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Analytical Study on Feasibility of Applying Vapor Extraction Method for Sudanese Heavy Oil Reservoir

دراسة تحليلية لجدوي تطبيق طريقة الاستخلاص بالبخارالهيدروكربوني لمكمن نفط ثقيل بالسودان

A Research Submitted in Partial Fulfilment for Degree of M.Sc. in Petroleum Engineering

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April 2021

Dedication:

This thesis is dedicated to my parents, my daughters and my wife. For their love, endless support and encouragement. They have always been helpful and guided me towards the right way without them I would never have achieved everything in my life. The moral support from my brothers and Sisters also helped me a lot. I am always thankful to The Allah Almighty for blessing me with such a caring family.

Acknowledgement:

I would like to thanks everyone who helped me throughout this thesis and supported me in every way possible. I would like to directly acknowledge the following individuals and organizations:

Prof. Babiker Karama Abdalla, my supervisor, for his excellent guidance, valuable advice, strong support, and continuous encouragement throughout this thesis study.

Eng. Ahmed Albushari, for his useful technical discussion and assistance during the early stage of this thesis.

College of Petroleum Engineering and Technology, Department of Petroleum engineering at Sudan University of Science and Technology for their support and guidance.

My colleagues at Greater Nile Petroleum Operating Company GNPOC, Development Department, and 2B Operating Company 2B OPCO, Exploration & Development Department for their valuable technical discussion, support, and guidance throughout this thesis study.

Abstract:

World's conventional oil reservoirs are depleting on an alarming rate and alternative sources must be found to keep the supply undisturbed. Currently the best alternative is the heavy oil which can be extracted by applying techniques which are different from the conventional methods. Sudan have large amount of heavy oils which aren't extracted yet, and need the applications of new technologies to be extracted. In this research reservoir and crude oil properties data has been collected and analyzed to study the feasibility of applying vapor extraction process (VAPEX) to Sudanese heavy oil field. In vapor extraction process a pair of horizontal wells will be drilled one on the top of the other, and vapor of light hydrocarbon solvent are to be injected into the upper horizontal well. The vapor diffuses into the heavy oil causing reductions in viscosity, and makes it easier for oil to flow by gravity to the lower horizontal well. This research attempts to provide some initial understanding and evaluation tool for the potential of applying VAPEX process in heavy Sudanese crude oil reservoirs. Based on the results obtained it could be possibly applied.

Butler and Mokrys analytical model of VAPEX process had been applied in the area of study to predict the initial oil rate from VAPEX process. New technologies such as Cyclic Steam Stimulation (CSS) and Multifunctional Chemical Agent (MFCA) also had been applied before in the area of study. Then the results of VAPEX process had been compared with the previous results of new technologies (CSS and MFCA), the result obtained from the VAPEX process was promising from technical point of view. While from an economical point of view it should be taken into account that in the CSS and the MFCA implementation was on the existing wells no need for drilling new wells. Regarding the VAPEX process it need to drill a pair of horizontal wells or to drill horizontal well and convert vertical wells to injectors. So the additional cost should be taken into account. The Recovery factor of the field can be enhanced significantly by applying the VAPEX process technology compared with the other technologies which were already been applied. Finally the optimum pilot area for applying the VAPEX process was proposed according to the simulation results.

المستخلص:

مكامن النفط التقليدية في العالم تستنفد بمعدل ينذر بالخطر ويجب إيجاد مصادر بديلة للحفاظ على الإنتاج دون انقطاع. أفضل بديل حالياً هو الاعتماد على الزيت الثقيل الذي يمكن إستخراجه بتطبيق تقنيات مختلفة عن الطرق التقليدية، السودان لديه كميات كبيرة من النفط الثقيل الذي لم يتم استخراجه بعد، والذي يحتاج إلى تطبيق تقنيات جديدة لاستخراج؛ في هذا البحث تم جمع وتحليل بيانات المكمن وخواص النفط الخام لدراسة جدوى تطبيق عملية الإستخلاص بالبخار (VAPEX) على حقول النفط الثقيل السودانية، معروف تقليدياً في عملية الإستخلاص بالبخار يتم حفر زوج من الآبار الأفقية أحدهما فوق الآخر ويتم حقن البخار الهيدروكربوني الخفيف في البئر الأفقي العلوي ومن ثم ينتشر البخار الهيدروكربوني في الزيت الثقيل مما يؤدي إلى إنخفاض لزوجةالزيت الخام، ويسهل حركة النفط عن طريق الجاذبية للبئر الأفقي السفلي في هذا البحث تم تقديم بعض المفاهيم الأولية ومدى إمكانية تطبيق عملية الإستخلاص بالبخار في خام النفط السوداني الثقيل، وبناءاً على النتائج التي تم الحصول عليها من هذا البحث يمكن تطبيق عملية الأستخلاص بالبخار في الحقول السودانية؛ تم تطبيق نموذج بتلر ومكريس (Butler and Mokrys) التحليلي لعملية الاستخلاص بالبخار في منطقة الدراسة للتنبؤ بمعدل جريان الزيت من عملية الإستخلاص بالبخار، كما تم من قبل تطبيق تقنيات جديدة لإستخلاص النفط الثقيل مثل التحفيز الدوري للبخار (CSS) والعامل الكيميائي متعدد الوظائف (MFCA) في منطقة من الدراسة. ثم تمت مقارنة نتائج عملية الإستخلاص بالبخار مع النتائج السابقة للتقنيات الجديدة المطبقة في منطقة الدراسة، وكانت النتيجة التي تم الحصول عليها من عملية الاستخلاص بالبخار واعدة من الناحية الفنية، ولكن من الناحية الاقتصادية يجب أن يأخذ في الاعتبار ان تنفيذ التحفيز الدوري CSS والعامل الكيميائي متعدد الوظائف MFCA يتم على الآبار الحالية و لا حاجة لحفر آبار جديدة، ولكن في عملية الإستخلاص بالبخار فإننا نحتاج إلى حفر زوج من الآبار الأفقية او حفر بئر افقية وتحويل بعض الأبار الرأسية الي أبار حقن، لذلك يجب أن تأخذ التكلفة الإضافية في الاعتبار يمكن تحسين معدل الإستخلاص لمنطقة الدراسة بشكل كبير من خلال تطبيق عملية الإستخلاص بالبخار مقارنة بالتقنيات الأخرى التي تم تطبيقها من قبل، وأخيرًا تم إقتراح المنطقة التجريبية المثلى لتطبيق عملية الإستخلاص بالبخار وفقاً للنتائج التي تم الحصول عليها.

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LIST OF SYMBOLS / ABBREVIATIONS

EOR	Enhanced Oil Recovery
IOR	Improved Oil Recovery
OOIP	Original Oil In Place
SAGD	Steam Assisted Gravity Drainage
S_{or}	Residual Oil Saturation
Nc	Capillary Number
M	Mobility Ratio
ASP	Alkaline Surfactant Polymer
MEOR	Microbial Enhanced Oil Recovery
API	American Petroleum Institute
GNPOC	Greater Nile Petroleum Operating Company
PDOC	Petrodar Operating Company
KBOPD	Thousand Barrel Oil per Day
WNPOC	White Nile Petroleum Operating Company
OEPA	Oil Exploration and Production Authority
STOIIP	Stock Tank Oil initial In Place
SEMAR	Smart ChEmical Modifier for Accelerated Recovery
PI	Production Index
BBW	Bamboo West
CSS	Cyclic Steam Stimulation
STB	Stock Tank Barrel
FNE	Fula North East Field
BOPD	Barrel Oil per Day
VAPEX	Vapor Extraction Process
MFCA	Multi-functional chemical agent

THAI	Toe to Heal Air Injection
ES-SAGD	Expandable Solvent – Steam Assisted Gravity Drainage
MMSTB	Million Stock Tank Barrel Oil
NPV	Net Present Value

CHAPTER I

INTRODUCTION

As conventional crude oil production declines, bitumen and heavy oil reserves have become increasingly important to world's oil supply, however the main difficulty in producing these vast reserves is bitumen, which is immobile under reservoir conditions due to its high viscosity (greater than 1000 cp under reservoir condition) and costly to produce and refine, as general rule the heavier or denser crude oil the lower its economic value. Heavy crude oils tend to have higher content ratio of metals and other elements, requiring more effort and expense to extract useable products and dispose of waste.

Heavy oil and Bitumen is located in several parts of the world (Figure 1.1) such as Canada, Venezuela, and Russia each possessing more than one trillion barrels in place (Smalley, 2000).

Figure 1.1 Major heavy oil and bitumen resources (Smalley, 2000)

1.1   Oil Recovery Processes:

Oil recovery processes may be subdivided into three major categories, Primary, Secondary, and Enhanced Oil Recovery. These terms are traditionally used to describe hydrocarbons recovered according to the method of production or the time at which they are obtained (Tarek Ahmed, 2018).

1.1.1 Primary Recovery Process:

Primary recovery is the recovery of oil by any of the natural drive mechanisms, the term refers to the production of hydrocarbons from a reservoir without use of any process (such as fluid injection) to supplement the natural energy of the reservoir (Tarek Ahmed, 2018).

During primary recovery the natural energy of the reservoir is used to transport hydrocarbons towards and out of the production wells. There are several different energy sources, and each gives rise to a drive mechanism. Early in the history of a reservoir the drive mechanism will not be known. It is determined by analysis of production data (reservoir pressure and fluid production ratios). The earliest possible determination of the drive mechanism is a primary goal in the early life of the reservoir, as its knowledge can greatly improve the management and recovery of reserves from the reservoir in its middle and later life (Nabilou, 2016).

There are five important drive mechanisms (or combinations):

- Water drive
- Gas cap drive
- Solution gas drive
- Gravity drainage
- Reservoir compaction
- Combination or mixed drive

1.1.2 Secondary Recovery:

Secondary oil recovery refers to the additional recovery that results from the conventional methods of water injection and immiscible gas injection. Usually, the selected secondary recovery process follows the primary recovery but it can also be conducted concurrently with the primary recovery. Water flooding is perhaps the most common method of secondary recovery. However, before undertaking a secondary recovery project, it should be clearly proven that the natural recovery processes are insufficient; otherwise there is a risk that the substantial capital investment required for a secondary recovery project may be wasted. (Tarek Ahmed, 2018)

1.1.3 Enhanced Oil Recovery (EOR):

Enhanced oil recovery is that additional recovery over and above what could be recovered by primary and secondary recovery methods. Various methods of enhanced oil recovery (EOR) are essentially designed to recover oil, commonly described as residual oil, left in the reservoir after both primary and secondary recovery methods have been exploited to their respective economic limits (Tarek Ahmed, 2018). Figure 1.2 illustrates the concept of the three oil recovery categories (Tarek Ahmed, 2012).

The target of EOR varies considerably by different types of hydrocarbons. Figure 1.3 shows the fluid saturations and the target of EOR for typical light and heavy oil reservoirs. For light oil reservoirs, EOR is usually applicable after secondary recovery operations with an EOR target of approximately 45% original oil in place (OOIP). Heavy oils respond poorly to primary and secondary recovery methods, and the bulk of the production from these types of reservoirs come from EOR methods (Tarek Ahmed, 2012). The diagram of oil recovery processes are illustrated in Figure 1.4.
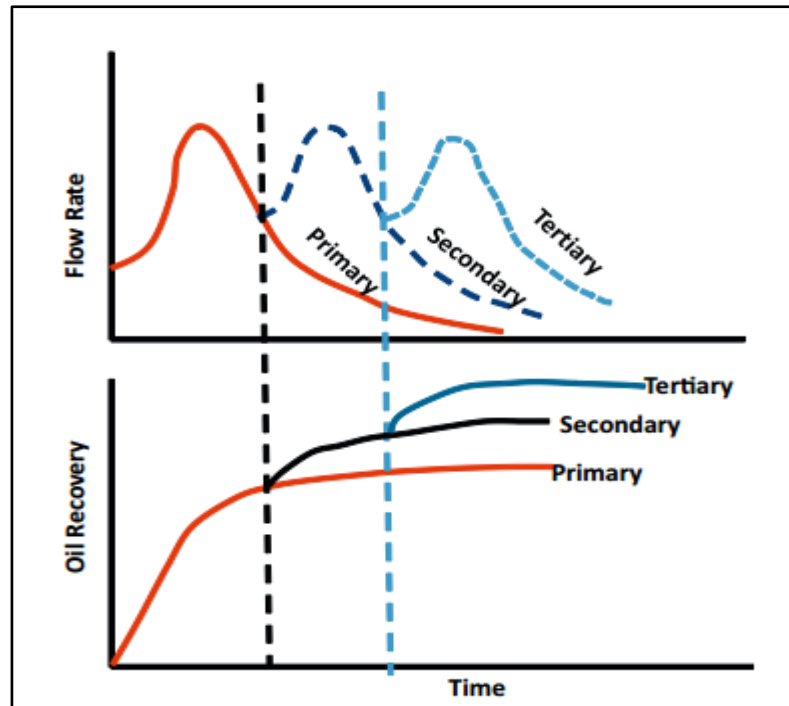
FIGURE 1.2 Oil recovery categories (Tarek Ahmed, 2012).
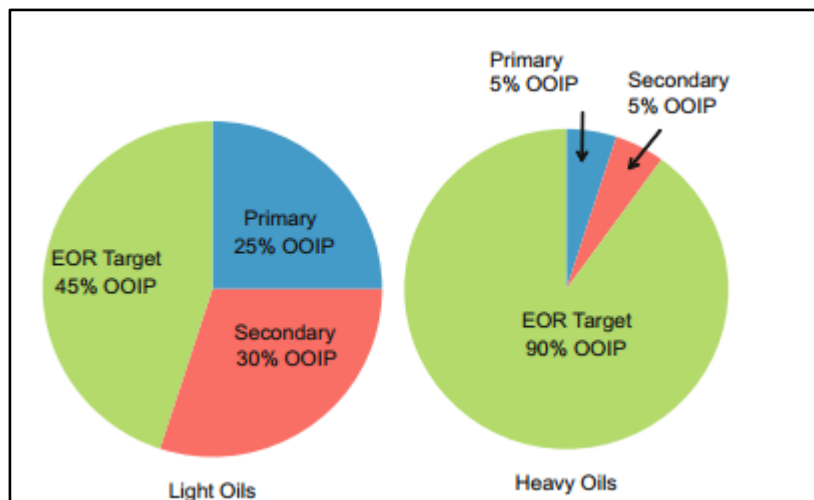
FIGURE 1.3 Target for different crude oil systems (Tarek Ahmed, 2012).
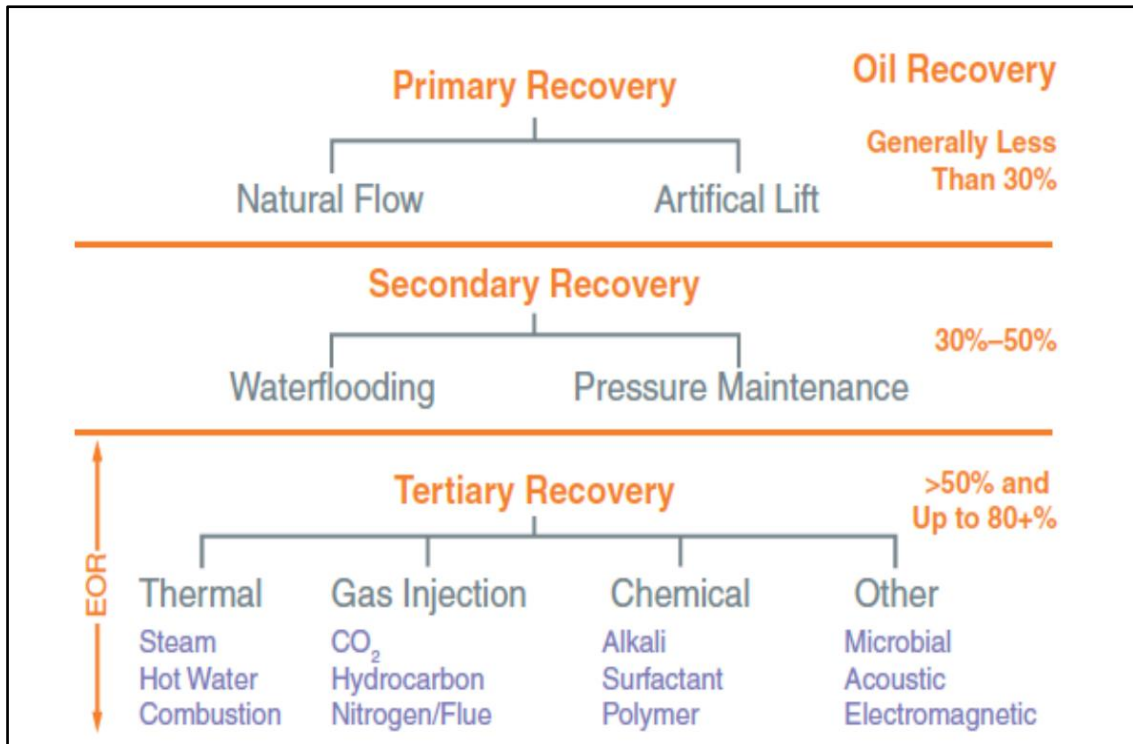
FIGURE 1.4 Oil recovery stages and the corresponding oil recovery factor
(Abu baker H. Alagorni, 2015)

