The displacement efficiency is increased by the heat to the proportion that more oil flows. Oil saturations behind the steam zone can be as low as 5%.

Oil field staff should be familiarized with the operation of the steam generator in order to maintain the efficiency. Operations at high temperatures carry additional safety risks. Thermal operations require higher attention from engineering and operation staff to keep them efficient. High viscosity oils, usually considered for thermal projects, are also the ones with a lower price. Successful projects generally use centralized facilities to reduce production costs and steam generation [8].

2.3. In-situ combustion (ISC).

This process was first tested in Pennsylvania in the early 1950s. Over 200 in situ combustion field tests and commercial operations have been carried out worldwide, but only a few are still in operation. In in-situ combustion, fire is generated inside the reservoir by injecting a gas containing oxygen, such as air and a special heater in the well ignites the oil in the reservoir and starts a fire. Heat is generated as a result of oil oxidation, increasing the temperature [2, 7].

The heat generated by burning the heavy hydrocarbons in place produces hydrocarbon cracking, vaporization of light hydrocarbons and reservoir water in addition to the deposition of heavier hydrocarbons known as coke. As the fire moves, the burning front pushes ahead a mixture of hot combustion gases, steam and hot water, which in turn reduces oil viscosity and displaces oil toward production wells as depicted in figure 12 [2, 10].

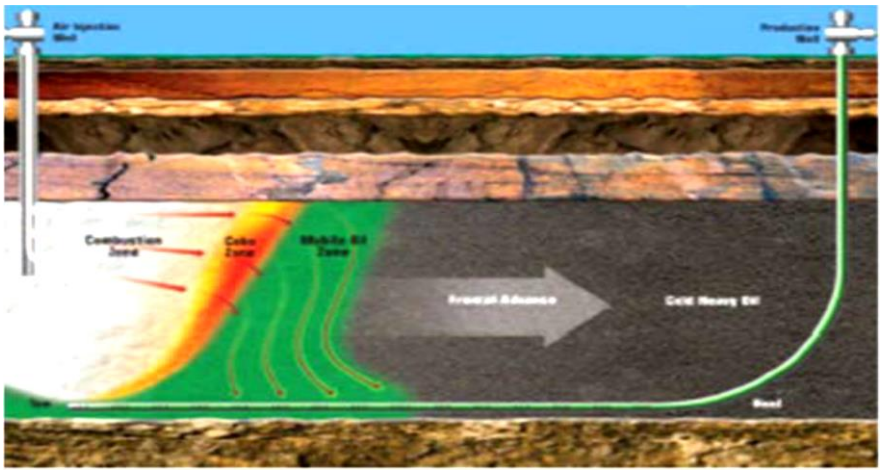


Figure-2.3: In-Situ Combustion [10].

In this process, care should be taken with parameters such as combustion temperature and gravitational segregation of the gases that leads to early combustion zone breakthrough in the producers. This is not as successful as steam-flood operation, but it is more effective for moderately thick reservoirs with viscous oils. The methods used in in-situ combustion can be divided as-Forward combustion methods: dry combustion, wet combustion, and reverse combustion methods [2].

2.3.1 Dry Forward Combustion

The most commonly used form of the combustion process is simple air injection. It is called dry combustion to distinguish it from wet combustion, in which water and air are injected together [2].

2.3.2 Wet Combustion

Wet combustion is the process in which water passes through the combustion front along with the air and always applied to forward combustion. The water entering the combustion zone may be either in the liquid or vapor phase, or both [2].

2.3.3 Reverse Combustion

In this process, air is injected through ignition wells that eventually become oil producing wells. Initially, the reverse combustion process starts as forwarding combustion process. After the burning zone moves within a short distance from the ignition well, air injection is stopped in the ignition wells, and it is started in adjacent wells. The air injection is continued in the adjacent wells in order to drive the oil towards the wells which previously were ignition wells. The combustion front moves in the opposite direction towards the adjacent wells. The oxygen required for combustion is only supplied by air, which is continuously injected into the adjacent wells [2].

