2016

Development of Single-Well Gas Assisted Gravity Drainage Process for Enhanced Oil Recovery

Bikash Deep Saikia
Louisiana State University and Agricultural and Mechanical College, bsaiki1@lsu.edu

DEVELOPMENT OF SINGLE-WELL GAS ASSISTED GRAVITY DRAINAGE PROCESS FOR ENHANCED OIL RECOVERY

A Dissertation

Submitted to the Graduate Faculty of the
Louisiana State University and
Agricultural and Mechanical College
in partial fulfillment of the
requirements for the degree of
Doctor of Philosophy

in

The Department of Petroleum Engineering

by
Bikash Deep Saikia
B.E. (Chemical Engineering), NIT Karnataka, India, 2000
M.S. (Petroleum Engineering), Louisiana State University, 2010
May 2017

This work is dedicated to my beloved deuta, whom I will miss every day of my life…!

ACKNOWLEDGEMENTS

First of all, I would like to offer my heartfelt gratitude to my advisor Dr. Dandina Rao for accepting me to be his student and for his continued guidance, encouragement and support over the years. I would also like to extend my sincere thanks to Dr. Stephen Sears, Dr. Seung Kam and Dr. Mileva Rodanjic for their kind acceptance to serve as members on the examination committee and for providing valuable feedback and guidance towards this dissertation. My sincere thanks to Dr. John Fletcher as well for kindly agreeing to be Dean's representative on my committee at such a short notice.

At this juncture when I am stepping out of school, I would like to take a moment to express my immense gratitude to our entire faculty members, past and present for the knowledge that they bestowed upon us and for being such a positive force in our development. Even outside the confines of the classroom, those snippets of talks and interactions that we had, have been so enriching. I would also like to acknowledge the ready help and support provided by our administrative staff during this period.

Last but not the least, I would like to thank my friends for their cherished friendship and my family members for their unconditional love and support throughout. I would specially like to remember my beloved father, who has been such a positive force and integral part of my life.

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

NOMENCLATURE

CGI	= Continuous Gas Injection
WAG	= Water Alternating Gas
GAGD	= Gas Assisted Gravity Drainage
S-WGAGD	= Single-Well Gas Assisted Gravity Drainage
OOIP	= Original Oil in Place
ROIP	= Remaining Oil in Place
EOR	= Enhanced Oil Recovery
DGOM	= Deepwater Gulf of Mexico Reservoir
N_B	= Bond No.
N_C	= Capillary No.
N_G	= Gravity No.
SCCM	= Standard Cubic Centimeter per Minute
PV	= Pore Volume
RF	= Recovery Factor
IFT	= Interfacial Tension
NL	= Non Layered
LBLP	= Layered Bottom Low Permeable
LBHP	= Layered Bottom High Permeable
T-t-H	= Toe-to-Heel
ROI	= Return on Investment
OCS	= Offshore Continental Shelf

ABSTRACT

EOR application in prolific deepwater Gulf of Mexico (DGOM) reservoirs has remained a challenge. Exorbitant well cost (>200M$) precludes having extensive injection patterns and very characteristics of the reservoirs themselves are partly to blame for negligible EOR activity in DGOM. We have been able to develop and demonstrate a novel design in the form of Single Well – Gas Assisted Gravity Drainage (SW-GAGD) process, which is potentially cost effective, at the same time ensuring very high oil recoveries. In this design, a single well acts as an injector as well as a producer, thereby minimizing well cost. The efficacy of the process has been demonstrated using partially scaled visual glass models and material balance calculations. The recovery factor is in the range of 70-80% in the immiscible mode and near 100% in the miscible mode at abandonment. Such high recoveries are as a result of highly efficient film flow aided gravity drainage process. Being a forced gravity drainage process, SW-GAGD is, however, an order of magnitude faster and thus expected to be an economically viable recovery process. For example, at just 2.5 SCCM (2.3 ft/day), the process was 23 times faster than pure gravity drainage for recovering 61% OOIP (ultimate recovery factor for pure gravity drainage). This process has also been shown to be immune to reservoir heterogeneities like vertical fractures, reservoir permeability layering and reservoir dip and hence laboratory results are more likely to be translatable to the field. In fact reservoir layering with low permeability layering near horizontal lateral was shown to improve the sweep and recovery efficiency compared to no layering case by 6-7% at abandonment. Among various models, semi-analytical Hagoort model was found to best represent forced gravity process in an analytical fashion. It used a non-dimensional form of solution with velocity incorporated in the gravity no. definition to account for forced gravity drainage process. A reasonable match was obtained for SW-GAGD recoveries, with slight under prediction of

recoveries post breakthrough. This is attributed to non-consideration of film drainage, which is anticipated to play an important role, especially post breakthrough.

CHAPTER 1: INTRODUCTION

1.1 Gas Injection EOR in the Context of US EOR Scenario

Most of the oil produced within continental US comes from mature oil fields. Production from these mature oilfields has been declining over the years and a great deal of emphasis is placed on new discoveries, so as to be able to keep pace with the decline. Massive discovery efforts have been made in Federal Outer Continental Shelf (OCS) and tight oil basins relying on deep sea drilling and hydraulic fracturing technologies, whereas disproportionate interest has been shown towards Enhanced Oil Recovery (EOR) from these depleted fields. This is partly because of the widespread industrywide notion that cost-benefit equation is quite lopsided against EOR as a result of low recovery factor and additionally low ROI on developmental expenditure. Our industry, which is sensitive to the bottom line, has been unwilling to invest in expensive chemical EOR processes as the outcome has not been lucrative enough. Thus chemical EOR has been close to non-existent in US after peaking in the 90s as per biennial O&GJ surveys (Koottungal[35]-2014). The best performing among EOR processes have been gas injection processes, particularly miscible CO_2 EOR process, accounting for over 68% of US EOR projects. Gas injection, particularly CO_2 EOR, has been attracting the most new market research as per DOE[14]. The popularity is mainly because of high microscopic displacement efficiency of gas injection processes and relatively lower costs. One of the success stories relying primarily on gas based CO_2 EOR processes is a company, whose business model consisted of acquiring mature fields and using CO_2 gas injection EOR to maximize recovery. Their considerable success, however, has not been able to make much of a dent into that prevalent notion of low ROI on EOR. In terms of a sound business model and on ground resources, the company was one of the best placed EOR company to make any headway in that regard, but because of low recovery factor (5-10% RF for WAG) associated with default industry standard CO_2 injection processes, their stock price has taken a hit, exacerbated by current (2016) low crude prices. As a result, in conventional light-medium oil space, EOR still remains a somewhat exotic choice. Thus a sizable oil chunk is getting left behind in the depleted mature fields. The size of prize for EOR in US alone is around 400 billion barrels. This number is only slated to increase as newer oilfields are brought online in Federal Outer Continental Shelf (OCS) with much lower recovery factors. To keep the numbers in perspective, proven oil reserves in US is around 40 billion barrels and that estimates of yet undiscovered, technically recoverable oil resources is 198 billion barrels[28]. So, roughly the EOR prize is 10 times the proven oil reserves and twice the total estimated discoverable resources in US. This should be sufficient incentive for pursuing EOR projects in the US and around the world.

1.2 Water Alternating Gas (WAG) Vs Gas-Assisted Gravity Drainage (GAGD) Process

Water Alternating Gas (WAG) process as depicted in DOE website is shown below in Figure 1.1.

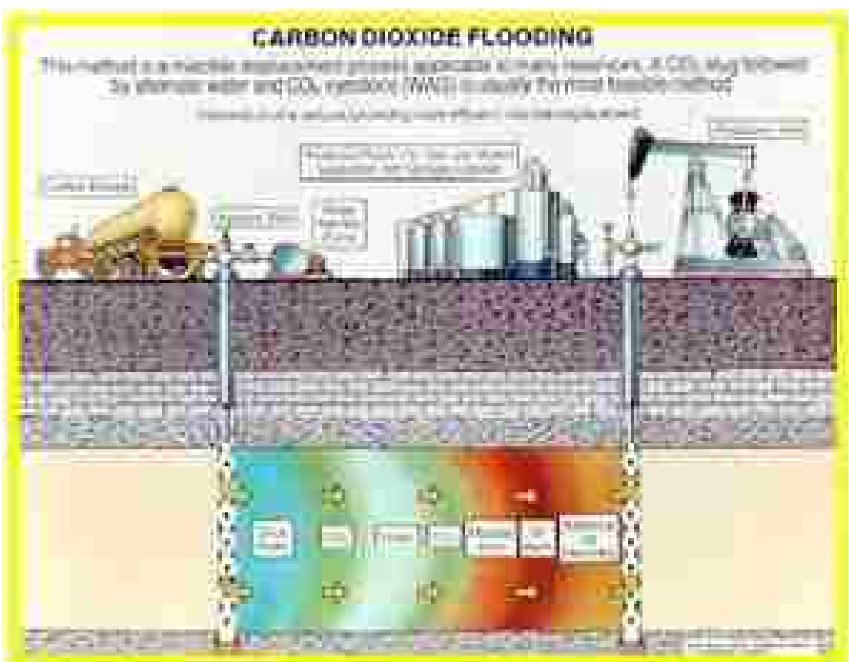

Figure 1.1: Conceptual view of WAG (Ideal case)
(Ref: US-DOE[14])

WAG process was first proposed in 1958 by Caudle and Dyes[8] as an improvement over Continuous Gas Injection (CGI), continues to be the default option for mobility control in horizontal gas floods in spite of poor additional recoveries. As depicted in Figure 1.1, we would expect almost 100% recovery efficiency for the WAG process. An extensive field review by Christensen et al.[10] reported only 5-10% OOIP additional WAG recovery. Water injected in WAG floods, blocks part of the oil from solvent contact resulting in reduced displacement efficiency. Furthermore, gravity override of the injected gas also leads to poorer sweep of the reservoir. Hence, a more realistic view of WAG would be as shown in Figure 1.2.

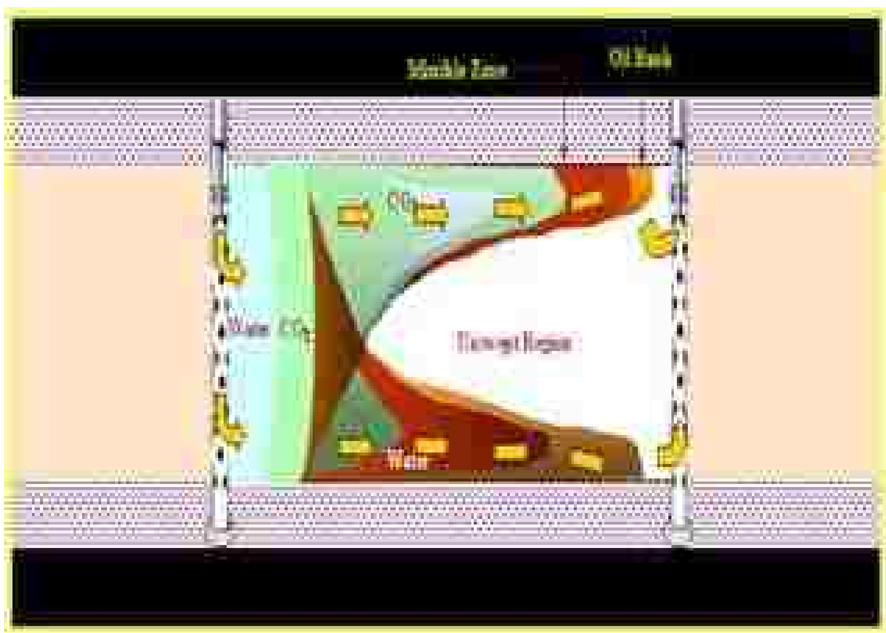

Figure 1.2: A more realistic view of WAG (Rao et al.[53])

To overcome the limitations of WAG, Gas Assisted Gravity Drainage (GAGD) was developed in EOR labs of LSU-Pete-Engg. Dept.[53]. Following events occur in a typical GAGD process:

- Gas is injected at the top of the pay zone using vertical injectors.
- Expanding gas zone pushes oil downward and sideways.

- Oil drainage and film flow of oil occurs to the horizontal producer at the bottom of payzone.

A typical GAGD process is shown in Figure 1.3. GAGD has been successfully tested through

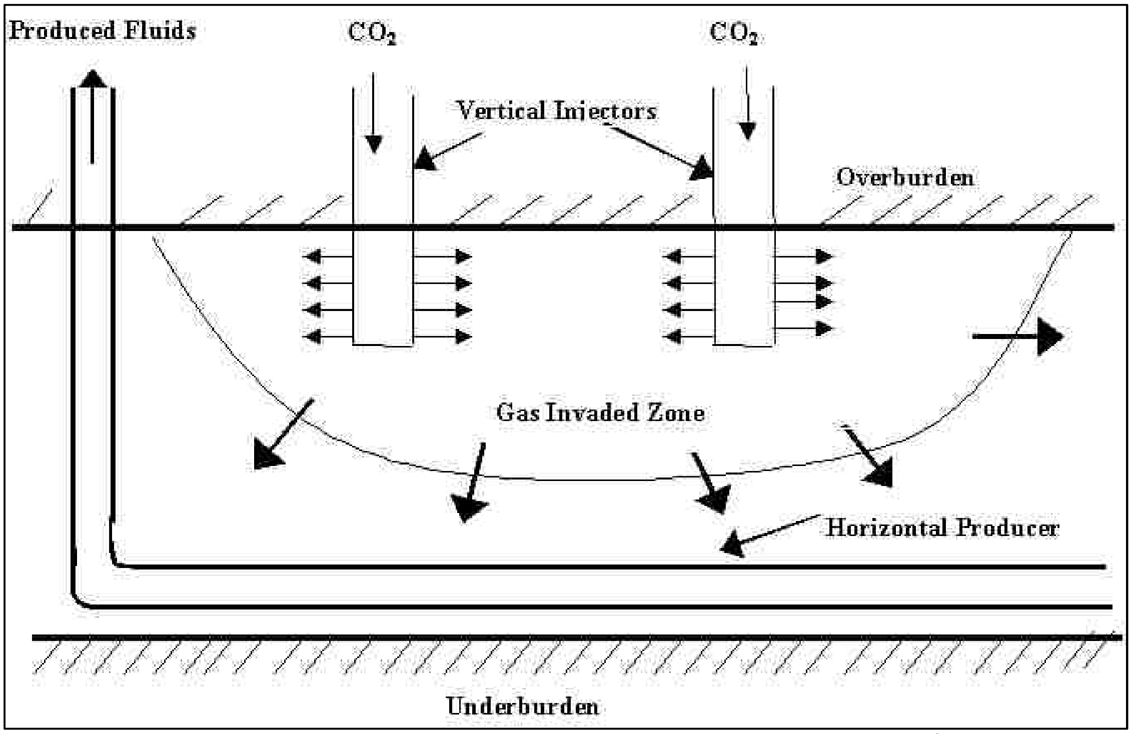

Figure 1.3: Conceptual view of GAGD process (Rao et al.[53])

stages of partially scaled visual models, reservoir condition corefloods and showed recoveries in the range of 65-100% OOIP including miscible mode. GAGD process has been shown (Mahmoud[46]-2007) to be insensitive to reservoir heterogeneities such as fractures and in fact benefit from their presence unlike WAG. Detailed compositional reservoir simulation of a planned field test also yielded recovery of 65% OOIP (88% ROIP) on a field scale. More results are awaited with the ongoing field test in a Louisiana oil field.

An Advanced Resources International report[1] (ARI - 2006) prepared for US Department of Energy has defined the state of the art technologies while discussing technologies that can hugely impact the CO_2 EOR scenario in continental US and GAGD exactly fits that definition. In terms of the way we view gas floods and the recoveries, it truly presents a paradigm shift in the gas injection EOR scenario.

1.3 Adaptation of Gas-Assisted Gravity Drainage (GAGD) Process to Deepwater GOM

Deepwater Gulf of Mexico in Federal OCS contains some of the most prolific reservoirs and has seen rapid growth in terms of oil and gas exploration and production activities. But unlike onshore reservoirs, offshore is an extremely high cost environment, particularly in terms of drilling and completion, where a single well costs in excess of $200 Million (U.S. EIA[64]-2016). Even though the recovery factors upon primary depletion are dismal for these reservoirs, we still do not have a robust secondary or tertiary recovery process in place to sustain the production in the longer term. As we are gradually moving into deeper Paleogene reservoirs, well costs are going to get higher and recovery factor even lower. Deeper Paleogene reservoirs are estimated to have a recovery factor of just 10%. Thus the need for a suitable EOR/IOR is imperative or else those high cost well would simply be plugged up upon depletion. Now, conventional pattern floods that are commonly employed in onshore fields become cost prohibitive, especially in the face of challenges such as low additional recovery factor of present EOR processes, exorbitant well costs, smaller reservoirs and exacting depositional environment. GAGD process that works with nature and which has been shown to be such promising in terms of recovery factor and robust because of its immunity against reservoir heterogeneity is thus a potential candidate for such an environment. However, multi-well GAGD may need to be adapted so as to make it amenable to this high cost environment. Could we do so in an effective way will be answered in the following study.

CHAPTER 2: CONCEPT OF SW-GAGD PROCESS AND RESEARCH OBJECTIVES

2.1 Concept of SW-GAGD Process

As discussed in chapter 1, Gas Assisted Gravity Drainage (GAGD) process, patented by LSU, has yielded recoveries in the range of 65-95% and is found to be impervious to natural vagaries like reservoir heterogeneities. This is a quantum leap in terms of recovery factor over the commercially practiced industry standard processes of Continuous Gas Injection (CGI) and Water Alternating Gas (WAG), whose recoveries fall in the range of 5-10% of the remaining oil. Hence, we would very much like to translate the success of GAGD to deepwater Gulf of Mexico environment containing some of the prolific reservoirs in the world. But the cost of drilling and completing a well in deepwater Gulf of Mexico environment is extremely high and thus having a conventional pattern flood using commercial processes or even Multi-well GAGD process will be cost prohibitive. Moreover as high as 57% of the deepwater Gulf of Mexico reservoirs have OOIP <50MMSTB (Lach et al.[39]-2010) and thus may not even qualify for a multi-well process from an economic standpoint.

Based on these considerations, to emulate the success of GAGD in high cost deepwater Gulf of Mexico environment, concept of a Single-Well GAGD (in short SW-GAGD) came to be realized. Since for drilling and completing a deepwater Gulf of Mexico horizontal well, the production casing necessarily goes through the upper formations. So the idea of using that casing in the upper part of the payzone for injection and then producing through the horizontal lateral at the bottom of the payzone was conceived. In the novel SW-GAGD process, a single well will performs both as an injector and a producer operating in GAGD mode. Gas is injected through the perforations in the vertical casing at the top of the payzone; accumulates at the top of the payzone due to gravity segregation and displaces oil, which drains to the horizontal producer. The conceptualized schematic of the novel process of SW-GAGD process is as shown in Figure 2.1.

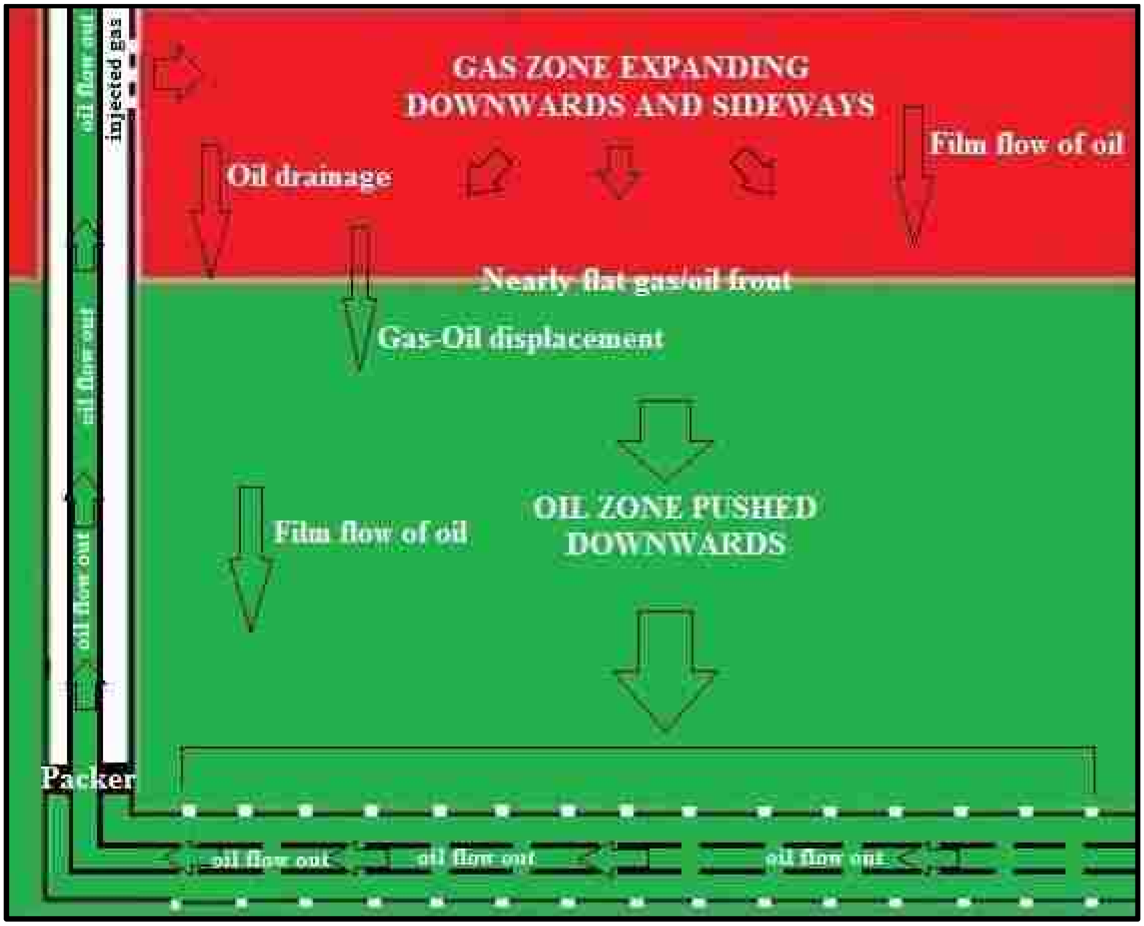

Figure 2.1: Conceptual schematic of SW-GAGD process

In this novel SW-GAGD process gas would be injected through top perforations (lateral) existing in the production well borehole itself, rather than through multiple vertical injector wells existing in a conventional GAGD process. The oil production will take place through the horizontal lateral at the bottom of the payzone.

With continued gas injection at the top of the payzone, the gas chamber would grow laterally sweeping the entire extent of the reservoir at the top before propagating down in a gravity stable top-down manner. This will maximize the volumetric sweep without any increase in water saturation in the reservoir, which is in sharp contrast to WAG process, wherein water is injected in alternating slugs along with gas. The gravity segregation of gas also helps in delaying, or even eliminating, gas breakthrough to the producer as well as preventing the gas phase from competing for flow with oil. This is also in stark contrast to WAG process, where water, oil and gas compete to flow to the producing wells.

Additionally, in case of water-wet formation, oil will be preferentially displaced by gas through continuous spreading films while the water is held back by adhesive forces at the rock surface as well as by capillary pressure within smaller rock pores. In case of oil-wet formations, the thick wetting films will create continuous drainage paths for the oil to flow to the horizontal producer.

Thus the proposed SW-GAGD process not only tackles dual problems of poor sweep and water-shielding associated with conventional WAG process but also increases oil saturation, thereby improving oil relative permeability near the producing well bore with the elimination of competing gas flow. Because of these factors, SW-GAGD is expected to perform much better in terms of recovery factor and rates, compared to current processes like WAG and CGI. Moreover these benefits are accrued at fraction of the cost of conventional EOR processes or even GAGD. Thus in short, the proposed SW-GAGD process offers significant benefits in terms of production rates and recovery factor with minimal cost and promises to bring the benefit of highly efficient EOR, specifically GAGD, to smaller deepwater DGOM reservoirs. The benefits of SW-GAGD process need not be confined to deepwater Gulf of Mexico reservoirs and can also be taken to onshore reservoirs.

2.2 Economic Potential for SW-GAGD process

As stated in chapter 1, the size of prize for EOR is 400 Billion barrels of stranded oil within US and 2 Trillion barrels worldwide. Thus there exists a tremendous potential for SW-GAGD process from resource perspective. Only a fraction of small, independent operators within United States currently engage in EOR activities and it's mostly employed by either the big oil companies or a handful of dedicated EOR companies. EOR is still perceived within the industry at large as influencing only the marginal returns. The cost effectiveness of SW-GAGD process, however, can change that perspective and make EOR as widespread as primary depletion. This can help the bottom line of smaller operators, who currently are simply happy with producing the easy oil through primary depletion because of lopsided cost-benefit equation against current EOR processes. SW-GAGD process can even replace primary depletion as the production of choice in the future. Thus SW-GAGD can be a game changer in terms of recovery, cost effectiveness and can potentially to incentivize hitherto smaller operators to jump in on the EOR bandwagon.

As mentioned previously, 57% of DGOM reservoirs are small (<50 MMSTB) reservoirs and there isn't the incentive for EOR application in those reservoirs even for the oil majors. SW-GAGD by virtue of its cost effectiveness vis-à-vis recovery can change that cost-benefit equation and take the benefit of EOR to these reservoirs. CO_2 sequestration is gaining attention worldwide and depleted oil and gas reservoirs are floated as CO_2 storage sites. However, CO_2 sequestration by itself is a costly proposition and coupling of CO_2 sequestration with CO_2 EOR is thus considered to provide the needed economic incentive. SW-GAGD can be a great facilitator in that regard by virtue of its cost effectiveness and recovery enhancement.

Thus SW-GAGD process potentially offers a host of benefits that can revolutionize the way our industry operates.

2.3 Research Objectives

The main research objectives for the development of SW-GAGD process are summarized below:

1) To carry out feasibility study and subsequent development of a suitable Single-Well process for successful application of Gas-Assisted Gravity Drainage (GAGD) process.

2) To prove the concept (Proof-of-Concept) of SW-GAGD process

3) To build and run experiments on partially scaled physical models, so as to be able to scale-up the model results to fields

4) To evaluate performance of SW-GAGD process and compare with GAGD process

5) To test various well configurations to be able to determine the best possible practical designs.

6) To develop an empirical model to predict the performance of SW-GAGD process

In relation to the research objectives, Chapter 3 will compile the pertinent literature needed to understand, explain and design the experiments needed to advance this study. Chapter 4 will deal with the methodology employed in fulfilling those objectives and then Chapter 5 will discuss the results obtained, followed by summary and conclusions in chapter 6.

CHAPTER 3: LITERATURE REVIEW

This project is on development of a single-well gas assisted gravity drainage process. The literature on this area of gas injection have been thoroughly investigated and reported in following categories.

3.1 Field Gas Injection Projects – Horizontal Floods

Cubillos et al.[12] (2005) have reported on a successful peripheral miscible gas injection in RKF field, Berkine Basin, Algeria. RKF was a flat structure with good vertical and lateral continuity. Reservoir consisted of stacked fluvial deposits of sandstone interbedded with claystones. Average porosity was 16% with an average permeability of 200 mD. Thickness of gross reservoir sequence averaged around 225 m with a vertical stacking pattern of 10m coarsening upward. Reservoir fluid consisted of both volatile oil and retrograde condensates. The challenges they faced was distortion of miscible gas front by reservoir anisotropy leaving behind a large amount of bypassed oil. Gas breakthrough was seen as the main reason for production decline under constraints of gas compression capacity.

Davis et al.[13] (2004) reported on the seismic monitoring of CO_2 miscible flood in a thin carbonate reservoir (30m) in 1.4 billion barrel Weyburn field. It consisted of 2 distinct zones, the upper unit, the Marly, has a low permeability of 10 mD with a porosity of 26%. It ranges in thickness from 7-10 m. The lower unit, the Vuggy, is slightly higher permeability 15mD with a lower porosity of 15% and ranges in thickness from 15-20 m. The lower Vuggy unit has much higher flow capacity relative to upper Marly unit resulting in low oil recovery in Marly unit. Reservoir was reported to have extensive natural fractures. After primary depletion and subsequent waterflood, the recovery factor was at 25 % and thus had a huge potential for tertiary CO_2 flood. The project was anticipated to recover 15% of OOIP. The flood was designed to target unswept reserves in the upper Marly unit. CO_2 flooding started in October 2000 and initially 19 horizontal wells were converted into a CO_2 miscible flood with CO_2 injection rates of 3-7 MMSCF/Day/well. Seismic studies indicated the preference of the flood to move along fracture zones. Production enhancement due to CO_2 injection was observed in certain directions but not observed in certain other directions. This was attributed to preferential movement along fracture zones, as stated earlier. Natural fractures were also a concern with regard to early breakthrough of CO_2 leading to poorer lateral sweep.

Christensen et al.[10] (1998) have reported a review of 59 WAG field projects, starting with WAG flood in 1957 by Mobil in North Pembina field, Alberta, to the latest till date in 1996 in North Sea. This seminal review paper included both offshore and onshore projects as well as hydrocarbon and non-hydrocarbon injectant based WAG. It also covered all kinds of reservoir types including sandstone, limestone, dolomite and carbonates. Despite being the most popular gas injection process in terms of field application, the performance of WAG has not been very promising. The overall recovery factor for WAG has been between just 5-10% but yet these recoveries have been touted as a success and the reason may be the absence of viable alternative in our arsenal. WAG process suffered from early breakthrough as a result of override or channeling and sometimes the wells need to be shut off. This overriding is particularly in critical because of limited nos. of well. Among the miscible projects, loss of pressure as a result of early breakthrough is a serious problem as miscibility gets affected. Apart from poor recoveries, WAG suffered from hordes operational issues like corrosion, scaling, Asphaltene and hydrate formation, reduced injectivity of water, etc. Nevertheless, WAG continues to be the default option for gas injection with over 90% of projects employing WAG and more projects brought under its umbrella.

Kokal et al.[34] (2016) presented the early results of CO_2 miscible WAG pilot study in a Saudi field. It had 4 injectors with 4 producers placed in line drive pattern, up dip about 2000 ft from the injectors. CO_2 was injected into 2 injector wells at a maximum capacity of 40 MMscf/d and water was injected into the rest 2 injectors with 1 month alternation cycle between the water and CO_2 injectors. Initial results indicate a positive response to oil production with CO_2 breaking through in 2 of the producers.

Choudhary et al.[9] (2011) presented the results of WAG pilot tests in field E, an offshore West Africa field. The first pilot WAG (B6i-B1) Injection was carried out in a down dip injector well with producer well around 1.5 km apart. The evaluation period was for 18 months. WAG was shown to have some effect in mitigating the downward trend in production. They have found that the decline rate prior to WAG was 55% and after a year since commencement of WAG the decline rate was 25%. This would require the assumption that the production trend follows a linear decline. The incremental oil was 60,000 bbls from 990 MMSCF gas injected with gas utilization ratio of 17.5 MSCF/BBL. The breakthrough of injected gas was estimated around 170 days but the GOR trend started the upswing even before that. Buoyed by the success of the first WAG pilot, they embarked on the second WAG (B9i-B2) and it had a better production trend than the first one. For this WAG, however, GOR trend remained closely flat, raising questions about preferential movement of gas towards the other WAG pair.

Kane et al.[33] (1979) reviewed the performance of CO_2 WAG project conducted at SCAROC unit since 1972. Kelly-Snyder field located in Texas is a major unitized field among four contiguous fields along the 35 X 5 mile Canyon Reef formation. Estimated OOIP was 2.73 billion STB. CO_2 WAG was started in Oct 1971 by doing a prewater injection of 21.5 million bbl, representing 3.7% HCPV. CO_2 injection began in Jan 1972 and breakthrough at producers happened in June 1972. Project suffered from reduced CO_2 supplies as well as CO_2 handling capacity and it was partly offset by increasing the WAG ratio. Use of higher WAG ratios resulted in loss of lift and hence necessitated installing artificial lift. Notwithstanding these operational problems, WAG process was affected by vertical and areal reservoir heterogeneity. The project was still considered an economical success owing to low standards expected of EOR processes.

Erbas et al.[17] (2014) presented the studies carried out to explore the possibility for improving booth the areal and vertical sweep efficiency of a mature WAG pattern in Magnus oilfield in North Sea. Magnus field, discovered in 1974, started producing in 1983, followed by start of water injection in 1984 to provide pressure support and sweep. Plateaus production phase was maintained until 1995, at a rate of 150 MSTB/D, succeeded by a period of decline for the next 7 years. This decline led to initiation of a miscible gas injection scheme using WAG process in 2002. The field is a late Jurassic turbiditie reservoir containing undersaturated oil with an API gravity of 39^0. The crest of the field was 185 meter above the OWC. The reservoir is divided into upper sandstone (Magnum Sandstone Member) and lower clay formation (LKCF). MSM was further divided into 3 prominent layers (lobes), MSM-G, MSM-E and MSM-A from top. In the WAG scheme lean hydrocarbon gas with an MMP of 5000 psi was injected. The average net gas utilization factor was 3.5 mcf/stb. Till date WAG was implemented in 3 panels, namely A3-B3, Central and South as per their field classification. The GUF in these 3 panels varied depending on their structure, showing good numbers for A3-B3 because of its confined structure and Up dip injection, leading to efficient areal and volumetric sweep. However, the central panel fared poorly and was a candidate for improvement because only 19% PV of gas had been injected. Even though as a whole Central fared poorly compared to A3-B3, lobe-wise, MSM-A performed the worst, with MSM-E still relatively immature. Looking at the remaining oil data in the Central panel, it is seen that it is at the middle lobe that has not been swept well. The reason is because of overriding of gas and underriding of water, leaving the middle part unswept in the vertical cross section. MSM-A, the lowermost lobe suffers from low gas utilization efficiency for the same reason. This is despite a large well count in that panel. Based on 4-D seismic and PLT data, there is severe overriding of gas leading to poor areal and vertical sweep, after years of WAG injection. The recovery stands at less than 5% OOIP for the lower lobes and below 10% even for the upper lobe. To mitigate this problem of poor sweep, they are having to go through complex process of identifying and maturing expensive wellwork. Vertical sweep control has been especially bad, necessitating consideration of foam treatment options. This excellent paper on Magnum field brings out the inherent problems of poor volumetric sweep associated with WAG process to the fore.

Hsie et al.[27] (1988) reported on a miscible WAG flood pilot in Quarantine bay 4RC (QB 4RC) project. It was a watered out and low dip reservoir with a net pay of 15ft. Considerable heterogeneity existed within the formation. Porosity averaged around 26% and permeability ranged from 100 to 900 mD. The residual oil saturation average 38% prior to start of WAG. The 57 acre pilot consisted of one injection well, two monitor wells and 5 producers. CO_2 injection was started in Oct 1981 and was completed by Feb 1983. Oil production only began in Feb 1982, 3 months after the start of WAG. Continuous water injection was started after the last cycle of CO_2 injection. Cumulative oil recovery was 16.9% through 31st October, 1987. Even though gravity segregation was predicted by simulation, however, field data didn't indicate severe channeling or override. This discrepancy was believed to be because of reservoir heterogeneity, dispersion and diffusion which promoted spreading and mixing between CO_2 and reservoir oil.