EOR implies a reduction in oil saturation below the residual oil saturation (S_{or}). Recovery of oils retained due to capillary forces (after a water flood in light oil reservoirs), and oils that are immobile or nearly immobile due to high viscosity (heavy oils and tar sands) can be achieved only by lowering the oil saturation below Sor. Miscible processes, chemical floods and steam based methods are effective in reducing residual oil saturation (S. Thomas, 2008).

Mobilization of residual oil is influenced by two major factors: Capillary Number (Nc) and Mobility Ratio (M). Capillary Number is defined as Nc = v µ/ϭ, where v is the Darcy velocity (m/s), µ is the displacing fluid viscosity (Pa.s) and ϭ is the interfacial tension (N/m). The most effective and practical way of increasing the Capillary Number is by reducing ϭ, which can be done by using a suitable surfactant or by the application of heat (S. Thomas, 2008).

Mobility ratio is defined as $M = \lambda_{ing} / \lambda_{ed}$, where λ_{ing} is the mobility of the displacing fluid (e.g. water), and λ_{ed} is the mobility of the displaced fluid (oil). ($\lambda = k/\mu$, where k is the effective permeability, (m2) and μ is the viscosity (Pa.s) of the fluid concerned). Mobility ratio influences the microscopic (pore level) and macroscopic (areal and vertical sweep) displacement efficiencies. A value of $M > 1$ is considered unfavourable, because it indicates that the displacing fluid flows more readily than the displaced fluid (oil), and it can cause channelling of the displacing fluid, and as a result, bypassing of some of the residual oil. Under such conditions, and in the absence of viscous instabilities, more displacing fluid is needed to obtain a given residual oil saturation (S. Thomas, 2008).

EOR methods have been developed are designed to increase the capillary number. In general, EOR technologies can be broadly grouped into the following four categories (Tarek Ahmed, 2012):

Thermal:

- Steam injection (Cyclic steam stimulation, Steam flooding & Steam-assisted gravity drainage SAGD).
- In situ combustion (Forward combustion, Reverse combustion, &Wet combustion).

Chemical Flooding:

- Polymer
- Surfactant slug
- Alkaline
- Micellar
- Alkaline-surfactant-polymer (ASP)

Miscible:

- CO_2 injection
- Lean gas
- N_2
- Rich gas
- WAG flood

Others:

- MEOR
- Foam

As a first step in selecting and implementing an enhanced oil recovery method, a screening study should be conducted to identify the appropriate EOR technique and evaluate its applicability to the reservoir. Taber et al. (1997) proposed screening criteria for enhanced oil recovery methods that were developed by compiling numerous data from EOR projects around the world. Based on extensive analysis of the collected data, the authors listed the optimum reservoir and oil characteristics that are required for implementing a successful EOR project in a particular field, as shown in Table 1.1.

Table 1.1 Screening Criteria for EOR Methods (Taber et al., 1997)

TABLE 1.1	Summary of Screening Criteria for EOR Methods	
Process	Crude Oil	Reservoir
N2 and flue gas	> 35 API < 1.0 cp - High percentage of light hydrocarbons	- So > 40% - Formation: SS or carbonate with few fractures - Thickness: relatively thin unless formation is dipping - Permeability: not critical - Depth > 6000 ft. - Temperature: not critical
Chemical	> 20 API < 35 cp - ASP: organic acid groups in the oil are need	- So > 35% - Formation: SS preferred - Thickness: not critical - Permeability > 10 md - Depth < 9000 ft. (function of temperature) - Temperature < 200 F
Polymer	> 15 API < 100 cp	- So > 50% - Formation: SS but can be used in carbonates - Thickness: not critical - Permeability > 10 md - Depth < 9000 ft. - Temperature < 200 F
Miscible CO_2	> 22 API < 10 cp - High percentage of intermediate components (C5C12)	- So > 20% - Formation: SS or carbonate - Thickness: relatively thin unless dipping - Permeability: not critical - Depth: depends on the required minimum miscibility pressure "MMP"
First-contact miscible flood	> 23 API < 3 cp - High Cm	- So > 30% - Formation: SS or carbonate with min fractures - Thickness: relatively thin unless formation is dipping - Permeability: not critical - Depth > 4000 ft. - Temperature: can have a significant effect on MMP
Steam flooding	10 - 25 API < 10,000 cp	- So > 40% - Formation: SS with high permeability - Thickness > 20 ft. - Permeability > 200 md - Depth < 5000 ft. - Temperature: not critical
In situ combustion	10 - 27 API < 5000 cp	- So > 50% - Formation: SS with high porosity - Thickness > 10 ft. - Permeability > 50 md - Depth < 12,000 ft. - Temperature > 100 F

1.2   EOR in Sudan:

Sudan has been producing its petroleum resource commercially since 1999 when block 1/2/4 started production of its locked oil reserve. This was the major achievement by operator, GNPOC, when they commercialize and export crude to foreign buyers via 1500 km new pipe line to Port Sudan. Since then, its daily production has increase to maximum of 300 KBOPD in 2006 before it started declining rapidly with increasing water production. Three more operators, petro-energy, PDOC, and WNPOC started their oil production in 2006 (Khider, 2011).

EOR potential evaluation had been conducted for both GNPOC and PDOC fields in Sudan, from the initial EOR screening, the most amenable EOR processes identified for both GNPOC and PDOC are mainly chemical and thermal EOR. Chemical EOR is the leading EOR process in GNPOC fields while thermal EOR is the leading EOR process in PDOC fields (Wang Qiang et al., 2013).

Chemical EOR evaluation was performed using Eclipse EOR black oil simulator. Simulations were performed on sector models constructed or extracted from full field models which have been conditioned to the current reservoir condition. The chemical input data was referenced mainly from Qing Hai oil field lab data which oil properties are similar to that of Sudan's. The chemical EOR evaluation encompass 3 different types of chemical processes; polymer flooding, surfactant-polymer (SP) flooding and alkaline-surfactant-polymer (ASP) flooding. Chemical EOR can potentially improve field recovery factor between 4-18% depending on the type of chemical EOR process. ASP flooding possess the highest potential with incremental oil recovery over water flooding ranging between 12%-18% followed by SP flooding and polymer flooding. ASP flooding is taken as the reference chemical process and it represent the highest chemical potential (Wang Qiang et al., 2013).

Gas EOR is generally not suitable for fields in Sudan due to the unavailability of gas source for some fields. Oil in both GNPOC and PDOC field is mostly dead oil. There is no sufficient associated gas that could support gas EOR. Greater Neem is reported to have CO_2 but the volume is not significant enough to implement a CO_2 EOR. Nitrogen gas though is abundant in the air is also not suitable. Viscosity of oil in Sudan ranges between 3cp to as high as 450cp. Nitrogen on the other hand has very low density and viscosity as compared to the oil in Sudan. The adverse mobility ratio and the difference in density between oil and gas will result in very poor sweep efficiency due to severe viscous fingering and gravity segregation, translating into low incremental recovery (Wang Qiang et al., 2013).

As stated earlier Chemical EOR is the main EOR process in GNPOC while thermal EOR is the main EOR process in PDOC by screening. The Sudan oil fields can be grouped into two distinct groups when plotted on a temperature vs viscosity cross plot. The targets suitable for chemical EOR which have lower oil viscosity while the thermal targets which have high viscosity. Some of the chemical candidates have very high temperature will be parked under Phase 2 instead of chemical EOR.12 fields have been identified to hold EOR potential. The total target STOIIP for EOR for all the fields may be less than the total STOIIP because some of the reservoirs within the fields are not feasible for current EOR implementations for the very same reason of unfavourable reservoir conditions (Wang Qiang et al., 2013).

Chemical EOR SEMAR pilot project had been conducted in Bamboo Oil Field, and it considered as the first chemical EOR pilot laboratory study and implementation, Bamboo field is located in block 2A Muglad Basin in Sudan and it covers an area of 144 Square km. It consists of multi block, multi-layered under-saturated sandstone reservoir of late Cretaceous ages

barried at depth ranging from 1000 m to 1700 m with crude oil viscosity ranges from 70 cp to 3000 cp. The total Field STOIIP are estimated around 506 MMSTB, Among various Enhanced Oil Recovery (EOR) process and techniques, Bamboo reservoirs appear especially amenable to thermal injection process. But Sudapet, ITB and PERTAMINA (an especial study) came up with different solution which is Huff and Buff of Chemical EOR, This proved to be one of the practical, promising and potential options in enhancing the recovery factor in Bamboo Field (Ali Farog et al., 2016).

This chemical (SEMAR) when mix with heavy oil phase can generates an oil-rich colloidal dispersion which has low viscosity value. This type of chemical is also able to alter oil wetting to water wetting which can make oil mixture easy to flow in porous media, also the Combinations of micro emulsion effect, imbibitions effect and viscosity reduction caused by implementing SEMAR will improve PI significantly and increase oil production as shown in figure 1.4 (Ali Farog et al., 2016).
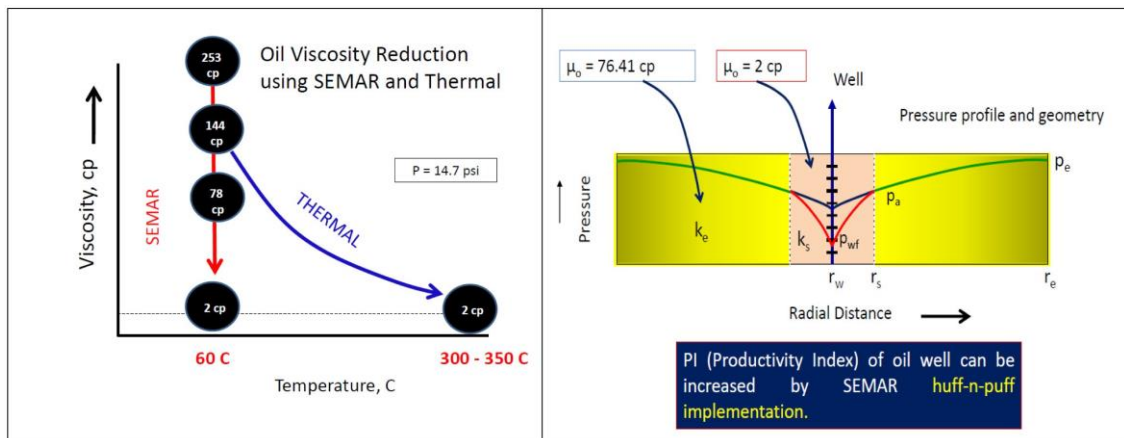
Figure 1.5 Oil Viscosity Reduction using SEMAR (Ali Farog et al., 2016)

Three wells has been selected for SEMAR huff and puff which are BBW-21, BBW-27 and BBW-23, After implementation of the pilot as Huff and Puff in the three wells the results show that about 18,000 STB of oil gained from adjacent wells, which indicate that SEMAR is very interesting to be

evaluated for further steps in chemical EOR implementation for continuous Injection (Ali Farog et al., 2016).

The first cyclic steam stimulation (CSS) pilot test in Sudan was at FNE Fula North East Field, FNE field is located in the East of Fula sub-basin, southeast of Sudan, with area of about 10.7 Km2, which was sub-divided into two small faulted blocks by a normal fault with uniform oil-water contacts. B reservoir is one of the major producing series in FNE field, taking 85% of total reserves. Burial depth of B reservoir is shallow, averaging 520 m, the porosity is ranging from 26% to 34%, and oil saturation ranging from 61% to 86% with permeability above 3000 md (Wang et al., 2011).