Running this method might be risky due to the probability of decomposition of the rock and production of carbon dioxide at high temperatures. Besides all the concerns, economy and instrumentation requirements are other considerations that should come into account. The most significant operation problems affecting recovery from heavy oil reservoirs using vertical-vertical good pattern in situ combustions are [7]:

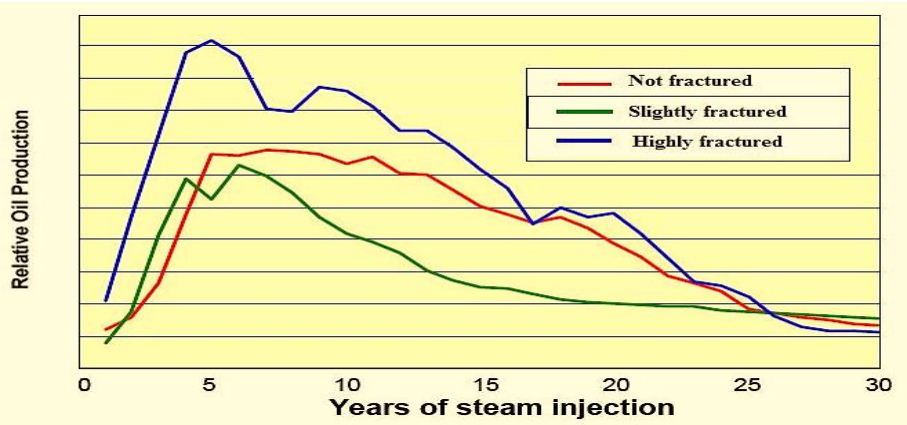


Figure-2.3.3: Effect of fracture intensity on oil recovery of steam injection [7].

(a) Gravity segregation, or gas overriding, due to the difference between the gas and oil densities. (b) Channeling, due to the unfavorable rock heterogeneity. (c) Unfavorable gas/oil mobility ratio.

THAI 'Toe-to- Heel Air Injection' is an EOR process which integrates into situ combustion and advanced horizontal well concepts. In this process, a horizontal well is used as oil producer at the bottom of the reservoir, and a vertical well is employed as air injector at the top and near the end (toe) of the horizontal well. The air injected into the vertical well generates the combustion front that burns part of the oil and releases heat. The heat reduces the oil viscosity inside the reservoir, which flows to the horizontal well at

the bottom, due to gravity. The combustion front sweeps from the end of the horizontal producer (toe) up to the heel, leading to recoveries of oil up to 80%. Investigations reveals that during the first hours of the operation the oil recovery from the fractured medium is higher due to ease of production from fracture while later production from the fractured medium will be limited to the production of oil from the matrix which is controlled by diffusion of the oxygen into the matrix and expansion of the oil from the matrix [7, 15].

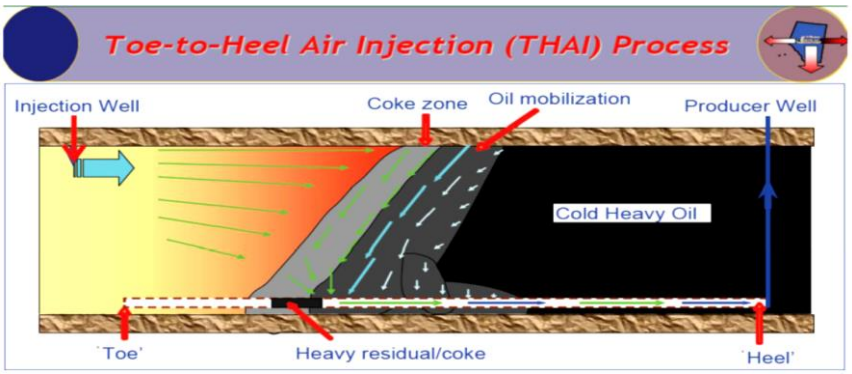


Figure-2.3.4: THAI Recovery Process [10].