Crogh et al.[11] (2002) presented WAG operation experience in Statfjord field in North Sea. Discovered in 1973, it was the largest oil discovery to date (2002) in Europe. OOIP was 1 billion Sm^3 and the expected recovery was 65%. At plateau phase the production phase was 110,000 Sm^3/Day. In around 1997, the production declined to oil rate of just 29,000 Sm^3/Day, when WAG was implemented to turn around the production decline. Statfjord field is 25 km long by 4 km wide with good pressure communication, despite the fact that east flank is a highly faulted area. Two most important reservoirs are the middle Jurassic Brent group and the Triassic to Jurassic Statfjord formation. It's the Brent reservoirs with 80% pf the OOIP, which was subjected to WAG. The reservoir structure was believed to be conducive to WAG because of the associated reservoir dip . Prior to WAG, the reservoir was waterflooded by having series of injectors below the OWC and having producers located near the structural top. The waterflood earlier provided a good oil displacement. In 1997, the waterflood was supplemented by downdip WAG in order to displace remaining oil in the attic and roof areas and to improve sweep efficiency in water flooded part. Increase in oil production was seen prior to breakthrough. The average daily incremental oil rate due to WAG implementation was assessed to be around 3600 Sm^3/Day. The field results during WAG indicated extensive gas migration upwards in the formation. This vertical migration led to poor sweep efficiency by gas, which they opined to be relatively underestimated in reservoir simulation models.

Ghahfarokhi et al.[19] (2016) presented on the WAG sensitivity in SACROC unit in Kelly Snyder field covering approximately 56,000 acres with 2,800 MMSTBO of OOIP. The reservoir thickness varies from 10 ft on the flanks to 900 ft on the crest of the reef. By late 1950s around 1600 producing wells were drilled with irregular 40 acre spacing. Reservoir pressure dropped by 50 % in 2-3 year time frame as it produced by solution gas drive and the expected recovery was 19%. In 1954 a massive pressure maintenance program through water injection was initiated. By 1971 the recovery factor was 19% of OOIP and percentage of reservoir area with bottom-hole pressure values above bubble point pressure increased from 1% to 80% in 7.5 years. After pilot testing of WAG, the first phase of WAG implementation began in 1972 and expanded over the years under different operators. The response to WAG has been mixed in this field. In some areas, within hours of CO_2 injection channeling was reported. They found, in their terminology, a number of injection patterns (150) to be WAG sensitive showing decrease in water injectivity with corresponding production decline. The WAG sensitive wells also showed CO_2 and water injection profile redistributions. In their limited dataset, higher WAG sensitive patterns had higher Dykstra-Parson's coefficient.

3.2 Gravity Stable Gas Injection – Laboratory and Field Cases

Carlson et al.[7] (1988) and Langenberg et al.[40] (1995) reported on the gas drive gravity drainage in Hawkins field. Hawkins field, discovered in 1940 is in the southeast corner of Wood County, TX. The field was developed with 20 acres spacing. Production is from Woodbine formation, which is divided into upper Lewisville and lower Dexter sands. The Dexter sands were thick, massive and had good lateral continuity with a 6^0 dip. The Woodbine reservoir originally contained >1.3 billion bbl and 430 Bscf of cap gas. The Dexter sands contained 70% of OOIP. The field itself was divided into 2 fault blocks – East and West. Gas injection started in March 1977 in EFB in the crestal gas cap of this dip structure and by 1979 gas drive was the predominant drive mechanism and severely limited the water influx, aimed at producing the remaining oil column by gas drive and depressing the movement of OWC. From the start of gas drive until 1987, EFB produced 58 MMSTB of oil with 90 Bscf of gas and the oil column thickness was reduced from 305 to 25 ft during this 10-year period. The project is estimated to produce 200 million barrels of incremental oil, amounting in an additional recovery of 20% of OOIP.

Bangia et al.[3] (1993) reported on miscible CO_2 flood in Wellman field, a limestone reef reservoir in Terry County, TX. A vertical CO_2 miscible flood was implemented in 1983 to improve the recovery in already waterflooded upper reservoir. The injection began just below the secondary gas cap at 5 MMscf/D which was increased to 10 after 6 months. The field showed good tertiary CO_2 injection response. Immediately after CO_2 injection, increase in oil production was noticed and oil production rose to 2350 from 1750 BOPD. This production increase continued for 6 months or so, when it plateaued.

Johnston et al.[32] (1988) reported on the Week's Island S sand reservoir B gravity stable CO_2 field test. This was a highly permeable steeply dipping sandstone reservoir. Gas injected was a mixture of CO_2 with 6 mole %Methane. S sand Reservoir B (S RB) initially contained about 3 MMSTB of oil underlying a 38 BCF gas cap. The oil column was first produced by gas cap expansion followed by water injection. CO_2 plus hydrocarbon slug started in Oct 1978 and continued till Feb 1980. The oil bank grew to 57 ft from starting 28 ft by early 1981. Overall, the project demonstrated excellent displacement efficiency of the gas flood. Core analysis showed displacement of >90% of waterflood residual oil saturation.

Martin et al.[47] (1982) presented on the Wizard lake D-3A pool miscible flood. The reservoir is a dolomitized bioherm reef. The oil column covered an area of 3725 acres at the original oil-water contact. The reservoir was initially undersaturated with no gas cap had an initial pressure of 2270 psig. The saturation pressure was 1975 psig at a reservoir temperature of 167^0F. The reservoir developed on 40 acre spacing was fully delineated by 1950s and the production continued till 1969 by combination of gas expansion, water drive and gravity segregation. In 1969 a hydrocarbon miscible scheme was initiated on this reservoir in the crestal part. The injectant slug used was liquefied petroleum gas. The recovery from primary depletion, which was a combination drive, was 66% of OOIP. The rest 18% ROIP, totaling 84% OOIP is attributed to the miscible flood.

Bilozir et al.[4] (1989) presented the performance analysis on a mature miscible flood in AA pool Rainbow field, Canada. Rainbow field is a dolomitized carbonate reservoir. It had an OOIP of 11 million cubic meters. It was discovered in 1967 and primary production resulted in pressure decline below bubble point within a year. In April 1969, a gas injection scheme was implemented and following that in April 1971, water injection into aquifer was started. A vertical hydrocarbon miscible flood was started in August 1972. The injectant slug composed of a minimum 45 mole % ethane plus at the apex of the reservoir. The miscibility was designed to be a multi-contact condensing gas drive. The recovery with miscible flood was estimated to be 75% OOIP over the waterflood estimated recovery factor of 49%.

Lee et al.[41] (1994) put forward performance review of Brazeau river Nisku Dry gas miscible flood project. He compared the performance of 3 Nisku pools, namely “A”, “D” and “E”. The reservoir contains light volatile oil with a density of 800 kg/m^3. Average porosity is 7-10% and net pays are between 40 to 80 m. Average pool permeabilities vary from 50 to 330 mD. The reef base covers around 256 hectares. The reefs are mostly dolomitized. All three pools produced under primary depletion till bubble point pressure was reached, when a dry gas miscible flood was started. The injectant consisted of a 10 mole% ethane-plus concentration. Structurally high well was chosen as the injector well for the flood. The three pools compared differently to the gas flood in terms of breakthrough time and the height above the perforation of OWC at the time of breakthrough. Breakthrough time ranged from 6 months to 7 years and the height above the perforation of OWC at the time of breakthrough ranged from 15m to 40 m. The varied production performance was explained as a result of geologic differences. Pool E which performed best was the most homogenous with a good permeability of 250 mD and best overall porosity. Pool D, which performed the worst heterogeneity and much lower permeability of 50 mD. The recovery factor for the 3 pools ranged from 60-80% of OOIP.

Vilela et al.[65] (2007) reported on the performance evaluation of a reservoir under EOR recovery Intisaar "D" reef, Libya. Intisaar "D" reef is a carbonate reef of Paleocene age with no appreciable flow barrier. It was an initially undersaturated oil reservoir at a discovery pressure of 4257 psia with 40^0 API oil. With a thickness of 452, the reservoir has an OOIP of 1.76 billion STB. With a series of successful reservoir management strategies, they claim to have recovered 69.2 % OOIP as of 2007. The field development began in June 1968 and was completed in May 1970. Mode of operation of the field has changed a couple of times over these years starting with primary depletion, secondary recovery with bottom water injection, then addition of crestal gas injection with bottom water injection, secondary gas injection only to tertiary oil recovery with gas injection. In the course of the production they found gas sweep efficiency to be higher than water sweep efficiency. So, they continued gas injection so that GOC could continue moving down and water production was increased on purpose so that WOC could move down to allow gas to get into contact left behind by waterflooding. They noticed the formation of a huge gas cap with a pretty homogenous front pushing down. According to their analysis, waterflood has produced a recovery factor of 48.5% and crestal high pressure gas injection has resulted in a recovery factor of 81%. The gas injected was determined to be immiscible most of the time since the MMP was higher than the reservoir pressure for most of the period. They attributed the success of gas injection to the 3 phenomena of phase effect, gravity effect and swelling effect.

Hyatt et al.[30] (2005) described a pilot immiscible gas injection study in a mature oilfield that produced under water drive. The pilot in this study was a large, fault dependent closure from the lower Cretaceous Albian formation of the East Texas basin. Oil quality averaged 23 API with a viscosity of 23 cp. The reservoir had fine channel sands at the top with lower permeability (10-500 mD) compared to higher permeability (2000-6000 mD) coarser sands at the channel bases.

They reported low waterdrive recovery of 35 % owing to low permeability sands in the upper part, unfavorable mobility ratio (20) and high oil density. The large volume of unswept oil led to investigation of immiscible gas injection scheme since reservoir pressure was not suitable for miscible injection. Their pilot operated in 2 phases. During the first phase methane gas was injected at the top allowing displacement of gas-oil contact in a stable manner while the water moved down the sands to other parts of the field to be produced through high water cut producers. Phase 1 was continued till the front movement slowed down, which was attributed to presence of mostly low mobile oil below gas-oil contact. Phase 1 successfully demonstrated the ability to maintain a stable gas cap and rapid downward movement of oil. During phase 2, 2 horizontal wells were drilled below the gas-oil contact in the channel base, one in the center and the other along the margin. The production was started at a higher producing rate until gas breakthrough, when the rate was brought down by using variable speed artificial lift. Based on the results of the pilot, they concluded that gas injection based on gravity dominated film drainage has the potential to significantly increase oil recovery.

Gunawan et al.[24] (2001) shared three years of lean gas injection experience in previously waterflooded Handil field. Handil field is a giant field with more than 500 hydrocarbon accumulations compartmentalized in fluvio-deltaic sands. Most of these accumulations are thick saturated oil columns of more than 100 m thick with gas caps overlying them. Reservoir permeability ranges from 10-2000 mD and porosity is approximately 25%. The reservoir dip ranges from 5 to 12^0. Oil density is between 31-34 ^{0}API and viscosity values range from 0.6-1.0 cp. Oil production started in 1975 with depletion drive and shortly afterward peripheral water injection was initiated as the reservoir seemed to benefit from a week aquifer. Water injection has been successful in the field with a projection of 65% OOIP recoverable to waterflood. In 1995, 20% of the field, which has had a waterflooded recovery factor of 58%, were considered for crestal injection by lean gas. Log data showed that peripheral water injection had flooded the reservoirs up to their level of initial gas-oil contact, leaving mainly capillary trapped oil behind. Two gas injection wells were drilled at the crest of the reservoir and completed with 2 strings each. 3 of the reservoirs had a dedicated injection string whereas other 2 had commingled injection with a downhole choke to control the injection split. After 3 years of lean gas injection with the associated gas in an immiscible manner, the additional recovery factor from these 3 reservoir stands at 1.2 % of OOIP and also the decline in oil production has stopped and the oil rates have stabilized. Thus the lean gas injection project has been deemed a technical and economic success in Handil field.

3.3 Gravity drainage models

Buckley and Leverett[5] (1941) put forward their famous paper on mechanism of fluid displacement in sands. Their displacement theory, though not on gravity drainage, can be thought of as the precursor to the gravity drainage theory. They, however, suggested that the gravity drainage process is an exceedingly slow and inefficient process of oil recovery. They stated that crude oil by itself doesn't have the inherent ability to expel itself from the reservoir pores and that it must be forcibly ejected or displaced from the pores by the accumulation of other fluids. Thus the knowledge of the mechanism of fluid displacement by another is essential to understanding oil recovery and hence their displacement theory. Some of the salient features of their theory are outlined below. They assumed that the mechanism of invasion of area of high oil saturation by high gas saturation is similar to water encroachment to displace oil from sand. In either case, the displacing fluid moves from a region of high saturation into one of lower saturation and in doing so removes oil and converts the invaded region to one higher in saturation of the displacing fluid. They maintained that it is never a piston like displacement with either gas or water and in all cases displacing fluid flows together with the oil through the same pores resulting in incomplete displacement. The actual amount of oil displacement during the process depends on the relative ease of flow of the fluids and which in turn is directly proportional to the saturation of the fluids. They derived displacement equations through material balance and neglected capillary and gravity effects to derive a simpler form of the same. They maintained that in any reservoir in which water is advancing upward or gas downward to displace oil, the capillary and gravitational effects oppose each other and tend somewhat to cancel. At high rates of displacement, frictional forces exceed both, with the result that their effects are obscured and the flow is regulated primarily by the relative permeabilities and viscosities. However, at extremely low rates, the frictional forces may be negligible and the balance between capillary and gravity forces control the saturation distribution. Since Buckley-Leverett considered only displacement problems and that too mostly horizontal flow as in secondary waterflood, the hydrodynamic property of "viscosity ratio" played a major role in determining the residual saturation of oil. Assuming a viscosity ratio of gas to oil of 0.0009, they obtained residual oil saturation as high as 85% in initial gas flood compared to 40% for waterflood. They thus concluded that water is a better displacing fluid than gas as it sits favorably compared to gas in terms of viscosity.

Cardwell and Parsons[6] (1948) made the earliest known effort to model the gravity drainage phenomenon in particular free fall gravity drainage analytically. They had a practical approach to solving this long standing need by neglecting certain terms from the general differential equation which according to them were of little importance. They considered a porous medium of unconsolidated sand, open at top and bottom, is saturated with a single liquid and surrounded by a gas phase with negligible pressure gradient. Because the porous medium was open at the top and bottom and the gas surrounding the column had no pressure gradient, hence the externally applied pressure was same at the top and bottom. At equilibrium the liquid saturation in the porous column had two distinct regions – (i) Incompletely saturated region at the top and (ii) A 100% saturated at the bottom due to free fall gravity drainage. They used Darcy's law, laws of capillary behavior and continuity equation to derive a second order partial differential equation to model the behavior of the system. However, since the equation formulated was difficult to solve so they neglected the capillary pressure terms to make it solvable. They have reasoned out the omission of capillary pressure terms by stating that the variation of capillary pressure terms with concentration is small at intermediate to high saturations and at low saturations where the variation is not so small, the drainage process is dominated by the low relative permeability of the liquid. They opined that the laboratory determination of capillary pressures at low saturations were of doubtful meaning because of predominant effect of low permeabilities. Even Leverett quoted that "the nearly vertical trend of the drainage data [the height-saturation relationship] at low saturations represents a relatively poor approach to equilibrium, caused by the low permeability to water in that region". So they suppressed the capillary pressure terms by provisioning the joint effects of capillary retention and low permeability by appropriately treating the terms involving saturation-permeability relationship, which in this case was treating the permeability below 10% saturation to be zero. They could get a solvable form of the differential equation by neglecting the capillary terms and then solved the remaining quasi-linear partial differential equation to get the saturation-height and time relationship. They also found the relationship for the position and velocity of the demarcator, the boundary between the two saturation regions. Some of the salient observations they made from the solution were (i) saturation plane moves linearly with time, (ii) rate of movement of saturation plane is proportional to fluid density, the acceleration due to gravity and (iii) the derivative of the permeability to the liquid at that saturation. The distance was inversely proportional to the fluid viscosity and the porosity. They checked on the consistency of their theory by using the data of Stahl, Martin and Hunting and found good fit of their theory. They finally discuss that their simple theory is suitable for only high permeability porous medium to make gravity drainage important and appropriate modifications are required for oil field recoveries which are complexed by simultaneous action of other recovery mechanisms convergence of flow into draining wells etc. Nevertheless, their effort at an analytical expression for the simplified case of gravity drainage was a very important first step in the effort at modeling this multiphase phenomenon involving gravity forces.

Terwilliger et al.[62] (1951) reported theoretical and experimental investigation of a constant pressure gravity drainage system. They covered only gravity drainage systems in which the gas is injected at the top of the structure to maintain pressure above the bubble point pressure. They experimentally determined and found an expression for the "maximum rate of gravity drainage" , which is defined as the rate of production from a 100% liquid-saturated system under a flow gradient equal to the gravity gradient of static pressure differential between oil and gas due to density difference. They acknowledge that their reference rate includes only part of the factors which affect the gravity drainage, namely, permeability, area, viscosity of the oil and pressure gradient due to density difference between the gas and the oil. The factors excluded are capillary pressures, relative permeabilities and displacing fluid viscosities, which they say may also be important but in field calculations these factors are same for the entire field and hence do not affect the calculations. However, they cautioned about their omission when comparing different fields. The experiments carried out by them were conducted at constant rates and were not under free fall gravity drainage. They achieved very high oil recoveries of the order of 70-80% when gravity force was dominant. They compared their experimental data with a method developed using

Buckley-Leverett method and found a good fit. In their experimental protocol, however, they used a pump at the outlet of the sandpack model to draw out fluids at a constant rate. Even though in case of such a field situation, say at well borehole through ESP, might not affect the gravity drainage process, it could have potentially impacted the gravity drainage process itself in his laboratory scale sandpack model.

Dykstra[16] (1978) showed seven comparisons of recovery calculated from Cardwell and Parson's theory with recoveries determined experimentally. He modified their equations to account for immobile gas saturation at the start of the gravity drainage and for relative permeability to oil decreasing to zero at residual oil saturation rather than at zero oil saturation in order to generalize them. He redefined saturations and permeabilities in his modifications of Cardwell and Parson's equations to derive the gravity drainage and recovery equations. He also showed that the assumption by Cardwell and Parson's that limiting recovery would be unaffected by allowing the relative permeability curve to decrease to zero at 10% liquid saturation rather than at zero % liquid saturation is not valid at late drainage time. His test of theory with experimental data produced good fit for 100^0F crude oil but there was greater deviation at early times for 115^0F and for the 130^0F crude the calculated curve was 3-7% below the observed data. However, it was a good fit at all temperatures on assuming permeability of 10 D, which might have been altered while sampling for oil content analysis, according to the author.

Hagoort[25] (1980) has developed a new method based on centrifugal gas/oil displacement in small cores for accurate measurement of oil relative permeability, which he observed is an important factor in a vertical gravity drainage process. He used concepts of relative permeability and capillary pressure, together with continuity equation and Darcy's law to for incompressible fluids for the two phases, namely, gas and oil, to describe mathematically the simple case of vertical downward displacement of oil by gas. He used a non-dimensionless form of solution by defining dimensionless terms like reduced porosity, reduced oil saturation, dimensionless time and distance along with established gravity and capillary numbers to get insights into the effects of various parameters. He obtained an expression of the fractional flow that indicated the effect of capillary forces on the Buckley-Leverett solution in regions of high saturation gradient. On neglect of capillary terms, the equation reduced to familiar Buckley-Leverett equation. He also derived an equation similar to that derived by Cardwell and Parson's for time and distance derivative of saturation by using a different approach. He claims to have confirmed through his measurements that gravity drainage can indeed be a very effective oil-recovery process in water-wet, connate water bearing reservoirs, i.e. low remaining oil saturations can be obtained. However, he maintains that whether these low saturations are indeed attained in the lifetime of the reservoir depend on the magnitude of gravity relative to viscous forces, the shape of oil relative permeability and reservoir geometry and heterogeneity. He, too, claims that his centrifuge method is an accurate method for measuring oil relative permeability, the key factor in gravity drainage process.

Li et al.[44] (2003) conducted a study on free-fall gravity drainage. They suggested that analytical models are complicated, at times do not have analytical solutions and do not work well. So, they also proposed an empirical oil recovery model to characterize gravity drainage process. The model that they used was originally developed by Aronofsky et al.[2] to match oil production in naturally fractured reservoirs developed by water flooding They tested their empirical model, both experimentally (at core scale) and through numerical simulation (field scale). They found excellent match of the experimental data generated by Pedrera et al.[52]-2006 and Li and Firoozabadi[43] to their model. A similar good fit was observed for the numerical simulation data generated by Li and Horne[44]. Their model was also tested against production data from Lakeview Pool, Midway Sunset field and good match was obtained. They observed increase in residual oil saturation with the entry capillary pressure but decrease with increase in the pore size distribution index as expected. They observed almost linear relationship between the average residual oil saturation and entry capillary pressure for a pore size distribution index of 7. They also developed an analytical model to determine average oil saturation by free fall gravity drainage. They claim that their model can be used in both spontaneous imbibition on free-fall gravity drainage because of the presence of only two forces in both cases, namely, gravity force and capillary force. They too stressed the need for an accurate analytical gravity drainage model since empirical models are case specific.

3.4 Rock and Fluid Aspects Affecting Gas Injection Processes

The popularity of gas injection processes is because of excellent microscopic displacement efficiencies with miscible gas injection. But there are multitude of physical factors and mechanisms, both macroscopic and microscopic that come into play to determine the success of a gas flood. It is very important to have a thorough understanding of each of these factors and their interactions that come into play in such a process. Below is a short discussion on some of the pore level factors that affect gas-injection processes.

1) Miscibility

Miscibility and interfacial tension are coupled in that at miscibility conditions gas/oil IFT reduces to zero. There are basically two kinds of miscible displacements, first contact miscible and multi-contact miscible and the latter in turn is mechanistically sub-divided into vaporizing and condensing gas drive and a combination the two. Miscibility is dependent on the composition of fluids, both in situ crude and injectant as well as the P-T conditions. Miscibility is undoubtedly desired in case of gas injection as it will reduce the trapping associated with capillary forces, giving theoretically 100% displacement in contacted areas. But it’s worth noting that reservoir is not an ideal homogenous system and it's difficult at times to achieve miscibility to the extent desired. At times we may as well get by with near miscible condition (IFT~0 but not = 0). Thomas et al.[63] (1995) stated that if a system is strongly water wet, then we may not need the injected gas to enter those small pores to recover all of the oil. In such a case, absolute miscibility is not required. However, in case of an oil-wet system, where a substantial amount of oil is contained in smaller pores, it will be necessary to reach miscibility. Also, in case the flow is viscous dominated rather than miscibility dominated, it is more prudent to focus on viscous effects rather than miscibility. Stern et al. have found that during multiple contact miscible floods, the amount of bypassing is not sensitive to flow rate but increases as solvent/oil viscosity ratio decreases. Wang et al.[67] characterized near miscible as semi-miscible between the extremes of miscible and immiscible. His observation of semi- miscible was the process in which oil got disintegrated into microscopic droplets and was transported with injected CO_2 stream.

2) Interfacial tension – Interfacial tension can manifest its presence through miscibility or spreading. Its effect on miscibility has already been discussed in the section on miscibility above. Here we would like to dwell on the spreading aspect. Spreading coefficient of oil on water in the presence of a gas phase, S_o is defined as a force balance of their IFTs as shown in Figure 3.1

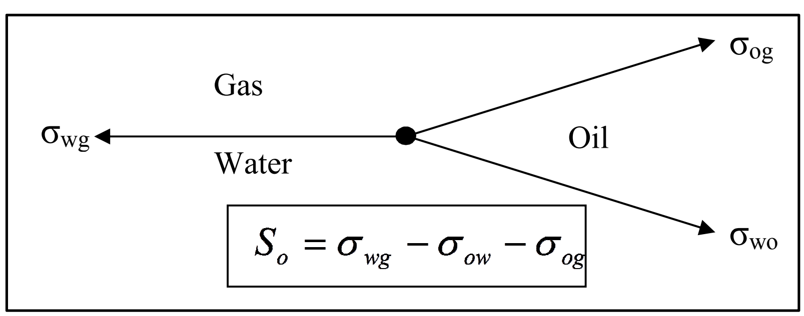

Figure 3.1: Schematic depiction of the spreading coefficient

If the spreading coefficient is positive ($S_o > 0$), it denotes that one of the tensions is larger than the sum of the other two and results in the total spreading of that fluid over the others, forming a continuous fluid layer; if it is negative ($S_o <= 0$), non-spreading occurs and will lead to fluid lenses with a definite contact angle against the other two fluids. Wettability states of reservoir rocks, water-wet or oil-wet, also lead to difference in spreading behavior. Figure 3.2 illustrates the distribution of water, oil and gas in the reservoir rock for two wettability states.

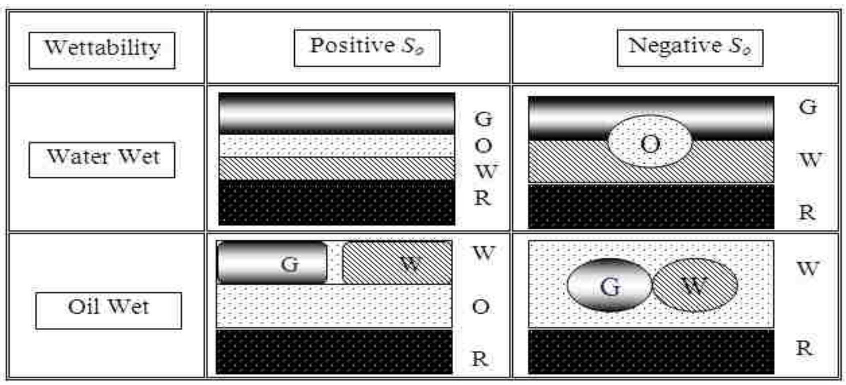

Figure 3.2: Oil-Water-Gas distributions for different wettability states (Rao et al. - 2007)

In case of water-wet rock surface, $S_o > 0$ leads to oil spreading between gas and water while $S_o < 0$ leads to oil lenses floating on the gas-water interface. On the other hand, if it is oil-wet, $S_o > 0$ leads to oil isolating gas and water by spreading between them and $S_o < 0$ leads to the flow of gas and water phases as discreet globules entrained in the oil phase. In case of intermediate wet behavior, thin continuous oil film is likely form along the entire length of flow channel facilitating its flow. Spreading is one of the two ways in which formation of oil film occurs, the other being through wettability. Many authors like Oren et al.[50], Vizika et al.[66] have shown that formation of oil films greatly enhances the recovery efficiency of gas injection processes by assisting in the flow of oil. Vizika et al.[66] found that in water-wet and fractionally-wet porous media, spreading coefficient of oil on water is a key parameter in recovery efficiency, recovery kinetics and fluid distributions. In oil-wet porous media, it affects more in terms of fluid distributions but not so much in terms of recovery efficiency. Oren et al.[50] have found similar results with regard to the effect of spreading films. As is expected, they found the spreading films to be much thinner than wetting films. Their results from tertiary immiscible gas floods on water-wet micromodels indicated 35% recovery efficiency for positive spreading coefficient compared to 18% for negative spreading coefficient in horizontal gas floods.

3) Wettability

Wettability is one of the most important but conveniently downplayed parameter in petroleum recovery, particularly because of ambiguity in exactly defining and dealing with this parameter in a practical manner by the industry at large. Wettability, as it is widely understood in petroleum community is the preference of oil or water to adhere to rock surface in the presence of the other phase. For a broad quantification purpose, a contact angle of 0-70^0 is termed as water wet, 70^0 – 110^0 is termed as intermediate wet or neutral wet and 110^0 – 180^0 is termed as oil wet. Rocks can vary in their wettability characteristics from strongly water-wet to strongly oil wet through the full spectrum of weakly water-wet, intermediate-wet and weakly oil-wet characteristics. Critics of the contact angle approach argue that these contacts angle measured on smooth surfaces don't take into account rock roughness, widely varying minerology or presence of organic materials. As a result they advocate using average wettability indices like USBM index or Amott test. Proponents, however, argue that at the 3-phase line of contact, is always a smooth surface and hence roughness does not appear to play a significant role is establishing wettability. In addition to these states, there is another wettability state known as mixed-wet. In this condition, the fine pores and grain contacts would be preferentially water-wet and the surfaces of the larger pores would be strongly oil-wet. Frequently encountered is yet another wettability state known as fractional wet state, where both oil-wet and water-wet sands are packed in different parts of the rock matrix. It exists due to variation in the mineralogy exhibiting different surface physio-chemical properties. These different wettability states are important in our recovery processes to the extent that continuous hydrodynamic path for oil exists throughout the matrix to be able to flow out. Oren et al.[50] (1994) reported much higher oil recoveries for oil-wet displacements compared to water-wet displacements in their immiscible gas flood studies. They also noted that in case of oil-wet displacements, positive spreading coefficient led to decrease in recovery efficiency. This may be because in such a scenario, some of the oil becomes unrecoverable as oil particles spread around the dispersed water phase, making themselves harder to be dislodged. Mahmoud et al.[46] (2007) also found similar results for immiscible gas injection using sandpack GAGD models.

3.5 Dimensional Analysis

The analysis of the performance of an oil reservoir is dependent on a number of variables, which can be combined to form dimensionless groups. Dimensional group analysis is based on the fact that the physical laws are invariant of units. A very powerful application of dimensional group methods is in scaling up. Rappaport[54] (1955) stated that if the ratio of dimensional groups on a larger geometric scale to dimensional groups on a smaller geometric scale is kept equal to one then the mechanisms occurring in both the scales would be similar. Two general methods, which are popularly used for the purpose of forming dimensional groups are dimensional analysis and inspectional analysis.

Dimensional analysis is a trial and error process of combining the variables affecting a particular process so that the resultant group of variables is dimensionless. The effect on certain variables is then studied in terms of the whole group rather than the individual variables combining it. Dimensionless analysis requires the knowledge of complete set of variables affecting the particular process (Geertsma et al.[18] – 1956). Buckingham pi theorem states that the number of dimensionless groups in a complete set is equal to the total number of variables minus the number of fundamental dimensions.

In case of inspection analysis these dimensional groups of variables are generated using the underlying physical laws rather than through the trial and error process. As such inspectional analysis is a more fundamental way of analysis than its counterpart.

Geertsma et al.[18] (1956) conducted pioneering work in dimensionless group analyses of three types of displacement processes for petroleum reservoirs, namely. cold-water drive, hot-water drive and solvent injection. They chose inspectional analysis to identify the similarity groups and later combined them in dimensional form for further analysis. This method of combining inspectional analysis with dimensional analysis is stated to be more advantageous than either of the individual methods. They considered the basic conservation equations of mass, momentum and heat along with PVT equations of state, effect of temperature on viscosity, diffusion and capillary forces for this purpose. They observed that the design of a scaled model of an oil reservoir in which all the similarity groups have the proper value is not possible and stated that the proper choice of group(s) to be deleted in a given case is essential for the experiment to be representative of the behavior of the prototype. They stressed that this decision be taken after experimentally confirming the unessential ones among them. They stated that the requirement of most of the physical models is that the influence of inertial forces is not significant in the range of interest, so that the Reynold's group can be left out of consideration. The sets of dimensional groups derived by them were found to be equivalent to sets of groups existing in other engineering sciences. However, they said their derived groups are particularly suited for the flow through porous media because of the fact that most of the conventional groups are ratios of inertial forces, which are of minor importance in porous media.

Grattoni et al.[23] (2000) carried out a series of experiments of gas gravity drainage with special attention to wettability and water saturation on three phase flow. The experiments were performed in rectangular packs, which were packed with glass beads in a homogenous manner so as to nullify any edge effect. The absolute permeability of the pack was approximately 6 Darcies and pore volume was 51 cm^3. Their transparent bead packs provided for viewing the movement of the fluids apart from simplistic representation of the average flow characteristics of the reservoir porous rocks. They used distilled water, paraffin and air for the fluids and performed their experiments under both water-wet and oil-wet state of the glass beads. Spontaneous gas invasion experiments were performed by them by allowing the gas at atmospheric pressure to enter at the top of the test section while the effluent fluids were collected from the bottom and measured. They conducted two sets of experiments at irreducible water saturation and residual oil saturation for both water-wet and oil-wet cases to ascertain the relative importance of gravity, viscous and capillary forces. They defined a new dimensionless group, N [$N= N_B + A (\mu_d/\mu_g) N_C$, where A is a scaling factor] by combining the effect of gravity and viscous forces to capillary forces. For the experiments that were carried out at irreducible water saturation, gravity forces were found to be more prominent than capillary forces for the water wet case than the oil wet case. Gas fingering was also more pronounced in case of the oil wet state. Gravity forces were observed to increase with the progress of gas invasion. Influence of capillary forces in water wet case was minor but in case of oil wet case, all the three forces were important.

For the other set of experiments at residual oil saturation, similar observation was made regarding domination of gravity forces over capillary forces for the water wet case than oil wet case. The oil recovery behavior in water wet state indicated two different mechanisms of drainage. In the first stage, oil is collected below the gas front by reconnection, and is produced later as a small bank and in the second stage, film drainage occurs between gas and water. The displacement in oil-wet case was found to be capillary dominated and the mechanism was oil film drainage.

Gharbi et al.[21] (2002) studied scaling up flow through heterogeneous reservoirs for the case of miscible displacement of oil by solvent. They generated thirteen dimensionless scaling groups (i.e. eight flow scaling groups and five heterogeneity scaling groups) from inspectional analysis based on the previous works of Gharbi et al.[20] - 1998 and Li et al.[42] – 1995 for scaling displacement in a two dimensional, heterogenous, anisotropic vertical cross section. The groups identified by them are: t_D (dimensionless time), P_{eL} (Peclet number), N_{DA} (Dispersion number) M (Viscosity ratio), N_α (Dip angle number), N_g (Gravity number), R_L(Effective aspect ratio), A_r (Aspect ratio), N_σ (Global heterogeneity number), N_n (Local heterogeneity number), λ^*_{Dx} (Effective correlation length in x direction), λ^*_{Dy} (Effective correlation length in y direction) and H_e(Hurst number). Numerical sensitivity analysis was performed by them to reveal the relationship between the scaling groups and the fractional oil recovery of miscible displacements in heterogeneous reservoirs. They observed higher dependency between permeability realization and fractional oil recovery when both N_σ and λ^*_{Dx} were large signifying that as heterogeneity increases, there is more uncertainty in the performance of miscible displacement. They observed that at low values of N_g, the displacement is dominated by viscous forces and gravity override is not so important in this case. As expected higher dip angle (purely a geometric parameter) meant higher recoveries. Higher N_{DA} was seen to reduce heterogeneity effects and stabilize the displacement process. It is observed that fractional oil recovery decreased with R_L for small values of N_σ and increased with R_L as N_σ increased. They mapped the relationship using an artificial neural network so as to form a quick prediction tool for the fractional oil recovery for any combinations of the scaling groups, thereby eliminating the need for fine mesh simulations. For this purpose they used twelve dimensionless scaling groups and systematically varied those over a range normally encountered in oil production. Some of the simulated data was used to train the network while others were used to test the effectiveness of the training process. They claim that their work establishes a foundation for scaling miscible displacement in porous media.