Crude oil properties falls into the category of heavy oil with API gravity being 18˚, and surface viscosities around 3500 mPa.s at 45˚ C. PVT analysis shows low GOR of 5 scf/bbl. B reservoir crude oil viscosity drops evidently with the increase of temperature in good exponential relationship, which is quite advantageous to the application of Cyclic Steam Stimulation (CSS) (Wang et al., 2011).

Well tests have shown low oil rates under cold production, averaging at 50-150 BOPD. Denser well spacing will be required if under cold production, which will be quite cost consuming. CSS generally could yield enhanced oil for heavy oil reservoirs. Therefore CSS pilot test on two wells began in 2009. Convincible results have been monitored with well daily rates 3-4 times of cold production wells with low water cut. Another six CSS wells further came on stream from July. 2010, achieving similar positive results, a detailed summary of pilot test wells is shown in Table 1.2 CSS pilot test wells production performance (Wang et al., 2011).

Heavy oil reserves are estimated to take 40% of Sudan's total reserves. Sudan is also abundant in natural gas reserves, therefore cost-effective CSS development strategy has wide applications for similar Sudanese and

African fields. Conclusions drawn from pilot test were as follows: 1) Optimized perforation contributed to low water cut; 2) steam injection density was optimized around 120 t/m; 3) Natural gas as heating source greatly reduce operating cost (Wang et al., 2011).

Table 1.2 CSS pilot test wells production performance (Wang et al., 2011)

No.	Well	Start production Date	Net Pay	Total Injected steam	Injection intensity	Cum. Oil	Oil Steam Ratio (OSR)
			(m)	(t)	(t/m)	(t)	
1	FNE-38	02-Oct-09	10.8	1683	156	21940	13.0
2	FNE-16	12-Mar-10	15.9	1782	112	16235	9.1
3	FNE-17	19-Jun-10	12.8	1536	120	5558	3.6
4	FNE-18	23-Jun-10	13.5	1600	119	14919	9.3
5	FNE-26	29-Jul-10	20.5	2350	115	14041	6.0
6	FNE-28	13-Aug-10	10.2	1440	141	8922	6.2
7	FNE-30	20-Aug-10	30.0	3600	120	5119	1.4
8	FNE-27	29-Aug-10	8.4	1008	120	8045	8.0

1.3 Statement of the Problem:

The objectives of this research is to investigate the feasibility of applying vapour extraction process (VAPEX) for extraction of heavy oil from Sudanese heavy crude oil reservoirs, and to compare the expected results of Appling the vapor extraction process (VAPEX) with the currently applied technologies of extracting heavy oil, currently cyclic steam stimulation (CSS) and Multi-functional chemical agent MFCA are applying in some Sudanese oil fields for extracting the heavy oil. And also to recommend the optimum area for pilot implementation.

CHAPTER II

LITERATURE REVIEW

Heavy oil is often overlooked as a resource because of the difficulties and costs involved in its production. But more than 6 trillion barrels [1 trillion m3] of oil in place attributed to the heaviest hydrocarbons triple the amount of combined world reserves of conventional oil and gas deserve a closer look. While other factors such as porosity, permeability and pressure determine how a reservoir will behave, it is the oil density and viscosity that dictate the production approach an oil company will take. Dense and viscous oils, called heavy oils, present special, but not insurmountable, production challenges (Carl Curtis, 2002).

Natural crude oils exhibit a continuum of densities and viscosities. Viscosity at reservoir temperature is usually the more important measure to an oil producer because it determines how easily oil will flow. Density is more important to the oil refiner because it is a better indication of the yield from distillation. Unfortunately, no clear correlation exists between the two. A medium density, or light, crude with high paraffin content in a shallow cool reservoir can have a higher viscosity than a heavy, paraffin free crude oil in a deep hot reservoir, Viscosity can vary greatly with temperature. Density varies little with temperature, and has become the more commonly used oil field standard for categorizing crude oils (Carl Curtis, 2002).

2.1   Classification of crude oil

Generally we use the API (American Petroleum Institute) gravity to specify the specific gravity (SG) of the crude oil as API = (141.5/SG) − 131.5, SG is the specific gravity defined as the ratio of the density of the crude oil to the density of water both at 15.6 °C (60 °F) (Ai-Fu Chang, 2012). Table 2.1 and figure 2.1 illustrate the classification of crude oil.

Density is usually defined in terms of degrees American Petroleum Institute (API) gravity, which is related to specific gravity the denser the oil, the lower the API gravity. Liquid hydrocarbon API gravities range from 4° for tar rich bitumen to 70° for condensates. Heavy oil occupies a range along this continuum between ultra-heavy oil and light oil. The US Department of Energy (DOE) defines heavy oil as between API gravities 10.0° and 22.3°. However, nature recognizes no such boundaries. In some reservoirs, oil with gravity as low as 7° or 8° is considered heavy rather than ultra-heavy because it can be produced by heavy oil production methods. The most viscous tar, pitch and bitumen deposits at even lower API gravities usually require mining-style methods for economic exploitation (Carl Curtis, 2002).

Table 2.1 Classification of crude oil (ANP, 2012 as cited by Silva, 2013).

Classification of Oil	°API
Light	≥ 31
Intermediate	31 > °API ≥ 22
Heavy	22 > °API > 10
Extra Heavy (Bitumen)	< 10
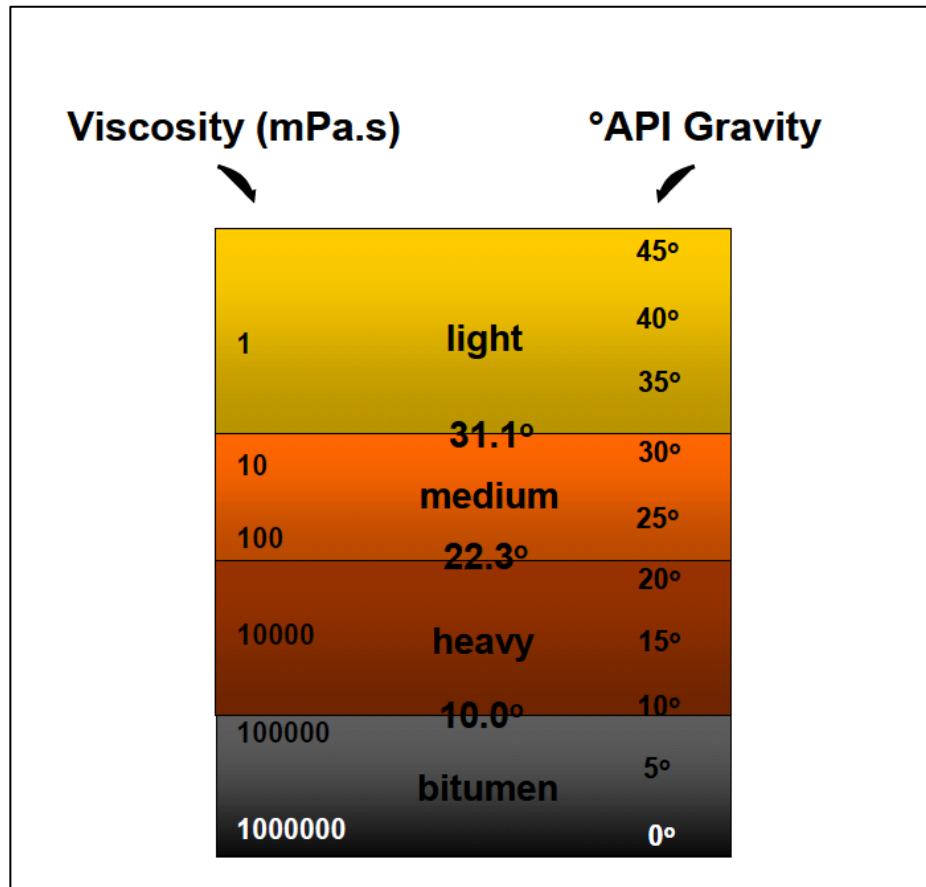
Figure 2.1 Petroleum liquid classification based on viscosity and density (Amin, 2013).

2.2   Recovery of Heavy Oil:

The high viscosity of these crude oils presents a serious challenge for the recovery of these resources. In some reservoirs, the oil viscosity is millions of centipoise at reservoir conditions and cannot be produced by primary production. In heavy oil reservoirs with slightly lower oil viscosity, some primary production could be achieved using horizontal wells. However, because most of the reservoirs have bottom aquifers, water coning at the early stage of the primary production limits recovery (Das, 1998). In some heavy oil reservoirs, a foamy oil behaviour is observed because of the presence of solution gas, which leads to unusually high recovery.3 In Venezuelan reservoirs, the bottom hole temperature is 60 to 70°C, and

although the oil is of low API gravity, the in-situ oil viscosity is significantly lower and the oil is produced at a higher rate (primary recovery factor 14%), (Miraba, 1996).

Apart from cold production, bitumen and heavy oil recovery processes are generally classified as three types: thermal, non-thermal solvent dilution, and hybrid processes. The mobilized bitumen in any process cannot displace cold or undiluted high viscosity bitumen in the reservoir. However, it can drain to the bottom of the reservoir by natural gravity force, provided it does not have to displace immobile bitumen in the process. Such gravity drainage also requires that sufficient density difference be present between the mobilized bitumen that is draining down and the fluid phase that is replacing it in the pore space. A vapour phase heat carrier (e.g. steam) or vaporized diluents can provide sufficient density difference to induce the gravity drainage of mobilized bitumen to a production well located at the bottom of the reservoir (Amin, 2013). The following is a list of recovery processes for heavy oil and bitumen:

I. Thermal Process

- Steam Assisted Gravity Drainage (SAGD).
- Cyclic Steam Stimulation (CSS).
- In situ Combustion, Toe to Heal Air Injection (THAI).
- Electrical Heating.

II. Non –Thermal Solvent injection

- Vapour Extraction (VAPEX).

III. Hybrid Process

- Expandable Solvent – Steam Assisted Gravity Drainage (ES-SAGD).
- Solvent Aided Process (SAP).
- Hot Solvent (n-Solve) Process.

2.2.1 Thermal Processes:

In most of heavy oil reservoirs, the high viscosity limits the primary production necessitating improved oil recovery IOR methods; mostly thermal processes are currently being used. With thermal recovery processes such as cyclic steam stimulation CSS, in-situ combustion, SAGD, etc., the viscosity is reduced by heating the reservoir. Currently SAGD and CSS are the only commercially proven recovery processes (EUB 1998 cited by Amin, 2013).

With thermal recovery processes (such as CSS, in-situ combustion, SAGD, etc.), the viscosity of the oil is reduced by heating the reservoir. Maximum recovery with CSS is relatively low and seldom exceeds 20%. CSS is usually followed by a steam flooding that may yield a significant additional recovery. For reservoirs with highly viscous oil, this flooding technique may not be suitable. The in-situ combustion technique requires sufficient mobility of the oil and is difficult to control. This process has been investigated and piloted for many years. However, it has met with limited success. Currently, SAGD has become a popular technique for the recovery of heavy oil and bitumen.

With SAGD process, steam is injected into the reservoir through a horizontal well; when the steam contacts the cold heavy oil, heat transferred from steam to heavy oil causing the steam to condense and heavy oil's temperature to increase, since the viscosity is a strong function of temperature the added heat decrease the heavy oil viscosity, when sufficient heat has been added and the reduced viscosity of heavy oil permits flow, gravity oil flow downwards towards the lower production well, the flowing oil produced is referred to as a live oil, with continuous addition of steam and removal of a live oil, a steam chambers forms and spreads both vertically and laterally in the reservoir, the figure below

illustrate the steam assisted gravity drainage (SAGD). (Das, 1998), Figure 2.2 illustrate the Schematic of a SAGD process.
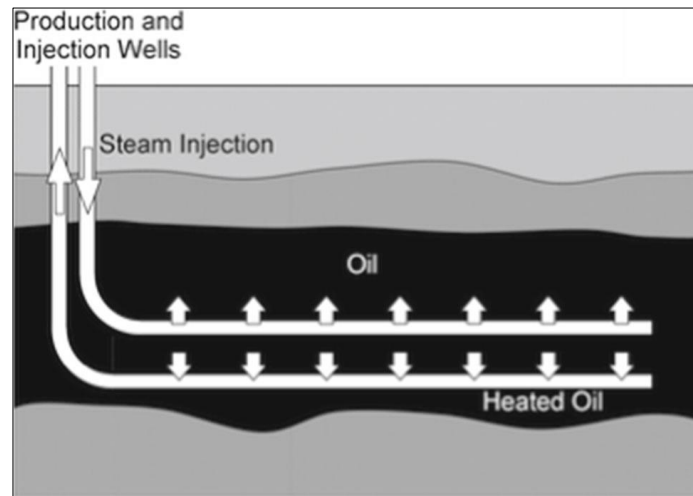
Figure 2.2 Schematic of a SAGD in-situ development (Tamer, 2018)

Despite the apparent success of the steam processes for the recovery of heavy oil and bitumen, they suffer from their inherent disadvantages. Steam process become more difficult to operate in a thin reservoir where heat losses to the base and cap rock make the steam / oil ratio prohibitively high. In reservoirs containing swelling clays, in-situ condensation of steam can cause severe permeability damage near the production well.   For example, a simulation study using SAGD for the recovery potential of the Ugnu Tar Sands, North Slope of Alaska showed great promise, but the possibility of formation damage when steam is injected is a great concern. With a steam process, approximately 30 % of the capital investment is used for steam generation facilities. The recycling of produced water requires elaborate processing; disposal of the waste water poses a serious environmental problem. The area requirement and operational hazards may prohibit implementation of a steam project on offshore platform thermal well completion and other surface and sub-surface accessories, such as

pump, wellhead, cement, tubing, and casing, cost several times more than the normal well completion. Many of these heavy oil and bitumen reservoirs, SAGD may become uneconomic because the thermal energy released by condensation of steam in the water layer ends up heating the aquifer rather than the oil (Das, 1998).