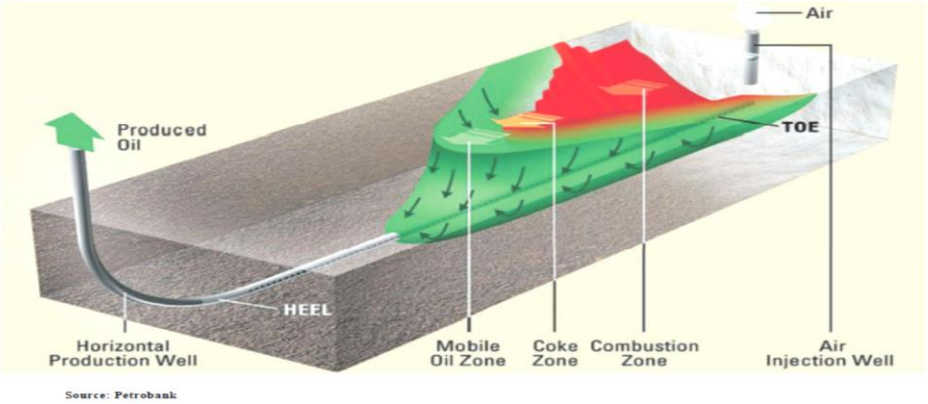


Figure-2.3.5: THAI 3-D Process Illustration. [10]

2.4. Steam-assisted gravity drainage (SAGD)

Steam-assisted gravity drainage (SAGD) and its variations are technologies that have been recently considered as more effective in the recovery of heavy oil and bituminous sands. The method involves two horizontal parallel wells vertically separated by a short distance, where the top well serves as steam injector and the bottom well picks up reservoir water, condensed water, and heated oil. Gravity is the acting force in this process. When steam is continually injected at the top well, oil is heated up and forms a steam chamber that grows up and towards the surroundings, as can be observed in Figure 10.This technology is characterized by high production capacity, high oil/ gas ratio, high final recovery factor, reduced inter-well interference and minimized premature inter-well channeling. To make an SAGD process successful, a steam circulation process for both the injection and production wells, in a period of about three months is required to establish the communication between injection and production wells [3, 8, 9].

In early 2005, SAGD development involving a combination of vertical well and horizontal well was implemented successfully in Guantao Formation (with an average depth of 600m) as can be seen in figure 2.4 and 2.4.1 respectively. At the same time, favorable SAGD development performances have been obtained through dynamic tracing and optimization. The trend of production reduction has been turned and productivity increased together with enlargement of the steam chamber [8].

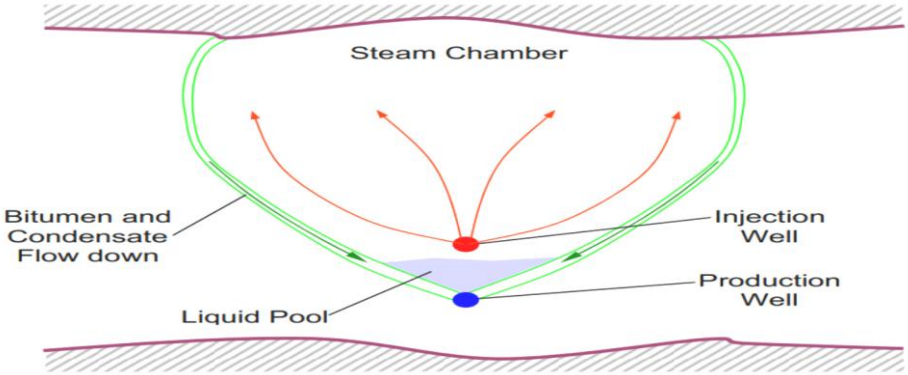


Figure-2.4: Illustration of the steam chamber cross-section in SAGD process [3].

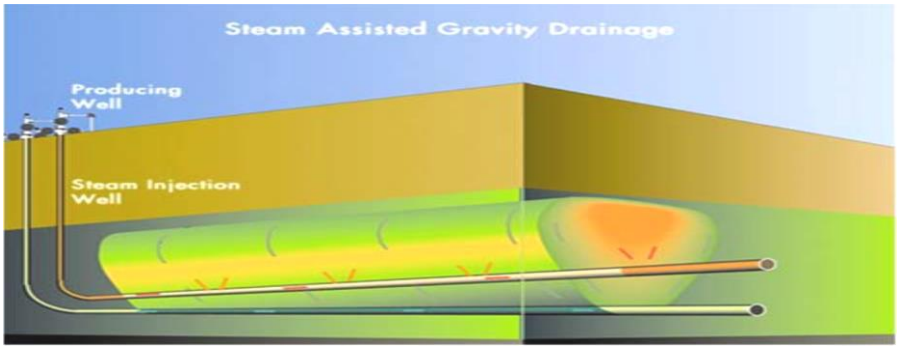


Figure-2.4.1: SAGD Process [10].