Jadhawar et al.[31] (2008) conducted risk analysis on various parameters and their relative influence on the rate of recovery for a gas-oil gravity drainage process. The parameters they considered were viscous/gravity/capillary forces, the rate of gas injection and oil production, the difference of oil and gas density, the oil relative permeability, the oil viscosity and number of other operational parameters. They identified and modified various scaling groups to understand the interactions between various process parameters governing the gas displacement process thereby estimating the fractional oil recovery for a particular combination of scaling groups. They generated ten dimensionless groups for the scaling purpose. Those groups are effective ratio, dip angle, mobility ratio (water-oil/ CO_2-oil), gravity number (based on gas injection rate), gravity number (based on gas injection and oil production pressures), injection pressure group, producing pressure group, residual oil saturation to water (water-oil system) and residual oil saturation to gas (gas-oil system). They studied the sensitivity of the groups to changes in the operation parameters using numerical simulation results from CMG IMEX software. They used PALISADE'S RISK software to identify the relative dominance of the parameters operational in the process. Monte Carlo simulation using the RISK software were also carried out. In their sensitivity analysis, they kept the vertical permeability and the difference in density between reservoir oil and injected fluid (CO_2) constant while the critical parameters like the total superficial velocity and end point mobility of oil were treated as variable. On their sensitivity analysis they found that the gas driven gravity drainage is highly sensitive to small changes in the residual saturation of water and oil. They claim through their dimensionless oil recovery performance study that the pressure based gravity number is more appropriate than gas injection based gravity number for scaling up the process. They noted that the scaling groups used by them in their study were adequate for a gas driven gravity drainage process especially in a horizontal type (non-dipping) reservoir.

Sharma et al.[58] (2008) conducted physical model experiments using scaled variables so as to characterize the gas assisted gravity drainage process. Their research was based on identifying the relative importance of the three forces, namely, gravity, viscous and capillary during such a process. The effect of mobile water saturation and operating parameters (gas injection pressure and rates) and water shielding during tertiary mode were also addressed. The experimental apparatus consisted of a two dimensional Hele – Shaw type model. Visual experiments were carried out using different fluids and packings, in order to obtain the dimensionless numbers that fall in the same ranges as observed in the field projects. The dimensionless numbers that they narrowed down for the purpose of scaling down based on their literature survey, consisted of these six groups, namely, Geometric aspect ratio (R_L), Capillary number (N_C), Bond number (N_B), Fluid property group (α), Gravity number (N_G), Dimensionless time (t_D). On selection of the dimensionless numbers, the identification of particular experimental variables to satisfy each dimensionless number was separately done. Their first set of experiments were aimed at identifying the operating mode for such a process. They had experimental runs at constant pressure as well as constant rate so as to determine the right operating mode. The gravity drainage rates after gas breakthrough during constant pressure runs were found to be much higher than those during constant rate runs. The experiments carried out at constant rate helped in keeping the required dimensionless numbers constant thereby possible identification of their effect during the process. They obtained better recoveries as the Bond number increased signifying the fact that gravity dominated flow regime facilitates better recovery in such a process. For a typical run they could observe recovery increase by as much as 11% for a tenfold increase in Bond number. They also observed that the type of injectant is immaterial in case of an immiscible gas injection process. This they attributed to the similar Bond and capillary number values for the cases. Capillary number also was observed to facilitate significant increase in recovery but unfortunately capillary number could only be increased to a certain critical value due to constraints of critical gas injection rates. Most of the oil was recovered in their experiments during early phase of the flood within around 100 days which corresponded to a period of 3 years for the Dexter Hawkins field. This illustrates the quick economic benefits of such a process. They observed a straight line relationship between the total recovery and the natural log of Bond number. This relationship prevailed for the cases of ambient physical model, reservoir condition core floods as well as the field production data. A logarithmic relationship between total oil recovery and the capillary number was also observed by them. The correlation developed by them between recovery versus capillary and Bond numbers validated earlier work by Kulkarni et al.[37] for near miscible system, thereby confirming its applicability for both immiscible and near miscible displacements. They also observed strong effect of water shielding for the tertiary recovery case compared to secondary.

CHAPTER 4: EXPERIMENTAL METHODOLOGY

4.1 Summary of Experimental Methodology

Methodology involves the following broad steps:

1) Dimensional analysis for determination of range of values of dimensional numbers at field scale in order to partially scale up model findings to field scale
2) Construction of partially scaled visual sand-pack and consolidated rock models with simplified yet representative well configurations and reservoir structure.
3) Proof of concept of SW-GAGD process.
4) Conduct of experiments on these models and data analysis to investigate their performance in terms of recovery factor so as to come up with a suitable design.

4.2 Dimensional Analysis for Scaling-Up of Physical Model Results

The objective here is to be able to translate the results obtained with SW-GAGD physical model from laboratory to field. Principle of dimensional analysis based on Buckingham Pi theorem has been used for this purpose. Dimensionless analysis is a great scaling tool as it helps us in deriving useful functional relationships that can be applied across various length scales since the relationships are based on dimensionless groups. The analysis has been broken down into a couple of sub-steps under a separate heading so as to illustrate the importance of each step.

4.2.1. Determination of dimensionless scaling groups

Determination of pertinent dimensionless groups is critical for the success of scale up from laboratory to field scale. At the outset, it is important to acknowledge that SW-GAGD process is also subjected to the same forces that influence conventional gas-injection processes, albeit to a different degree. In any gravity drainage or displacement process in porous media, the forces that affect flow are gravity, capillary and viscous. Dimensionless numbers that are widely accepted in the literature to represent the interplay of these forces are Bond number, Capillary number and Gravity number. Bond number, being a ratio of gravity to capillary forces, gives an indication of the relative importance of gravity force over that of capillary force. Similarly, Capillary number gives the relative importance of viscous force over capillary force. These dimensionless numbers can be used to quantify the dynamic behavior, which has a predominant effect on recovery efficiency, of a gravity drainage process. They thus help to compare not only dynamic behavior but also the recovery factor of gravity drainage processes across different scales. Aspect ratio is another scaling group that has been used in scaling of displacements in reservoirs. Aspect ratio is the ratio of one dimension to another dimension of any shape. In case of petroleum reservoirs, the aspect ratio is the ratio of length to height (thickness) of the reservoir. Sometimes the reciprocal of square root of permeabilities in both directions is multiplied with this ratio of lengths, which has been referred to as effective aspect ratio $\left(\frac{L}{H}\sqrt{\frac{K_V}{K_H}}\right)$ by many authors. In case of petroleum reservoirs, aspect ratio is an important dimensionless scaling group that has been found to have a significant influence on horizontal displacements, in both water and gas floods. Shook et al.[59] have shown that higher aspect ratios negatively impacted horizontal flood performance by amplifying the gravity effect. This is because as the flood front moves horizontally, the gravity/buoyancy effect leads to segregation of injectant (gas/water) with respect to the oil phase. The longer the lateral length compared to thickness (higher aspect ratio), greater is the segregation, thus leading to poor vertical conformance. Even though it is an important scaling group in case of horizontal floods, it is anticipated to not significantly affect vertical floods like SW-GAGD process that operates on a totally different mode. In GAGD mode, the gas is injected at the top of the payzone with the horizontal producer at the bottom of the payzone with a flood front that moves vertically in a top-down fashion rather than horizontally. Aspect ratio, as stated earlier, does play a significant role with conventional gas floods like CGI and WAG, as these floods constitute horizontal displacements and higher aspect ratios are similarly detrimental to those processes. Here aspect ratio amplifies the unfavorable gravity effect, leading to early breakthrough of injected gas at the production well. The salient point here is that, the gas in this case has the tendency to move upwards due to gravity and longer lateral length (higher aspect ratio) fosters that segregation, leading to eventual breakthrough of gas. For a SW-GAGD process, however, lighter gas is injected at the top and since gas has a tendency to remain at the top, no adverse gravity effect is suspected and consequently it is anticipated that aspect ratio may not play a significant role. In our experiments, we found that even when the gas is injected at the bottom of the payzone, it first travelled up to fill the top of the payzone before doing a top-down displacement. Because of this reason, aspect ratio has not been considered in our choice of dimensionless groups.

Another scaling parameter that is important while considering displacement floods is the ratio of vertical permeability to horizontal permeability, K_V/K_H. Just the way aspect ratio amplifies the gravity effect, this permeability ratio (K_V/K_H), mitigates the gravity effect by fostering the flow within a layer rather than across layers. For example, in case of horizontal floods (gas/water), lower (K_V/K_H) will promote vertical conformance, in contrast to higher aspect ratio. That is why aspect ratio (L/H) is oftentimes multiplied with square root of (K_V/K_H) to give "effective aspect ratio" $\left(\frac{L}{H}\sqrt{\frac{K_V}{K_H}}\right)$ that was mentioned earlier. Unlike pure aspect ratio, whose effect is anticipated to be less significant in case of vertical SW-GAGD floods, this permeability ratio (K_V/K_H) is expected to be important. Lower (K_V/K_H) ratio is expected to be beneficial to SW-GAGD floods. As a rule of thumb, K_V is around one-tenth of K_H because of the very nature of geologic sediment deposition in layers (law of original horizontality). Here the extreme case scenario in terms of breakthrough would be (K_V/K_H) close to unity, which is the case we have in our sandpack physical models. So, if at all it would have any impact it would be expected to be positive with regard to breakthrough compared to what we have in our models. This is considered to be potentially good in the sense that the model results would be conservative compared to field case and that would mean potential higher recoveries in reality compared to model recoveries. Because of limitation of our sandpack SW-GAGD models, we were not able to look into the beneficial effect of this ratio on SW-GAGD performance. This aspect would be studied in suggested future work in continuation of the present work.

4.2.2. Choice of representative deepwater Gulf of Mexico reservoir properties

Deepwater Gulf of Mexico reservoirs represent varied and complex geology, rock and fluid properties and drive mechanisms. Hence no single reservoir will be representative of the gamut of reservoirs encountered in the deepwater Gulf of Mexico. For our task, one of the prolific reservoirs in the deepwater Gulf of Mexico, viz., N/O reservoir in Mars field was chosen[39]. N/O (Yellow) reservoir is a Miocene to Pliocene age sand with a thickness of 99 ft. and acreage of 4,917 acres. Initial reservoir pressure at datum was 11,305 psia with and OOIP of 535 MMSTB. The reservoir is highly over-pressurized and highly compacting with a limited aquifer influx. Reservoir also has good vertical and horizontal permeability and good connectivity. Reservoir pressure went down to 6800 psi when water injection was started to keep the reservoir producing above bubble point pressure (6,306 psia) and also to avoid compaction of the reservoir. Waterflood recovery is estimated at 56% for the reservoir. For our hypothetical SW-GAGD application the intervention pressure has been chosen to be slightly above the saturation pressure at 6500 psia. Though the base properties are that of Mars field, in order to represent the entire span of deepwater Gulf of Mexico reservoirs, rock and fluid properties have been spread out to cover the full range of properties encountered in DGOM.

4.2.3 Calculation of Dimensionless numbers

The following definitions have been used while calculating the dimensionless numbers.

$$N_B = \frac{\Delta\rho_{(oil-gas)} g \left(\frac{K}{\phi}\right)}{\sigma_{og}} = \frac{\Delta\rho \left(\frac{kg}{m^3}\right) g \left(\frac{m}{s^2}\right) L^2 (m^2)}{\sigma_{og} \left(\frac{N}{m}\right)} = M^0\, L^0\, T^0 \qquad \text{----------------- (1)}$$

$$N_C = \frac{v\mu}{\sigma} = \frac{v\left(\frac{m}{s}\right)\ \mu\ (Pa.s)}{\sigma_{og} \left(\frac{N}{m}\right)} = M^0\, L^0\, T^0 \qquad \text{-- (2)}$$

$$N_G = \frac{\Delta\rho_{(oil-gas)} g \left(\frac{K}{\phi}\right)}{v\mu} = \frac{\Delta\rho \left(\frac{kg}{m^3}\right) g \left(\frac{m}{s^2}\right) L^2 (m^2)}{v\left(\frac{m}{s}\right)\ \mu\ (Pa.s)} = M^0\, L^0\, T^0 \qquad \text{------------------ (3)}$$

Since, some of the rock and fluid property data were missing for Mars field, some analogs were used from other deepwater Gulf of Mexico reservoirs. Injectant gas used is Nitrogen gas and the displacement process is characterized as immiscible to near miscible. Choice of immiscible to near miscible displacement is necessitated by the fact that at miscibility conditions, IFT between gas and oil phases will become zero and that will make these dimensionless numbers infinite. Since, this exercise is for comparing the dynamic performance of the process across different scales, this assumption will not limit the scope of the comparison. The use of nitrogen in place of CO_2 is considered from an economic perspective, as Nitrogen can be generated on site whereas CO_2 will have to be transported across hundreds of miles.

As can be seen from equations (1)-(3), the parameters and properties needed for the calculation of the dimensionless numbers are: $\Delta\rho_{og}$ [22], L, σ_{og} [29], v [28] and μ [39]. For calculation of v (Darcy velocity), the base injectivity value was chosen to be one half of the peak gas production rate from a similar depth well in the deepwater Gulf of Mexico. This was done as there were no reported values for gas injectivity in deepwater Gulf of Mexico as there isn't a single gas injection projects in there till date. The range of values for the dimensionless numbers are presented in Table 1 below.

Table 1: The range of values for dimensionless numbers

Dimensionless Nos.	Typical Value	Minimum Value	Maximum Value
N_B	3.42E-05	7.73E-06	7.52E-03
N_C	5.36E-09	3.57E-10	3.06E-04
N_G	6370.53	5.05	105228.61

Here, typical value represents the value observed for the base properties and the range is depicted through minimum and maximum values. The calculation spreadsheet for the dimensionless numbers is attached herewith.

4.2.4. Dimensionless numbers for the physical SW-GAGD model

Having obtained the range of dimensionless numbers for deepwater Gulf of Mexico fields the next task is to construct the SW-GAGD model and to choose appropriate fluids to obtain the dimensionless numbers within the range exhibited by DGOM reservoirs. Dimensionless numbers have been calculated for a typical SW-GAGD model with the following specifications:

Dimensions: 22" x 10" x 0.37"

Sand Size: 60 Mesh (0.251mm)

Fluids: Decane and N_2

Gas Injection Rate: 10 cc/min

The calculated values obtained for Bond number (N_B) and Capillary (N_C) numbers for this model are 1.92×10^{-5} and 3.11×10^{-5}. As can be seen, these values are within the range of values for the deepwater Gulf of Mexico reservoirs. Hence, it can be safely asserted that our results obtained with SW-GAGD physical model can be translated to DGOM reservoirs.

4.3 Construction of Physical Models

Visual glass models are a great way to follow the progress of gas floods. As a material, glass offers very good transparency and also the right wettability to suit our purpose. But the problem with glass is that it can't withstand much pressure and tends to crack up easily on application of little pressure. Moreover, glass to glass bonding requires the right kind of glue and also proper curing procedure, which may as well require pressure application at the bond. Construction of physical glass models was one of the most critical part of the experimental protocol. Proper care was taken during construction as well as operation phase to have hermetically sealed models needed for the study. Mahmoud et al. constructed similar glass models but reported leakage in his models on sustained exposure to Decane. Hence, proper sealing of the glass models was of paramount concern during construction. Construction of glass models was as much an art as it was science. A lot of trial and error went on to ensure proper bonding, sealing of the glass model so as to ensure that it was able to withstand the organic chemicals used during the conduct of experiments. Detailed protocol for the construction of the glass models is given below:

1. Glass pieces of following dimensions were cut of plate glass (All dimensions in inches):

(a) 24.5 (L) x 12.5 (W) x 0.25 (T) – 2 nos. frame glass

(b) 21.0 (L) x 1.0 (W) x 0.375 (T) – 1 no. spacer

(c) 23.375 (L) x 1.0 (W) x 0.375 (T) – 1 no. spacer

(d) 10.125 (L) x 1.0 (W) x 0.375 (T) – 2 nos. spacers

(e) 1.0 (L) x 0.5 (W) x 0.375 (T) – 9 nos. spacers

2. All glass pieces were thoroughly cleaned using Acetone to remove dust and any oil smear on the surface. They were then dried to remove moisture on the surface. Frame glass was then marked appropriately.
3. Epoxy based glue EP41S-1HT from Masterbond was used for the purpose of glass bonding. Based on the area of spread, right amount of hardener (30% W/W) was added to the epoxy and was thoroughly mixed. Proper mixing is essential to ensure good bond. This resultant mixture is then used for bonding.
4. For the purpose of bonding, the glue is applied to one surface of the spacers using an applicator. It is important to have a uniform layer of glue on the surface of the spacer and excess glue is wiped off.
5. Firstly, spacers (c) – (e) were bonded to one of the frame glass as per the markings. The bond does well with applied pressure. Clamps were placed 1-2 inches apart to ensure proper bondage.
6. This assembly (hereafter referred as part A) was then left overnight (12-15 hrs) for curing at ambient temperature followed by high temperature 225^0F curing at high temperature for 3.5 hours.
7. A horizontal well was prepared using ¼" plastic tubing and by drilling fine holes in it with a handheld drill machine with 0.0046785 inches size drill bit. Holes were drilled all around the tubing to have minimize trapped oil volume within the model.
8. Horizontal well was placed in part A sub-assembly very carefully and held in place by using the same glue. This is essential otherwise that will be the weakest point for leakage later on.

9. Upon placement of horizontal well, the 2nd frame glass (part B) was glued and clamped onto assembly A similarly and allowed to stand for 8 hours. Next both sides of horizontal well were filled up with this glue and allowed overnight curing at room temperature.
10. The whole assembly was then hot cured at 225^0F for 3.5 hours again.
11. Sand grain sizes of 20/30 and 50/70 mesh were used for making the sandpack in these glass models. Sand-packing was carried out to incorporate the natural layering pattern in reservoir sediments. Frequent shaking and levelling of the sand was done to uniformly pack the sand bed in the model.
12. Upon completion of the sand-packing, spacer (a) was glued in place and the entire assembly was again allowed to cure at room temperature overnight before hot curing at 225^0F for 3.5 hours.
13. This was followed by tight packing of the sand with frequent rocking of the model for the sand to get into the nooks and corners and really pack snugly. This step was essential to tighten the sand pack on all sides of the model.
14. The top well was then fitted in place and sealed using the same glue and was allowed to cure using the same curing protocol.
15. As an extra step the model was also sealed on all sides by a bi-layer comprising of Epon-828 epoxy resin and silicone. This was done to doubly ensure that model didn't leak out.
16. This basic procedure was followed overall with appropriate modifications when different well configurations were attempted in the glass model.

The model was then connected to rest of the flow and data acquisition apparatus.

4.4 Conduct of Experiments

The experiments were conducted with the following protocol.

a) Determination of pore volume and permeability of the model.

b) Establishing original oil saturation in the model.

c) Experimental runs with the right injectant.

4.4.1 Saturation and determination of pore volume and permeability of the sand-pack

1. The model was placed upright on the stand and the horizontal well was connected to a burette containing distilled water. The top well was kept open to the atmosphere.
2. The bottom valve was cracked open to slowly allow water to imbibe into the model through the bottom horizontal well.
3. Water gradually imbibed into the sandpack model from the bottom in a gravity stable manner displacing the air from top of the model. Water was allowed to flow in till the first drop of water was observed in the top well.
4. The amount of water imbibed into the model was noted.
5. The dead volume of tubing inside the model was calculated knowing their dimensions.
6. The dead volume was then subtracted from the total water imbibed to determine the pore volume and thereby porosity of the sand pack.
7. Model was then allowed to stand overnight with the water load to ensure that there was no leakage. This was important to check for hermetical sealing of the model and to be able to attend any corrective action before the experimental runs.
8. The next step was the circulation of water through the model and permeability determination. Distilled water was circulated from top of the model in a top-down gravity stable fashion to

ensure washing of the sands and stabilization of the sandpack. 3-4 pore volumes of water was circulated through the model.

9. For permeability determination, the buret was filled to the top and connected to the top well of the model. The outlet was fully opened with the burette stopcock closed. Stopcock was then opened and flow was established. The time taken for water level to drop 10 cm in the buret was noted for a particular graduation (arbitrary) in the buret. Readings were repeated a couple of times to ensure reproducibility. The height difference between this particular graduation and the top of sand was noted and the potential difference between the inlet and outlet was calculated.
10. Permeability was thus calculated using this potential difference, flowrate and other known other geometrical and fluid parameters.

4.4.2 Establishing irreducible water saturation in the sand pack (S_{wi})

1. A buret filled with red dyed Decane was connected to the top well. The buret was positioned as high as possible from the model so as to maximize the pressure head for flow. This helped to quickly displace all the mobile water from the sand-pack model.
2. It was important to ensure that there was no obstruction including needle valves at the outlet of the model. The outlet of the model was connected to 2 burets connected through a diverter valve so as to be able to have one buret online at a time, with the other isolated.
3. Decane was allowed to flow into the model in a top-down gravity stable manner. Decane displaced the water in the model and was produced in the downstream buret. The flow of Decane was continued till there was no more water production at the outlet. The volume of water produced was noted down.
4. The volume of water produced gave the original oil in place in the model.

4.4.3 Conduct of experimental runs

1. The model was connected to the downstream oil and gas collection and metering system.
2. Data acquisition system was also hooked up. The apparatus schematic is shown in Figure 4.1.
3. Prior to the start of runs with injectants, an experimental run was carried on to quantify the recovery with just the gravity in play by having the inlet open to the atmosphere. This was pure gravity drainage and served as the base case for rest of the runs with injectants.
4. For Nitrogen injection runs, Nitrogen flow rate was maintained using a regulator and a mass flow meter. Various flow rates 2.5-20 SCCM were used for flood.
5. For miscible flood Naptha, which is soluble in Decane but with a slightly lower density was used.

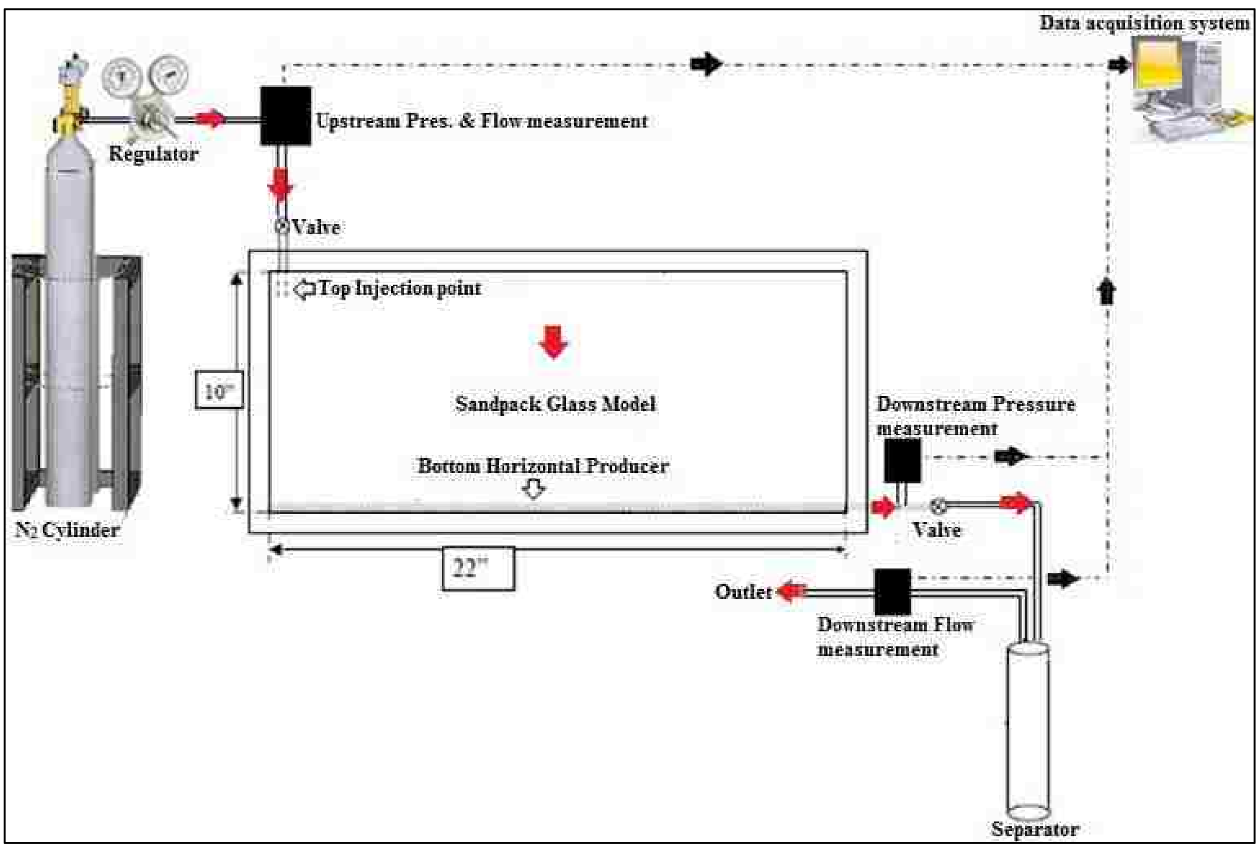

Figure 4.1: Picture of experimental apparatus

CHAPTER 5: RESULTS AND DISCUSSION

5.1 Proof of concept of SW-GAGD process

Picture of a SW-GAGD sandpack model is shown in Figure 5.1. It has a horizontal producer spanning the entire width of the model and a single injector (top perforations) at the left top edge of the model.

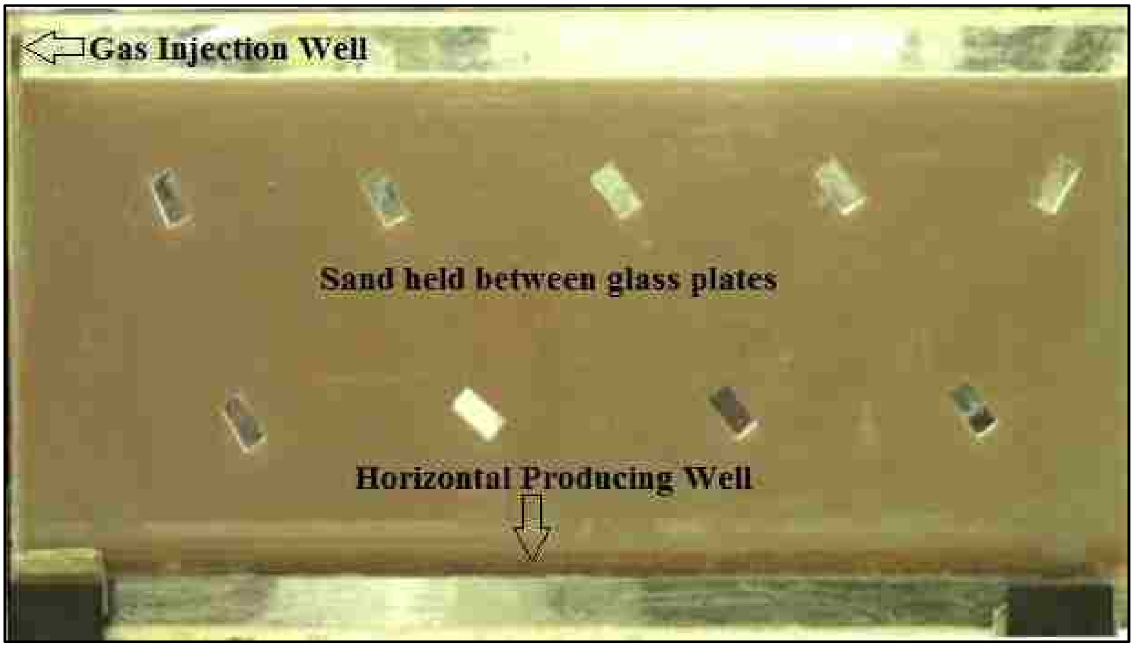

Figure 5.1: A sand-packed glass SW-GAGD model with injection well at top corner

Firstly, proof of concept of SW-GAGD process was carried out using a sand-packed glass model. One of the main concerns with the design of SW-GAGD process was the behavior of the gas front as the gas is injected through the injector. Short circuiting of the injected gas to the horizontal producer was highly suspected. This would have led to poorer sweep of the model area, resulting in shelving of the concept itself.

As was visually observed (Figures 5.2, 5.3), these fears were allayed, when instead of short-circuiting, the injected gas was seen to spread out horizontally to fill the entire model top, before starting a top-down displacement of the model area. Figure 5.2 shows the frontal position of the gas front at the beginning of the flood. As shown the front position was gravity stable and gas zone filled out the entire top of the model. Figure 5.3 shows the same gas front towards the end of the flood. As can be seen, the front is fully developed at this point and still maintaining its gravity stable top-down characteristics.

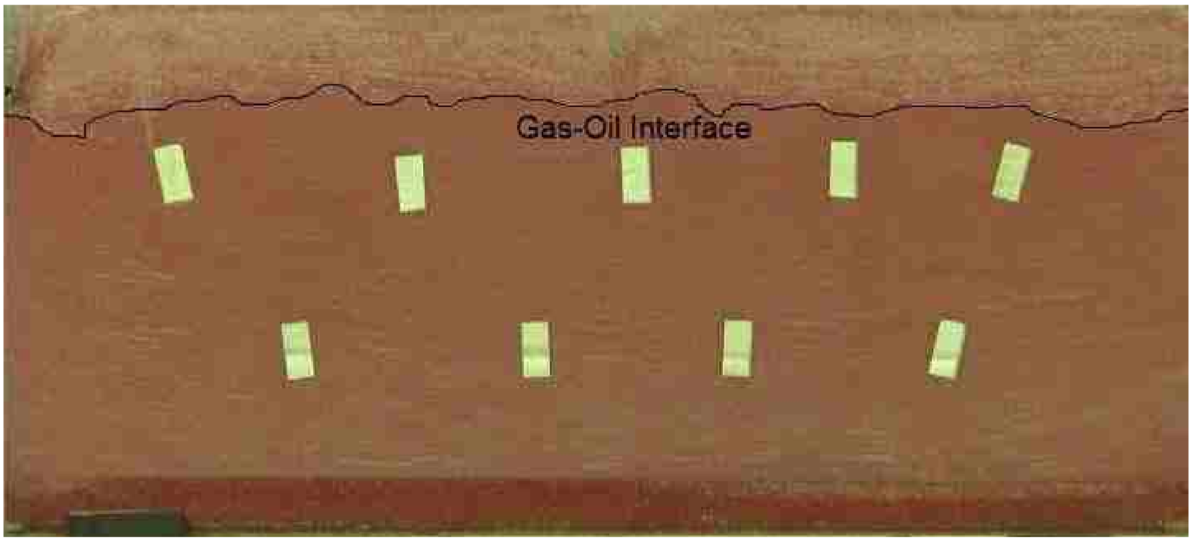

Figure 5.2: SW-GAGD model showing development of a gravity stable front at the top of sand (At the beginning of gas-flood)

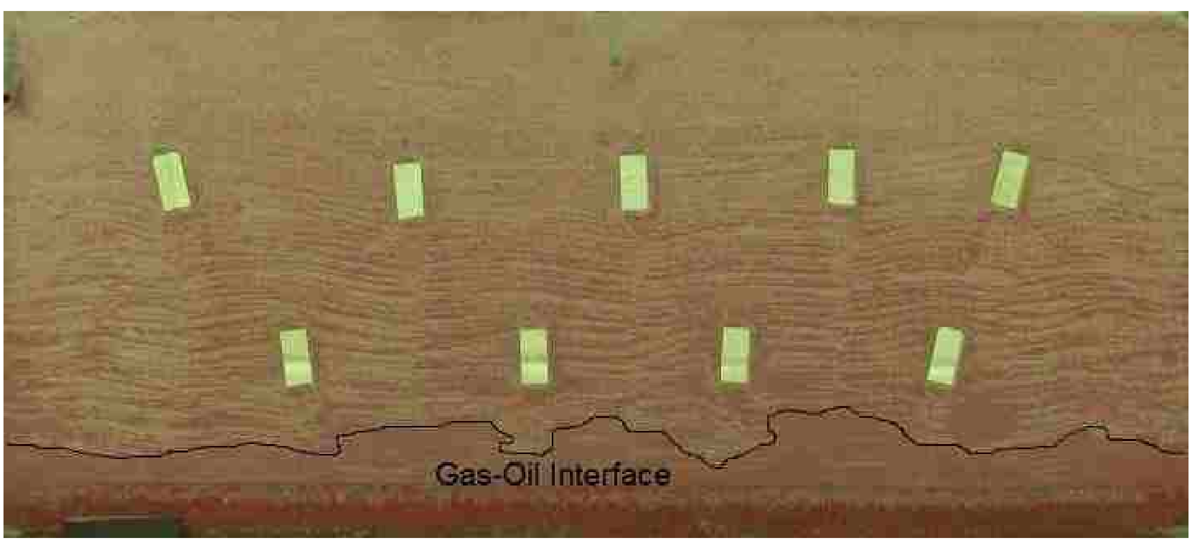

Figure 5.3: SW-GAGD model with a fully developed gravity stable gas-front showing good vertical sweep of model

5.2 Performance of a SW-GAGD model configuration with top injection point

This is the first and the most basic configuration of SW-GAGD model that was tested for its performance. Here as the title states, the injection point for the SW-GAGD model is at the very top of the payzone. A labelled picture of the model is shown in Figure 5.4.

Figure 5.4: SW-GAGD configuration with injection well at the top

The horizontal well spans the bottom of the model as indicated by red marked area. This configuration was used for evaluating the performace of SW-GAGD model in terms of rate and miscibility. In all of the following SW-GAGD experimental runs the initial condition of the model was, $S_{oi} = 1 - S_{wi}$ with $S_{gi} = 0$. The injection condition was $S_{gi} = 100\%$ of injectant for all the runs.

5.2.1 Effect of rate on SW-GAGD model recovery

One of the most important operational parameter is the rate of injection of the injected gas. Too high a rate is fraught with viscous instability and early breakthrough of the injected gas leading to poorer sweep and too low a rate would mean low production rates and low ultimate recoveries. In this study, Nitrogen gas, was injected at 5 different flow rates, viz., 2.5, 5, 10, 15 and 20 SCCM.