2.2.2 Solvent Extraction:

The viscosity of heavy oil and bitumen can also be reduced by the addition of solvents. Any solvent process involves the diffusion of solvent into bitumen. Since the molecular diffusivity of solvent in bitumen is lower than thermal diffusivity in the reservoir by orders of magnitude, it is generally expected that production rates will be much lower in this solvent process than those in a steam process. Butler and Mokrys (1989) studied the extraction of untreated Athabasca bitumen and Suncor coker feed bitumen with toluene (liquid) in a line source Hele-Shaw cell following the principle of SAGD. Extraction rate with liquid solvent would be even less than 1% of the SAGD. It is clear that the use of vaporized solvent in combination with de-asphalting may enhance the rate considerably (Das, Butler, 1997).

2.3   The VAPEX Process

VAPEX was first developed by (Butler and Mokrys, 1989) as a solvent analogue to steam assisted gravity drainage (SAGD), VAPEX is non thermal alternative for bitumen and heavy oil production, and it uses the second method of viscosity reduction, dilution. Since the process is non thermal, VAPEX can applied to reservoirs that are unsuitable for thermal methods such as those with low thermal conductivity, bottom water, and thin pay zone.

The concept is similar to that of SAGD, except solvent are injected instead of steam in the VAPEX process. The concept of the process is shown schematically in Figure 2.3, which shows a vertical cross section of the reservoir. In this process vaporized hydrocarbon solvents (low molecular weight) are injected into the reservoir through the upper horizontal injection well. The solvents initially dissolve in bitumen around the injection well until the breakthrough of the diluted oil to the lower horizontal production well placed vertically below the injection well. Solvent vapour rises slowly to form a vapour chamber in the extracted sand matrix above the injection well, dissolves in the bitumen at the solvent bitumen interface and diffuses into the bulk of bitumen and dilutes it (Das, Butler, 1997).

The diluted oil drains to the production well driven by gravity. Apart from the configuration of injector and producer shown in the Figure 2.3, several other configurations of injector and producer wells are also possible. Even a series of existing vertical wells can be utilized as injection wells (Das, Butler, 1997).
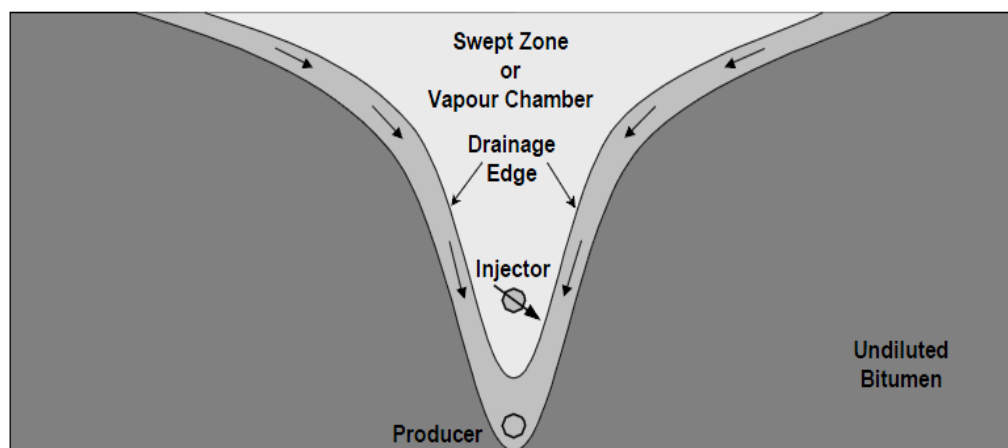
Figure 2.3 Vertical Cross Section of the VAPEX Process (Kulada, 2003)

The use of vaporized rather than liquid solvent produces a higher driving force for gravity drainage due to the higher density difference between bitumen and solvent vapour and also ensures that the residual amount of solvent in the extracted reservoir is less than that with liquid solvents. At a given temperature the solubility of a vaporized solvent is maximum near its vapour pressure. Hence the solvent pressure should be as close as possible to its vapour pressure at the reservoir temperature. In the field conditions, to avoid liquefaction of a solvent at any point in the reservoir, the partial pressure of the solvent should be lower than its vapour pressure at the prevailing temperature. Hence it is clear that the reservoir pressure and temperature play a significant role in the selection of the solvent. The criteria for selection is that the dew point pressure of the solvent should be slightly higher than the reservoir pressure. Thus even if the pressure is only slightly lower than the dew point pressure, since it is higher than the reservoir pressure the injection of solvent will not be a problem and the maximum solubility could be achieved at the same time (Das, Butler, 1997).

If the pressure used is close to the vapour pressure of the solvent at the reservoir temperature, the concentration of solvent in the diluted oil may be enough to cause de-asphalting leading to an additional reduction in viscosity. This in situ upgraded oil is of better quality from transportation and refining point of view and has a higher market value. However, the important concern in the development of the VAPEX process is the possibility of the reduction of permeability (or plugging) of the reservoir matrix due to asphaltene deposition, and the consequent hindrance to the flow of oil out of the reservoir (Das, Butler, 1997).

2.4   VAPEX and SAGD Comparison:

VAPEX has a number of advantages over other heavy oil and bitumen recovery processes. To begin with, VAPEX has low capital costs as the injection of vaporized solvents does not require extensive surface facilities such as those for hot water or steam generation (for hot water or steam drive) and the subsequent treatment of waste water produced with live oil. Since solvent injection does not involve the energy losses that are characteristic of thermal recovery processes, VAPEX is relatively very economical (Upreti, 2007).

VAPEX uses approximately 3% of the energy consumed by SAGD In addition, the implementation of VAPEX cuts down greenhouse gas emission by 80% with the additional scope for significant carbon dioxide sequestration in depleted reservoirs to maintain their pressure. VAPEX is a very environmentally friendly process of heavy oil and bitumen recovery, VAPEX carried out at pressures close to the saturated vapor pressure of solvent results in de-asphalted and upgraded heavy oil and bitumen (Upreti, 2007).

VAPEX does not require facilities for steam generation, water processing, or recycling and operates at the reservoir temperature with almost no heat loss. The capital and operating costs of VAPEX are estimated to be respectively 75% and 50% of those of SAGD. VAPEX is very suitable for the heavy oil and bitumen reservoirs, which frequently have high water contents, thin pay zones, low thermal conductivities of rock formations, and underlying aquifers. The heavy oil and bitumen recovery from these reservoirs with displacement or thermal recovery processes is neither economical nor environmental friendly because of accompanying losses of displacement fluid or energy to the under burden and overburden. One limitation with VAPEX is the slow mixing of the solvent with the heavy

oil and bitumen reserves, resulting in long start up times and low initial rates of heavy oil and bitumen recovery (Upreti, 2007

The solvent mass diffusion into the bitumen is one of the controlling factors in the VAPEX process. Since mass diffusivity is smaller than thermal diffusivity, the recovery in VAPEX is slower compared to thermal processes. Also, since heat can pass through shale barriers by conduction where solvent cannot, reservoir heterogeneity may be a bigger challenge for the VAPEX process than thermal processes. The other potential disadvantages of the VAPEX process are: the high cost of the solvent and the loss of the solvent which remains in the vapour chamber or in an overlying gas cap; and the possible loss of reservoir permeability due to asphaltene precipitation (Karmaker and Maini, 2003). In the reservoir the steam condenses as fresh water which may cause formation damage by clay swelling. So VAPEX & SAGD Process potential advantages and disadvantages for economic scale oil production can be listed below as stated in Table 2.2.

Table 2.2 VAPEX versus SAGD

Features	SAGD	VAPEX
Thin/Deep Reservoirs	✗	✓
Bottom Water	✗	✓
Clay Swelling	✗	✓
Reservoir Heterogeneity	✓	✗
Low Temperature Operation	✗	✓
Produced oil with better quality	✗	✓
Environmentally Friendly	✗	✓
Field implementation	✓	✗
High Oil Recovery	✓	✗
Large Surface Facilities	✗	✓
CAPEX & OPEX	✗	✓

2.5   Previous Work:

Application of VAPEX (vapour extraction) process on carbonate reservoir, in this study a total of 20 VAPEX experiments performed with Hele-Shaw cell utilizing three different Turkish crude oils. Two different VAPEX solvents (propane and butane) were used with three different injection rates (20, 40 and 80 ml/min). Garzan, Raman and Batı Raman crude oils were used as light, medium and heavy oil. Apart from normal Dry VAPEX experiments one experiment was conducted with CO_2 and another one with butane plus steam as Wet VAPEX experiment (Yıldırım, 2003).

The results of the study were, for both VAPEX solvents, oil rates increased with injection rates for all crude oils, for asphaltene precipitation, propane gave better results than butane in almost all injection rates for Garzan and Raman oil. The experiments with Batı Raman oil, butane made better upgrading than propane with the injection rate 80 ml/min. With the other two rates both solvents showed almost same performance. The results of the experiments conducted with CO_2 and butane + steam it was observed that CO_2 gave better performance than other systems and butane + steam system showed same almost same performance with propane alone System at the same injection rate. It can be proposed that the systems could be comparable in terms of economic point of view, which was not done by this study.

2.6 Winter Field VAPEX Pilot Project:

Nexen conducted pilot in the Winter Pool heavy oil reservoir with an active underlying water zone, the first phase of pilot between 2004 and 2006 was to determine the technical feasibility and identify the challenges of VAPEX process within the reservoir. The process of the first phase involved injecting solvent into two existing horizontal wells in the upper

part of the reservoir, and producing from a new third well drilled midway between the injectors in a lower part of the reservoir (see Figure 2.4) (Nexen Inc. 2009).
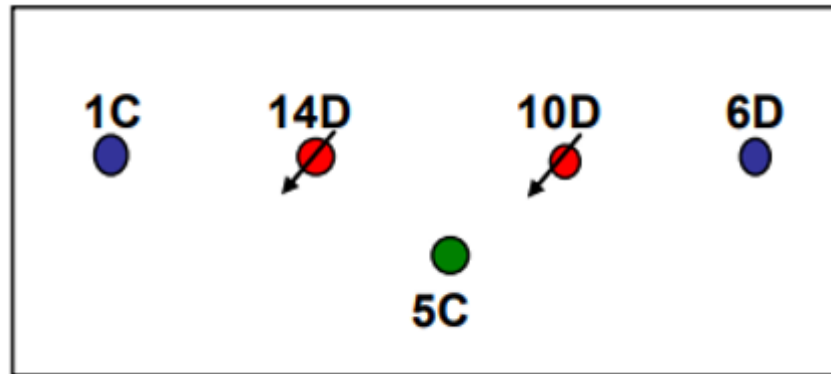
Figure 2.4 Configuration of the First Phase Pilot (Nexen Inc. 2009).

In December 2008 the 2nd phase of the pilot was conducted to determine if the VAPEX could be economically successful in the future, two additional horizontal wells were added midway between the existing upper horizontal injectors and primary producing wells. They were also placed lower in the reservoir and laterally offset the existing single lower horizontal producer to try to provide a confined pattern around it. If a confined pattern could be achieved it would help ascertain whether an economic solvent-oil ratio for the VAPEX process in this reservoir was possible (see Figure 2.5) (Nexen Inc. 2009).
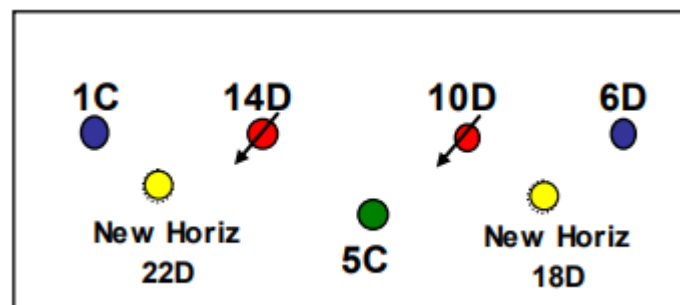
Figure 2.5 Configuration of the Second Phase Pilot (Nexen Inc. 2009).

Major technical risk factors identified at the initiation of the Winter VAPEX Pilot in 2004 were:

- Select an effective VAPEX solvent for the process.
- Operate the pilot to create effective gravity drainage of the oil to the producer.
- Create the solvent communication between the lower and upper wells along the entire well bore length.
- Control water conning into production wells.
- Placement of lower horizontal producing well.
- Unconfined pilot pattern resulting in gas migration outside the pilot boundaries.

As conclusion of this pilot project Continuous VAPEX injection was preceded by several cycles of Huff and Puff injection in the 3 wells in order to establish communication. A vapor chamber was successfully created and the process increased production in the bottom well in spite of poor conformance control issues in the wells but the solvent recovery and the solvent to oil ratios were poor. The pilot was later expanded by the addition of two external producers (Nexen Inc. 2009) in order to try and improve the performances by reducing solvent losses outside the pattern. In spite of that the solvent-to-oil ratio remained high (0.61) and it was calculated that 56% of the propane injected had migrated outside the pilot area (Nexen Inc. 2009).

CHAPTER-III

MATERIAL AND METHODS

3.1   VAPEX Process Mathematical Model

Butler and Mokrys have developed an analytic model describing the VAPEX process which is very useful for understanding the key parameters affecting the process. The model predicts that oil production rate Qo, will be given by.

$$Q_o = 2L\sqrt{2Kg\varphi\Delta S_o h N_s}$$

……………………………….. (Eq 3.1)

Where Qo is oil production rate, L is the length of the wells, K is the permeability, g is the acceleration of gravity, φ is the porosity, ΔSo is the mobile oil saturation, and the h is the height of the reservoir. Ns is a dimensionless parameter that incorporates the effects of dispersive mixing, to be defined below.

The parameter Ns depends in a complex way on the intrinsic dispersion of the solvent, according to the equation:

$$N_s = \int_{c\,min}^{1} \frac{\Delta\rho(1 - c_s)D_s}{\mu c_s} dC_s$$

………………..………………… (Eq 3.2)

Where Δρ the difference in heavy oil / bitumen and solvent density. Cs is the concentration of solvent in the mixture, Ds is the solvent diffusivity, and μ is the viscosity of the solvent-heavy oil and bitumen mixture (Upreti, 2007). All of the quantities Δρ, Ds and μ depend on the solvent fraction Cs.

Butler and Mokrys calculated Ns for two systems, toluene/Athabasca bitumen and toluene/Suncor Coker feed, obtaining values 9.44*10-7and 2.5*10-6, respectively. Utilizing these values in the analytic model gave reasonable agreement with the oil production rates observed in their Hele-Shaw cell experiments (Cuthiell, 2003).