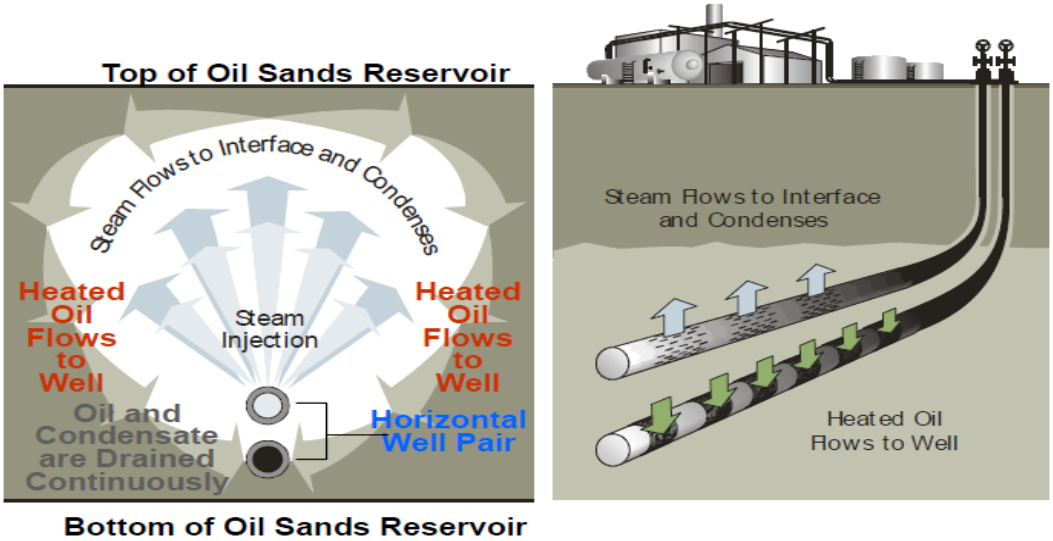


Figure-2.4.2: SAGD (Steam Assisted Gravity Drainage Process) [10].

The temperature inside the steam chamber becomes essentially equal to the temperature of the injected steam. It is noticed that steam condenses at the interface with cold oil and heat is transferred to the oil. Then, heated oil and condensed water drain by gravity, until the producing horizontal well located at the bottom of the reservoir.

In this process, the steam chamber begins to grow upward approaching the reservoir top and later extends horizontally. If the injector well is located very close to the producer, at the base of the reservoir, the vapor will tend to go up, and condensed fluids will go down. Therefore, the trend of the steam to flow directly to the producing well will be reduced. As a result, the SAGD process provides the drainage of a large area of the reservoir. This process depends mainly on the difference of densities between the steam chamber and the liquid phase, and also on the vertical effective permeability of the reservoir [9].

Compared to conventional steam injection, SAGD presents a very significant advantage: in continuous injection, oil is pushed into a cold region, and its mobility is low since it stays ahead of the steam zone. However, in the SAGD process, oil is drained in a flow which is approximately parallel to the steam chamber, still arriving at the producer at warm temperatures, and, consequently, with high mobility. In addition to the benefits of the gravity effects, this process foresees more systematic steam coverage of the reservoir,

provides a larger contact of oil volume and keeps the oil warm during production. The SAGD performance can be significantly affected by the selection of the geometry and by the operational parameters (Barillas, 2006). Examples of this can be vertical distance between wells, the horizontal length of both injector and producer wells, the presence of shale, permeability, oil viscosity, Aquifer Characteristics, gas cap, and others [9].

As another version of SAGD is that the horizontal oil production wells are placed perpendicular to the injection wells. With a mechanism combining gravity drainage and lateral displacement, the XSAGD method is suggested that it could realize better. [3]