Critical rate for our SW-GAGD model runs based on Hill's criteria was 68.74 ft/ day and all the SW-GAGD runs were well within Hill's criteria for the critical rate, ranging from 2.3ft/day for 2.5 SCCM run to 36.5 ft/day for 40 SCCM run. Nitrogen gas was chosen as the injectant gas since it was immiscible with Decane, the oil phase in the model. Recovery of the model was also evaluated when the production was simply due to gravity without the injection of Nitrogen gas. Figure 5.5 shows this base case when the production was solely because of gravity.

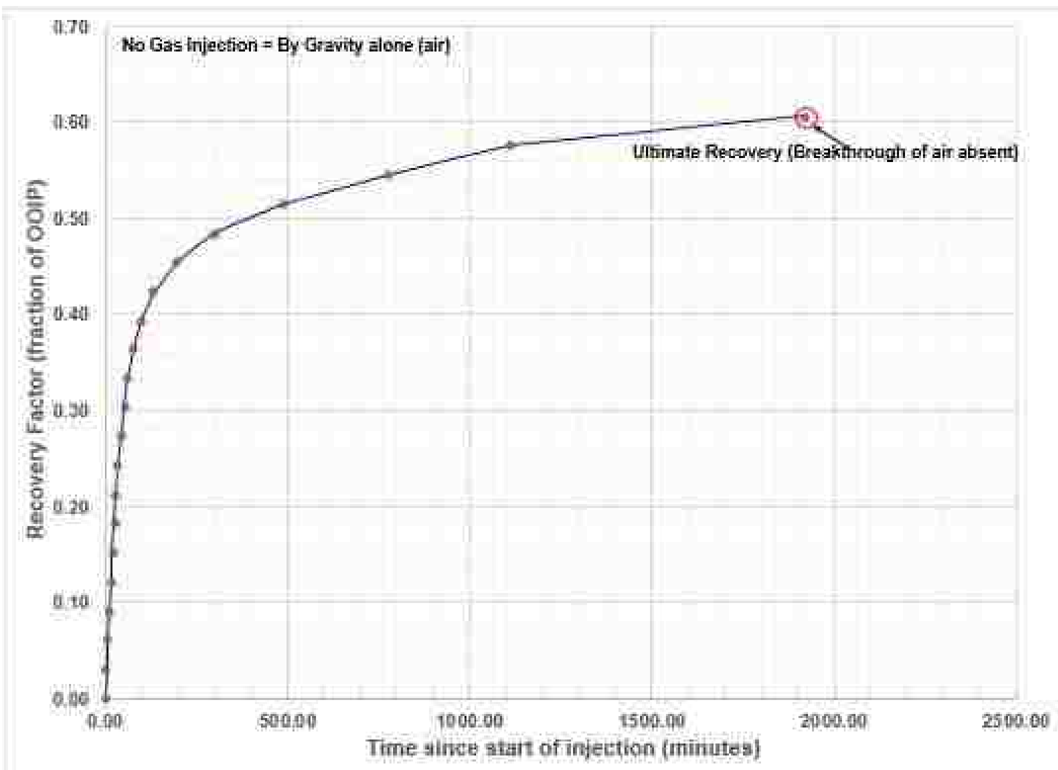

Figure 5.5: Recovery plot in case of pure gravity drainage

As can be seen from Figure 5.5, the production rate gradually slowed down with time and the ultimate recovery was around 61%. Almost 39% of the OOIP remained trapped within the model because of the capillary and frictional forces. Figures 5.6 below shows the corresponding recoveries for two injection rates of 2.5 and 20 SCCM.

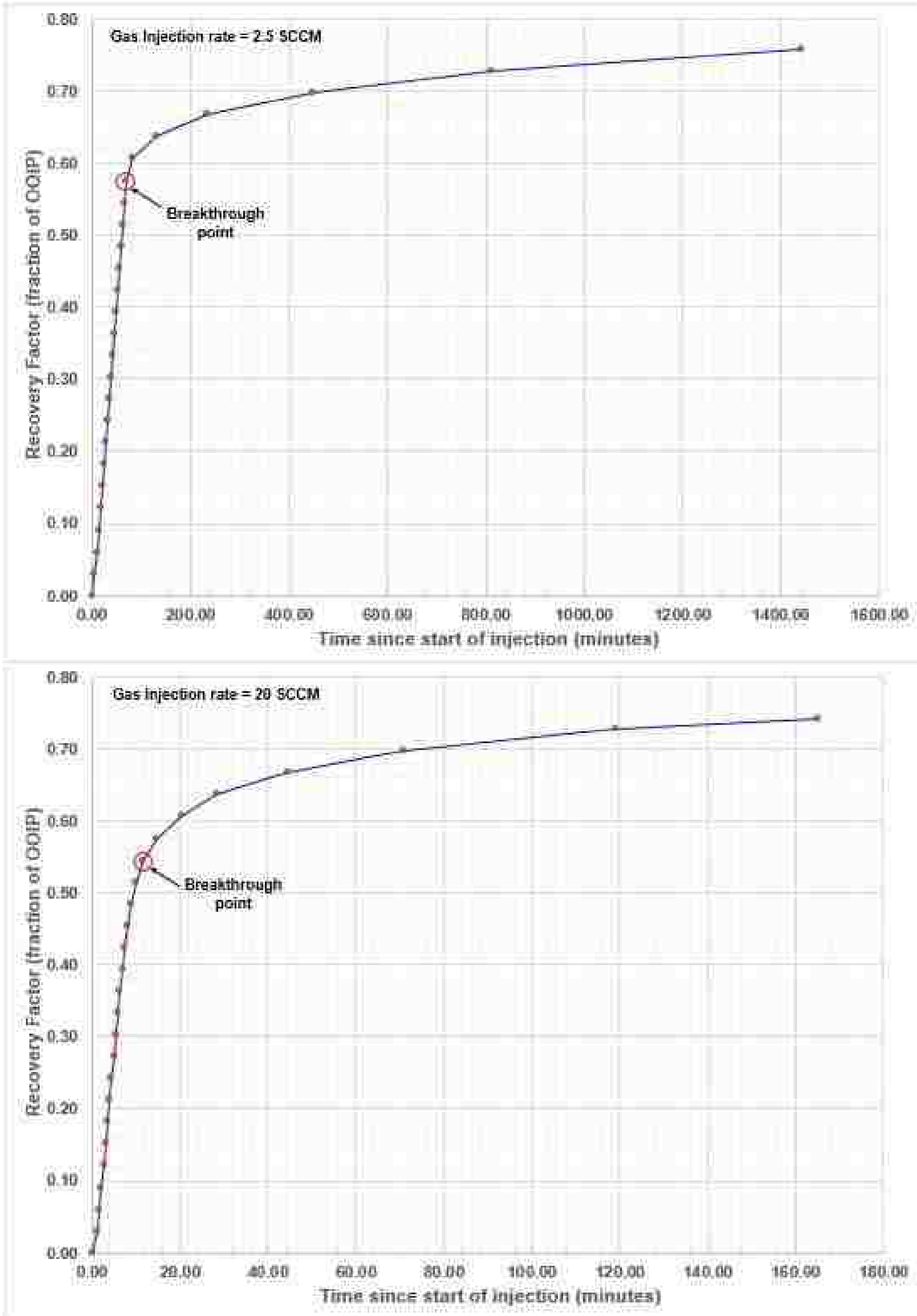

Figure 5.6: Recovery plot in case of 2 injection rates of 2.5 SCCM (top) and 20 SCCM (bottom)

Comparing Figure 5.5 for pure gravity drainage with that of Figures 5.6, it is apparent that injection of gas not only increases the recovery factor but also increases the production rates many fold. Recovery by gravity drainage is touted as one of the most efficient recovery method and the only drawback with natural gravity drainage process is the speed of such a process. By the injection of gas, we were able to remove this inherent drawback as well as increase the recovery factor. The increase in the recovery factor is clearly evident looking at Figure 5.7.

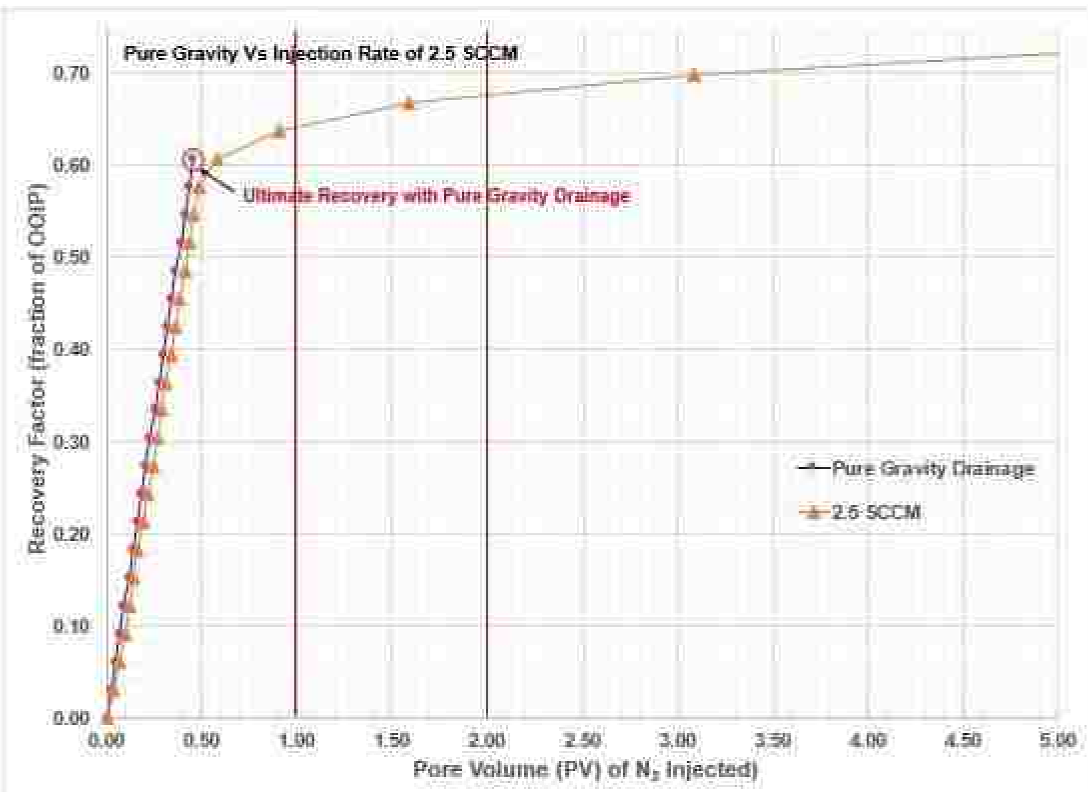

Figure 5.7: Comparison of pure gravity drainage with an injection rate of 2.5 SCCM

As can be seen from the figure, just by having an injection rate of 2.5 SCCM, the recovery at 1 PV of gas injection exceeds the ultimate recovery associated with pure gravity drainage by 3% OOIP and that goes up to 5.5% at 2 PV of gas injection. The additional recovery with gas injection is because of overcoming of capillary and frictional forces by the injected gas and will be discussed in detail at a later stage.

As stated earlier, the rate of recovery plays an important factor determining the economics associated with the production of hydrocarbons. Without high enough production rates, the most efficient recovery method will not be economically sustainable. Natural or pure gravity drainage which is known to produce very efficient recoveries, suffer from poor rates. This is one of the main concern with the operators. Figure 5.8 compares recovery factor at different rates including that of pure gravity drainage.

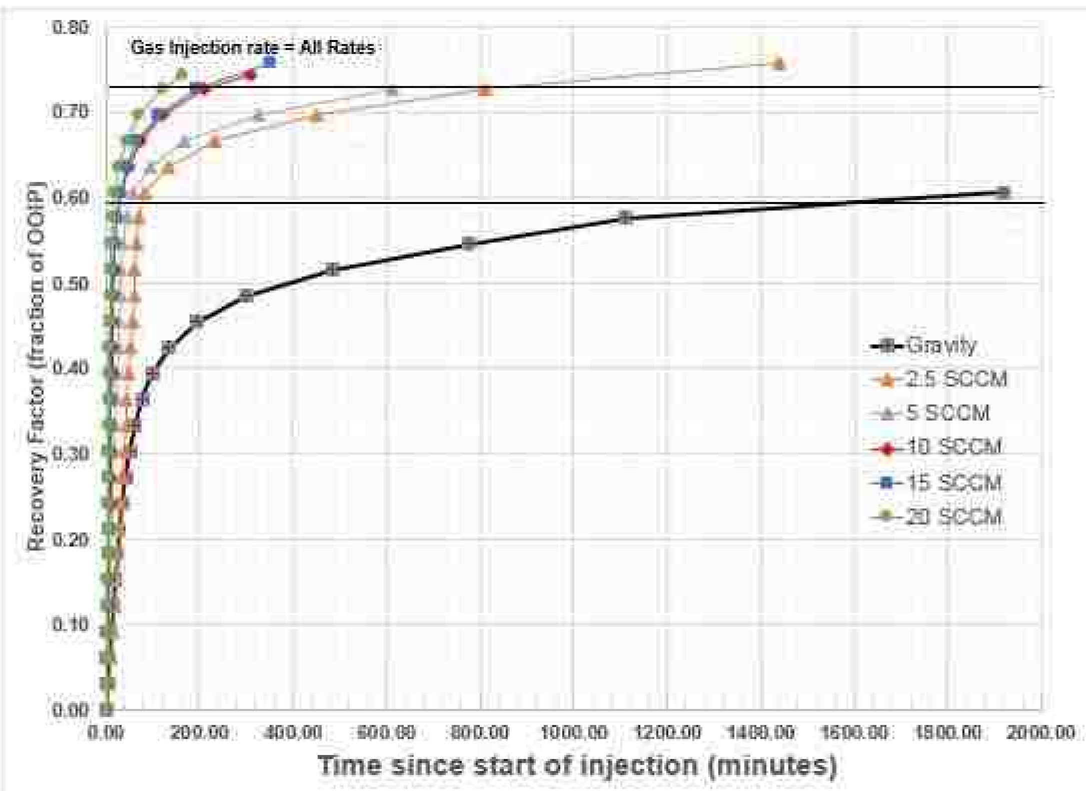

Figure 5.8: Recovery plot for all rates including pure gravity drainage

Considering the amount of time required to get to the ultimate recovery factor of 61% for pure gravity drainage, it can be seen that it takes much shorter to reach the same recovery factor in case of forced gravity drainage. Table 2 below lists the time taken in each of the cases of pure gravity drainage, 2.5 SCCM injection rate and 20 SCCM injection rate for achieving 61% recovery factor. As can be seen from the table, time taken in case of 2.5 SCCM is 23 times faster than pure gravity drainage and that in case of 20 SCCM injection rate is 93 times faster. Thus gas injection imparts significant rate enhancement to the gravity drainage process.

Table 2: Time to reach 61% recovery factor (URF with pure gravity drainage)

Rate/ Mode	Time taken to reach 61% recovery factor
Pure Gravity Drainage	1860 mins
Injection Rate = 2.5 SCCM	80 mins
Injection Rate = 20 SCCM	20 mins

Also, one important point that needs to be stressed at this point is that production of oil begins immediately upon gas injection. There is a pervasive perception that gravity drainage is a slow process and that it takes a significant amount of time after gas injection is started that oil production begins. This may be true for pure gravity drainage process but certainly not the case with forced gravity drainage process, as was observed in SW-GAGD runs. Mahmoud et al.[46], Silva et al.[60] found similar results. At this point, the question that arises is whether higher injection rates are better than lower injection rates? Not always! Of course, we get a tremendous enhancement in oil production rates with higher injection rates but the recovery factor is affected. Hagoort[25] (1980) also pointed out that before breakthrough, the rates of oil production should match the gas injection rate due to material balance. As can be seen in Figure 5.9, the recovery factor at 1 PV gas injected is, however, higher in case of lower injection rates than higher rates. The recovery factor does catch up at higher PVs injected though, for example, at 5 PV injected the difference in recovery factor almost vanishes. Hagoort[25] (1980) model also predicted higher breakthrough recovery efficiency for higher gravity no. $(\frac{\Delta\rho g k}{\mu_o V})$, which is inversely proportional to the rate of gas injection. Thus at higher injection rates, gravity no. decreases and so does the breakthrough recovery. One possible explanation for this is that the vertical displacement front is more stable. Even though all the rates were under Hill's[26] criteria for gravity stable rate as discussed, some disturbances, where an occasional bubble reached the production were seen at higher rates. But another more likely reason for higher breakthrough efficiency at lower injection rates seems to be because of greater enabling of film drainage as displacement front moves slowly downwards.

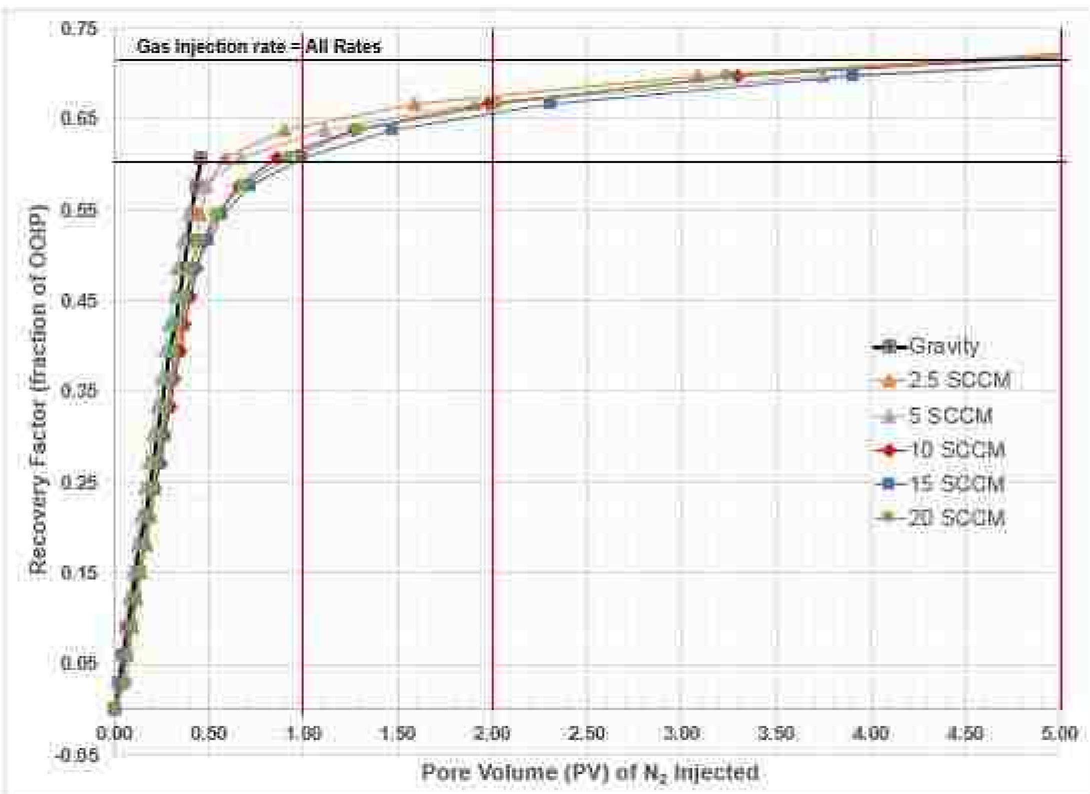

Figure 5.9: Recovery plots merging when plotted as a function of PV injected

There is a sharp discontinuity in rates of oil production before and after the arrival of the gas-oil displacement front at the production well. Before the arrival of gas-oil front at the production well, the production seems to be primarily due to displacement at the gas-oil interface. Post arrival of the gas-oil interface at the production well, there is no clear displacement front and the production continues through the interplay of forces of gravity, capillary and inertial. The oil continues to drain to the bottom of the payzone due to gravity. As it drains, it tries to connect to other aggregates of left out oil so as to form a continuous layer of oil in the already swept out region. Drainage of oil through oil films in presence of gravity continues throughout the process. After gas/oil displacement front has passed a particular height, the gas phase is no longer able to bear the weight of heavier oil globules, which then drains faster to lower reaches and tries to connect with continuous oil phase below. In case of slower rates this formation of connected oil films is sustained at the displacement front and as a result more oil drains to the production well before breakthrough. Figures 5.10 and 5.11 are the recovery plots for the two injection rates of 2.5 SCCM and 20 SCCM. In Figure 5.11 the point of first appearance of gas bubble due to instability and that of breakthrough point is marked separately as shown.

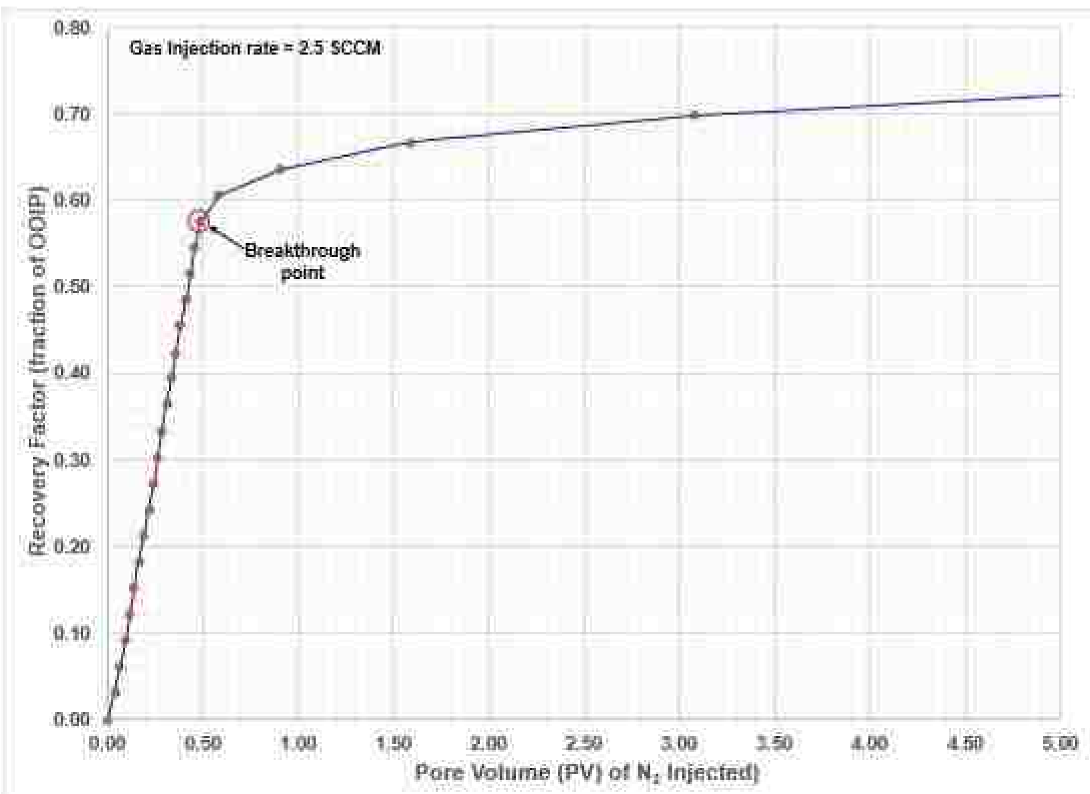

Figure 5.10: Recovery plot for a rate of 2.5 SCCM showing the breakthrough point

In case of an injection rate of 20 SCCM, the first instance of appearance of gas bubble was prior to actual breakthrough of gas, wherein continuous efflux of gas occurred. The first appearance of bubble in this case was as a result of viscous instability of the front at higher rates. However, the gravity force was able to quickly correct it and oil production resumed again. This intermittent appearance of bubbles and immediate restoration of continuous oil flow continued till the breakthrough point, when gas/oil displacement front reached the production well. As long as the displacement front is above the horizontal production well, gravity forces play a predominant role in nullifying the breakthrough of injected gas.

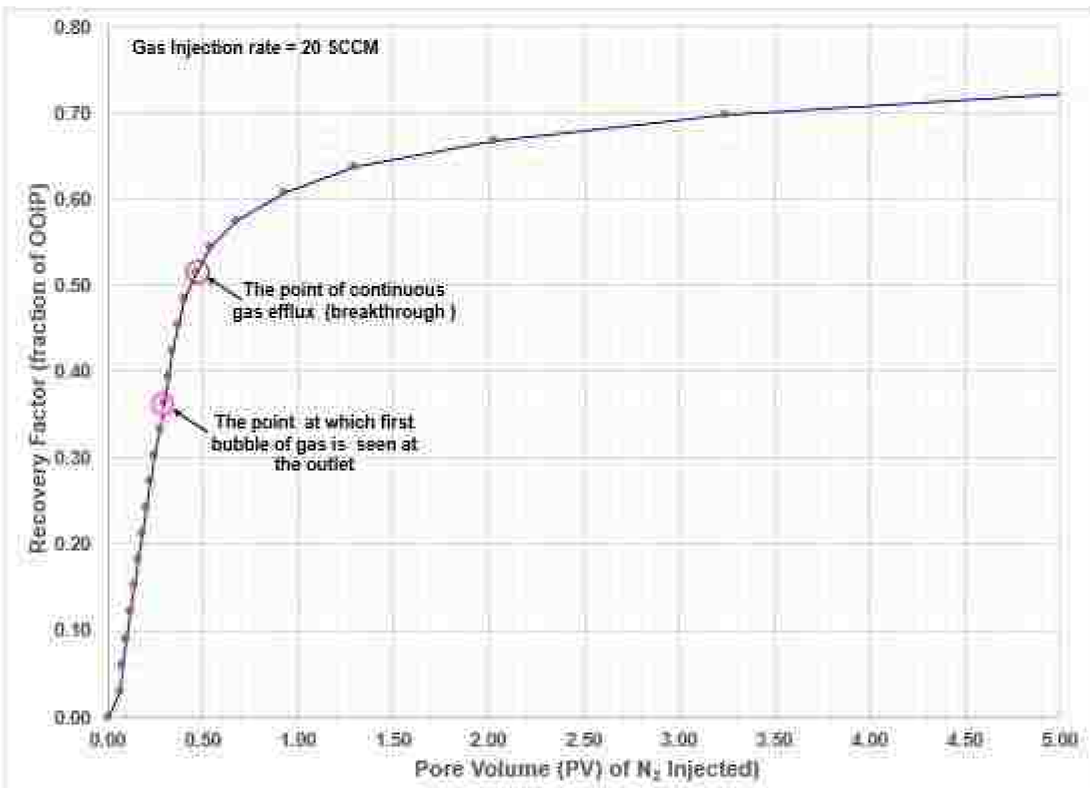

Figure 5.11: Recovery plot for a rate of 20 SCCM showing the breakthrough point

Even though breakthrough production is less for higher rates, ultimate production is equivalent for slower and faster rates alike. Terwilliger[62] (1951) also found that as the rate of recovery was increased, the amount of additional recovery after breakthrough constituted a more significant part of the total recovery.

5.2.2 Effect of miscibility

As seen in the previous cases, the Recovery Factor (RF) stands at around 70-75% with immiscible Nitrogen gas injection for SW-GAGD processes at 5 PV of injected gas. The rest 25-30% oil that remains trapped inside the model upon immiscible Nitrogen injection is because of capillary forces. Due to the very nature of immiscible injection, this capillary trapping is unavoidable. Since, miscibility leads to vanishing of capillary forces, thus using miscible injectant even this remaining oil should be recoverable. Even though that is the reason why CO_2 miscible flooding has got so much attention, but the best of conventional miscible floods have performed much worse (Christensen et al.[10]). As explained earlier that's because of poor volumetric sweep efficiency of miscible CO_2 floods. Miscible CO_2 floods are high pressure processes at pressures above MMP of CO_2 and that is around 2500 psi. However, SW-GAGD glass models are not able to withstand pressures beyond 2 psi. Hence it's not possible to do a miscible CO_2 flood using the glass models. So, we tried to mimic miscible CO_2 injection by using Naptha (miscible with Decane) as the injectant to displace Decane oil. Densities of Decane and Naptha are comparable at 0.73 g/cc and 0.72 g/cc respectively and this in essence represented the densities of miscible CO_2 and Crude oil in an actual reservoir. Figure 5.12 shows the progression of a miscible SW-GAGD process. As can be visually observed from the Figure 5.12, the microscopic displacement efficiency is 100% for the flood, hence giving a totally clear color in the swept region. Almost 95% of the oil was recovered using our simulated miscible SW-GAGD process. This was because of coupling of 100% microscopic sweep efficiency of miscible processes with excellent volumetric sweep efficiencies of SW-GAGD process.

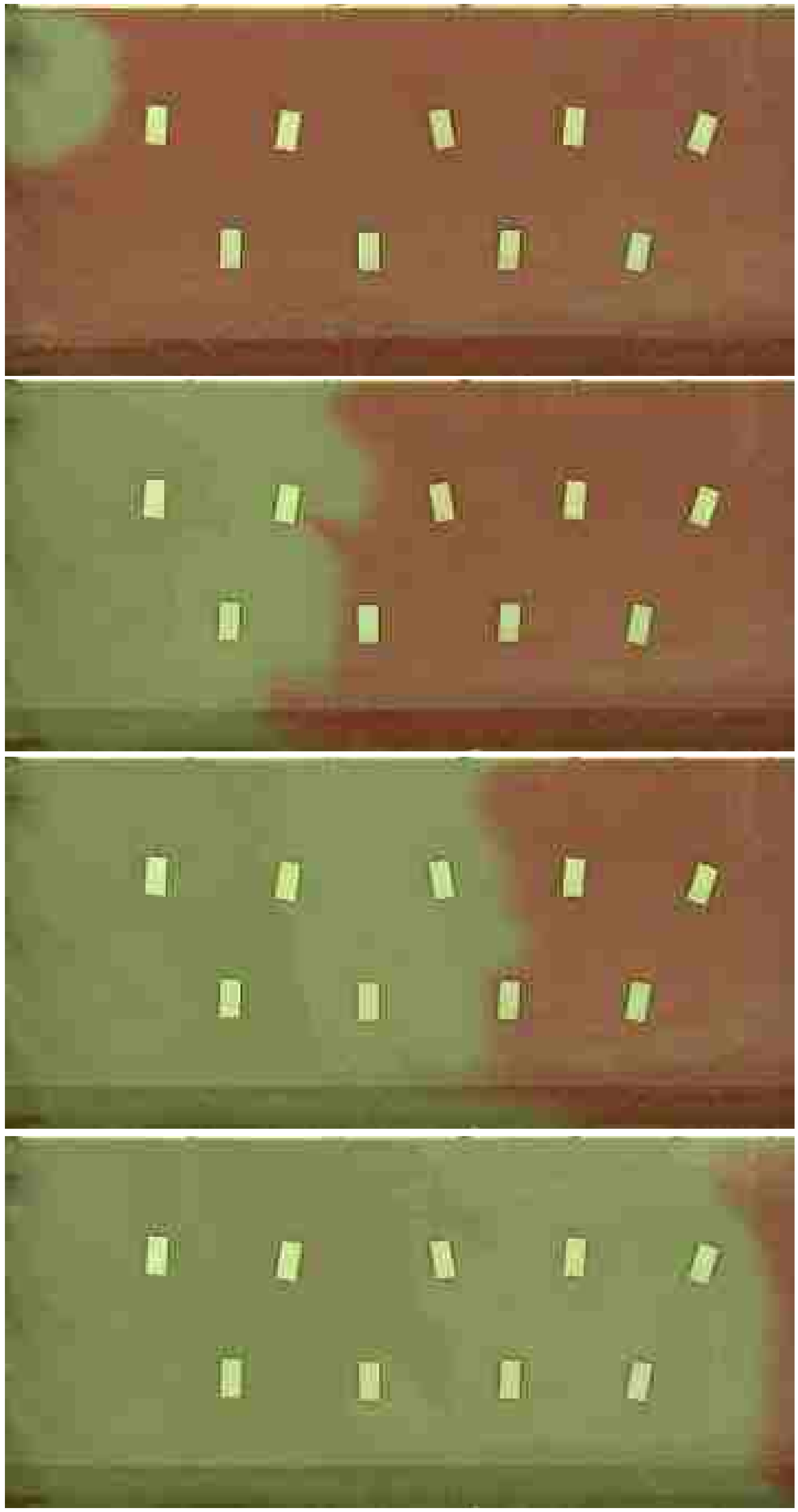

Figure 5.12: A miscible SW-GAGD flood progression
(sequenced top to bottom)

5.3 Film flow and gravity drainage

Many authors (Oren[50]-1994, Salathiel[56]-1973) have studied the existence and utility of oil films in aiding the flow of oil out of reservoir matrix in the form of continuous oil films. As discussed in the chapter on literature survey, positive spreading coefficient of oil in water-wet system allowed formation of thinner spreading films whereas oil-wetted ness of oil-wet system fostered formation of thicker oil-wetting films. These films established continuation migration pathway for the oil to flow out and are a major contributing factor to reaching very low oil saturations. Gravity drainage in presence of these films form a potent combination as in SW-GAGD process and were anticipated to play a significant role in boosting recovery of oil. This is supported by higher recoveries for oil-wet case than water-wet case in the earlier work of Mahmoud et al.[46] and Paidin et al.[51] on GAGD performance. In case of water-wet case, as was the case in SW-GAGD model, oil-spreading films rather than oil-wetting films, aided in forming continuous pathways for the oil phase. Figure 5.13 tries to throw light on this aspect of gravity drainage of oil in presence of such films. Spreading coefficient for our SW-GAGD model was high positive (~+30) considering the values of IFTs in between oil, water and gas phases and thus formation of spreading films was expected. Concentrating on the white colored circle and following the pathway indicated by red arrows, we see gradual lightening (clearing) of an already swept area as the oil drains downward and connects to a continuous oil phase. This drainage through films continued even after gas injection is stopped and the model allowed to stand. Upon overnight standing, the entire top part of the model lightened out with the oil draining to the bottom of the model. This illustrates the impact of film drainage in increasing the oil saturation near the horizontal production well at the bottom of the payzone.