The problem of extraction of heavy oil and sometimes in situ de-asphalting, of oil with solvents can be approached from several directions. There are several laboratory experiments were performed in which VAPEX solvents alone were injected in to the cell, which generally called dry VAPEX, both under steady state conditions and under pressure cycling regime. In another set of experiments called wet VAPEX, solvent is injected with steam to study the coexistence of a large, low temperature solvent chamber with a hot steam chamber limited to the proximity of the injector/producer (Butler & Mokrys, 1993).

Das and Butler, 1994 performed several experiments to analyze the asphaltene deposition from heavy oils by VAPEX process using a Hele-Shaw cell. They used propane as solvent and three different bitumen samples to investigate the asphaltene deposition in the experimental system and they concluded that asphaltene deposition did not prevent the oil flow and asphaltene precipitation starts if the injected solvent pressure was close to or higher than the solvents vapor pressure.

(Butler and Jiang, 2000) have done experimental study to achieve high oil production rates with economic solvent requirements. During their experiments they investigated the effect of major parameters to the VAPEX performance like temperature, pressure, solvent injection rate, type of solvent

etc. at the end of their study they concluded with the practical rates and high oil recovery can be achieved with the solvent injection rate of 0.2 b/b oil. They also expressed that wider lateral well spacing's allow higher production rates and made the process more economic.

(Butler and Mokrys, 1991) investigated VAPEX process on crude oil samples in both packed cell and Hele-Shaw cell with two solvent (propane and butane). They observed production rate, recovery percentage, density and viscosity of oil against the solvent rate and temperature. They also conducted series of experiments with solvent and steam as Wet VAPEX process to compare the hot water and hot water + solvent production rates. They found that the injection of propane vapor with hot water results in high oil recovery than hot water alone.

3.2   Factors affect the VAPEX process:

Butler and Mokrys considerable research has been devoted to study the various factors that influence VAPEX using lab-scale physical models of heavy oil and bitumen reservoirs. The important factors that influence VAPEX are the viscosity of heavy oil and bitumen, deasphalting of heavy oil and bitumen, diffusion of solvent into heavy oil and bitumen, dispersion of the solvent with heavy oil and bitumen, solvent selection for VAPEX, permeability of the reservoir, and geological aspects (Upreti, 2007).

3.2.1 Temperature:

The viscosity of heavy oil and bitumen is very sensitive to temperature. The oil viscosity falls drastically and hence the solvent diffusivity increases with the increase in temperature. Both the aforementioned effects are favorable for

the oil recovery. On the other hand, the solubility of propane in oil decreases with increase in temperature. However, the net effect of increase in temperature is positive (Kulada, Maini, 2003).

3.2.2 Pressure:

The solubility of the vaporized solvent in the oil increases with increasing pressure. This has two beneficial effects: (1) it reduces the viscosity of the diluted oil and (2) it increases the rate of mass transfer in the liquid phase by providing a larger concentration difference between the gas-oil interface and the bulk of the oil. However, the safe operating pressure must be carefully maintained in order to avoid the solvent condensation in the vapor chamber. This situation is undesirable as it can increase the chances of asphaltene plugging and it is likely to increase the solvent retention in the form of trapped liquid solvent in the swept zone (Kulada, Maini, 2003).

3.2.3 Viscosity of Heavy Oil and Bitumen:

The viscosity of heavy oil and bitumen depends on its chemical composition, temperature, pressure, and concentration of dissolved gases. Evidently, it is the high viscosity of heavy oil and bitumen reserves in their native state that is the major obstacle in their recovery. The reduction of their viscosity and the increase in their mobility are the objectives of all recovery processes. This objective is achieved in VAPEX by injecting solvents, which upon absorption reduce the viscosity of heavy oil and bitumen reserves, (Upreti, 2007). In the VAPEX process, the oil recovery rate is governed by the diffusion of solvent molecules into the heavy oil. The molecular diffusivity of propane increases with the decrease in oil viscosity, which in turn enhances the oil recovery rate (Kulada, Maini, 2003).

3.2.4 Solvent Injection Scheme:

The fraction of solvent, such as propane or butane present in in-situ heavy oil, bitumen and tar sands is negligible. Consequently, a high concentration gradient of solvent molecules develops and the mass transfer occurs at a high initial rate near the gas-oil interface immediately after the start of solvent injection. The consumption rate of solvent is expected to be much higher in the beginning of the process. To further promote the initial high mass transfer rate, it appears desirable to maintain a high solvent injection rate in the beginning. This would speed up the initial solvent concentration development at the interface and thereby the recovery process. In the presence of a gas cap, if the injection well is completed in the gas zone it takes time to build-up the desired solvent concentration in the gas cap. For this reason also, it is advantageous to start solvent injection at a higher rate. When the injection well is laterally displaced from the production well and a gas cap is involved, the injected solvent has to travel through the length of the gas cap to reach the production well. In this situation a high initial rate of solvent injection is essential to shorten the expected delay in the start of oil production (Kulada, Maini, 2003).

3.2.5 Well Spacing:

The increased in well spacing will delay the arrival of solvent to the producer, with increased well spacing, the contact area of solvent vapor with oil increases and thus the mixing of solvent with oil is enhanced, (BUTLER & Q. JIANG, 2000). In the reservoir with a small gas cap, the horizontal injector can be advantageously completed in the gas zone to achieve high injectivity during the process start-up. When the injected solvent reaches the pay zone

the vaporized solvent can rapidly spread out all over the gas zone through diffusion and dispersion processes. Therefore, the gas-oil contact area is less dependent on the lateral spacing between the injector and producer (Kulada, Maini, 2003).

3.2.6 Gas Cap:

In the reservoir containing a gas cap the injected solvent can rapidly spread over the gas-oil contact area and make the diffusion process fast from the beginning provided the injection well is completed in the gas zone (Kulada, Maini, 2003).

3.2.7 Diffusion of Solvent Gases:

During vapor extraction, the diffusion of solvent gas in heavy oil and bitumen is the primary, molecular phenomenon responsible for gas absorption and mixing with heavy oil and bitumen resulting in mixtures with lower viscosities. Thus, diffusion plays a very important role in VAPEX. For a VAPEX operation, accurate diffusion data for solvent gas-heavy oil and bitumen systems are necessary to determine:

1. The amount and flow rate of gas required for its injection into a reservoir.
2. The extent of heavy oil and bitumen reserves that would undergo viscosity reduction.
3. The time required by the reserves to become less viscous and more mobile as desired.
4. The rate of live oil production from the reservoir.

The diffusion coefficients of various solvents in heavy oil and bitumen have been experimentally determined by several researchers using (1) a direct

method involving the compositional analysis of liquid samples extracted at different times and (2) indirect methods based on property changes such as volume, pressure, solute volatilization rate, position of the gas- liquid interface, and nuclear magnetic resonance (Upreti, 2007).

3.3   Solvent Selection

The key aspects of solvent selection include:

1- Solvent should remain vapor in solvent chamber.
2- Solvent should cause upgrading (Asphaltene precipitation).
3- Solvent should have the maximum solubility in oil.

3.3.1 Maintaining the solvent as gas phase:

There are several benefits to maintaining the solvent as gas, including minimizing solvent requirement, maintaining higher rate of diffusion and maintaining high density difference for gravity drainage condition. When live oil drains form a pore, the oil volume will be replaced with the injection fluid, solvent for VAPEX and steam for SAGD. When propane is used as solvent in VAPEX, DAS and BUTLER estimate that before blow down, the net cumulative solvent required is 0.02 Kg of vapor or 0.5 Kg of liquid. Thus, propane vapor would fill 25 times the volume of an equal mass of propane liquid, at the same temperature and pressure, the total solvent required is reduced by recycling produced solvent and blow down at the end of production (Friedrich, 2005).

The two key mechanisms in VAPEX are mass transfer and gravity drainage, in VAPEX the solvent is transferred to bitumen through diffusion. Thus, a

higher rate of diffusion leads to higher production rate. The diffusion coefficient for vapor liquid diffusion is about four orders of magnitude larger than liquid-liquid diffusion and the diffusional flux is about one order of magnitude larger. The driving force for the second process, gravity drainage, is differences in density. There is greater density difference between solvent vapor and bitumen than liquid solvent and bitumen. The difference in density allows the solvent vapor to quickly rise in the chamber while the live oil flows down wards to the production well. A solvent vapor attains maximum solubility at or near its vapor pressure (for given temperature). Condensation is prevented if the reservoir pressure is below the solvent's vapor pressure. Butane is often used in VAPEX experiment, however it has a relatively low dew point pressure of 150 KPa at 10˚C and would condense in most reservoirs. However, at given temperature, condensation can be prevented with addition of non-condensable gas (NCG). The addition of a non-condensable gas however has two disadvantages. Firstly, the solvent molecules will also need to diffuse through the NCG to reach the bitumen. Secondly, mass transfer may be impaired due to a reduction in concentration caused by a buildup of NCG in solvent chamber (Friedrich, 2005).

DAS and BUTLER describe a process, (BUTEX) that co-injects liquid butane with a high pressure carrier gas. When the mixture reaches the reservoir, some of the liquid solvent will evaporate and swept towards the bitumen-vapor interface by the carrier gas. Depending on the selection of carrier gas, it could also participate in bitumen extraction. Butane was selected as the solvent as in previous work by DAS and BUTLER found butane results in less de-asphalting than propane and thus would reduce the chance of well bore plugging (Friedrich, 2005).

3.3.2 Asphaltenes:

Asphaltene is a component of the petroleum liquids defined operationally. It represents the heaviest fraction. A generally accepted definition of asphaltenes is by their solvent solubility. The fraction insoluble in heptane (or pentane) but soluble in toluene is called asphaltene. This fraction usually has high apparent molecular weight (often measured by vapor pressure osmometry, VPO), asphaltenes cannot be refined with currently technology. Thus, in many vacuum residua, asphaltene is the main component. In addition to the non-refinerable nature, asphaltene has been known to initiate wellbore plugging, pipeline deposition; hinder the refining yields, and initiate coking, etc. Such hindrance on production and processing have made asphaltene one of the most focused materials in petroleum research. The ultimate goal is to either separate asphaltene from the petroleum liquids before entering the refining processes or "upgrade" it to a less refractory (or lighter) fraction (SHEU & STORM, 1995).

Asphaltenes are complex molecules with high molecular weight, ranging from 1,000 to 2,000,000 g/mole. Molecular weight has been difficult to determine as asphaltenes tend to from molecular aggregates and are affected by temperature, solvent used and asphaltene concentration (SPEIGHT, 1991) as cited by Friedrich, 2005. Asphaltenes are heaviest fractions found in crude oil, and in bitumen they can account for much as 16 to 22% by weight. Though the exact structure of an asphaltene molecule is unknown, they are hydrocarbon, contain aromatic rings and oxygen, nitrogen, and Sulphur and heavy metals, especially vanadium, nickel and iron.

Solvents such as n-heptane and n-pentane are commonly used to remove asphaltenes from crude, the amount of precipitation depends on the solvent used, temperature, solvent concentration and contact time, A solubility parameter for non-polar solvents relating internal pressure of solvent to its solvent power, can be defined as the ratio of surface tension γ, to the cubic root of molar volume V (Hildebrand, 1919) as shown in equation below:

$$\beta = \frac{\gamma}{V^{1/3}}$$

……………………………………..…………….. (Eq 3.3)

The solubility parameter β, describes the ability of solvent to dissolve asphaltenes, thus the higher the solubility parameter the lower the amount of asphaltenes precipitated. For normal hydrocarbons (Pentane through Decane), the solubility parameter increases with the number of carbons atoms.

3.4   De-Asphalting in VAPEX:

High asphaltene concentration is undesirable as precipitation cause well bore plugging and pipe line decomposition, additionally, when crude containing asphaltenes is exposed to water, emulsion form because asphaltenes are the most polar faction of crude oil (ISLAM, 1995). Emulsions are difficult to separate in the presence of water in distillation. Increased temperature during refining increases the conversion of crude feedstock into lighter and more valuable fractions, however the amount of fouling also increases. When heated above 300˚C, asphaltenes decompose into carbon and volatile compounds. Carbon and heavy metals then deposit onto equipment causing fouling which results in reduced flow, increased pressure, reduced heat transfer, increased maintenance and the need to replace catalyst bed. Thus, it

is advantageous to reduce the concentration of asphaltenes in the crude feedstock (Friedrich, 2005).

When a light hydrocarbon diffuse into bitumen, the composition and phase behavior of the oil is altered. As a result the physical change can lead to precipitation of asphaltenes from solution once a critical solvent concentration is reduced. BUTLER and JIANG (2000) observed that the critical concentration is 20 to 30 wt% for propane for the onset of asphaltene precipitation. In work of (Ramakrishnan 2003), no significant asphaltene precipitation was reported although the propane content in the live oil was greater than 30 wt%.

In VAPEX, since the solvent concentration in bitumen is the highest at the solvent-bitumen interface, asphaltenes will tend to precipitate at the interface. An example of asphaltene precipitation in Hele-Shaw cell is shown in the figure (3.1) below. In this example, as the interface moves away, the precipitate can be seen in a fringe pattern with the micro-layer perpendicular to fringe.
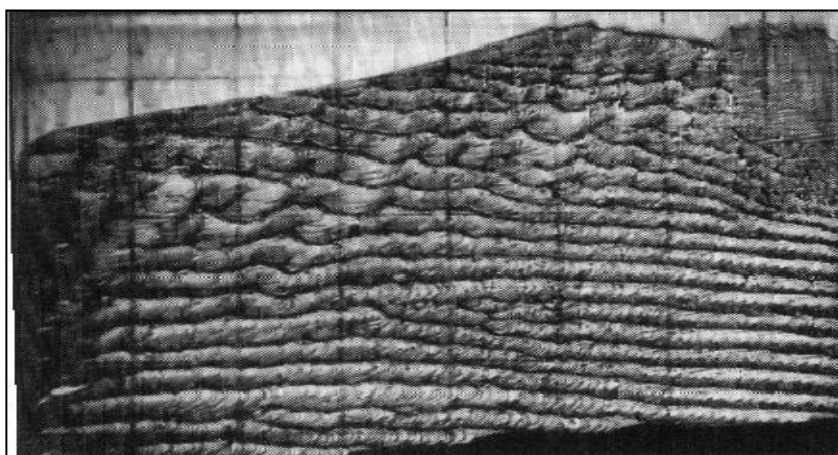
Figure 3.1 Asphaltene deposition in a Hele-Shaw cell (DAS and BUTLER, 1994)

It was expected that the precipitation of asphaltenes would lead to blockage of the pores and impede the flow of live oil. In the Hele-Shaw cell, the flow rate of the oil did not seem to be affected by the precipitation of the asphaltenes. Instead, the solvent vapor appeared to bypass the precipitate and continue to diffuse into the dead oil.