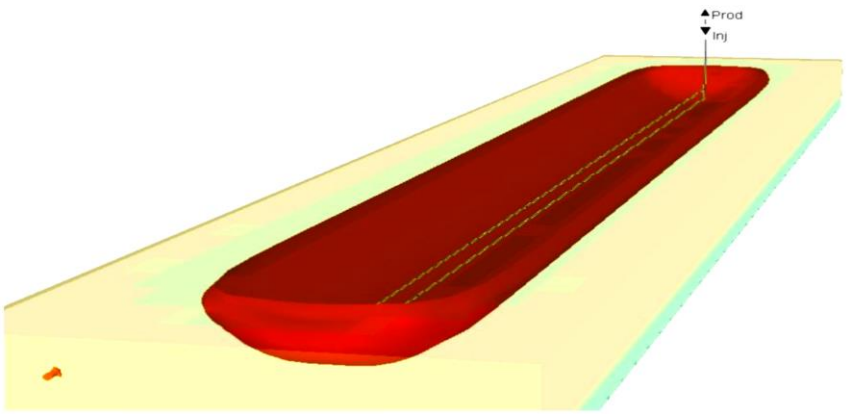


Figure-2.4.3: SAGD process in a homogeneous reservoir [9].

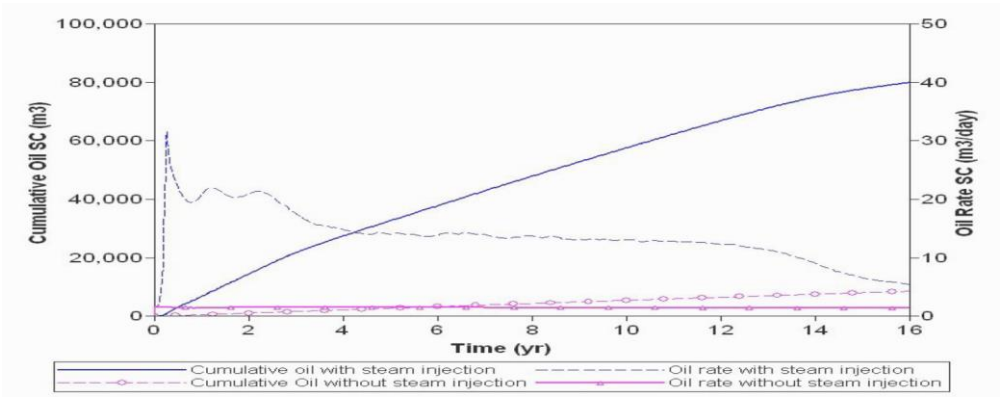


Figure-2.4.4: Cumulative oil and oil rate in 16 years of production in a model with SAGD and without steam injection [9].

Figure 2.4.3 shows an example of the SAGD process in a homogeneous reservoir. Figure 2.4.4 compares the SAGD process with cold production in terms of cumulative oil and oil rate. It can be seen that the SAGD process improves both cumulative oil and oil rate. In summary, Associated Steam Assisted Gravity Drainage (SAGD) technologies are mainly composed by following four standalone technologies [8]:

• High-efficient gas-water separation technologies
• SAGD intermittent steam injection technologies
• SAGD high-temperature high-duty pump uplifting technologies
• Heat-exchanging and metering technologies for produced fluids.

2.4.1. Steam-Solvent Hybrid.

A small amount of solvent injected with steam in SAGD or CSS to improve performance and reduce water usage and GHG emission.

• ES-SAGD - Expanding Solvent SAGD
• SAP - Solvent-Assisted Process
• SA-SAGD - Solvent-Assisted SAGD
• SC-SAGD - Solvent Cyclic SAGD
• SCI - Solvent Co-Injection
• LASER - Liquid Addition to Steam to Enhance Recovery (in CSS) [10].

2.4.2. Solvent-aided/based recovery technologies [10].

2.4.2.1. Expanding solvent (ES-SAGD)

This process is a combination of solvent and steam injection that take advantage of the benefits from the heat provided by steam and the miscibility offered by the solvent. This is a novel process that has already been tested in oil fields, resulting in improvement of oil rate production and steam oil ratio (SOR). This process requires less energy than conventional SAGD.
The basic concept of ES-SAGD can be pictorially observed in Figure 9. The idea in this process is to inject a light hydrocarbon additive at low concentration together with steam, in a process whereby the dominant force is gravity. The additive is selected in such way that can evaporate and condense at water conditions. In this way, the solvent can condense with steam close to the steam chamber interface. The added hydrocarbon is injected in the vapor form. The condensed solvent dilutes in oil and, aided by the heat, reduces the oil viscosity in the reservoir [9].