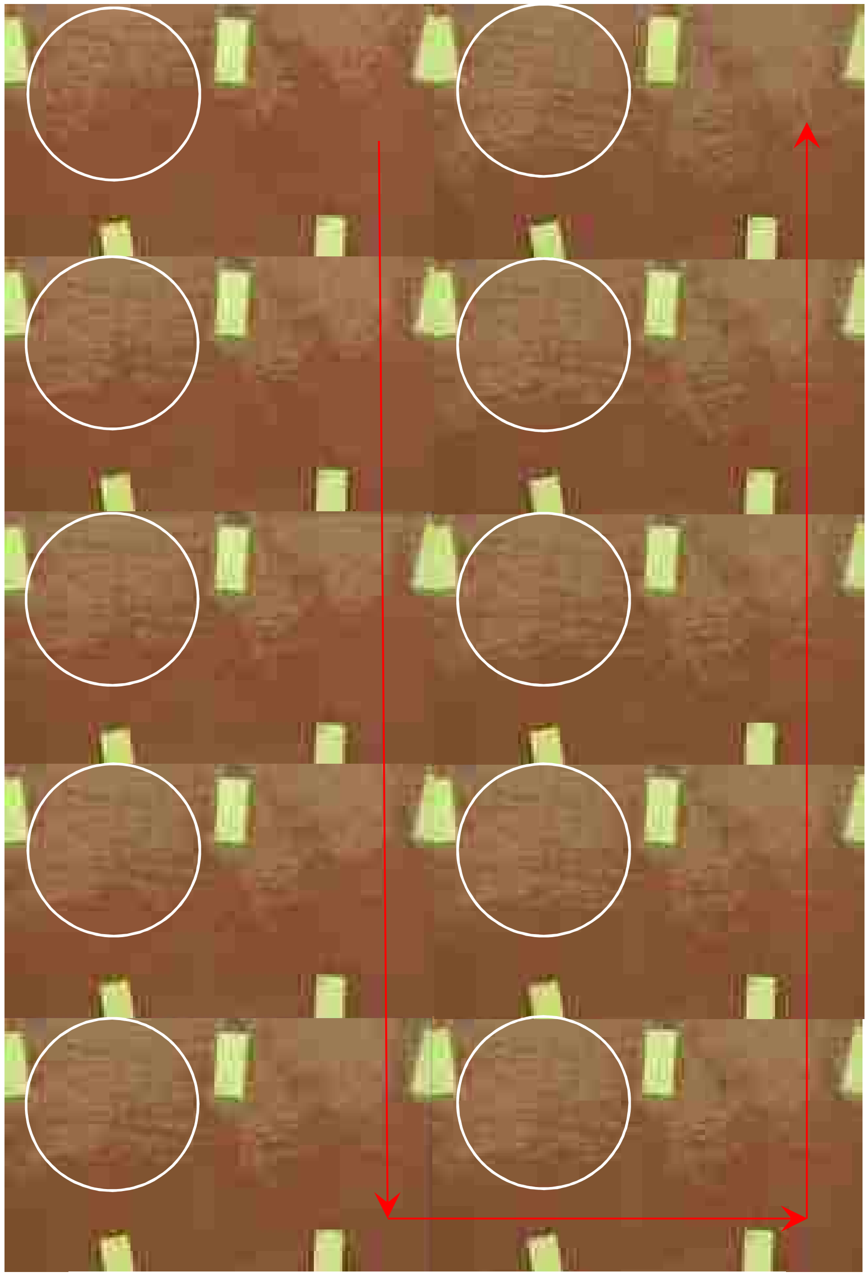

Figure 5.13: Film flow during gravity drainage
(direction along red arrows)

This mechanism of draining down of oil in oil-films due to gravity is always present but gets amplified after the gravity stable top-down flood front has passed below a particular height since the lighter gas phase is no longer able to support the heavier oil phase. Thus there is a stronger downward pull on the oil drop, which moves through oil films to connect with a continuous oil phase down below. Even though such film flow exist in case of horizontal floods as well but the force of gravity aiding the process is missing. Moreover in case of horizontal floods, the oil films would have to traverse miles under the inertial forces of injectant stream but it's only tens of hundreds of fee, at the maximum, in case of SW-GAGD process. In our SW-GAGD experiments, this effect led to accumulation of the oil phase at the bottom of the model with total bleaching out of the red dyed oil from the top zone, upon standing overnight without any injection.

5.4 Effect of injection depth –Top Vs Bottom injection point SW-GAGD model

To investigate the effect of depth of injection point in case of SW-GAGD model, a model was built with concurrent placement of a top and bottom injector well within the same model. Figure 5.14 shows the SW-GAGD configuration indicating the location of the injection points.

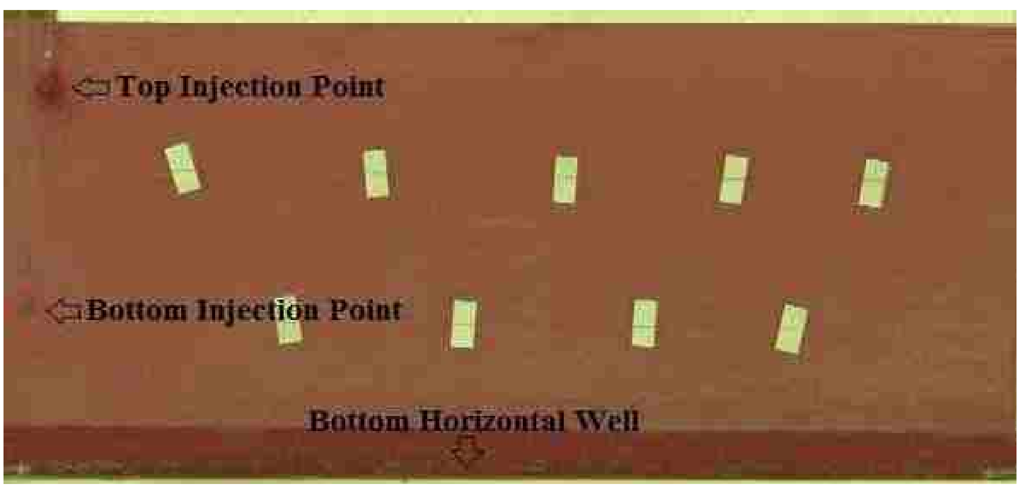

Figure 5.14: A SW-GAGD configuration with both a Top and a Bottom Injector wells

Figures 5.15 and 5.16 shows the development of displacement front with injection at top and bottom injection point respectively. The images in these figures are sequenced top to bottom with regard to time, meaning the top image is at the beginning of the flood, middle image is midway during the flood and the bottom image is at the end of the flood.

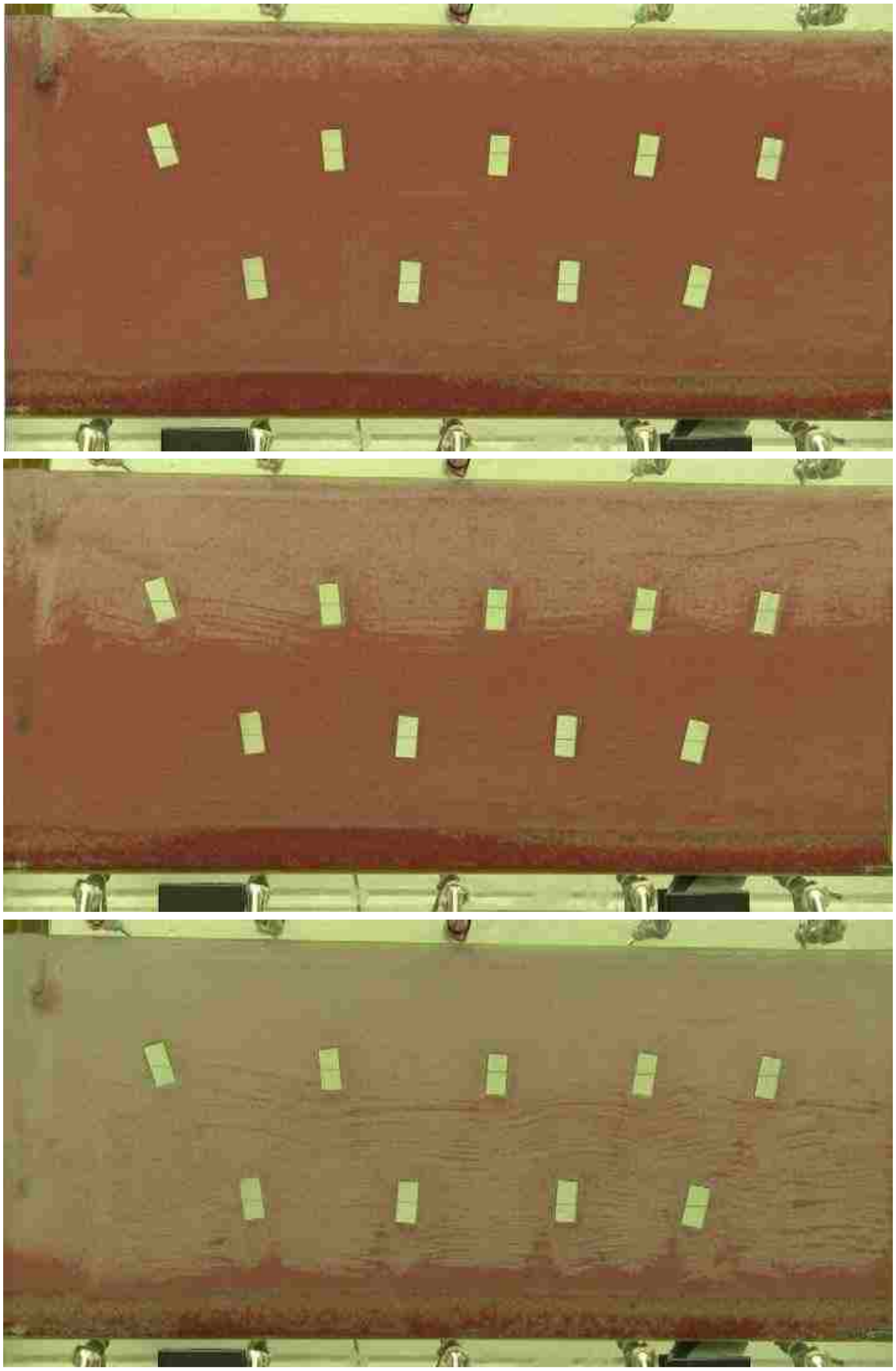

Figure 5.15: Development of displacement front with Top injection
(sequenced top to bottom)

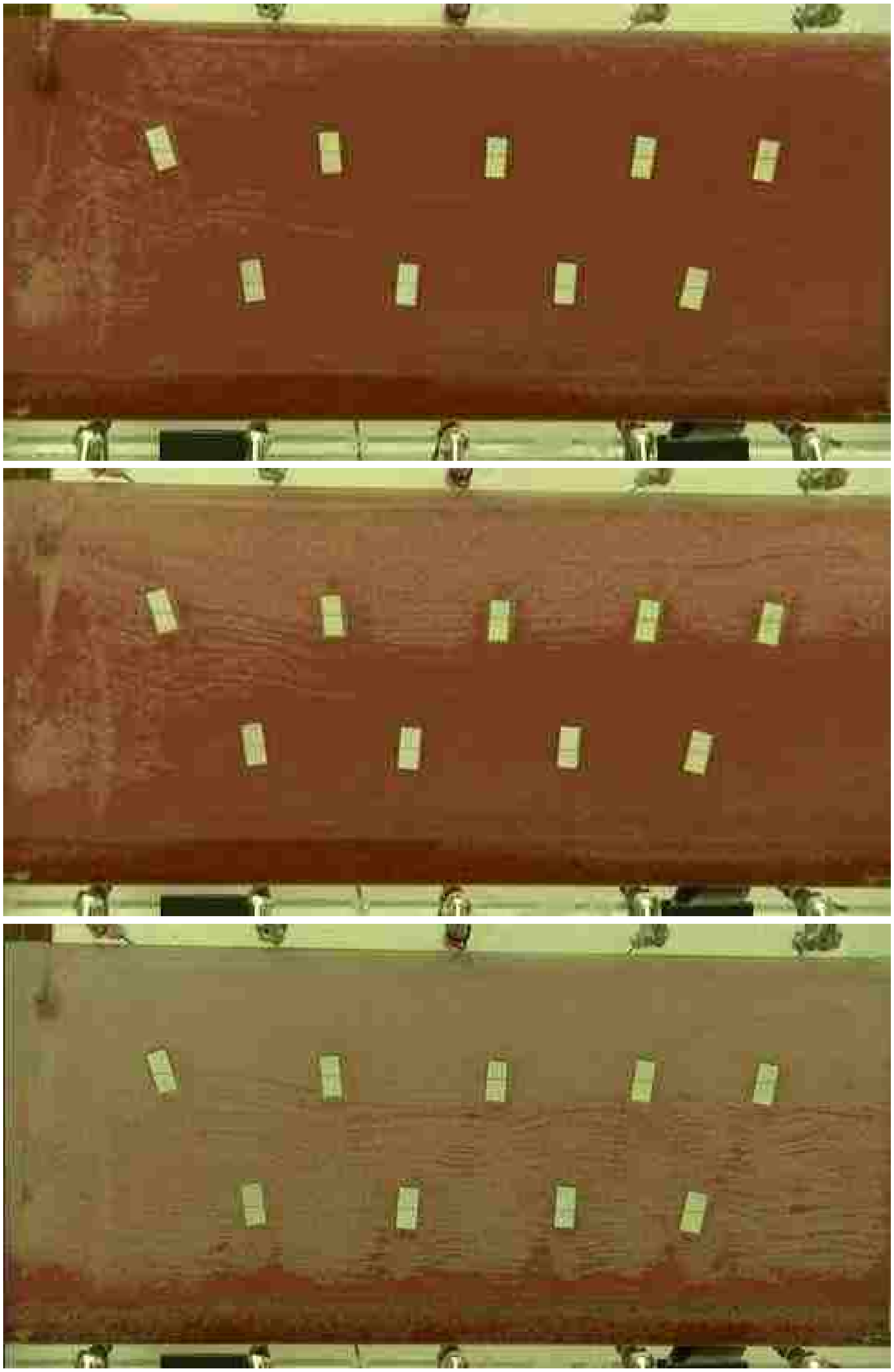

Figure 5.16: Development of displacement front with Bottom injection
(sequenced top to bottom)

Injection at the bottom injection well was fraught with suspicion of short-circuiting towards the bottom horizontal well as the injection point was much closer to that well. But it was observed that the injected gas rather than moving downward, headed upward to fill the model top first before doing a top-down displacement. No difference was observed in terms of development of the displacement front in both cases. However, looking at the recovery plot (Figure 5.17), there is marginal difference between the 2 cases. In case of bottom injection, recovery factor after breakthrough is higher by 2% and 1% at 1 PV and 2 PV injection respectively. This difference is attributed to boosting of inertial forces at the bottom of the payzone where most of the capillary and frictional trapping occur.

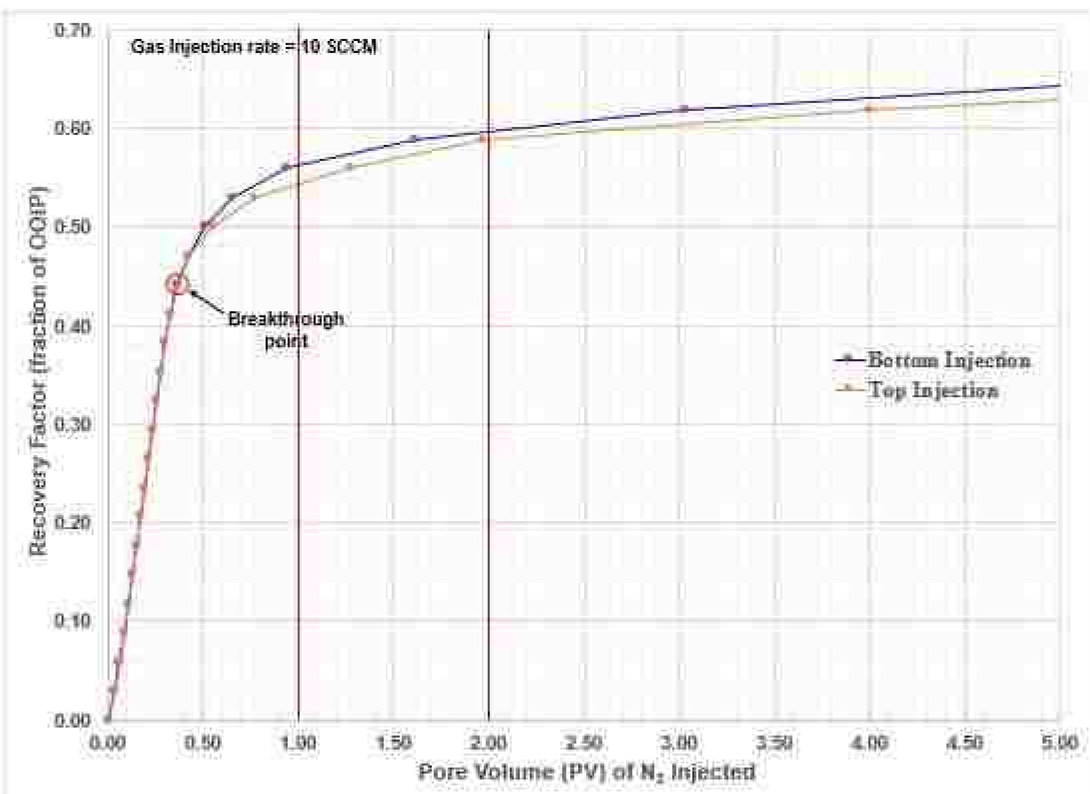

Figure 5.17: Recovery plot comparison between top and bottom point injection cases.

Looking at the recovery plot (Figure 5.17), even though there seems to be marginal benefit with bottom injection, it may not be actually beneficial in field application when layering of the reservoir may be an issue. Detailed discussion on the effect of layering on production is included under discussion on Toe-to-Heel configuration.

5.5 SW-GAGD Vs GAGD model

Comparison between a SW-GAGD well configuration and a GAGD well configuration is critical to the design of SW-GAGD process. It was anticipated that SW-GAGD might not perform as well as a GAGD process, wherein the injection point is symmetrically located with respect to horizontal production well. Even though the injected gas was observed to spread out at the top before initiating a top-down displacement in case of SW-GAGD well configuration, there were doubts about the progress of the displacement front from start to finish of injection. Moreover, there were apprehensions that mere match of displacement profile between them may not mean identical efficiencies in recoveries. So, to put these doubts to rest, a model was built with concurrent placement of 2 wells in SW-GAGD and GAGD configuration each. Figure 5.18 shows the actual model where both SW-GAGD and GAGD well locations are identified.

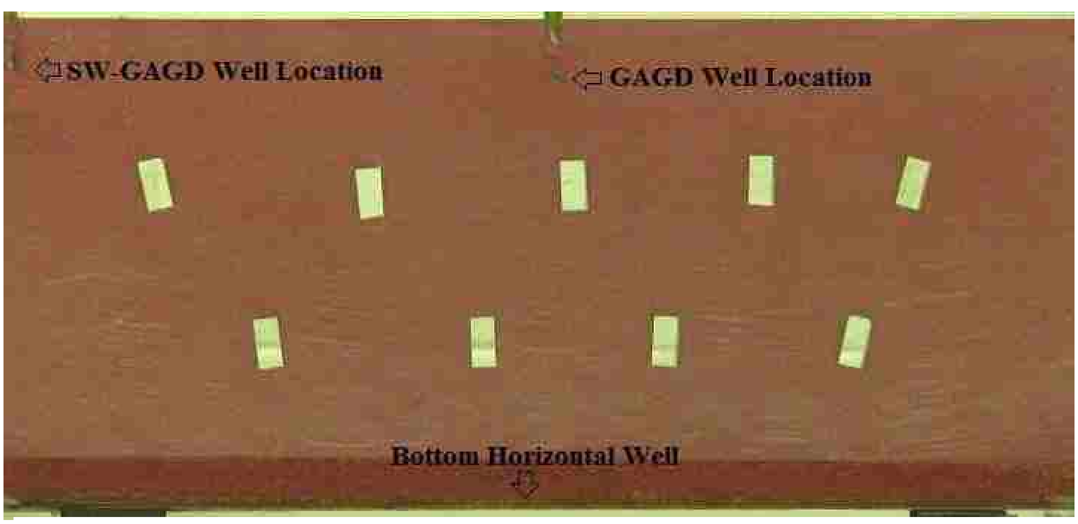

Figure 5.18: SW-GAGD Vs GAGD well configuration

Figures 5.19 and 5.20, show the development and progression of front in cases of SW-GAGD and GAGD, respectively.

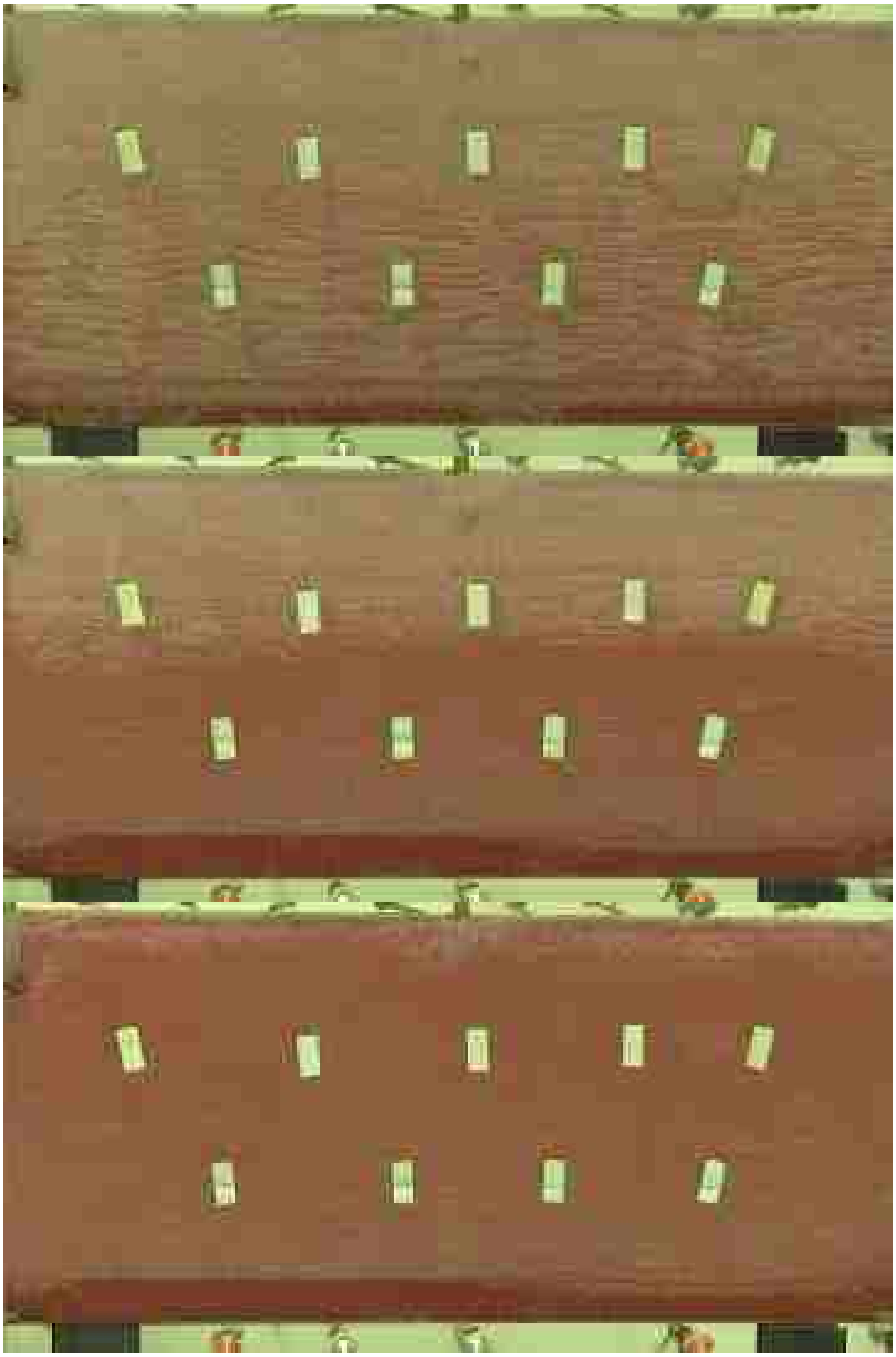

Figure 5.19: Development of displacement front with SW-GAGD well configuration (sequenced top to bottom)

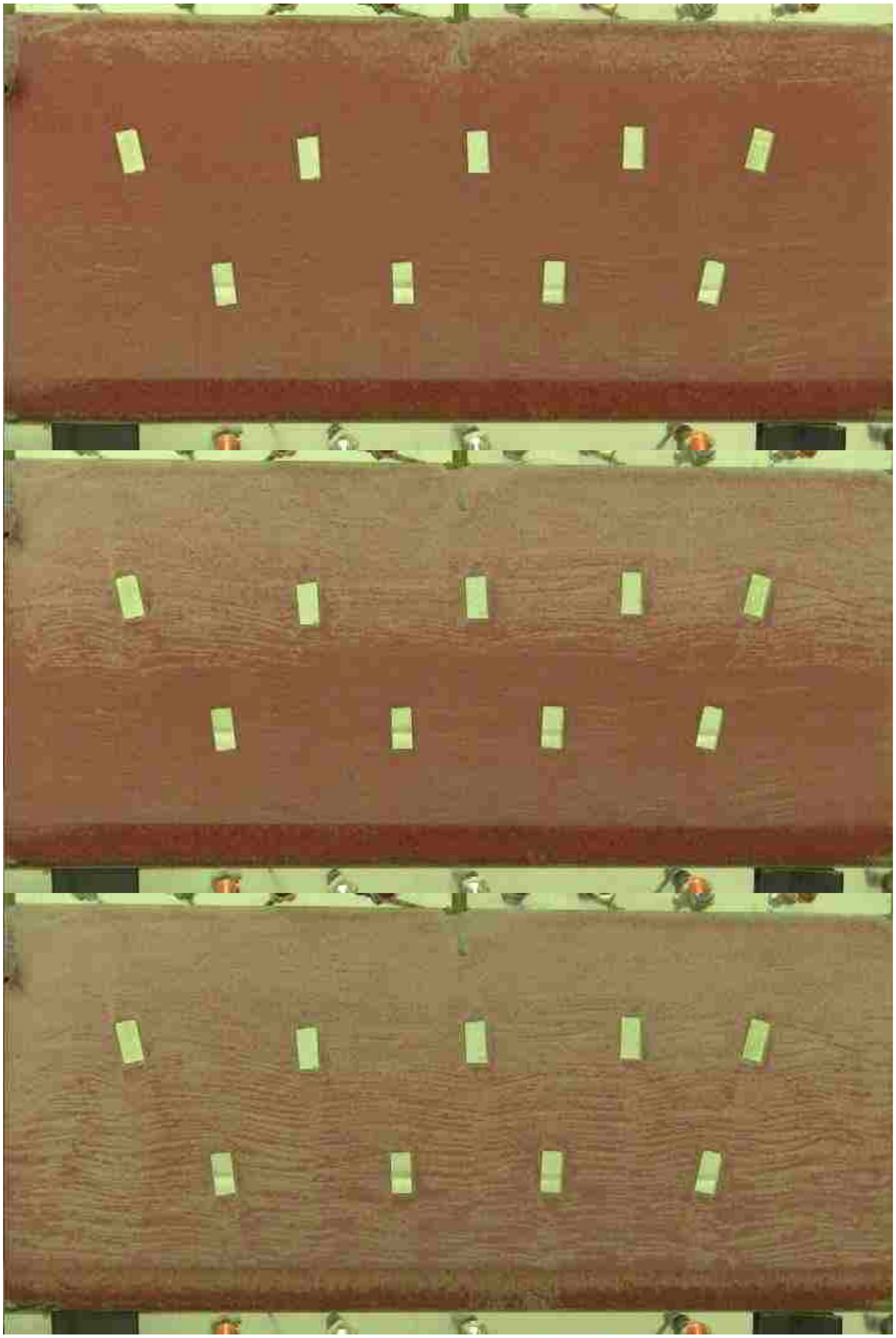

Figure 5.20: Development of displacement front with GAGD well configuration (sequenced top to bottom)

The progression of front was almost identical barring the initial part, thereby visually establishing the equivalence of the two processes. Figure 5.21 shows the recovery plot for SW-GAGD and GAGD, juxtaposed on one another. The recovery plots exactly overlapped from the beginning till the very end, dispelling any doubts about under-performance of SW-GAGD process compared to GAGD process. Thus, we need not be fixated on the idea of having multiple vertical injectors for establishment of the gas zone at the top of the payzone. A single well in SW-GAGD configuration should be able to serve as well thereby saving greatly in terms of the cost. Only limiting factor in case of a SW-GAGD process compared to a GAGD process, would be the rate of gas injection, since a single well would be required to injected as much gas. But nowadays with the advances in horizontal well technology, that should not be a constraint, should it occur.

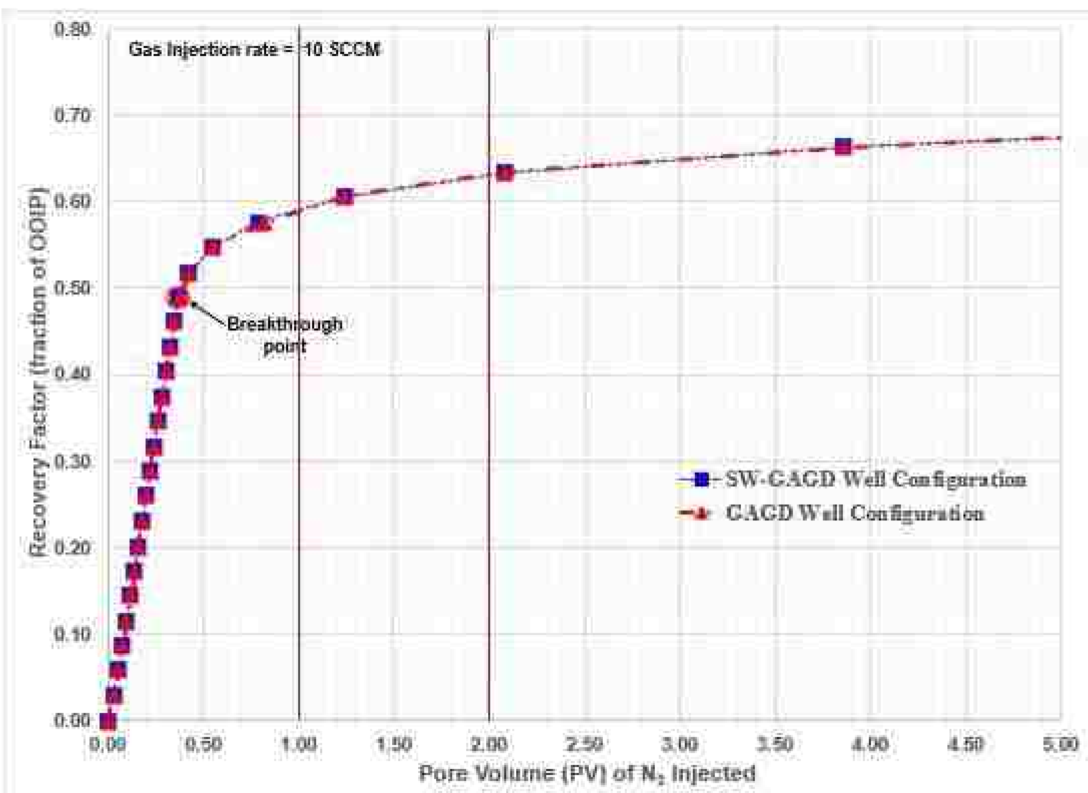

Figure 5.21: Comparison of recovery plot between SW-GAGD and GAGD mode

5.6 Toe-to-Heel configuration

Toe-to-Heel is a very popular well configuration used in the recovery of heavy oil through Toe to Heel Air Injection (THAI) process. Since the completion technologies for such a configuration is already available in the industry, hence it was considered as a suitable candidate for the application of SW-GAGD process. Figure 5.22 shows the Toe-to-Heel well configuration in use in a THAI process.

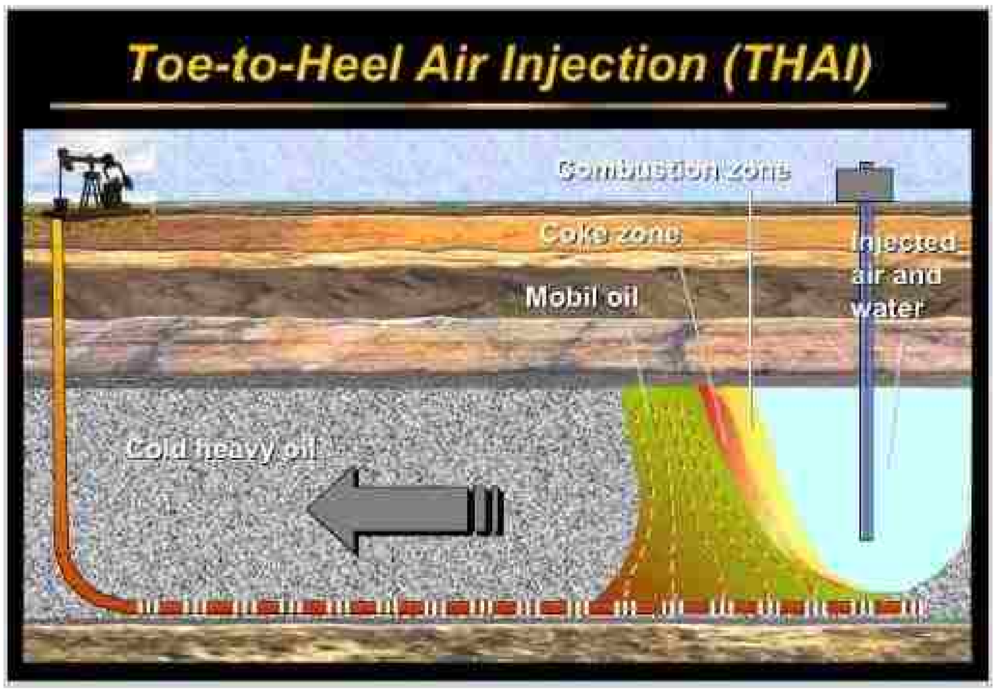

Figure 5.22: Toe-Heel well configuration in use in a THAI process
(courtesy: Tor Bjornstad, IFE)

For the purpose of SW-GAGD process, following four scenarios as depicted in Figure 5.23 were evaluated for the case of Toe-to-Heel well configuration:

1) Single Layer, Short Spaced: Model comprises of a single sand grain size (#50/70), giving uniform permeability throughout the model. Toe-to-Heel separation distance is SHORT (arbitrary relative to LONG) as shown in Figure 5.23[c].

2) Single Layer, Long Spaced: Model comprises of a single sand grain size (#50/70), giving uniform permeability throughout the model. Toe-to-Heel separation distance is LONG (arbitrary relative to SHORT) as shown in Figure 5.23 [d].

3) Bi-Layered with higher permeable layer at the bottom , Short Spaced : Model comprises of 2 layers with smaller sand grain size (#50/70) on top and larger sand grain size (#20/30) at the bottom, giving higher permeability to the bottom layer. Also, Toe-to-Heel separation is SHORT (arbitrary relative to LONG) as shown in Figure 5.23 [a].