In porous material it is expected that asphaltene precipitation will reduce the live oil production rate to some extent. Since clay and silica minerals tend to adsorb asphaltenes, the precipitate will remain in the pores, reducing permeability by up to 20%. Solvent vapor will still be able to bypass the asphaltenes to continue contacting bitumen.

In addition to preventing problems during transportation and refining, the removal of asphaltenes from bitumen has been seen to drastically reduce viscosity. Experimenting with Peace River bitumen, DAS and BUTLER (1994) found that the crude initially has 19.5% asphaltenes and viscosity of 123,000 mpa.s, but has viscosity of 3,500 mpa.s when all of the asphaltenes were removed. The viscosity of Cold Lake bitumen was reduced from 65,000 mpa.s to 4,000 mpa.s when the asphaltene content was reduced from 17.6% to Zero. The precipitation of asphaltene further reduced the viscosity of the bitumen thus increasing the oil flow rate. Thus, even after the solvent is removed from the oil (for recycling), the oil's viscosity remains lower than that of the dead oil due to the removal of asphaltenes. The effect of the asphaltene content on the viscosity of Cold Lake and Peace River bitumen is shown in figure (3-2) below; the viscosity reduction by asphaltene removal may allow the oil to flow through pipelines to refineries without addition of lighter fraction. A long with the asphaltenes, unwanted compounds such as heavy metals that are bonded on the asphaltenes are also left in the reservoir.

Over all, removal of asphaltenes leads of a product with a higher market value.

Asphaltene precipitation has seen observed by numerous researchers, the in-situ precipitation of asphaltene in the experiments carried out at the University of Waterloo was observed at the production end of the system where the solvent concentration is at maximum. DAS and BUTLER (1998) observed asphaltene deposition when the operating pressure was close to the solvent's vapour pressure at the experimental temperature.
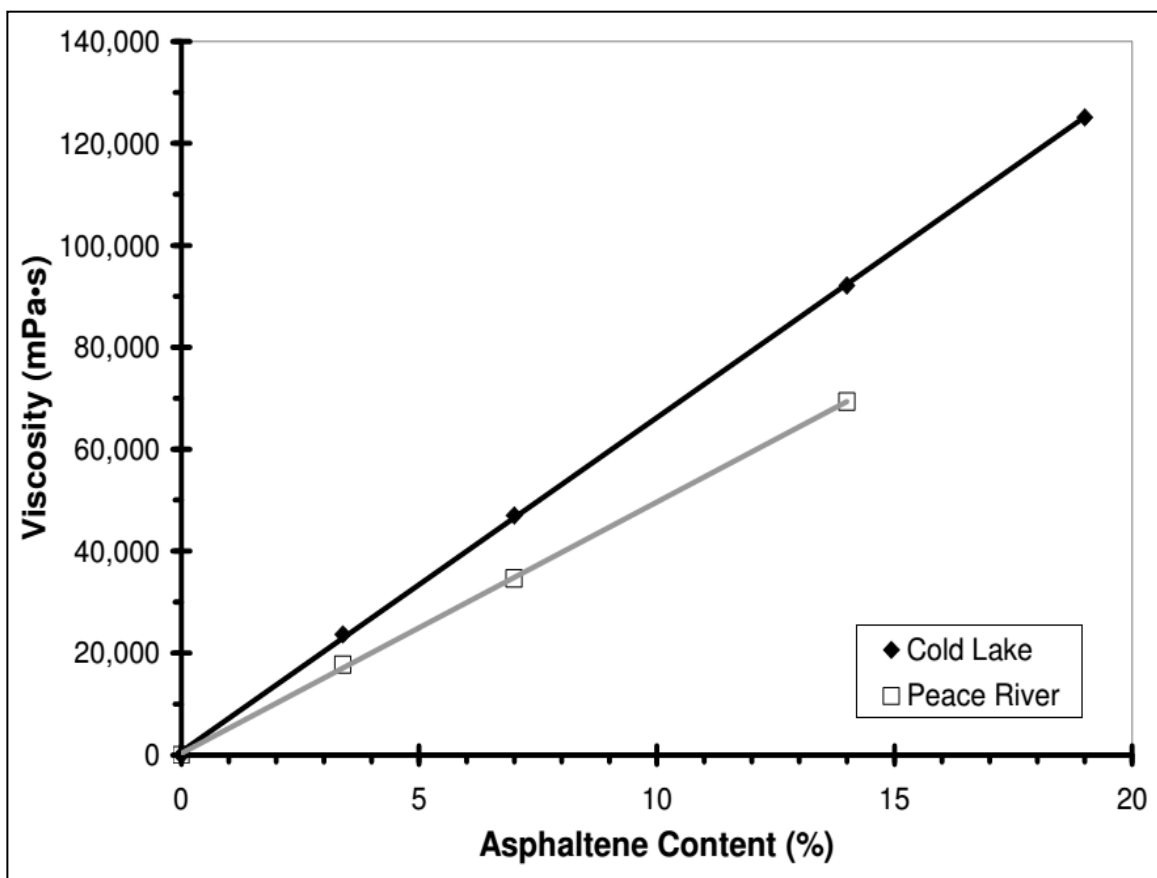
Figure 3.2 Effect of asphaltene content on the viscosity of bitumen (DAS, 1995 as cited by Friedrich, 2005).

3.5   Multifunctional Chemical Agent MFCA Overview:

MFCA has the flowing principle mechanism:

1- The mechanism of the energy support for oil displacement, the large quantity of stimulation liquid injected it will act to support formation energy to drive the oil.

2- The mechanism of Viscosity reduction by emulsification and micro-emulsion, it will greatly enhance the crude oil mobility for rapid recovery, also increase the drainage radius around the wellbore.

3- The mechanism of reducing the interfacial tension, the Stimulation liquid will make the oil/water interfacial tension at a lower level, that is, significantly reduce the capillary force, viscous force of fluid.

4- The mechanism of wettability alteration, With a great influence on rock wettability the heavy components of crude oil often makes rock surface oil-wet, result in reduction of the oil phase permeability. As the stimulation fluid injected, the oil wet surface becomes water wet, therefore improve the oil phase permeability.

5- The mechanism of blocking removal Stimulation liquid can dissolve the deposit heavy organic substance near wellbore zone, therefore restore its reservoir permeability, in addition the chemicals sticking in the wellbore has the function of preventing the asphalt remaining in the wellbore.

3.6   The Study Area:

H field has an OIIP of 120 MMSTB, and Amal reservoir is one of the H field reservoirs and is the target reservoir formation for this study. In Amal reservoir formation the reservoir is massive quartz sandstone, middle coarse grain size. Middle well sorted, sub rounded sub angular, un-consisted, high porosity. There are several interbedded mudstones. The Top depth of oil layer is 814m, the sand is massive with thickness of 59 m, the oil layer is 43 m, the porosity of oil layer is 30%, the So is 16% API: 10.38, the oil is main distributed in structure high the reservoir type is structural oil pool with strong bottom and edge water, Figure 3.3 show well H-01 reservoir X-section.

The 1st oil production was commenced in April 2015 through commissioning of H-01, as of Dec 2020 the cumulative oil production is 0.229 MMbbl and to date recovery factor is less than 1%. Table 3.1 show the reservoir rock & Fluid properties of Amal formation in H Field.
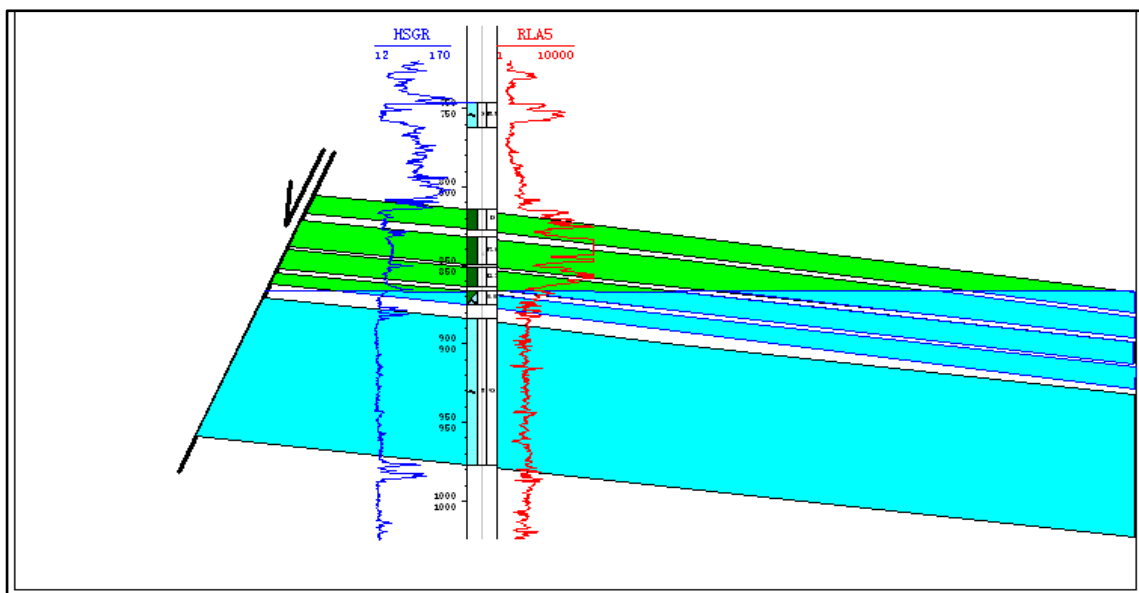
Figure 3.3 Well H-01 reservoir X-section (GNPOC, 2012)

Table 3.1 the reservoir rock & Fluid properties of Amal formation in H Field
(GNPOC, 2012)

Parameters	H Field, Amal Reservoir
Oil layer thickness, m	43
Porosity,%	31
Sw,%	48
API	10.38
Oil density, g/cm3	0.998
Top depth, mkb	814
Average Permeability, Darcy	10
Oil Viscosity @ reservoir temperature, cp	10,040
reservoir temperature, deg C	60
OOIP, MMSTB	120

Greater Bamboo is one of biggest field of GNPOC consisting of 25% of total
GNPOC STOOIP and also contained 85% of the Heavy Oil Resources in
GNPOC. The 1st oil production was commenced in July 2001 and a peak
production of ~20 Kbopd was achieved in July 2002. As in Jan 2016, the total
cumulative oil production of Bamboo fields is 64 MMSTB, recovery of
12.6% of the total STOIIP of 506.4 MMSTB. (Farog, 2016). Bamboo West
field is one of Greater Bamboo fields having OOIP about 374 MMbbl, As of
Dec 2020 the cumulative oil production is almost 63 MMbbl and to date
recovery factor is 16.5%. Table 3.2 show the reservoir rock & Fluid
properties of Bentiu-01 formation in B Field.

Table 3.2 the reservoir rock & Fluid properties of Bentiu-01 formation in

Bamboo Field (GNPOC, 2012)

Parameters	BBW Field, Bentiu-01
Oil layer thickness, m	13.6
Porosity,%	26
Sw,%	45
API	21
Oil density, g/cm3	0.934
Top depth, mkb	1200
Average Permeability, Darcy	2
Oil Viscosity @ reservoir temperature, cp	120
reservoir temperature, deg F	129
OOIP, MMSTB	374

CHAPTER IV

RESULTS & DISCUSSION

H field has an OOIP of 120 MMSTB, and Amal reservoir is one of the H field reservoirs and is the target reservoir formation for this study, as of Dec 2020 the cumulative oil production is 0.229 MMbbl and to date recovery factor is less than 1%. Bamboo West field is one of greater Bamboo fields having OOIP about 374 MMbbl, As of Dec 2020 the cumulative oil production is almost 63 MMbbl and to date recovery factor is 16.5%.

Throughout this chapter Butler and Mokrys analytic model of VAPEX process (equation 3.1) was used to predicts oil production rate Qo from wells (H-Hz, BBW-Hz) which will be proposed to be drilled in two Sudanese reservoir Bentiu-01 and Amal as trial to study the feasibility of applying VAPEX process on them, and to compare the VAPEX results with the Cyclic Steam Stimulation CSS and Multifunctional chemical agent MFCA which had been applied before in BBW-42 well (produce from reservoir Bentiu-01) and well H-01 (produce from reservoir Amal) respectively. firstly integral equation 3.2 must be solve to get the valve of VAPEX number Ns which depend upon many parameters (oil density, solvent density, density different, solvent diffusivity, viscosity of the mixture) as shown in table (4.1).

The propane will be used as solvent for this analysis and the propane diffusivity had been borrowed for literature 8.6E-08 m2/day, because there was no way to measure it at the lab, after complete the calculation of Ns valve using integral equation 3.2 very small valve of Ns was obtained (5.47168E-08) and when this valve had been applied to equation 3.1 to get oil flow rate,

very small valve of flow rate was obtained (0.7, 1.7 bbl/day) for well H-Hz and well BBW-Hz respectively which was not representative the actual performance of the wells.

Table 4.1 the Data Require for VAPEX number Calculation

Parameter		Value
Oil Density kg/m3	ρo	980
Solvent Density kg/m3	ρs	450
Density Different kg/m3	$\Delta\rho$	530
Solvent Diffusivity m2/day	Ds	0.000086
Solvent Concentration %	Cs	0.3
Viscosity of the Mixture kg/m.day	μ	419817.6
VAPEX number	Ns	5.47168E-08

The CSS project which had been implemented in Well BBW-42, the objective was to increase the recovery factor, reduce oil viscosity in order to increase its mobility, through the application of heat, creates easy movable oil. BBW-42 well produced from Bentiu-01 reservoir which have the flowing fluid properties (API 22, Viscosity 102 cp @ 65 ˚C, and pour point less than 6 ˚C), and the top reservoir depth at 1200 mkb. BBW-42 Well was selected to be drilled and completed with thermal completions. The CSS operation was carried out on 9th Dec 2012, and Hot Production started on 26th Dec 2012. Very encouraging results was observed. Production had increased by almost 100%.