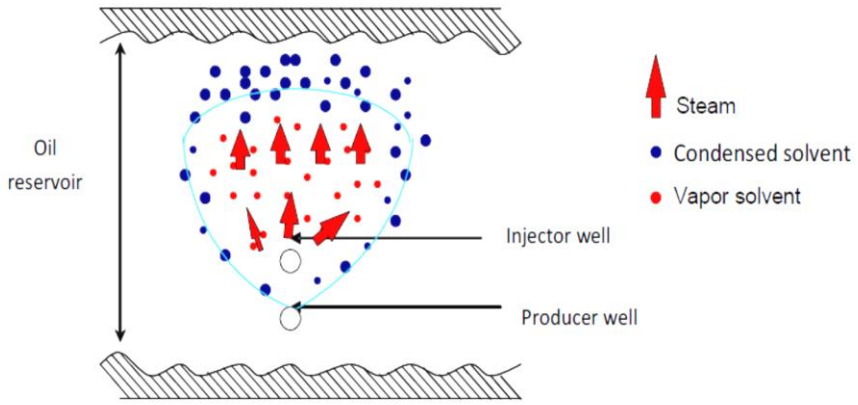


Figure-2.4.2.1: Basic theory of ES-SAGD [9].

The one major disadvantage to using ES-SAGD process which is the solvent retention in the reservoirs. Since solvents are more expensive than bitumen, it is therefore critical to ensure a high recovery of the solvent injected. Similar to SAGD process, it is challenging to apply ES-SAGD process to thin heavy reservoirs [3].

2.5. Emerging Recovery Technologies (Non-Steam) [10].

- VAPEX (*Vap*or *Ex*traction)
- JIVE (Joint Implementation of Vapor Extraction)
- N-Solv.
- ET-DSP (*E*lectro-*T*hermal *D*ynamic *S*tripping *P*rocess)
- ESEIEH (Enhanced Solvent Extraction Incorporating Electromagnetic Heating)

2.5.1. Vapor extraction (VAPEX)

For thin heavy oil reservoirs typically found in Northeastern Alberta and Southwest Saskatchewan, solvent based Vapor Extraction (VAPEX) method has been proposed and investigated for heavy oil and bitumen recovery. The vapor extraction (VAPEX) process, introduced by Butler and Mokrys as an alternative in-situ EOR method to SAGD, has been studied theoretically and experimentally in conventional, non-fractured systems [4, 7]. In the VAPEX process, a mixture of solvent vapor is injected into the reservoir through a horizontal injection well located in the upper oil zone and forms a solvent vapor chamber as shown in figure2.5.1. With the effective mixing of the bitumen and solvent at the edge of the chamber, the bitumen viscosity is significantly reduced and mobilized bitumen flows towards the lower production well under gravitational force along the edge of the solvent vapor chamber. The solvents are carefully chosen (e.g. ethane, propane, butane, etc.) so that they can form a vapor phase without additional heat at reservoir conditions. The injected solvent is dissolved into the bitumen by diffusion to reduce the oil viscosity and mobilize the oil. Due to the absence of heat loss to over-burden and under-strata, the VAPEX is suggested to be a more economic process, especially for thin heavy oil reservoirs. However, they also hold some disadvantages. For instance, compared with SAGD process, production rates of VAPEX process are lower due to the relative slow diffusion-based mixture process. There have been efforts in making VAPEX a more efficient heavy oil recovery method. Butler proposed that hot water can be injected along with the solvent vapor. As illustrated in Figure 2.5.2 below. The injection of hot water enables distribution of heat laterally away from the injection well to the reservoir.
This process is found to be a promising alternative to thermal processes. However, little information is available on the performance of the VAPEX process in fractured reservoirs [7].
The preliminary studies on the VAPEX process in fractured systems included a single block matrix surrounded by fractures. It was found that due to differences in the matrix and fracture permeability in the fracture system, the solvent first spreads through the fractures and then starts diffusing into the matrix from all parts of the matrix [7, 16].