4) Bi-Layered with lower permeable layer at the bottom, Short Spaced: Model comprises of 2 layers with larger sand grain size (#20/30) on top and smaller sand grain size (#50/70) at the bottom, giving lower permeability to the bottom layer. Also, Toe-to-Heel separation is SHORT (arbitrary relative to LONG) as shown in Figure 5.23 [b].

Each of these four scenarios given above were investigated to evaluate the effect of layering and spacing in the performance of SW-GAGD Toe-to-Heel configuration. Effect of layering was important as the reservoir, as we know it, is layered with varying permeability between layers. Only two (2) cases of spacing, namely, SHORT and LONG (arbitrarily chosen) were considered to understand the effect of spacing, if any, in the progression of a SW-GAGD process in Toe-to-Heel well configuration. SHORT spacing was roughly half the length of the bottom horizontal well whereas LONG spacing was roughly 6/8th of the length of the horizontal well. Even though the aim is to investigate Toe-to-Heel configuration, nevertheless, a top injector was included in each case for performance comparison in terms of recovery rates and development of gas-oil displacement front.

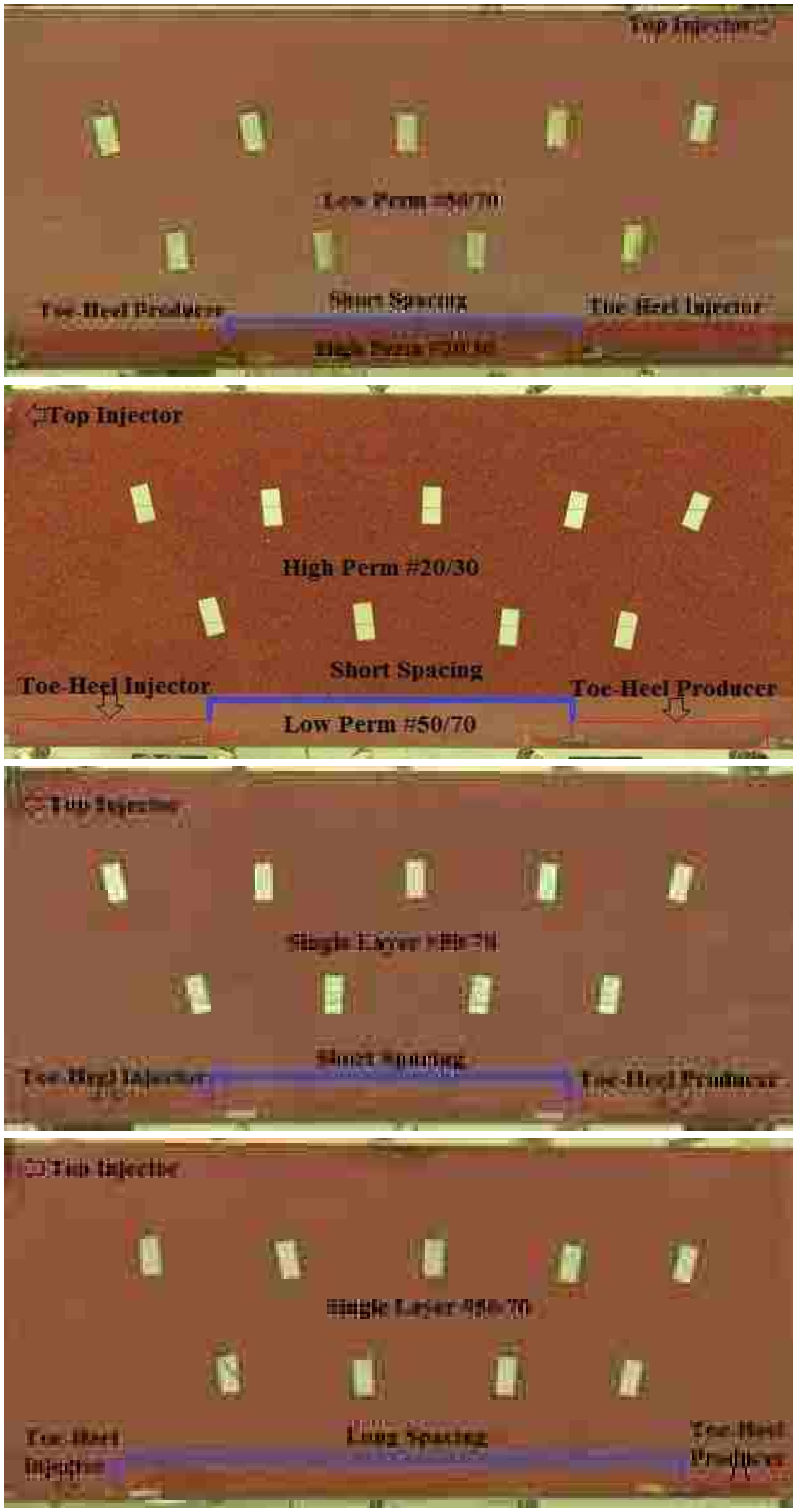

Figure 5.23: Four (4) different Toe-to-Heel Configurations (from top to bottom a, b, c & d respectively)

5.6.1 Bi-layered Toe-to-Heel model with high permeable layer at bottom, Short spaced

The progression of the SW-GAGD process is shown in Figure 5.24 (a) to (c). It was observed that because of high permeability near the horizontal well, the injected gas short circuited to the production well, with little change in oil saturation in the rest of the model at the top.

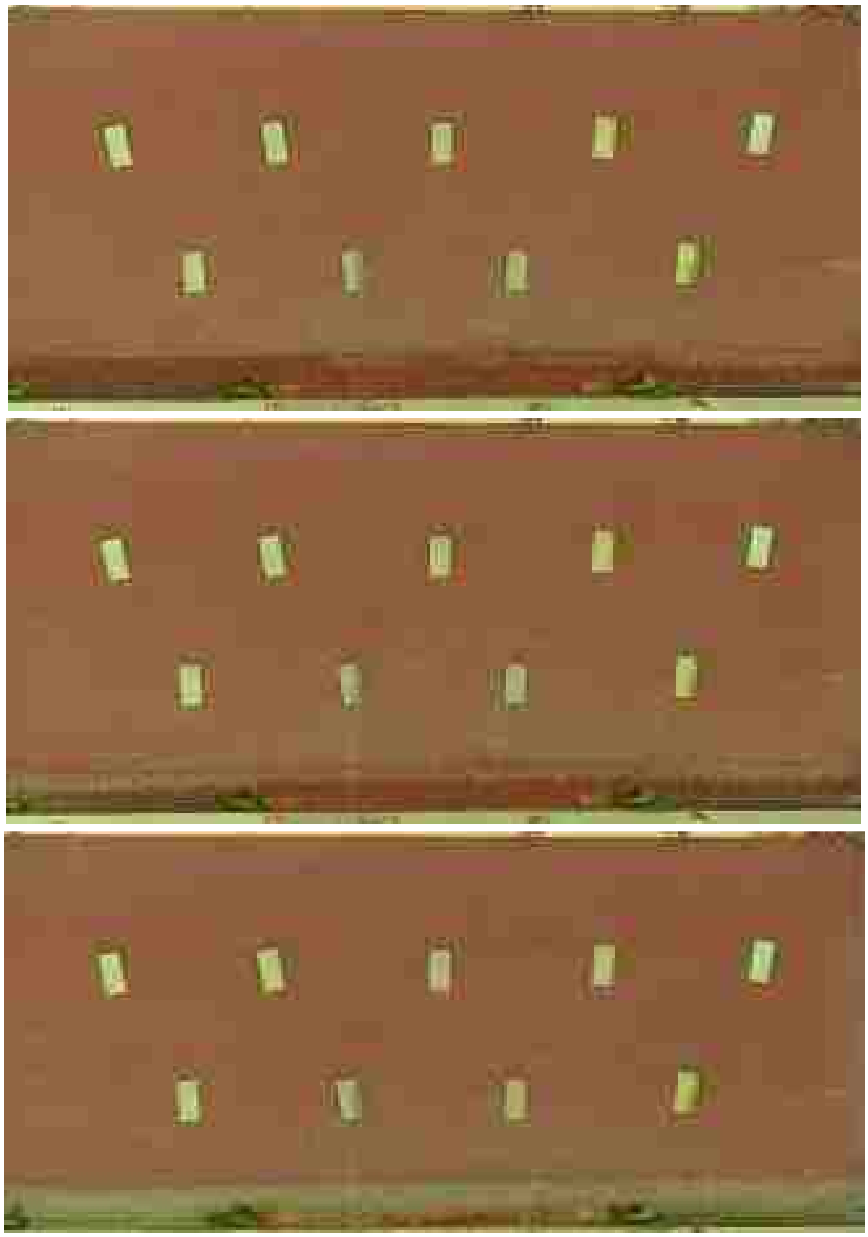

Figure 5.24: Progression of production in a Layered Short Spaced Toe-Heel model with High Perm Bottom Layer (Sequentially from top to bottom a, b, & c respectively)

The injected gas was seen to sweep most of the bottom high permeable layer. This can be inferred from the total absence of red dyed color in the bottom layer of the model. For the case of our model, a little amount of oil remained trapped in between the Toe and Heel of the well. Since in an actual field setting, a Toe-to-Heel configuration looks like shown in Figure 5.22, with injection tubing running concentric to the production annulus, such trapping is unlikely to occur. Less than 8% of OOIP was recovered at 1 PV of gas injection at an injection rate of 10 SCCM. Even a lower rate of 2.5 SCCM did not make any difference to the recovery factor. The rate did not seem to matter with respect to short-circuiting of injected gas to the production well. What seemed to matter was the permeability of the layer surrounding the well vis-à-vis permeability of the rest of the model. The oil recovered was commensurate to what was present in the bottom layer of the model. Figure 5.25 compares the recovery for 2 Toe-to-Heel cases with a Top-Down injection from the top injection well.

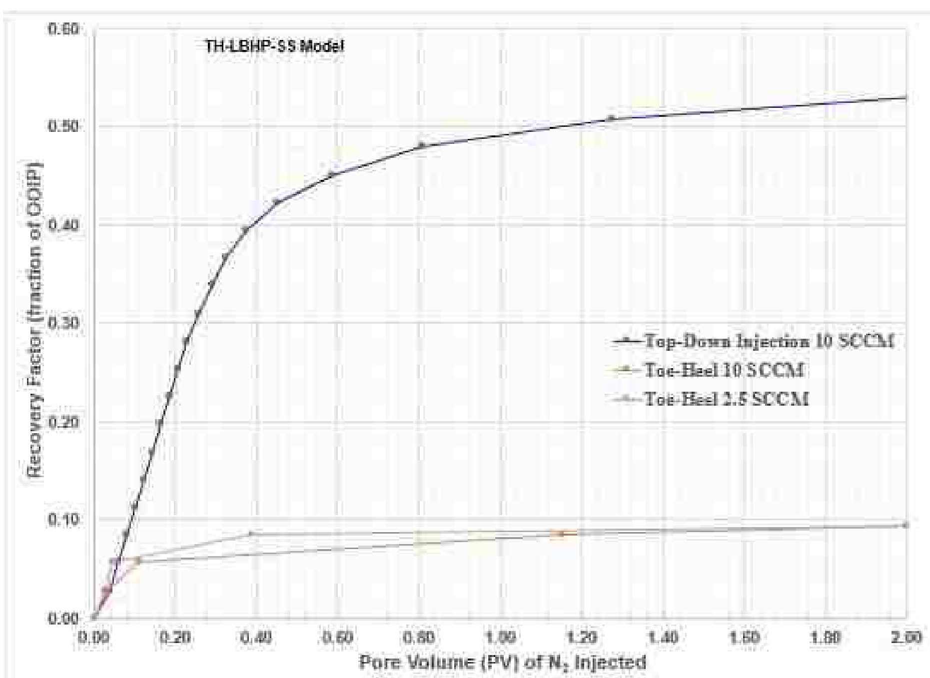

Figure 5.25: Recovery plot comparison for LBLP-SS model during T-t-H injection at 2.5, 10 SCCM and T-D injection at 10 SCCM

5.6.2 Single layered Toe-to-Heel model, Short spaced

The progression of the SW-GAGD process in this case is shown in Figure 5.26 (a) to (c). Short circuiting of injected gas was not observed, unlike the previous case with high permeable bottom layer.

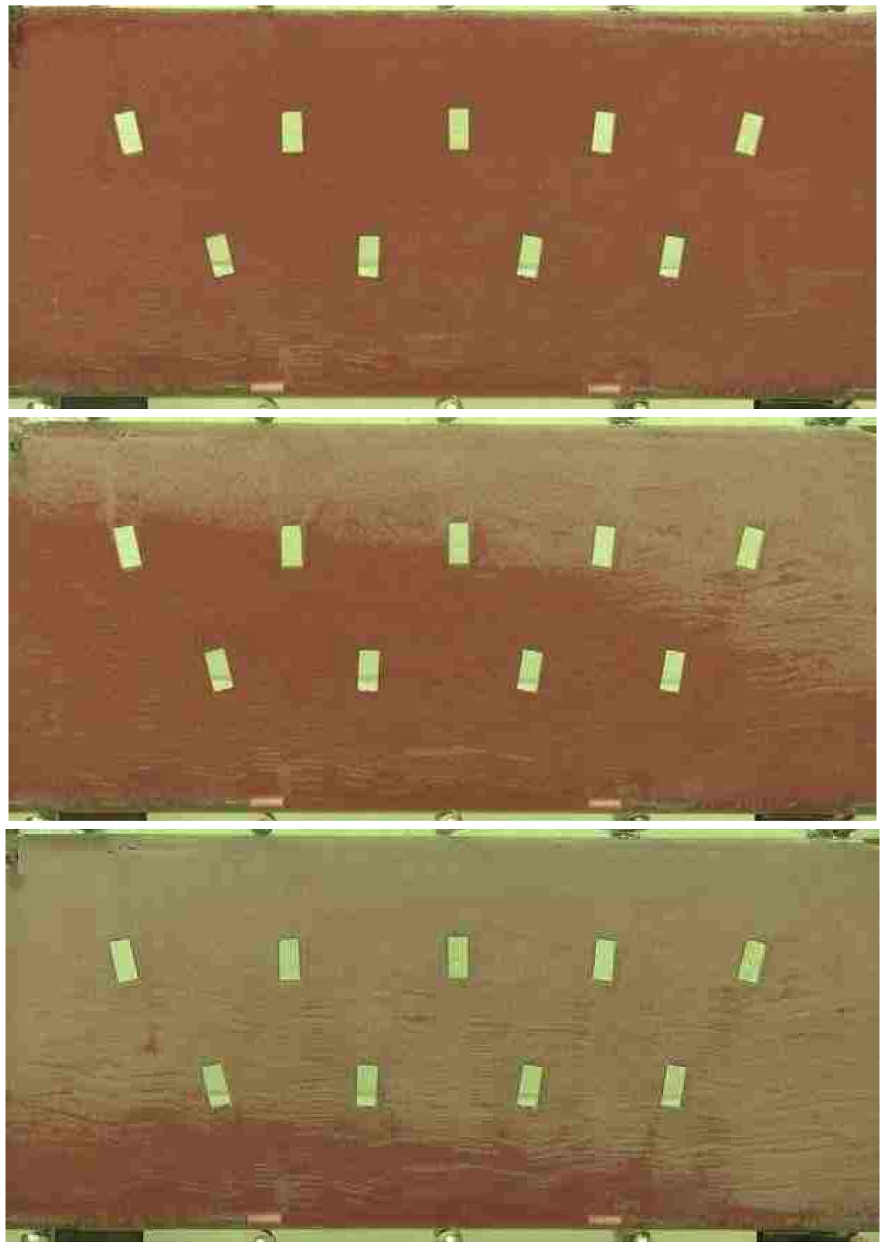

Figure 5.26: Development of displacement front in a Single Layered Short Spaced Toe-Heel model (Sequentially from top to bottom a, b, & c respectively)

The injected gas from the Toe was seen to rise to the very top of the model before moving down in a gravity stable top-down displacement front. Significant oil was produced from the Heel. The recovery profile in this case was similar to that from a top-down injection from the top injector well. Toe-to-Heel configuration in this case performed as well as in Top-Down injection through the top injection well. In all the three cases, however, tilting of the front towards the Heel (production side) was seen.

5.6.3 Single layered Toe-to-Heel model, Long spaced

The progression of the SW-GAGD process was similar to its short spaced counterpart and there was no short-circuiting as well. However, the tilting of the displacement front was even more acute in this case because of even shorter Heel length. Recovery profile between both Toe-to-Heel injection rates of 2.5 and 10 SCCM Vs Top-down injection rate of 10 SCCM were very similar. Thus in case of single layer, long or short spacing did not seem to matter in terms of short circuiting. Short circuiting was not present in case of a single layer model.

5.6.4 Bi-layered Toe-to-Heel model with low permeable layer at bottom, Short spaced

The progression of the SW-GAGD process is shown in Figure 5.27 (a) to (c). Unlike in case of 5.6.1, short circuiting was not observed even though the permeability of the area near was different, albeit lower, than the rest of the model. The injected gas was seen to rise through the high permeable upper layer to the top forming a gas zone at the top before moving down in a top-down displacement. Thus it can be safely inferred that as long as the permeability of the zone near the horizontal well is lower than the top layers, there will be not be any short circuiting.

Another interesting observation was the development of near flat displacement front unlike that in cases 5.6.2 and 5.6.3. Even though the Toe-to-Heel configuration was functionally similar between cases 5.6.2, 5.6.3 and 5.6.4, the inclination of the gas-oil displacement front for the case of 5.6.4

was in stark contrast to cases 5.6.2 and 5.6.3. Low permeable zone near the production well acted to flatten out the displacement front as can be seen from Figure 5.27(a) to (c).

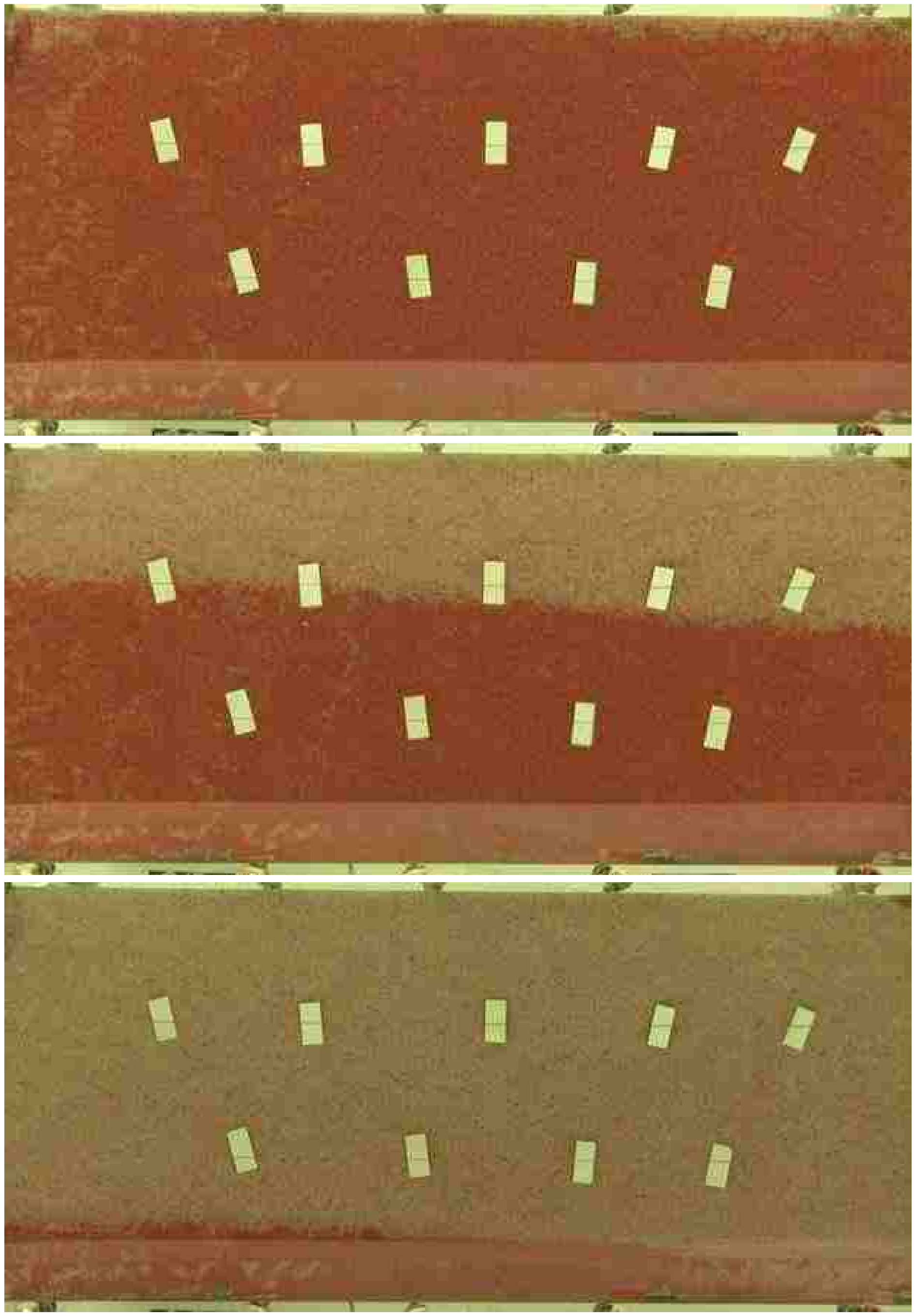

Figure 5.27: Development of displacement front in a Layered Short Spaced Toe-Heel model with High Perm Bottom Layer (Sequentially from top to bottom a, b, & c respectively)

Figure 5.28 shows the gas-oil displacement profile post breakthrough for cases 5.6.2 and and.5.6.3 respectively. We can see that, the displacement fronts are much more inclined in them compared to case 5.6.4.

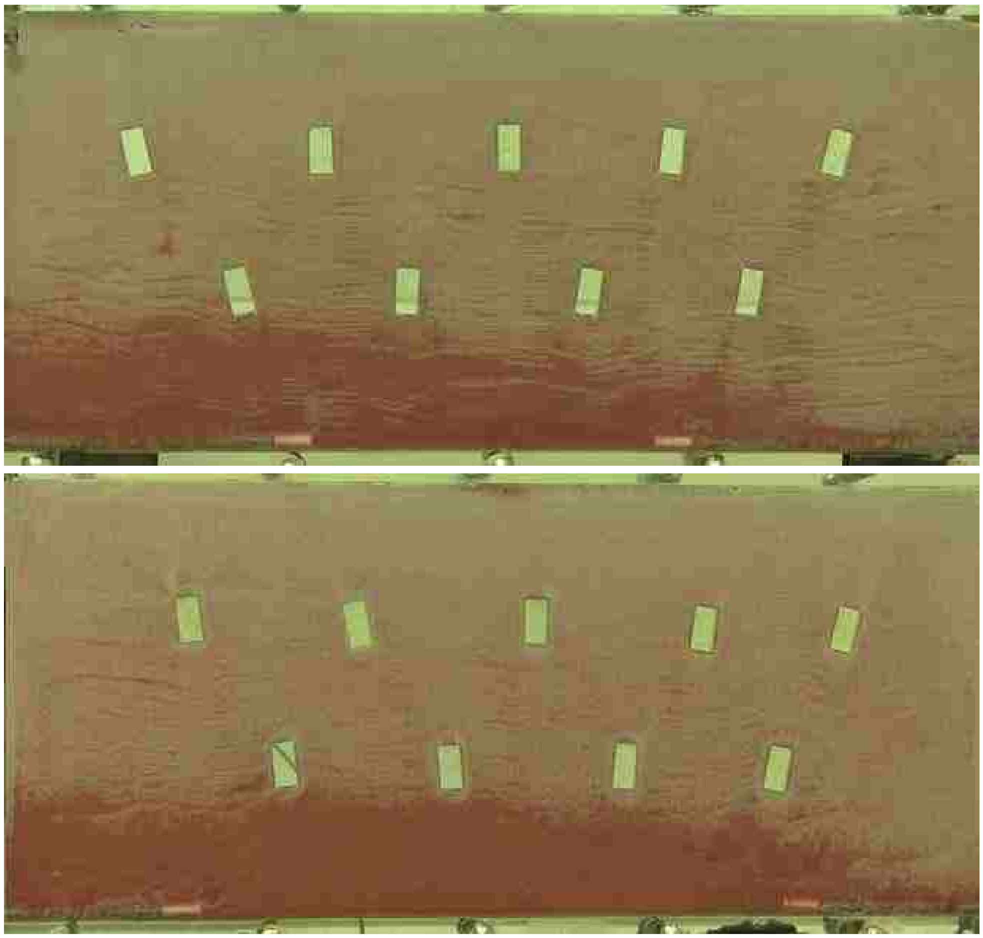

Figure 5.28: Displacement front post breakthrough for Single Layered Toe to-Heel models Top (Short Spaced) and Bottom (Long Spaced)

It was also observed that the gas-oil displacement front preferred to first sweep the upper higher permeable layer than to move into the bottom lower permeable layer. This is because of higher frictional resistance for the gas to flow in the low permeable layer. This preference of the injected gas to reside in the upper high permeable layer rather than moving down to the lower low permeable layer leads to much better sweep of the upper layer. Figure 5.29 gives the recovery plot for this case. Recovery factor at 5PV is 80% and even breakthrough recovery factor is close to 70%. This is a remarkably high recovery factor in the domain of immiscible gas injection.

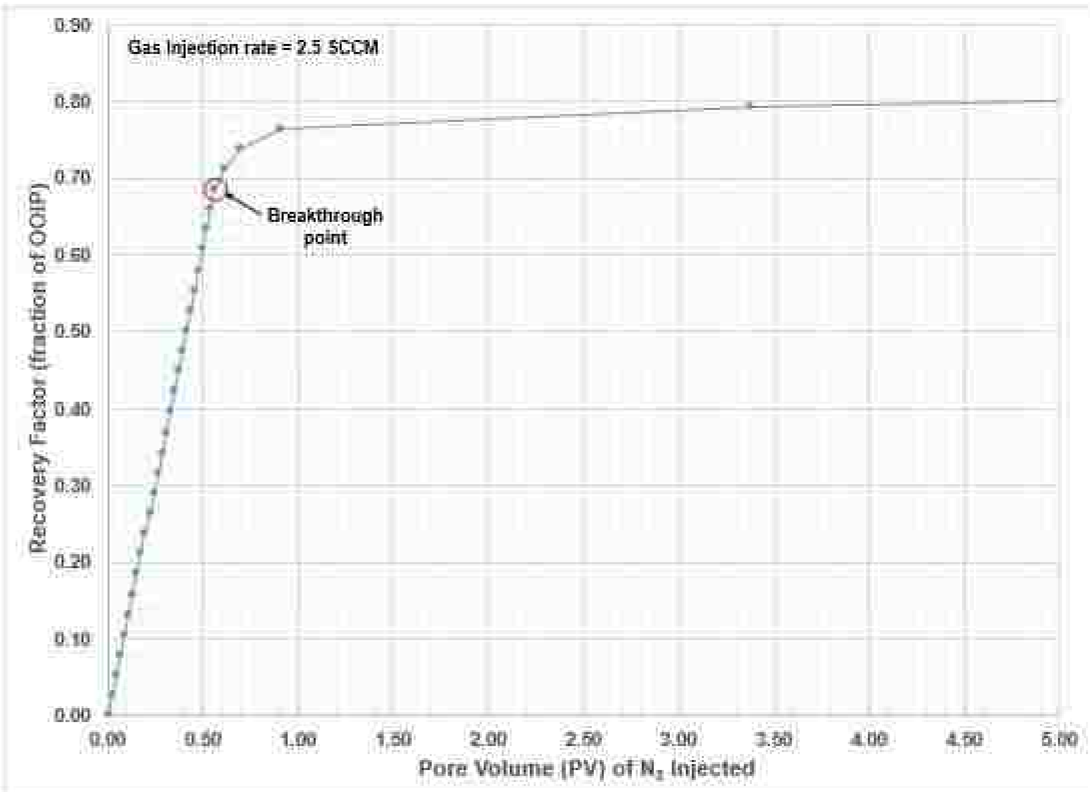

Figure 5.29: Recovery plot for Toe-to-Heel Layered Bottom Low Perm (LBLP) Vs Non Layered (NL), Short Spaced Models at 2.5 SCCM

Figure 5.30 compares the recovery graphs between cases 5.6.2 (Non Layered, NL) and 5.6.4 (Layered Bottom Low Permeable, LBLP). It is clearly evident that breakthrough and ultimate recoveries are significantly higher, close to 12% and 6% respectively, for the Bi-layered Toe-to-Heel model with low permeable layer at the bottom. Low permeability at the bottom acted to increase the recovery efficiency of immiscible gas injection. Similar result was seen at a higher rate of 10 SCCM as well. Recoveries in LBLP case was higher compared to NL irrespective of rate. A top down mode of gas injection at a rate of 10 SCCM also showed higher recovery efficiency. Figure 5.31 compares the recoveries at 5PV for all different cases

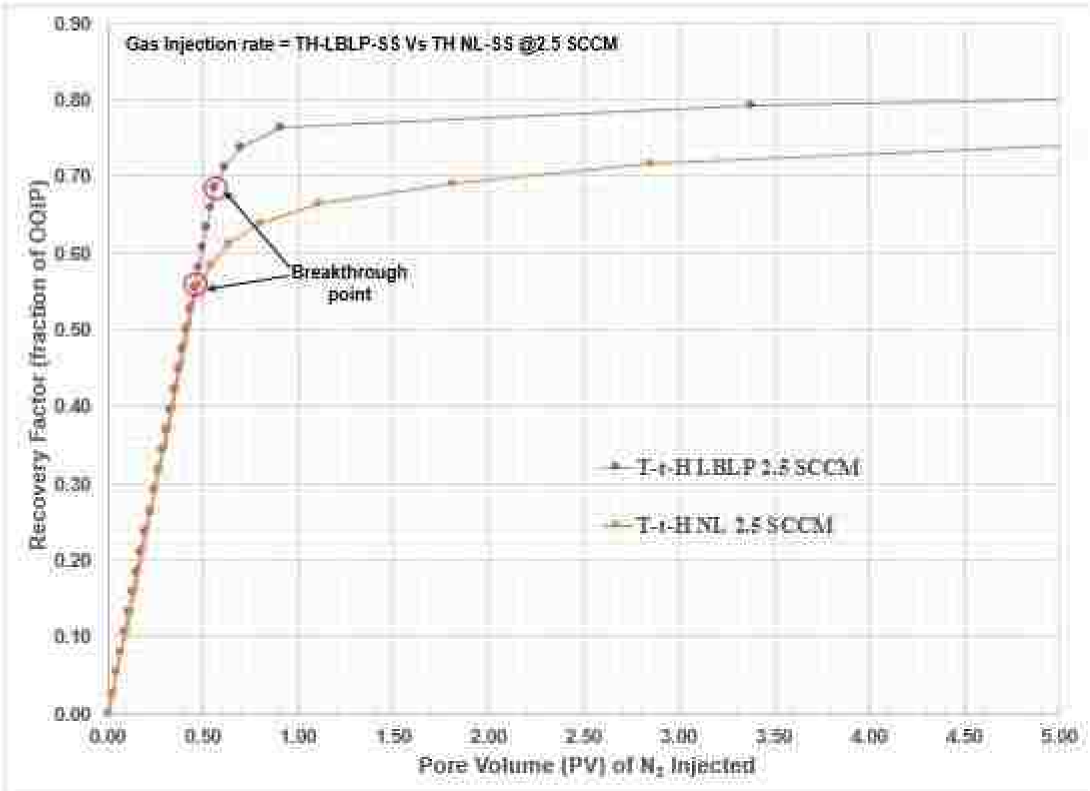

Figure 5.30: Recovery plot for Toe-to-Heel Layered Bottom Low Perm (LBLP) Vs Non Layered (NL), Short Spaced Models at 2.5 SCCM

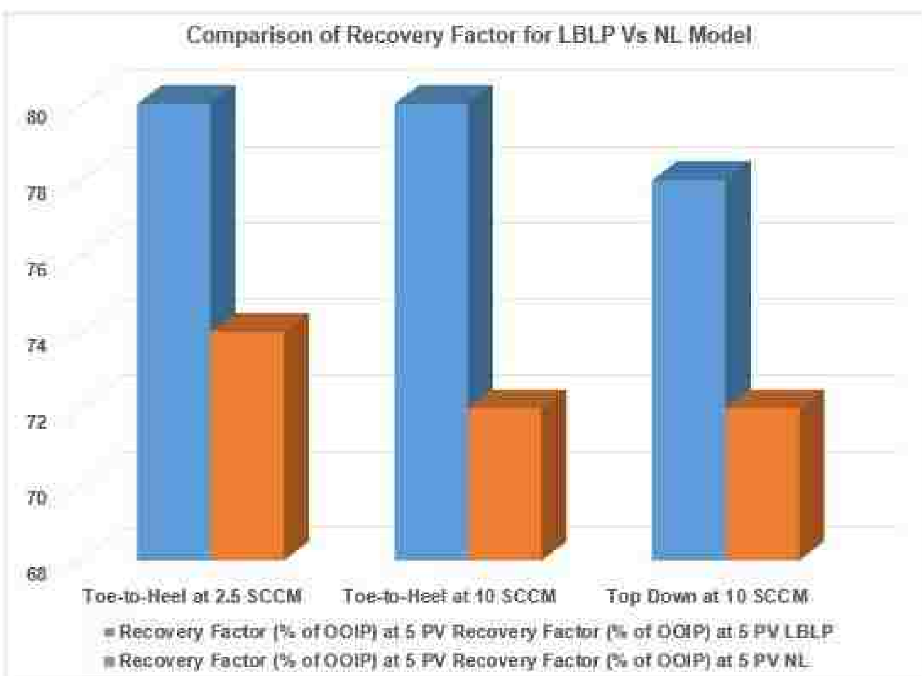

Figure 5.31: Recovery plot for Toe-to-Heel Layered Bottom Low Perm (LBLP) Vs Non Layered (NL), Short Spaced Models at 2.5 SCCM

Figure 5.32 compares recoveries for two different rates, 2.5 SCCM and 10 SCCM in Toe-to-Heel injection mode along with a 10 SCCM gas injection in top-down mode. The recovery factor at 5PV for top down gas injection at the rate of 10 SCCM was slightly lower at 78% compared to 80% for Toe-to-Heel gas injection of 2.5 and 10 SCCM. Nevertheless, the recovery factor is still significantly higher than the Non Layered case. Thus a low permeable zone near the wellbore can greatly increase the recovery efficiency in case of immiscible gas injection under a gravity stable top-down displacement, the likes of SW-GAGD. This observation can be utilized in the design a SW-GAGD process to get much better volumetric sweep efficiency even in immiscible mode. If we can design a lower permeable zone near the horizontal wellbore, we should be able to facilitate much better volumetric sweep efficiency in upper layers.