New Well BBW-Hz was proposed in study to be drilled in the same Reservoir Bentiu-01 to study the feasibility of applying VAPEX process and to compare the VAPEX results with the previous CSS results in BBW-42 well. The basic data required for calculation the VAPEX startup oil flow rate is listed in table 4.2 below and equation 3.1 was used to calculate the initial expected oil rate.

Since the calculated value of VAPEX number N_s was very small, Sensitivity analysis had been done to show the effect of VAPEX number on the expected oil rate, many values of VAPEX number were borrowed and used in the Sensitivity analysis, from this analysis it is clear that the expected oil rate increase with increase of VAPEX number figure 4-1 illustrate the results.
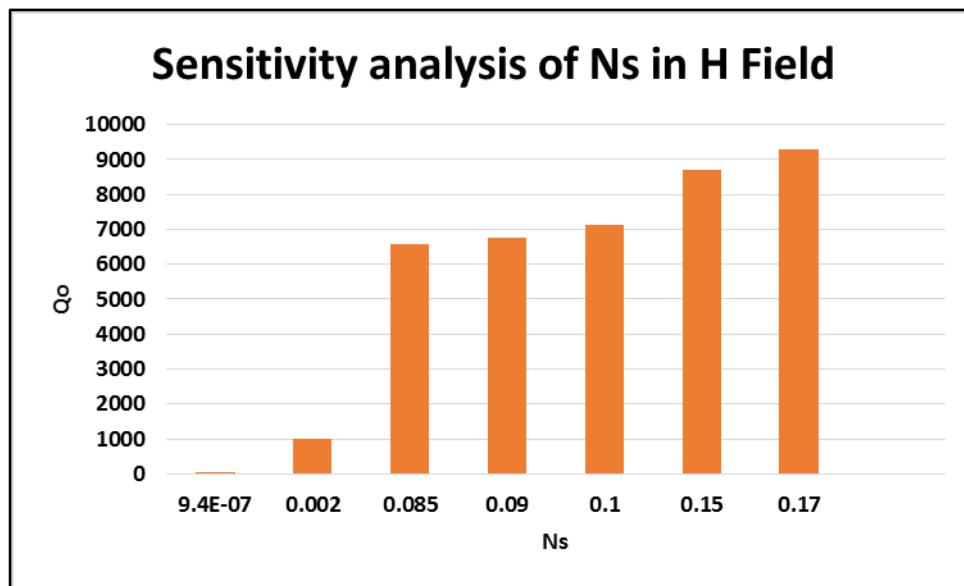
Figure 4.1 Sensitivity Analysis of VAPEX Number in H Field.

As stated in the previous paragraphs and because of small calculated value of VAPEX number N_s, accordingly literature valve of N_s (0.17) had been borrowed and used instead of calculated N_s valve, just to have an idea about the expected performance of VAPEX. The calculation had been repeated again using equation 3-1 and VAPEX number N_s obtain from literature, the

expected startup oil flow rate for well H-Hz and BBW-Hz and the data used for calculation are showed in the table (4.2), and table (4.3) for well BWW-Hz and H-Hz respectively.

As mentioned in chapter-III about Multifunctional chemical agent MFCA and their function and mechanism, MFCA was injected into the H-01 well to increase the oil rate. The MFCA project had been injected in H-01 Well to increase the recovery factor, reduce oil viscosity and interfacial tension in order to increase its mobility, through the injection of MFCA, and creates easy movable oil. H-01Well produced from Amal reservoir with the flowing fluid properties (API 10.3, Viscosity 10,040 cp @ 60°C, and pour point 9°C) and the top reservoir depth at 800 mkb. The fluid is very viscous one, even though the well can't be able to produce without applying heat or any other mean of stimulus. The MFCA injection operation was carried out on 15th August 2016, and the production started on 27th of January 2017.

Well H-Hz was proposed to be drilled in the same Amal Reservoir to study the feasibility of applying VAPEX process and compare the VAPEX results with the previous results of MFCA project in H-01 well. The basic required data for calculation the VAPEX startup oil flow rate is listed in table 4.3 below and used equation 3.1 for calculation startup oil flow rate.

Table 4.2 well BBW-Hz basic data for calculation oil rate.

BBW-Hz Well Data	
Parameters	
L (m)	400
K (m2)	1.9738E-12
g (m/day2)	73,231,257,600
φ %	0.219
ΔSo %	0.5
h (m)	12
Ns	0.17
2KgQSohNs	0.064576413
(2KgQSohNs)^.5	0.254118896
Qo (m3/day)	203
Qo (bbl/day)	1277

Table 4.3 well H-Hz basic data and calculated oil rate.

Well H-Hz Data	
Parameters	
L (m)	400
K (m2)	1.9738E-12
g (m/day2)	73,231,257,600
φ %	0.25
ΔSo %	0.8
h (m)	40
Ns	0.17
2KgQSohNs	0.393159289
(2KgQSohNs)^.5	0.627024153
Qo (m3/day)	502
Qo (bbl/day)	3155
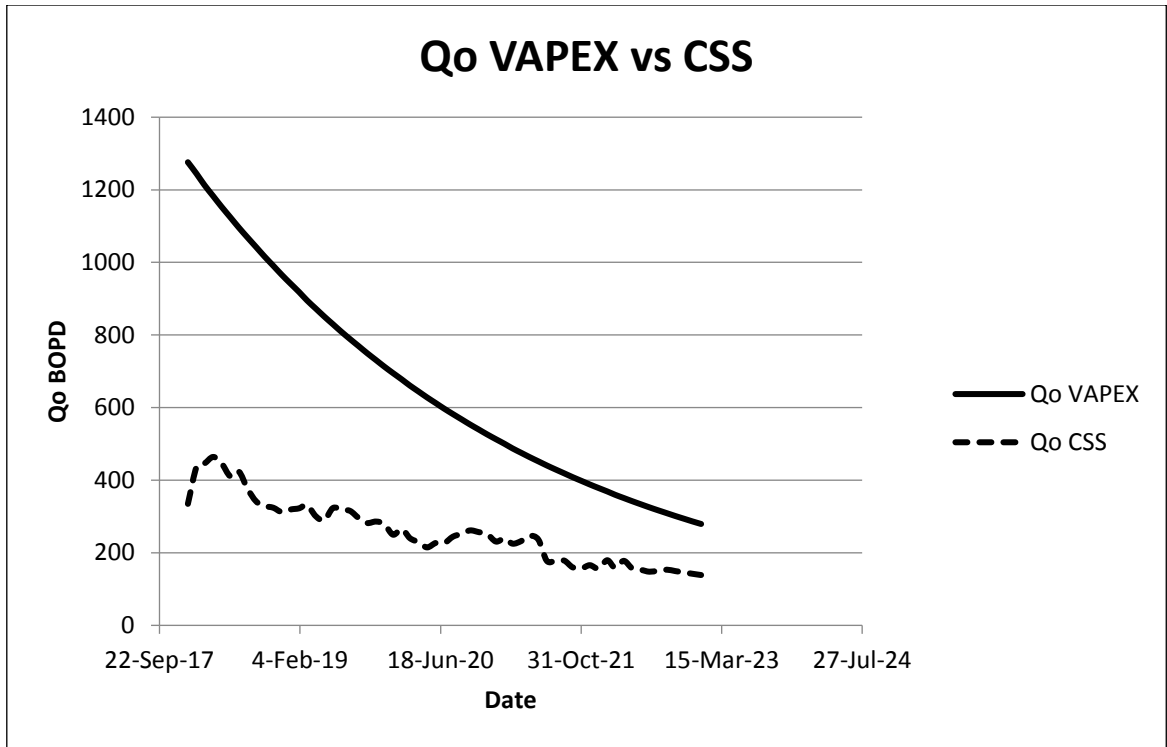
Figure 4.2 Oil rate VAPEX versus CSS.
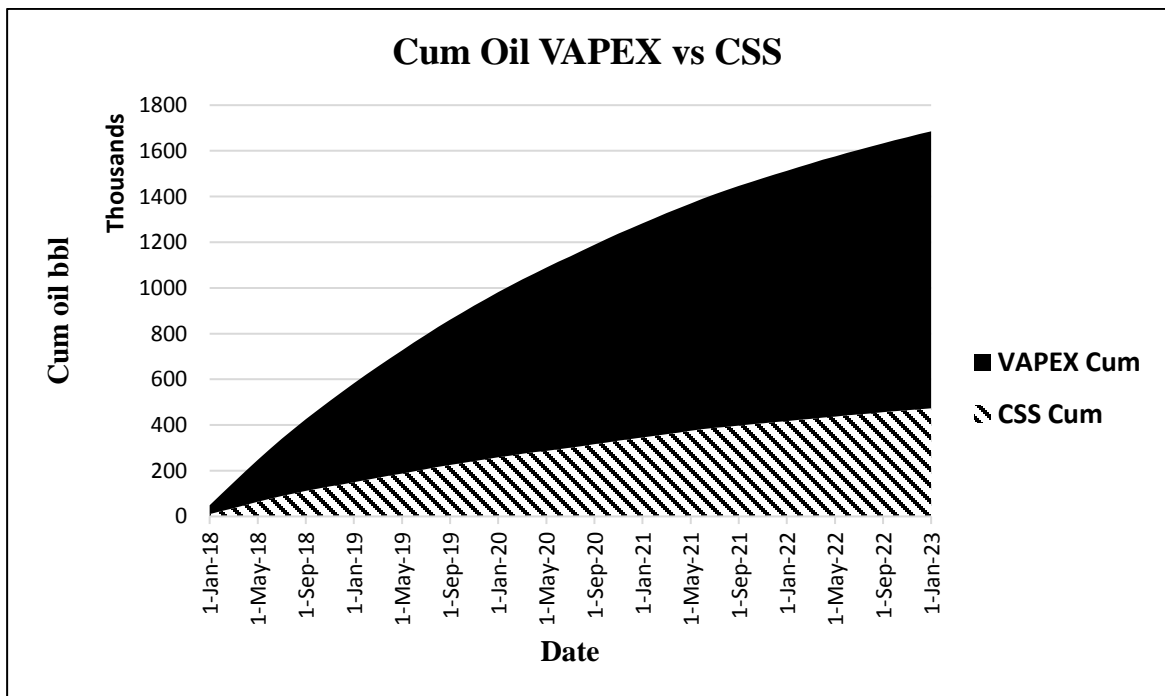
Figure 4.3 cum oil of VAPEX versus CSS.

Qo VAPEX VS MFCA
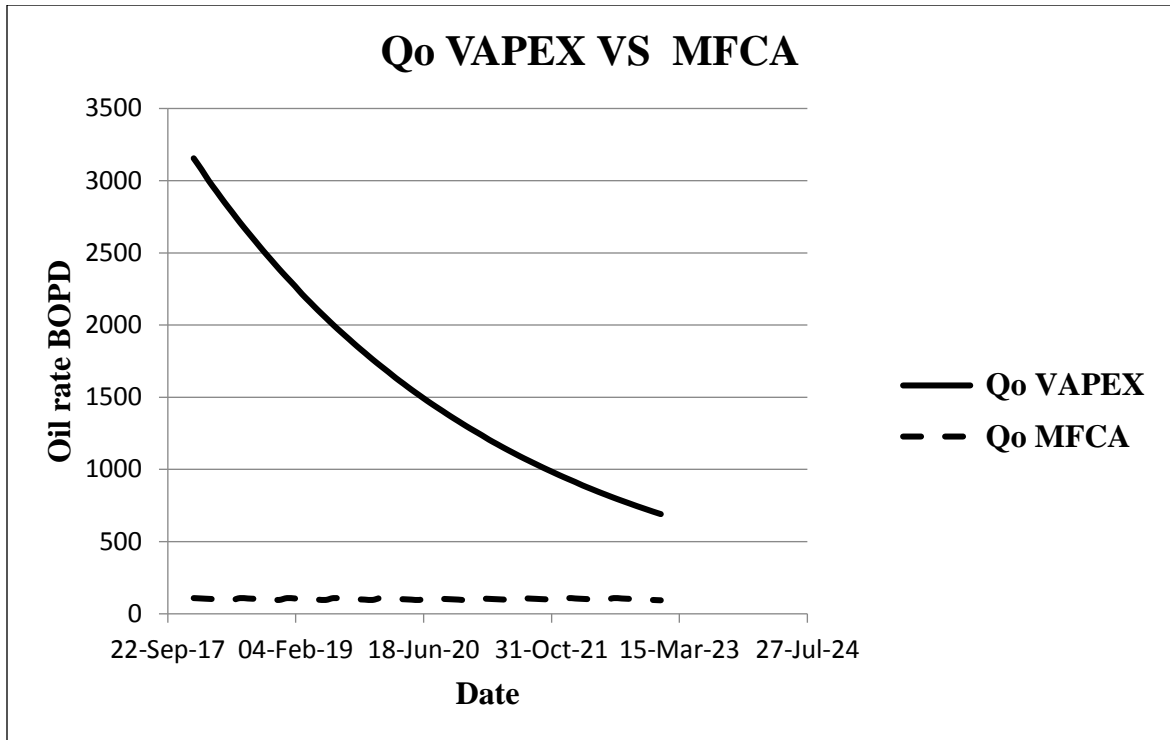
Figure 4.4 Oil rate VAPEX versus MFCA.