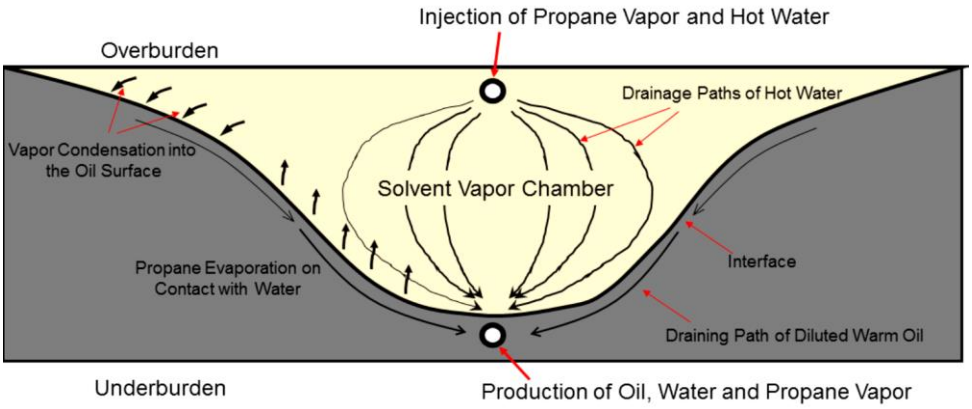


Figure-2.5.1: Illustration of solvent vapor chamber in VAPEX process [4].

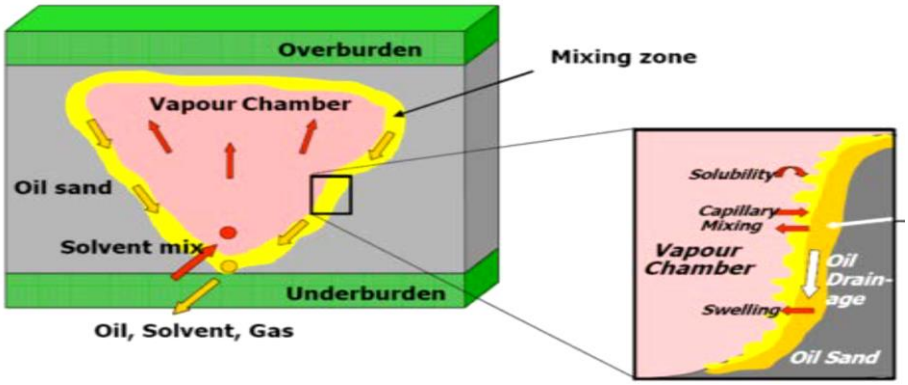


Figure-2.5.2: Solvent Processes (vapex) [10].

However, up to date, the success of VAPEX in laboratories has not been transferred into applications of VAPEX in commercial projects. This is possibly due to the low drainage rates and high solvent to oil ratio which are not promising enough to ensure the VAPEX to be economically viable [4].

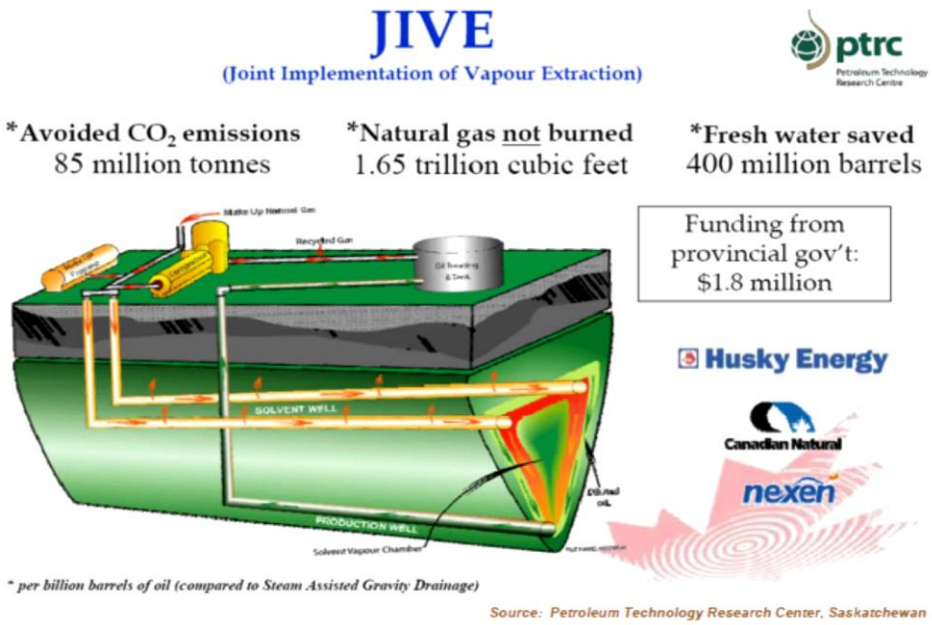


Figure-2.5.1.1: The JVE Project [10].