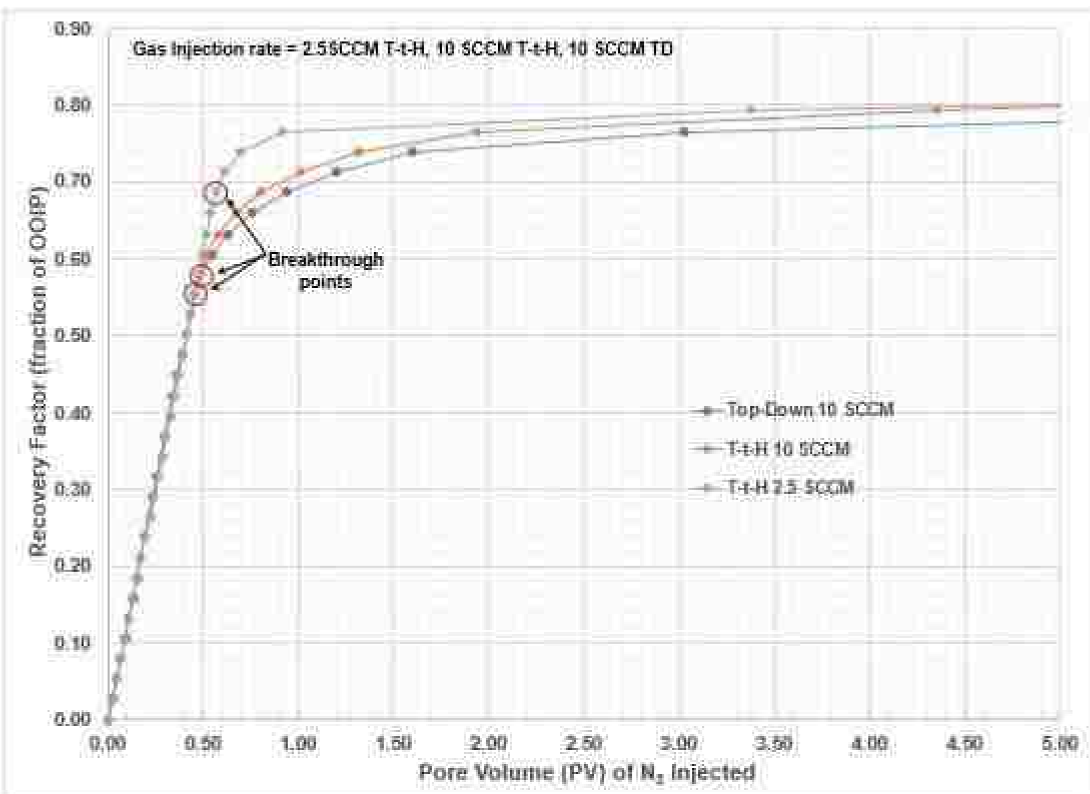

Figure 5.32: Recovery plot comparison for LBLP model during T-t-H injection at 2.5, 10 SCCM and T-D injection at 10 SCCM

5.7 Horizontal Displacement Front

We have dealt with the merits of gravity stable displacement front as in case of SW-GAGD but it will be instructive to see how a horizontal displacement front performs in terms of recovery. This is important because that's the normal way floods are carried out in the industry. For Horizontal flood the same SW-GAGD model that was used for top-down gravity stable flood was used but with a horizontal orientation. Figure 5.33 shows the schematic of the model and the various components.

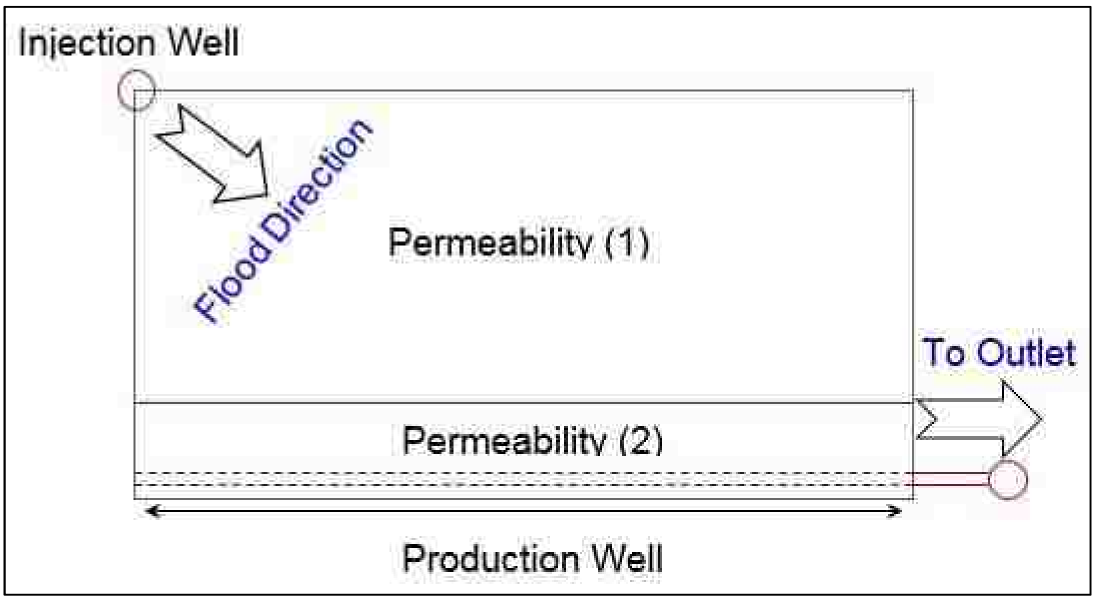

Figure 5.33: Schematic showing plan of Horizontal Flood

The model can be imagined to lie flat and parallel to the face of the paper. The horizontal floods were carried out in two different models such that in one case permeability (1) was higher than permeability (2) and in the other case, the opposite. Horizontal gas flood as well as water floods are very common and hence both gas flood and water floods were carried out for the 2 models. So, in total we have the 4 cases for the horizontal floods, which are given below:

1) Gas Flood, Permeability (1) < Permeability (2)

2) Water Flood, Permeability (1) < Permeability (2)

3) Gas Flood, Permeability (1) > Permeability (2)

4) Water Flood, Permeability (1) > Permeability (2)

5.7.1 Gas Flood, Permeability (1) < Permeability (2)

The recovery plot for the case of case (1) is shown below in Figure 5.34. As can be seen from the plot, only a minimal amount of oil, commensurate to what was in the high permeability layer (2) got produced. The flood was highly in efficient and only produced less than10% of OOIP. This shows the glaring effect of reservoir heterogeneity in case of a horizontal gas flood. Injected gas shoots to high permeable layer (2) totally bypassing layer (1), resulting in such dismal flood performance.

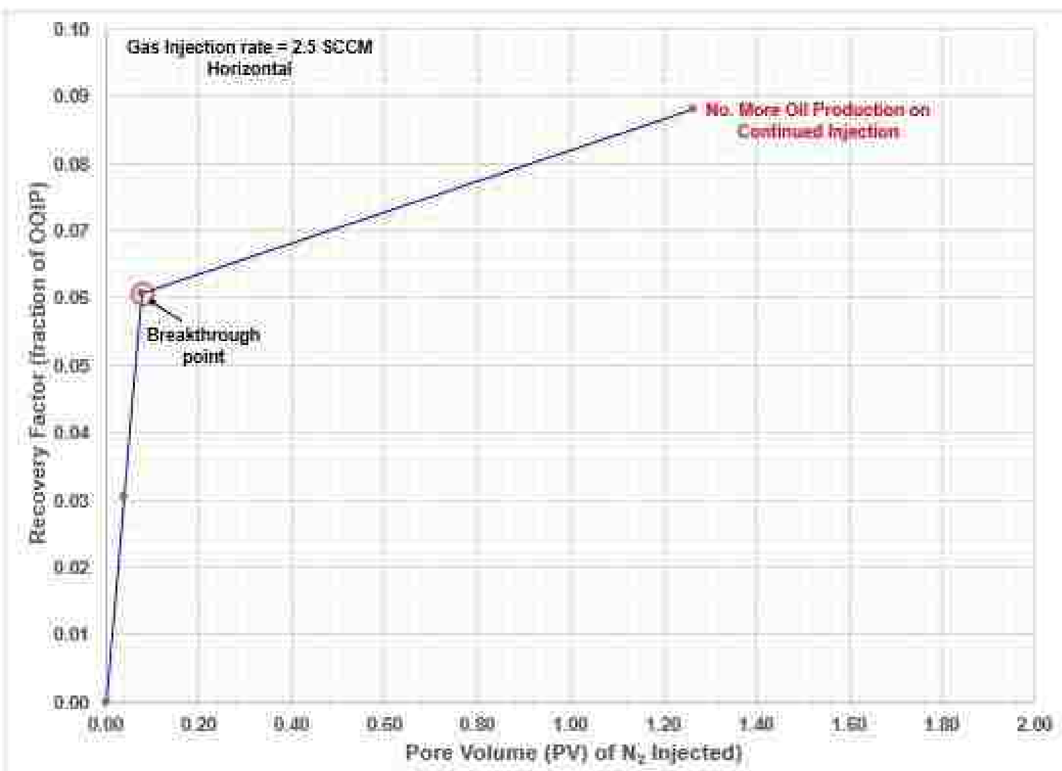

Figure 5.34: Recovery plot for horizontal gas flood for case (1) - higher permeability near horizontal well lateral

5.7.2 Water Flood, Permeability (1) < Permeability (2)

The recovery plot for the case of case (2) is shown below in Figure 5.35. On the face of it, the water flood was very efficient. It was able to recover almost 85% OOIP at 2 PV of injected water. This might give the impression that water flood is the way to go than immiscible gas injection. But what we must also remember is that the model is perfectly horizontal and that vertical thickness for the porous media is minimal. Moreover the production well is not only a horizontal well but totally confined to a different permeability layer and the boundary effect pushes the water to the production well. This effect enhance the recovery performance of the waterflood in our model here.

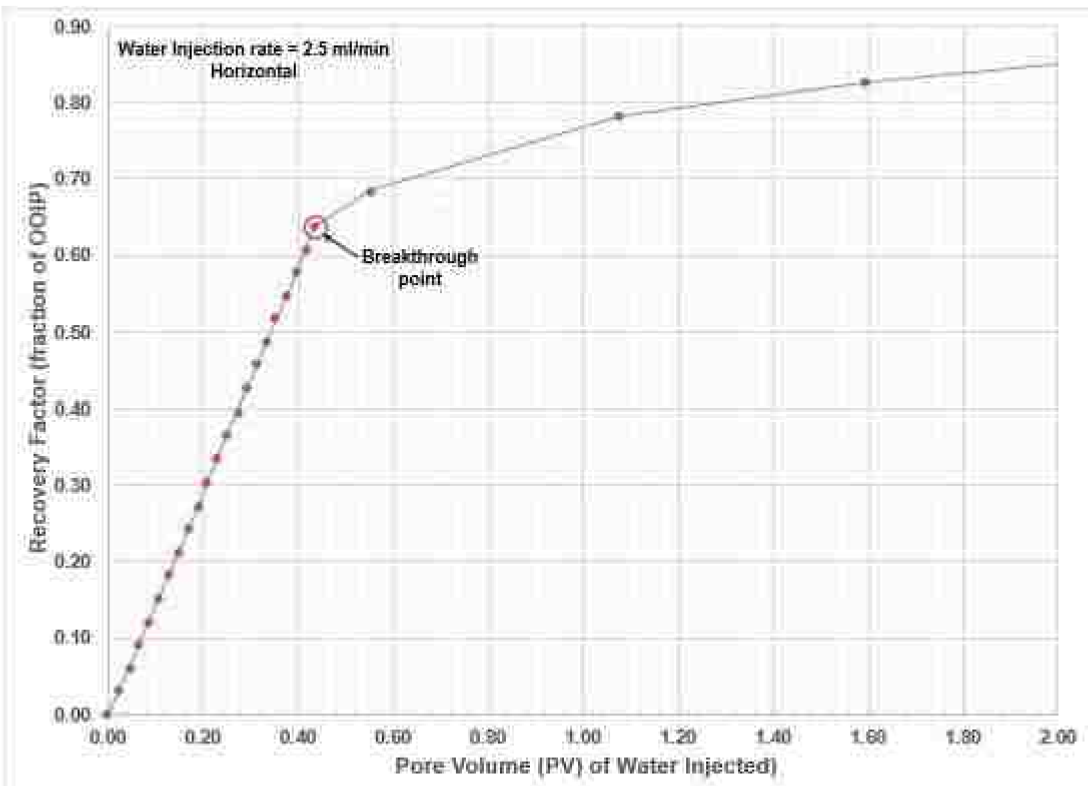

Figure 5.35: Recovery plot for horizontal water flood for case (2) – higher permeability near horizontal well lateral

5.7.3 Gas Flood, Permeability (1) > Permeability (2)

The recovery plot for the case of case (3) is shown below in Figure 5.36. Unlike case (1), the recovery performance is much better with an ultimate recovery of ~ 64% OOIP. This happens for the same reason that we have discussed earlier in LBLP case. The gas prefers to dwell in layer (1) rather than moving into layer (2) because of more resistance, thus giving a much efficient sweep.

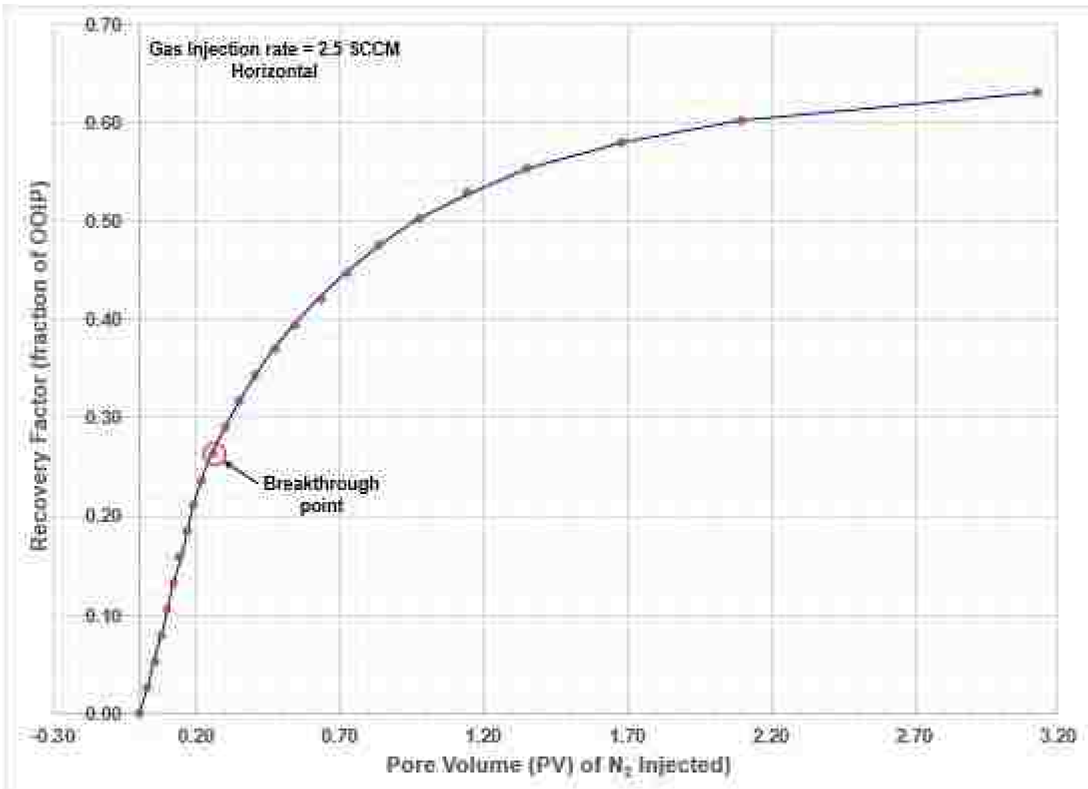

Figure 5.36: Recovery plot for horizontal gas flood for case (3) – lower permeability near horizontal well lateral

Figure 5.37 shows the pictures of the models at the end of horizontal gas floods between cases (1) and (3). It is apparent from the color of the model (Decane is dyed red), that the flood performance was extremely poor in case (1) compared to (3). In case (1) the model still retained the red color in full but in case (3), it got much paler. This is a direct visual evidence of poor performance of immiscible gas flood with regard to case (1). Whatever improvement in flood performance we see in case (3) is because of the mitigating effect of low permeable layer 2 that contained the production well. This shows the effect reservoir permeability layering has on flood performance.

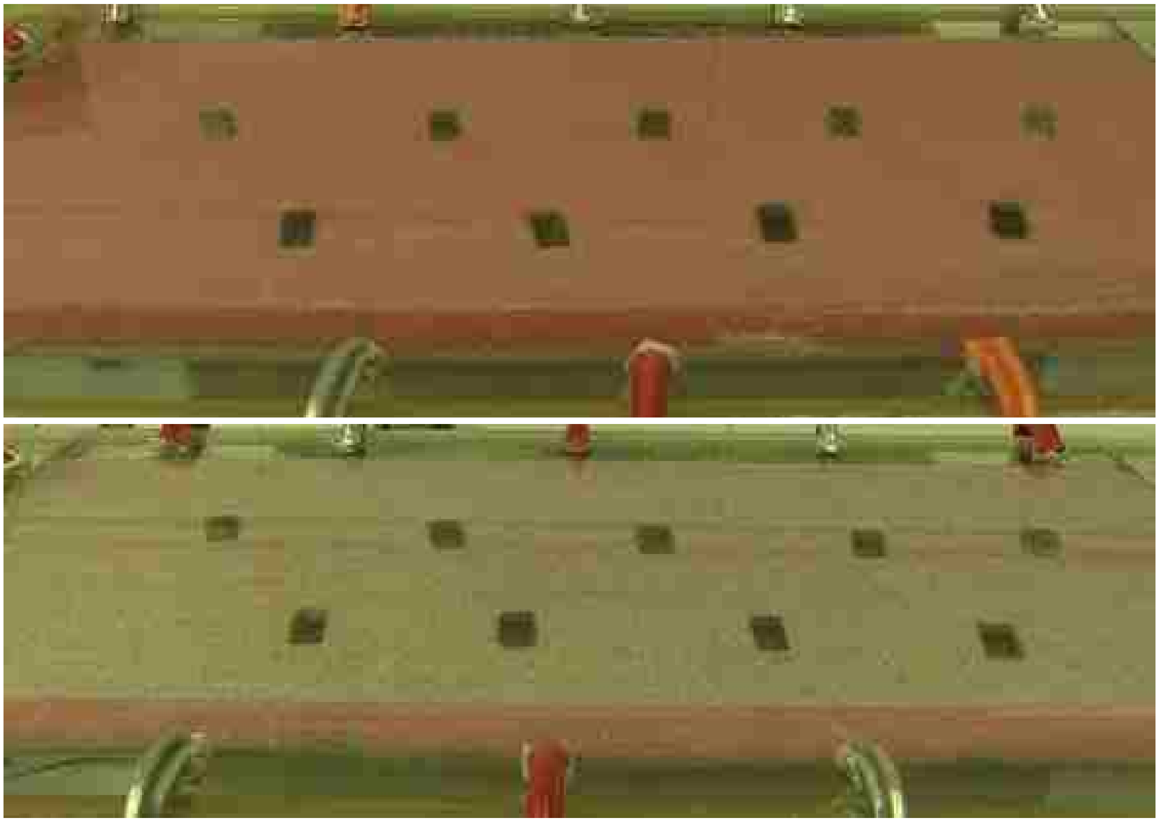

Figure 5.37: Picture of the model at the end of horizontal gas flood (Top, Case (1)): Permeability (2) < Permeability (1), (Bottom, Case (3)): Permeability (2) > Permeability (1)

Reservoir heterogeneity is thus a potent factor that deserves due attention while designing floods. Here, we need to be cognizant of the fact that the model in question has just 2 layers whereas an actual reservoir would have numerous such layers and facies of different permeabilities. Channeling through a high permeability streak can potential ruin a very elaborately designed flood and thus horizontal floods are very much exposed to natural vagaries in the form of reservoir heterogeneities.

It is also important to underscore the fact that horizontal floods are adversely impacted by gravity effects, thereby pulling down the recovery efficiencies of floods. Without the mitigating effect of the lower permeable layer (2), it has been shown in section 5.7.1 (case 1) that horizontal gas flood performed extremely poorly. Injected gas broke through to the production well quickly overriding the entire oil phase. Even in case 2, where there was this ameliorating effect of the lower permeable layer (2), the gravity effect was apparent. Figure 5.38 shows the topside and the underside of the model contemporaneously during the early phase of the horizontal gas flood for case 2.

Figure 5.38: Picture of the model early in the progress of the horizontal gas flood (Left): Shows the topside of the model, (Right): Shows the underside of the model contemporaneously with the Top side

As can be seen from the color contrast in the picture, the injected gas swept the topside in preference to the underside due to gravity override. Figure 5.39 shows the same view as in Figure 5.38 but at the end of the flood. These two Figures clearly illustrate the fact that gravity effects are vividly pronounced even in case of an almost flat model with thickness of just 0.375 inches.

Compared to this, a reservoir is tens of hundreds of feet thick and no wonder the combination of reservoir heterogeneity and gravity effects can totally kill a process if proper care is not taken.

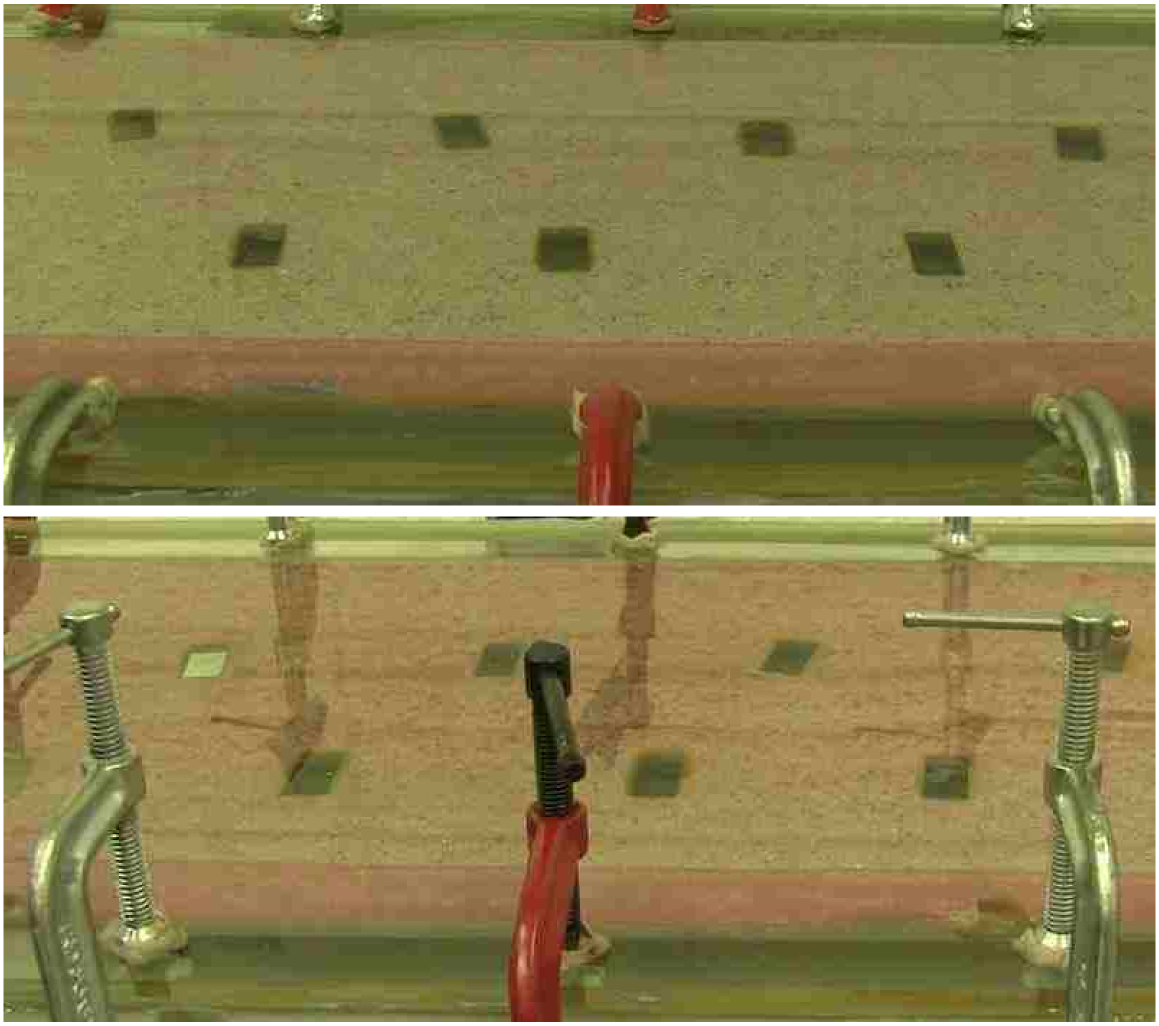

Figure 5.39: Picture of the model at the end of the horizontal gas flood (Top): Shows the topside of the model, (Bottom): Shows the underside of the model contemporaneously with the Top side

5.7.4 Water Flood, Permeability (1) > Permeability (2)

The recovery plot for the case of case (4) is shown below in Figure 5.40. As in case (2), the Water flood performance was excellent with an ultimate recovery of over 80% OOIP. But similarly, we must note the reasons why the performance may be inflated in this case. But based on the two cases, case (2) and (4), it can be said that a waterflood is less prone to layering than an immiscible gas flood is. This can be attributed to lower mobility ratio for a waterflood than a gas flood. A lower mobility ratio for a waterflood tend to mitigate the effects of reservoir layering.

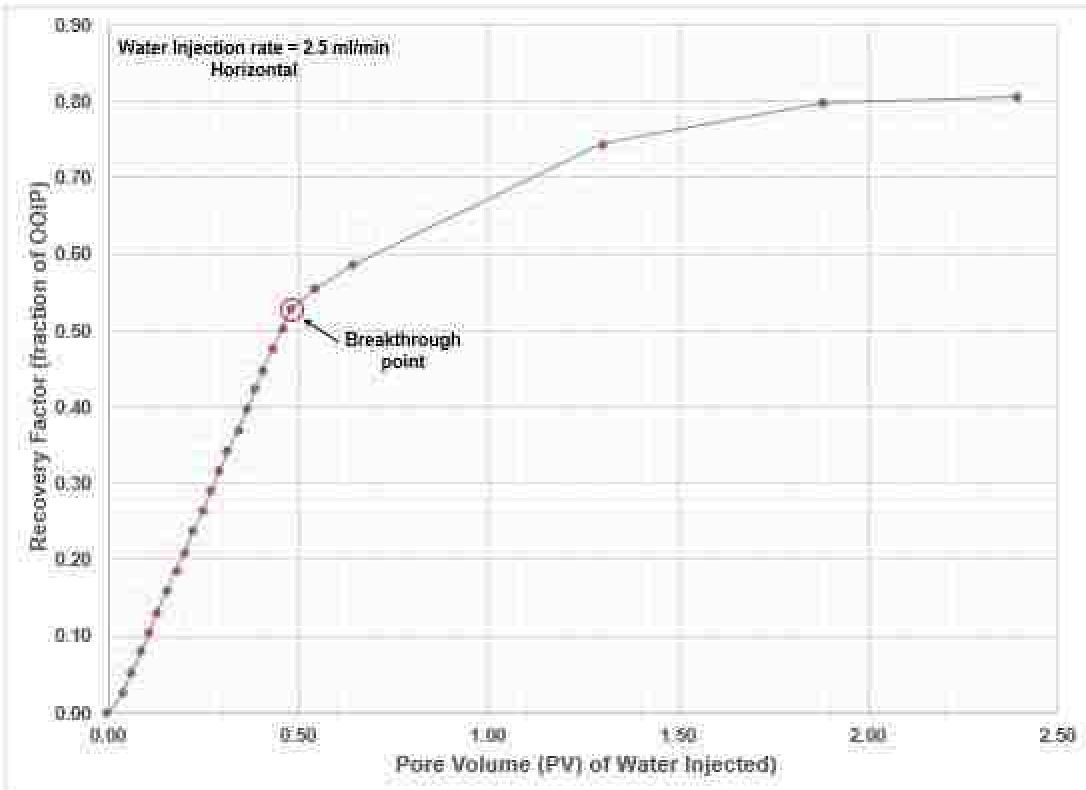

Figure 5.40: Recovery plot for horizontal water flood for case (4) – lower permeability near horizontal well lateral

5.8 Vertical Fractures

Natural fractures are a very common occurrence in reservoirs. This is another aspect of reservoir heterogeneity that can negatively impact a horizontal gas flood. Davis et al.[13] has mentioned how a CO_2 miscible flood in Weyburn field was adversely impacted by the prevalence of natural fractures. Agada et al. – 2014 have studied the response of WAG process to presence of fractures and found that the fractures lead to bypassing of hydrocarbon fluid, early breakthrough of injected fluids and lower oil recoveries. Hence, SW-GAGD process was investigated for the effect of natural fractures on it. For this a SW-GAGD model was built with 2 vertical fractures of different heights to monitor the progress of SW-GAGD flood. Figure 5.41 shows the SW-GAGD model with the 2 vertical fractures. The reason for having two vertical fractures of different heights was to be able to be able to spot variation in flood behavior, if any, as the flood front passes below a particular fracture. The fracture on the left stretched to just below the midline of the model height whereas the fracture on the right went down all the way to just above the bottom horizontal well.

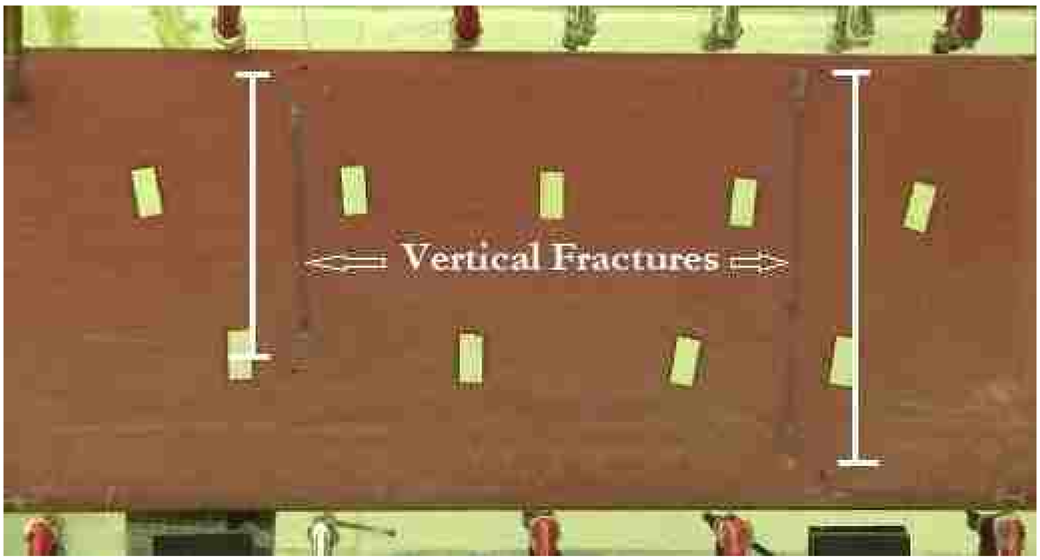

Figure 5.41: SW-GAGD model with 2 vertical fractures of different heights

Figure 5.42 (a-f) shows the progress of SW-GAGD flood for the case of vertical fractures. The progression is indicated by red arrows from (a) to (f). As can be visually observed, the progress of the flood front followed the same gravity stable top-down displacement, notwithstanding the presence of vertical fractures. The fractures, which were so much detrimental in case of WAG process, were enfeebled by the opposing force of gravity coming into play in SW-GAGD process. In fact these fractures enabled gravity segregation and facilitated gas front to be more gravity stable. Looking at Figure 5.42, we see a glimpse of this upwelling effect near the vertical fractures. A thin layer of oil is seen underneath the left vertical fracture and that is attributed to plugged bottom end of the vertical fractures and disruption of smooth layering of the sand during the placement of the fracture. In case of real fractures, the permeability of fracture walls enveloping the fracture will not allow such retention. Baring this layer, the vertical sweep was excellent and this was evident in the recovery plots. Figure 5.43 shows the recovery plot in presence of vertical fractures. The recovery factor at 5PV for 2.5 and 10 SCCM were 72% and 70% of OOIP respectively. The lower rate affords a slightly higher recovery factor because of better gravity stabilization of the flood front.