Cum Oil VAPEX vs MFCA
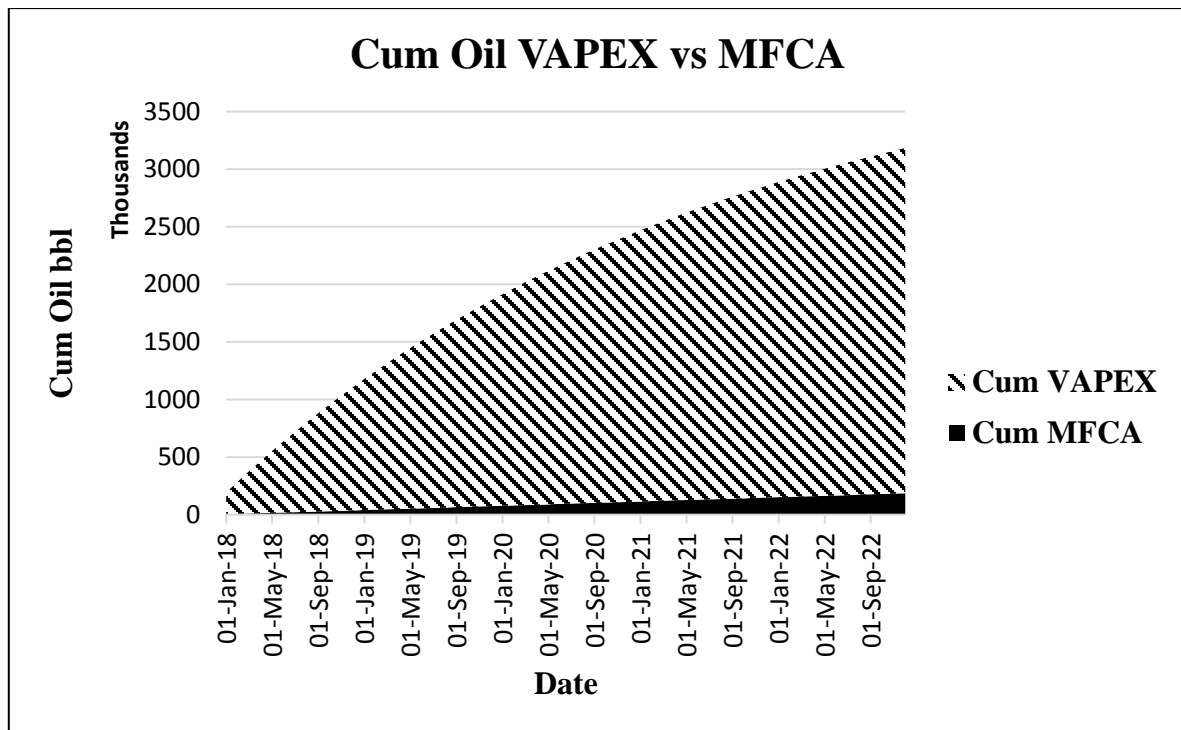
Figure 4.4 cum oil VAPEX versus MFCA

From figure 4.1 the startup oil rate of VAPEX process regarding well BBW-H is 1270 BOPD and that is fourth times the previous startup oil rate of CSS in BBW-42 well which was 335 BOPD, and from figure 4.2 the cum oil forecast of VAPEX in five years is equal to 1.2 million barrel oil compared to cum oil gained in the five years from CSS in BBW-42 well was 0.47 million barrel oil. So it appear that the VAPEX cum oil is three times the CSS cum in five years.

From figure 4.3 the startup oil rate of VAPEX process regarding well H-Hz is 3155 BOPD and that is thirty times the previous startup oil rate of MFCA in H-01 well which was 109 BOPD, and from figure 4.4 the cum oil forecast of VAPEX in five years is equal to 3 million barrel oil compared to cum oil forecast of MFCA for the five years in H-01 well was 0.188 million barrel oil. So it appear that the VAPEX cum oil is fifteen times the MFCA cum in five years.

From the above analysis it look like the H field seem to be good candidate pilot area for applying the VAPEX process because of it crude oil and reservoir properties in term of oil viscosity, reservoir thickness and permeability, and the results support that choice also, so the applying of this technology will enhance a lot the recovery factor of the field compared with the other technologies which already been applied. Also form technical point of view the VAPEX is the best, because it gives high oil gain compared to CSS and MFCA, but NPV should take into account for final execution decision.

CHAPTER V

CONCLUSION & RECOMMENDATIONS

5.1   CONCLUSION

In this research reservoir and crude oil properties data has been collected and analyzed to study the feasibility applying of VAPEX process to Sudanese heavy oil field, and promising results was obtained from technical point of view, and the conclusion of research is summarized as stated below:

- This research attempts to provide some initial understanding and evaluation tool of potential of apply VAPEX process in heavy Sudanese crude oil and based on the results obtained it could possibly be apply.

- From cost point of view it should take into account that in the cyclic stem stimulation CSS & multi-functional chemical agent MFCA implementation was on the existing wells no need for drilling new wells, but regarding the VAPEX process it need to drill a pair of horizontal wells, so the additional cost should take into account.

- H field seem to be good candidate pilot area for applying the VAPEX process because of it crude oil and reservoir properties in term of oil viscosity, reservoir thickness and permeability, as supported by the results.

- H field Recovery factor can be enhanced significantly by applying the VAPEX process technology compared with the other technologies which already been applied, and this was supported by the results.

5.2   RECOMMENDATIONS

Based on the results of this thesis, the following recommendations for future studies are advised to be made:

- To study the idea of using mixture of CO_2 and hydrocarbon gaseous as solvent, since CO_2 is cheaper than the hydrocarbon gases and has higher solubility into the heavy oil than most of the hydrocarbon gases, moreover CO_2 resources is available in nearby fields, so this advantage to be taken in to consideration.

- Mass transfer and diffusion are important factors in VAPEX process, so simulation study is required for better understanding the process and this will help us in selecting the optimum pilot area as well as the implementation.

- To study the idea of using the flared gas in nearby fields as solvent in the VAPEX process in the H field, this will have great an advantages, so instead of flare the gas it is better to be used to produce more oil.

- To use the current existing three vertical wells in H field as an injector and to drill Horizontals as producer this will make the application more economically feasible.

- Pilot projects on the VAPEX process are so far very limited; therefore, more in depth studies and lab experiment on the two Sudanese crude oil from reservoir Bentiu-01 and Amal should be done for better results.

✚ To perform in depth economic evaluation study to compare VAPEX versus CSS and VAPEX versus MFCA in term of project cost and Net present value NPV.

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APPENDIX

Table A.1 History results of CSS project in BBW-42 well

Date	Qo CSS BOPD	CSS Cum Oil MMBBL
1/31/2013	335	0.01
2/28/2013	437	0.02
3/31/2013	446	0.04
4/30/2013	464	0.05
5/31/2013	447	0.06
6/30/2013	411	0.08
7/31/2013	424	0.09
8/31/2013	377	0.10
9/30/2013	341	0.11
10/31/2013	329	0.12
11/30/2013	324	0.13
12/31/2013	312	0.14
1/31/2014	319	0.15
2/28/2014	323	0.16
3/31/2014	331	0.17
4/30/2014	301	0.18
5/31/2014	290	0.19
6/30/2014	323	0.20
7/31/2014	318	0.21
8/31/2014	315	0.22
9/30/2014	296	0.23
10/31/2014	282	0.23
11/30/2014	286	0.24
12/31/2014	279	0.25
1/31/2015	250	0.26
2/28/2015	266	0.27
3/31/2015	240	0.27
4/30/2015	229	0.28
5/31/2015	215	0.29
6/30/2015	227	0.29
7/31/2015	227	0.30
8/31/2015	244	0.31
9/30/2015	252	0.32
10/31/2015	262	0.32

11/30/2015	257	0.33
12/31/2015	252	0.34
1/31/2016	231	0.35
2/29/2016	239	0.35
3/31/2016	225	0.36
4/30/2016	232	0.37
5/31/2016	247	0.37
6/30/2016	236	0.38
7/31/2016	178	0.39
8/31/2016	178	0.39
9/30/2016	178	0.40
10/31/2016	160	0.40
11/30/2016	157	0.41
12/31/2016	166	0.41
1/31/2017	157	0.42
2/28/2017	179	0.42
3/31/2017	159	0.43
4/30/2017	178	0.43
5/31/2017	157	0.44
6/30/2017	153	0.44
7/31/2017	148	0.45
8/31/2017	151	0.45
9/30/2017	153	0.46
10/31/2017	150	0.46
11/30/2017	146	0.46
12/31/2017	142	0.47
1/31/2018	139	0.47

APPENDIX

Table A.2 VAPEX Forecast of BBW-Hz proposed well in Bentiu-01 reservoir.

Date	Qo VAPEX BOPD	VAPEX Cum Oil MMBBL
1-Jan-18	1276	0.04
1-Feb-18	1244	0.08
1-Mar-18	1213	0.11
1-Apr-18	1183	0.15
1-May-18	1153	0.18
1-Jun-18	1124	0.22
1-Jul-18	1096	0.25
1-Aug-18	1069	0.28
1-Sep-18	1042	0.31
1-Oct-18	1016	0.34
1-Nov-18	991	0.37
1-Dec-18	966	0.40
1-Jan-19	942	0.43
1-Feb-19	918	0.46
1-Mar-19	895	0.49
1-Apr-19	873	0.51
1-May-19	851	0.54
1-Jun-19	830	0.56
1-Jul-19	809	0.59
1-Aug-19	789	0.61
1-Sep-19	769	0.64
1-Oct-19	750	0.66
1-Nov-19	731	0.68
1-Dec-19	713	0.70
1-Jan-20	695	0.72
1-Feb-20	678	0.74
1-Mar-20	661	0.76
1-Apr-20	644	0.78
1-May-20	628	0.80
1-Jun-20	612	0.82
1-Jul-20	597	0.84
1-Aug-20	582	0.86
1-Sep-20	568	0.87

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1-Oct-20	553	0.89
1-Nov-20	540	0.91
1-Dec-20	526	0.92
1-Jan-21	513	0.94
1-Feb-21	500	0.95
1-Mar-21	488	0.97
1-Apr-21	475	0.98
1-May-21	463	1.00
1-Jun-21	452	1.01
1-Jul-21	441	1.02
1-Aug-21	430	1.04
1-Sep-21	419	1.05
1-Oct-21	408	1.06
1-Nov-21	398	1.07
1-Dec-21	388	1.08
1-Jan-22	379	1.10
1-Feb-22	369	1.11
1-Mar-22	360	1.12
1-Apr-22	351	1.13
1-May-22	342	1.14
1-Jun-22	333	1.15
1-Jul-22	325	1.16
1-Aug-22	317	1.17
1-Sep-22	309	1.18
1-Oct-22	301	1.19
1-Nov-22	294	1.20
1-Dec-22	286	1.20
1-Jan-23	279	1.21

APPENDIX

Table A.3 History results of MFCA project in H-01 well, (Amal Reservoir).

Date	Qo MFCA BOPD	MFCA Cum oil MMBBL
1-Jan-18	109	0.00
1-Feb-18	106	0.01
1-Mar-18	104	0.01
1-Apr-18	101	0.01
1-May-18	99	0.02
1-Jun-18	96	0.02
1-Jul-18	109	0.02
1-Aug-18	106	0.03
1-Sep-18	104	0.03
1-Oct-18	101	0.03
1-Nov-18	99	0.03
1-Dec-18	96	0.04
1-Jan-19	109	0.04
1-Feb-19	106	0.04
1-Mar-19	104	0.05
1-Apr-19	101	0.05
1-May-19	99	0.05
1-Jun-19	96	0.06
1-Jul-19	109	0.06
1-Aug-19	106	0.06
1-Sep-19	104	0.07
1-Oct-19	101	0.07
1-Nov-19	99	0.07
1-Dec-19	96	0.07
1-Jan-20	109	0.08
1-Feb-20	106	0.08
1-Mar-20	104	0.08
1-Apr-20	101	0.09
1-May-20	99	0.09
1-Jun-20	96	0.09
1-Jul-20	109	0.10
1-Aug-20	106	0.10
1-Sep-20	104	0.10
1-Oct-20	101	0.11

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1-Nov-20	99	0.11
1-Dec-20	96	0.11
1-Jan-21	109	0.11
1-Feb-21	106	0.12
1-Mar-21	104	0.12
1-Apr-21	101	0.12
1-May-21	99	0.13
1-Jun-21	96	0.13
1-Jul-21	109	0.13
1-Aug-21	106	0.14
1-Sep-21	104	0.14
1-Oct-21	101	0.14
1-Nov-21	99	0.15
1-Dec-21	96	0.15
1-Jan-22	109	0.15
1-Feb-22	106	0.15
1-Mar-22	104	0.16
1-Apr-22	101	0.16
1-May-22	99	0.16
1-Jun-22	96	0.17
1-Jul-22	109	0.17
1-Aug-22	106	0.17
1-Sep-22	104	0.18
1-Oct-22	101	0.18
1-Nov-22	99	0.18
1-Dec-22	96	0.19
1-Jan-23	94	0.19

Table A.4 VAPEX Forecast of H-Hz proposed well in Amal reservoir.

Date	Qo VAPEX BOPD	VAPEX Cum oil MMBBL
1-Jan-18	3155	0.10
1-Feb-18	3076	0.19
1-Mar-18	2999	0.28
1-Apr-18	2924	0.37
1-May-18	2851	0.45
1-Jun-18	2780	0.54
1-Jul-18	2710	0.62
1-Aug-18	2643	0.70
1-Sep-18	2577	0.78
1-Oct-18	2512	0.85
1-Nov-18	2449	0.93
1-Dec-18	2388	1.00
1-Jan-19	2328	1.07
1-Feb-19	2270	1.14
1-Mar-19	2213	1.20
1-Apr-19	2158	1.27
1-May-19	2104	1.33
1-Jun-19	2052	1.39
1-Jul-19	2000	1.46
1-Aug-19	1950	1.51
1-Sep-19	1901	1.57
1-Oct-19	1854	1.63
1-Nov-19	1808	1.68
1-Dec-19	1762	1.74
1-Jan-20	1718	1.79
1-Feb-20	1675	1.84
1-Mar-20	1634	1.89
1-Apr-20	1593	1.94
1-May-20	1553	1.98
1-Jun-20	1514	2.03
1-Jul-20	1476	2.07
1-Aug-20	1439	2.12
1-Sep-20	1403	2.16
1-Oct-20	1368	2.20

1-Nov-20	1334	2.24
1-Dec-20	1301	2.28
1-Jan-21	1268	2.32
1-Feb-21	1236	2.35
1-Mar-21	1206	2.39
1-Apr-21	1175	2.43
1-May-21	1146	2.46
1-Jun-21	1117	2.50
1-Jul-21	1089	2.53
1-Aug-21	1062	2.56
1-Sep-21	1036	2.59
1-Oct-21	1010	2.62
1-Nov-21	984	2.65
1-Dec-21	960	2.68
1-Jan-22	936	2.71
1-Feb-22	912	2.74
1-Mar-22	890	2.76
1-Apr-22	867	2.79
1-May-22	846	2.82
1-Jun-22	825	2.84
1-Jul-22	804	2.86
1-Aug-22	784	2.89
1-Sep-22	764	2.91
1-Oct-22	745	2.93
1-Nov-22	727	2.96
1-Dec-22	708	2.98
1-Jan-23	691	3.00