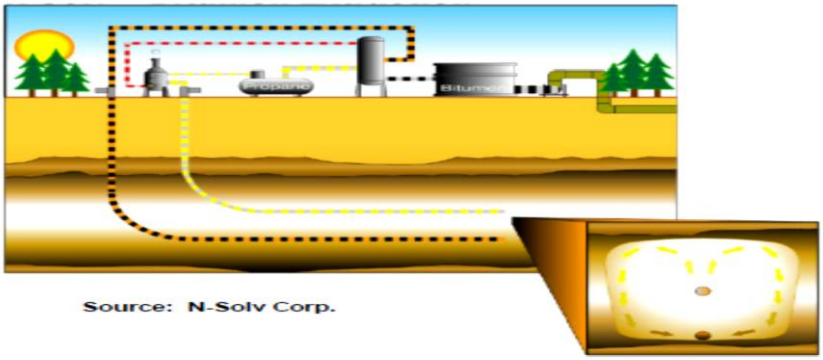


Figure-2.5.1.2: N-Solv [10].

• Similar to VAPEX but use heated solvent vapor
• Energy consumption and greenhouse gas significantly lower than SAGD
• Extraction rate 40-50 times faster than VAPEX (benchmark test)
• Upgraded product (from 7-8 0API to 13-17 0API)
• 500 b/d pilot near Fort MacKay at MacKay River site in progress [10].

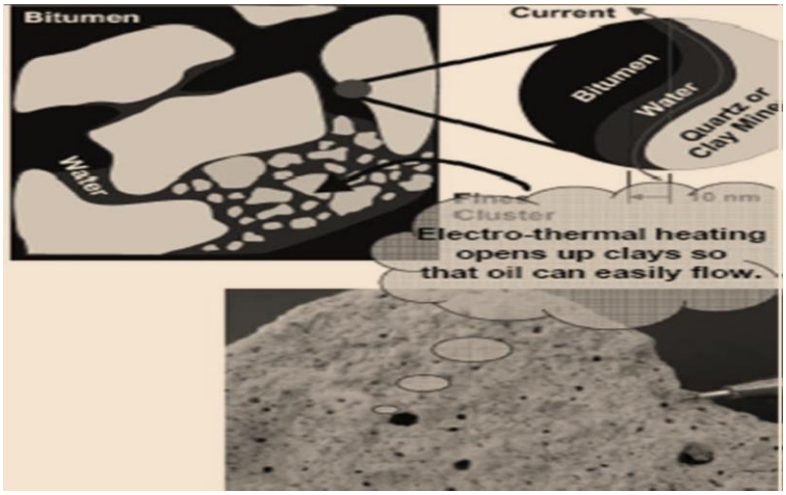


Figure-2.5.1.3: ET-DSP (Electro-Thermal Dynamic Stripping Process) [10].

2.5.3. ESEIEH (Enhanced Solvent Extraction Incorporating Electromagnetic Heating).
• SAGD well configuration with an antenna
• Preheat reservoir by Electromagnetic (EM) Heating
• Solvent Injection with continuous EM heating
• Partners: Suncor, Nexen, Laricina, Harris Corp [10].

3. CONCLUSIONS

At the end of the research on thermal enhanced heavy oil recovery methods, the following sum up conclusions holds;

1. In-situ recovery technologies are swiftly emerging with the promise to provide high recoveries for all bitumen environments.
2. SAGD principles are being extended with solvents and other heating techniques.
3. Emerging technologies carry the promise of both elevating bitumens in-situ with a significantly reduced environmental effect.
4. The selected process always depends on reservoir characteristics, reservoir fluids, area and experience from related reservoirs.
5. Numerical analyses, reservoir modeling and profitability analyses are continually required in order to determine which process is more effective.
6. Cold production (without sand) is not applicable to the thin heavy oil reservoir. Depletion of reservoir pressure and high water saturation make the oil production rate low and recovery factor less than 1%.

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