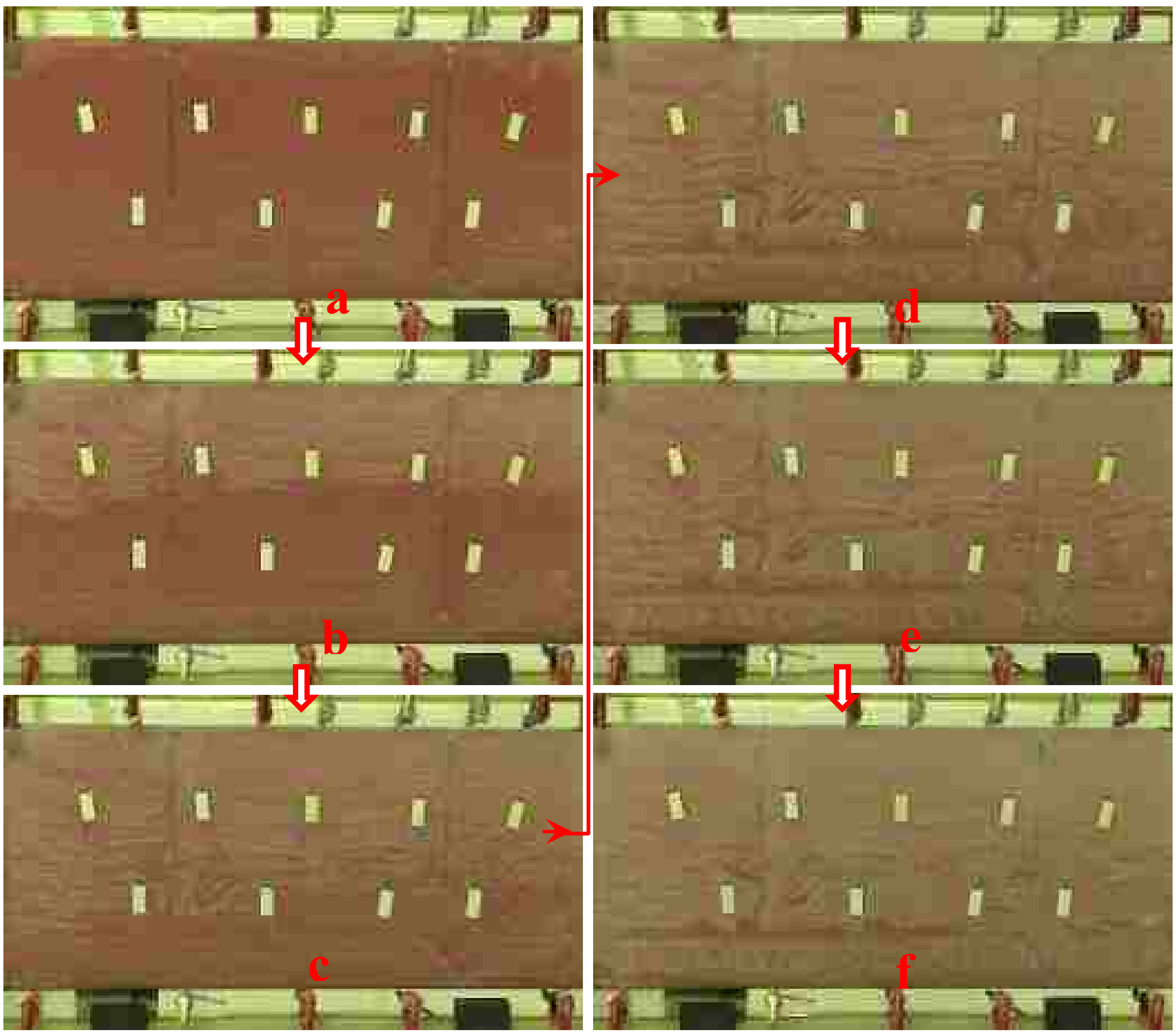

Figure 5.42: Progress of SW-GAGD flood in presence of vertical fractures (indicated by red arrows from a-f)

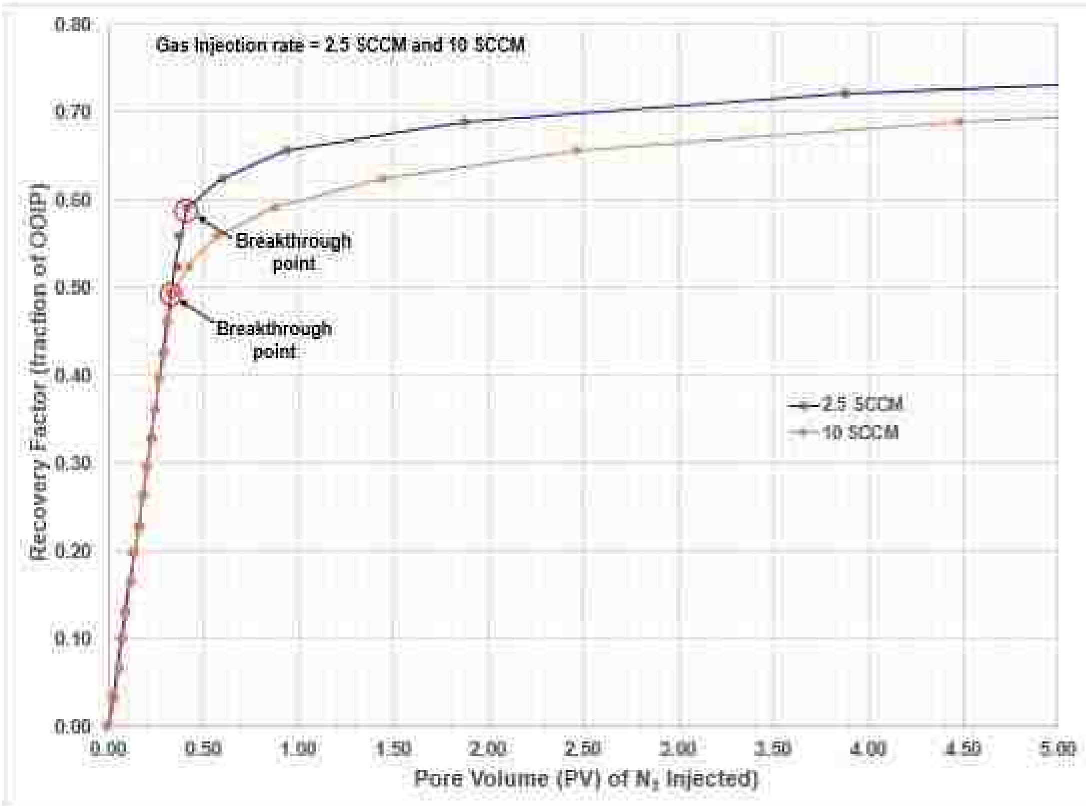

Figure 5.43: Effect of vertical fracture on SW-GAGD performance at 2 different rates of 2.5 and 10 SCCM

The vertical fractures were not observed to destabilize the gravity stable flood front in any way. Looking at the flood front (red drawn line) in Figure 5.44, the flood front near the fractures were in line with the rest of the front. It rather seemed to have an upwelling effect as fractures tend to facilitate gravity segregation. These recovery factors for this case of vertical fracture was, however, not significantly different from the case without vertical fractures. Only difference in the nature of the graphs were the trends following breakthrough of gas front. The trends post breakthrough flattened out rapidly. This is attributed to a vertical fracture extending all the way to just above the depth of horizontal production well. Hence, vertical fractures were not found to have severe impact on SW-GAGD recovery.

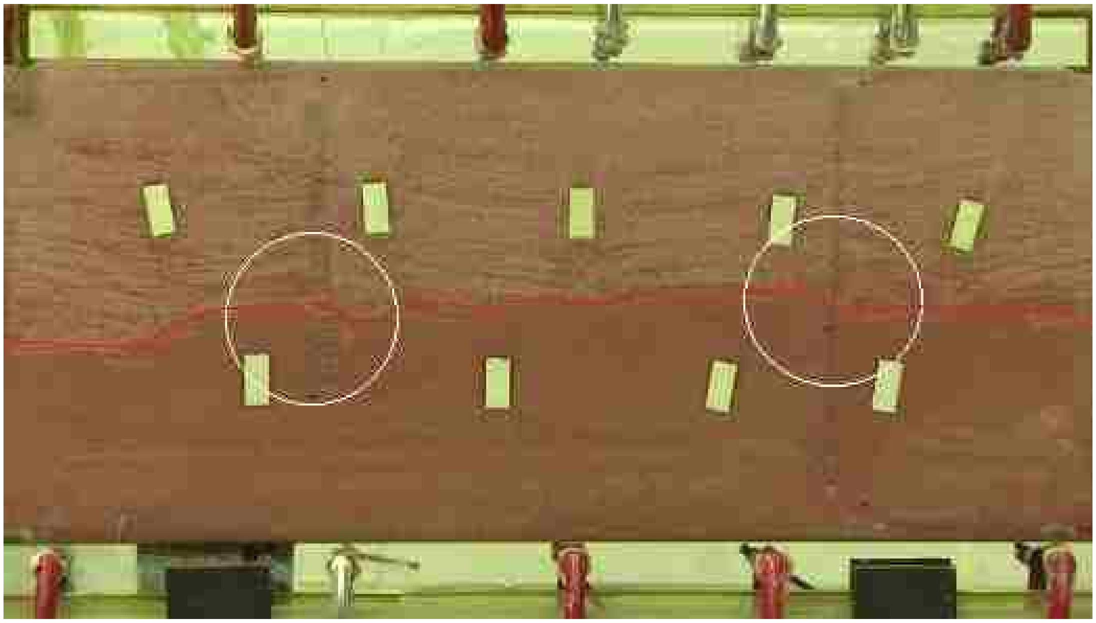

Figure 5.44: Gravity stable flood front with vertical fracture

5.9 Reservoir Dip Angle

Reservoirs are not always horizontal to the ground and have oftentimes some dip angle associated with them. This is an unavoidable part of reservoir structure and impacts any flooding process. Traditionally, the displacement floods carried out in reservoirs utilize this dip by having gas injected up dip or water injected down dip to make it gravity stable. SW-GAGD process was investigated for the effect of dip by tilting the model at an angle of 5.5^0. Figure 5.45 shows the schematic of up dip and down dip gas injection in SW-GAGD model.

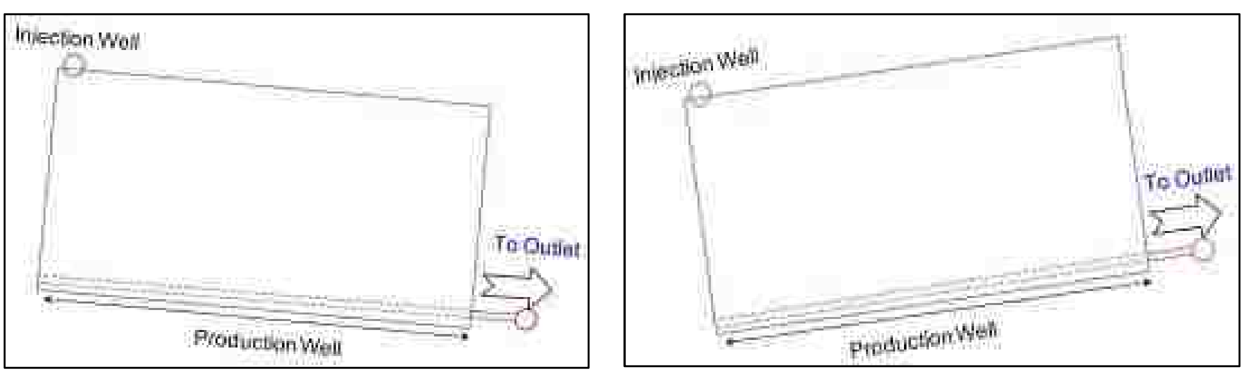

Figure 5.45: Schematics of up dip (Left) and down dip (Right) gas injection in SW-GAGD model

Figure 5.46 compares the recovery performance in case of up dip and down dip gas injection. As can be seen, the recovery performance is slightly higher in case of up dip gas injection case compared to down dip injection case. This is because of more assistance that up dip gas injection gets from the force of gravity, allowing the oil to drain to down dip production well. The depression in recovery performance in case of down dip gas injection was as a result of trapping of some oil in the heel part of the well rather than because of gas displacement effect. However, this highlights the importance of the completion of the well plays in case of reservoir dip. The horizontal well needs to be placed at the bottom most part of the reservoir to maximize drainage and efficient recovery.

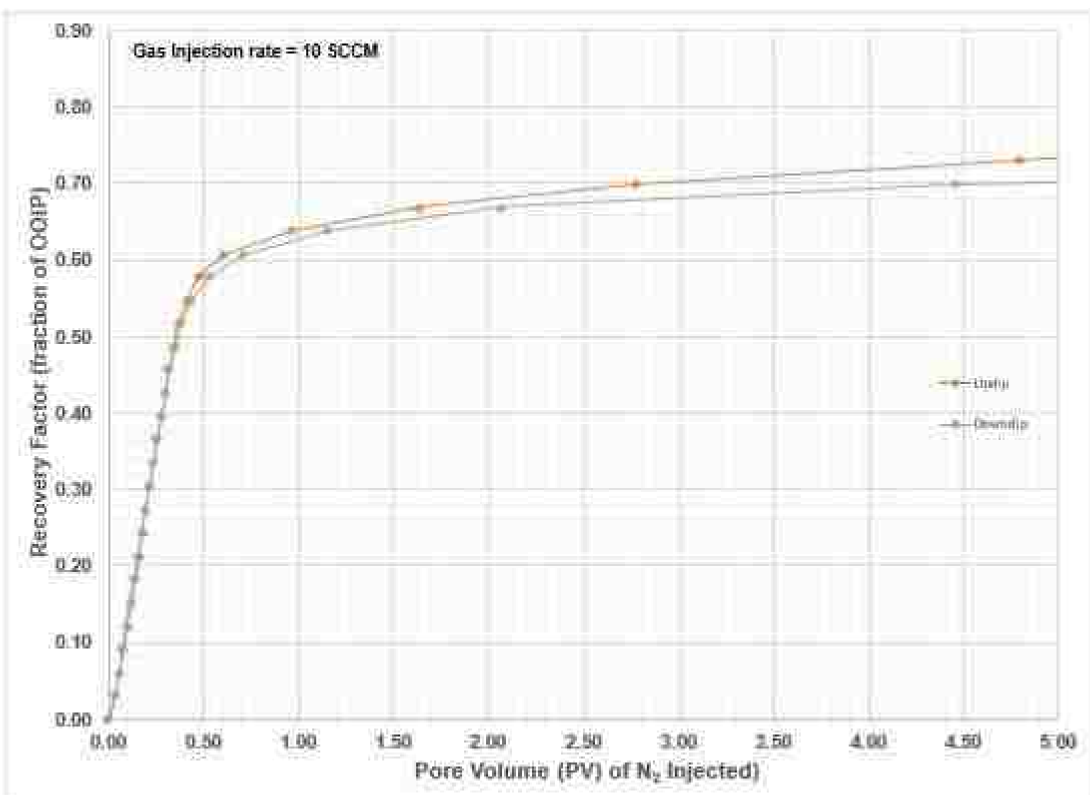

Figure 5.46: Effect of Reservoir dip angle on SW-GAGD performance

CHAPTER 6: MODELING OF GRAVITY DRAINAGE

6.1 The Need for Gravity Drainage Modeling

Although various authors have attempted to model gravity drainage over the years, the interest in this direction seems to be lukewarm at best. We still do not have adequate models that can predict gravity drainage performance to a sufficient degree. The blame is not on the modelers themselves as they need to rely on experimental data and without concerted effort between modelers and experimentalists to understand and quantify different multiphase mechanisms and physics of a gravity drainage process, predictive performance will remain poor. This is especially true for such a heterogenous and coupled system as petroleum reservoirs. There is a need to renew our efforts at gravity drainage modeling primarily because gravity drainage is one of the most efficient recovery process in terms of recovery factor. Many authors have reported very high recovery efficiency with gravity drainage both in labs as well as in fields (Dumore and Schols[15], King and Hagoort[25], Dykstra[16], Kulkarni et al[37], Mahmoud et. al.[46]). Gravity drainage has led in some cases to unexpectedly very high recoveries (Li and Horne). Dumore and Schols[15] have reported residual oil saturation of just 5% in high permeability cores. King and Stiles have reported 87% recovery for the case of Dexter Hawkins field. Being such an efficient process, it's imperative that we are able to model the performance in order to replicate such high recoveries. Secondly, till recently and still to a large extent among the petroleum community, gravity drainage as a process has been considered to be an extremely slow process. Although, this may be true for the most part for a free or pure gravity drainage process, it certainly can't be farther from the truth for a forced gravity drainage process. For example a recent forced gravity drainage process Gas Assisted Gravity Drainage (GAGD) has been demonstrated to be a significantly fast process, yielding equivalent or more recoveries compared to a pure gravity drainage process. In view of these encouraging developments, it's important that we put rightful attention to understanding gravity drainage processes as well.

6.2 Development of Gravity Drainage Theory

Below is an attempt at a summary of some of the major milestones in the development of theory for gravity drainage in conjunction with fluid displacement based on literature review. Buckley and Leverett[5] (1942) put forward their famous paper on mechanism of fluid displacement in sands. Their displacement theory, though not on gravity drainage, can be thought of as the precursor to the gravity drainage theory. Their theory dealt with the displacement of fluids in the direction of the bedding plane whereas gravity drainage need not be in the direction of the bedding plane. They developed an analytical model to capture the dynamics of oil displacement by free gas or water in a porous media. They indicated that the displacement by immiscible free gas or water is never piston like and it's the saturation that drives the flow of the fluids. For modeling purpose, they considered unit sand element within a continuous sand body and expressed the material balance as in equation (1) below.

$$\left(\frac{\partial S_D}{\partial \theta}\right)_u = -\frac{q_t}{\phi A}\left(\frac{\partial f_D}{\partial u}\right)_\theta \qquad (1)$$

Where,

S_D = saturation of displacing fluid, θ = time, u = distance along flow path, q_t = total rate of flow through section, ϕ = porosity, A = cross-sectional area, f_D = fraction of flowing stream comprising of displacing fluid.

Their transformed equation (2) read as

$$\left(\frac{\partial u}{\partial \theta}\right)_{S_D} = \frac{q_t}{\phi A}\left(\frac{\partial f_D}{\partial S_D}\right)_\theta \qquad (2)$$

Which expressed the speed at which a saturation front travelled in terms of the derivative of fractional flow of the displacing fluid with respect to its saturation. While arriving at their formulation, they assumed incompressible flow, no mass transfer between fluids and that the fractional flow of the displacing fluid is a function of saturation alone. Implicit in their formulation was also the assumption that there was homogeneity of fluid saturation at each cross section. However, this may not be the case in presence of heterogeneity. To simplify the fractional flow function with respect to saturation, they neglected capillary pressure and gravity effects. Although, these effects can be incorporated, the incorporation of these effects complicates the solution of the developed equations greatly. They also acknowledged this fact and in their own words stated that "the complexity of natural reservoirs prohibits the formulation of any single quantitative expression relating over-all flushing efficiency to the rate of production or to any of the other pertinent variables". Nevertheless, the theory was novel and was a significant milestone in the analytical treatment of fluid displacement in porous media. This B-L theory in conjunction with fractional flow theory is a handy tool for quantification of field scale immiscible displacement process. The authors seemed to believe that that gravity drainage in which free gas is overlying an oil phase without an impressed pressure gradient should be similar to water displacing an oil phase. They believed that the gravity drainage is an exceedingly slow process and that is in line with their perception of the mechanism as a pure or free gravity drainage rather than a forced gravity drainage. Cardwell and Parsons'[6] (1948) were among the first to deal with an analytical treatment for free fall gravity drainage based on draining in a vertical sand-pack model. Their simplistic formulation was based on a single fluid draining by gravity in a sand-pack column without any external pressure gradient. They brought out the concept of equilibrium drainage curve (equilibrium drainage curve is the final stabilized distribution of any fluid within a vertical column of sand pack) and demarcator (the boundary between the region of 100% saturation and partial saturation) and came up with a model giving the position of the demarcator at any time. They, however, neglected capillary pressure variation with saturation in order to simplify their solution. They also acknowledged that the theory would need to be modified to include other recovery mechanisms with gravity drainage. Though quite simplistic in its scope, their formulation of the problem and its solution served as a framework for future modifications and refinement. Nenniger and Storrow[48] (1958) also attempted on similar lines using bead packed bed and used an approximate series solution by incorporating a film drainage function to describe the movement of the fluids. Terwilliger et al.[62] (1951) carried out experimental and modeling study on forced gravity drainage system, where a production pump in the outlet helped keep a constant rate rather than a constant rate gas injection at top of the sand pack. He, however, used Buckley Leverett formulation, that were originally developed for free gravity drainage, for his theoretical analysis. His work was one of the first work on forced gravity drainage as the common perception with regard to gravity drainage is that of free fall or pure gravity drainage. Dykstra[16] (1978) expanded the work of Cardwell and Parsons on free fall gravity drainage. Dykstra also perceived gravity drainage to be a pure free fall process. He included the capillary pressure terms and modified the relative permeability terms to broaden the scope of Cardwell Parsons theory. Author acknowledged the need for more experimental data collection and reporting to bolster the use of the equations and to further test the validity of his modified approach. Hagoort[25] (1980) derived analytical expressions for gravity drainage under free and forced regimes and also gas/oil displacement under centrifugal field. He used Darcy's law and Continuity equation for incompressible fluids for the two phases, namely, gas and oil, in conjunction with capillary-pressure relationship and fractional flow theory to arrive at the displacement equation, which he non-dimensionalized and solved to get expressions for recoveries. His work was among the first to explicitly stated modeling effort at forced gravity drainage. Li and Horne[44] (2003) also tried to analytically derive equations for free fall gravity drainage. They acknowledged that analytical models do not work well and went on to develop an empirical model based on Aronofksy et al[2]. and were able to get a good match. Kulkarni et al.[36] (2006) used a lumped approach based on R&B and L&H model to predict the performance of a novel Gas Assisted Gravity Drainage (GAGD) process, which was a forced gravity drainage process. His lumped approach was necessitated by non-representative assumptions, which were originally used in the formulation of those equations.

6.3 Challenges to Gravity Drainage Modeling

Even though gravity drainage is such an efficient recovery process in terms of recovery, its proper characterization and modeling has remained a challenge (Li and Horne[44]). Satisfactory analytical treatment for the process has not developed so far since some of the physics of the process are not yet fully understood and as such not accounted for in the modeling equations. In literature, there is ambiguity in the usage of the words, drainage and displacement. Gravity drainage and gravity stable displacement are used interchangeably in literature even though technically gravity drainage is differentiated from gravity stable displacement by the presence of vertical pressure gradient on the liquid interface. This interchangeable use of these two words have also led to further confusion (Kulkarni et al.[36]). Another challenge facing the reservoir engineers is the lack of production data from such a process as fields employing gravity drainage as the primary production mechanism is few and far between. This is primarily because of exceedingly slow rates associated with free fall gravity drainage and as such hitherto the industry has been, rightfully, unwilling to rely on free fall gravity drainage as the primary production mechanism. Even though we have in place now forced gravity drainage processes likes GAGD, which have been shown to produce equivalent or higher recoveries compared to free gravity drainage process and also at much faster rates, the industry has been slow to turn around. There is still this wide spread perception that it's an exceedingly slow process. This has led to marginal interest in modeling of the process so far. The limited modeling activity that has taken place on gravity drainage has mostly focused on pure or free fall gravity drainage. As mentioned earlier, the point of intervention is an important consideration for all injection processes alike, including gravity drainage processes. It matters when the intervention is made. For example, it will matter a great deal whether the intervention point for injection of gas is above the bubble point or below or at abandonment of primary depletion. In case of Mars field in DGOM, water flood intervention happened at 6800 psia, which is slightly above the saturation pressure (6,306 psia). This intervention prior to saturation pressure acted to conserve the reservoir oil efflux energy and also avoided unnecessary competing gas production, which would have negatively impacted the oil production. Because of low recovery factors with conventional gas injection processes, waterflood has been commonly employed in the secondary stage and as such gas floods have been relegated to the tertiary stage, mostly through double displacement (DDP) process. Tertiary stage application coupled with historically low interest in gravity drainage has led to insufficient data available to modelers to properly fortify their modeling framework. From recovery standpoint, it would be beneficial to intervene with forced gravity drainage process like GAGD at the secondary stage, prior to reaching saturation pressure. That would bring with it the benefits outlined above for the case of waterflood injection prior to saturation point. Additionally, it would help in the draining of oil by film flow gravity drainage due to lower gas saturation. This is yet another reason, why the intervention by forced gas gravity drainage needs to happen at the secondary stage. Otherwise water shielding and low oil saturation will come in the way of efficient film drainage of oil, which significantly enhances gravity drainage recoveries. Thus there needs to be a vigorous discussion leading to consensus within the industry as to the stage of intervention for forced gas gravity drainage processes and this will enable the modelers to then make realistic models that would reflect the field results well. This also calls for more sharing and availability of field data with the researchers. Unless there is active interest in the part of the industry to first use this efficient recovery process and to foster research in this area, we would continue to do poorly in terms of modeling inadequacy. As we have seen in the case of fracture modeling; with fracking boom the corresponding modeling effort peaked as well. Similar is the case with gravity drainage modeling as well. Once the industry sees the economic benefits and the popularity of the process grows, so would the modeling activity.

6.4 Predictive Performance of Models

As stated above, most of the models developed with respect to gravity drainage are on free fall gravity drainage. Even those that were developed, made use of a number of simplifying assumptions and were seen to be limited in scope with respect to their predictive scope. Terwilliger et al.[62] (1951) was one of the first to model forced gravity drainage. But he used a pump at the outlet to force production of oil through gravity drainage rather than injecting gas at the inlet. This rate limiting mechanism could have potentially impacted the very gravity drainage mechanism that he tried to model. Kulkarni et al.[36] used a modified form of semi-empirical L&H model, which was originally developed for free gravity drainage, to predict his GAGD coreflood performance and got a reasonably good match. He modified the depth corresponding to entry capillary pressure term "Z_e" by multiplying it with "$L - \frac{P_c(Entry)}{P_s(Injection)}$" to account for multiphase mechanics operational in the forced gravity drainage GAGD process. Hagoort[25] (1980) model appears to be the only model looking at a forced gravity drainage gas flood performance. Hence, these two models, viz., modified L&H and Hagoort were used in this study to predict the experimental results of SW-GAGD flood. Data required for modified L&H model are given in Table 3. Figure 6.1 shows the comparison of modified L&H model with SW-GAGD run with an injection rate of 2.5 SCCM. As can be seen, the fit is far from being satisfactory.

Table 3: Data required for modified L&H model calculations

Experiment Number	Type	SW-GAGD	SW-GAGD
Beta (β)	Calculated	0.0009	0.0006
Pore Volume (V_p)	Expt. Data	405.0	405.0
Recovery (%OOIP)	Expt. Data	0.76	0.61
Connate Water Saturation (S_{wc})	Expt. Data	0.25	0.25
Residual Oil Saturation to Gas (S_{or})	Expt. Data	0.07	0.07
Initial Oil Production Rate (Q_{oi})	Calculated	0.2333	0.1167
Ultimate Oil Production by FGD (N_{po} Inf.)	Calculated	260.0	200.0
Average Residual Oil Saturation (S_{or} avg.)	Calculated	0.1080	0.2562
Depth Corresponding to Entry P_c (Z_e)	Expt. Data	0.1500	0.1500
Pore Size Distribution Index (l)	Assumed	5.0	5.0
Dimensionless Length (Z_c)	Calculated	0.4094	0.4094

The model did not take into account the saturation shock front reaching the production well at breakthrough. The production trend predicted with this model had a declining trend but there was no sharp demarcation to differentiate the production performance pre and post breakthrough. The recoveries outperformed the model predictions by a large margin. This poor fit may be the result of the fact that the model was originally meant for free gravity drainage. Another reason may be that our SW-GAGD rate, 2.5 SCCM was higher than the critical gravity drainage required rate

(GRR) for the model. But as discussed later in the section on GRR, that should not be the limiting reason for this poor fit. Since the model was originally developed for free gravity drainage, which was later on modified to account for forced gravity drainage, so it prompted us to match the recoveries obtained with free or pure gravity drainage SW-GAGD run with model predictions.

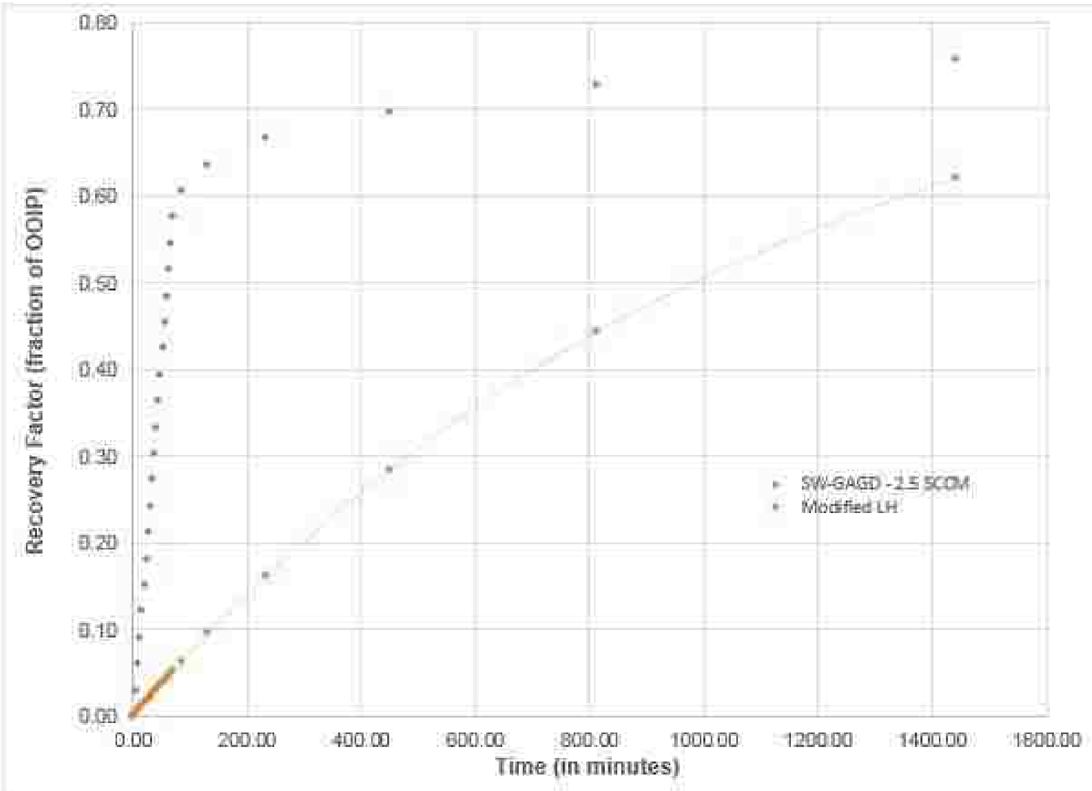

Figure 6.1: Comparison of experimental and modified L&H recoveries for SW-GAGD with a gas injection rate of 2.5 SCCM

Figure 6.2 shows the comparison of free or pure gravity drainage recoveries for SW-GAGD process with modified L&H model. As seen, the prediction was still poor even for the case of free gravity drainage. Unlike the previous case, with an injection rate of 2.5 SCCM, breakthrough corresponding to the arrival of shock front at the production well was absent in the case of pure gravity drainage. The production with pure gravity drainage ceased to produce after a recovery factor of 61%. The rest of the oil remained trapped because of capillary forces and the gravity force alone was not sufficient to free up the trapped oil due to capillary forces. The prediction with the model was still inadequate, even though slightly better than for the case of 2.5 SCCM. Thus, modified L&H model was not able to match the performance of SW-GAGD recoveries for both cases of pure and forced gravity drainage. Moreover, being empirical in nature, it rendered itself unamenable to rigorous analysis so as to be able to ascertain the model inadequacy. Next, we compared the performance of Hagoort model with SW-GAGD model recoveries. Since, Hagoort model was developed for the case of forced gravity drainage process, hence the matching with pure gravity drainage data was not performed.

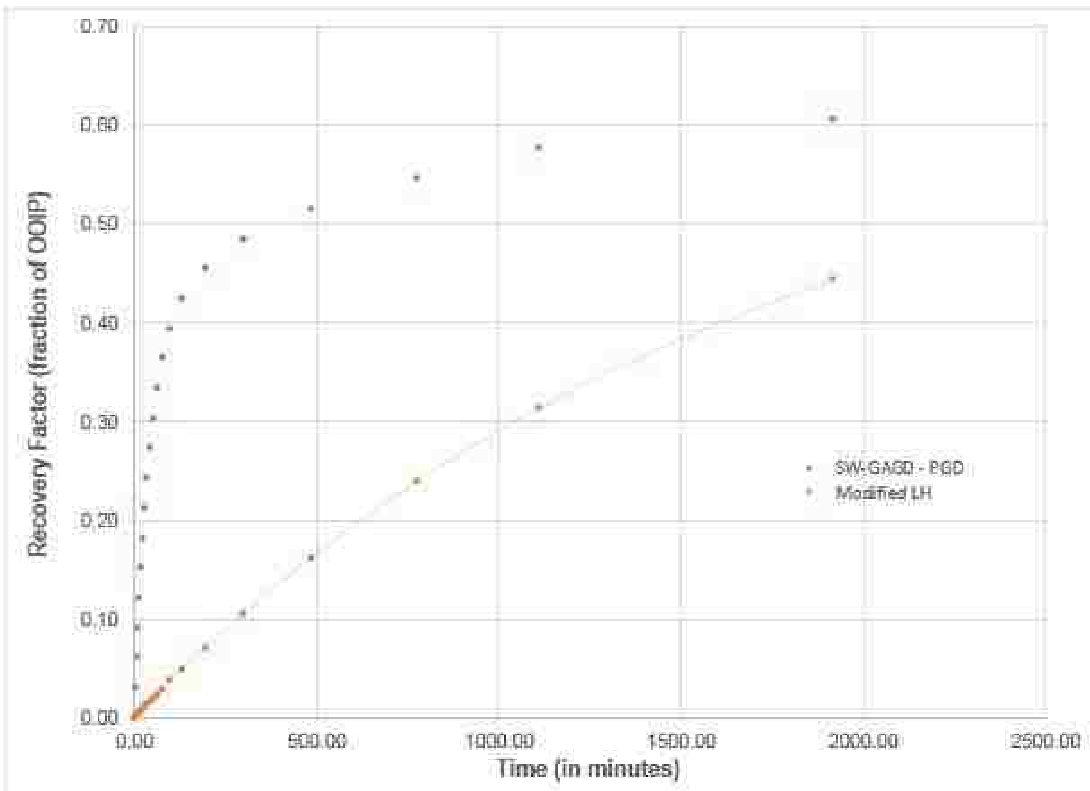

Figure 6.2: Comparison of experimental and Modified L&H recoveries for SW-GAGD with free or pure gravity drainage

Equation B gives the expression for cumulative oil production with Hagoort model.

$$N_p = 1 - \left(1 - \frac{1}{n}\right)\left(\frac{1}{nk^{o}_{ro}t_D}\right)^{\frac{1}{n-1}} \tag{3}$$

Where,

N_p = Cumulative oil production

n = Corey exponent

k^o_{ro} = relative permeability coefficient in k_{ro}

t_D = dimensionless time

Table 4 below lists the data required for Hagoort model calculations.

Table 4: Data required for Hagoort model calculations

Parameter	Value	Unit
Density Decane	730	kg/m^3
Density of Nitrogen at STP	34.31	kg/m^3
Acceleration due to gravity, g	9.81	m/s^2
Permeability, k	1.2E-11	m2
Gas flow rate	2.5	cm^3/min
Gas flow rate	4.16667E-08	m^3/s
velocity, v	8.0572E-06	m/s
Viscosity of oil	0.000859	Pa.s
Gravity no.	11.82077449	-
Height of the model	0.254	m
S_{org}	0.1	-
S_{iw}	0.25	-
Porosity, ϕ	0.396	-
Reduced porosity, ϕ^*	0.2574	-
Multiplication term for dimensionless "t"	0.001456759	t^{-1}

Figure 6.3 shows the comparison of with SW-GAGD run with an injection rate of 2.5 SCCM with Hagoort model (n=5). As can be seen, the fit is much better, even though not perfect. This model does take into account the shock front reaching the production well at breakthrough unlike the

previous model and thus is much more representative of actual behavior. This model, however, slightly over predicts the recovery pre breakthrough and under predicts the recovery post breakthrough. This may be as a result of ignoring the capillary pressure and the mobility ratio terms in the fractional flow function during the solution. Also, this formulation ignores the film drainage, which can play a significant role especially post breakthrough. For GAGD process, Mahmoud et al.[46] and Paidin et al.[51] have shown that oil wet recoveries were higher than water wet cases. This is anticipated to be as a result of formation of oil films that aid in flow of oil through films.

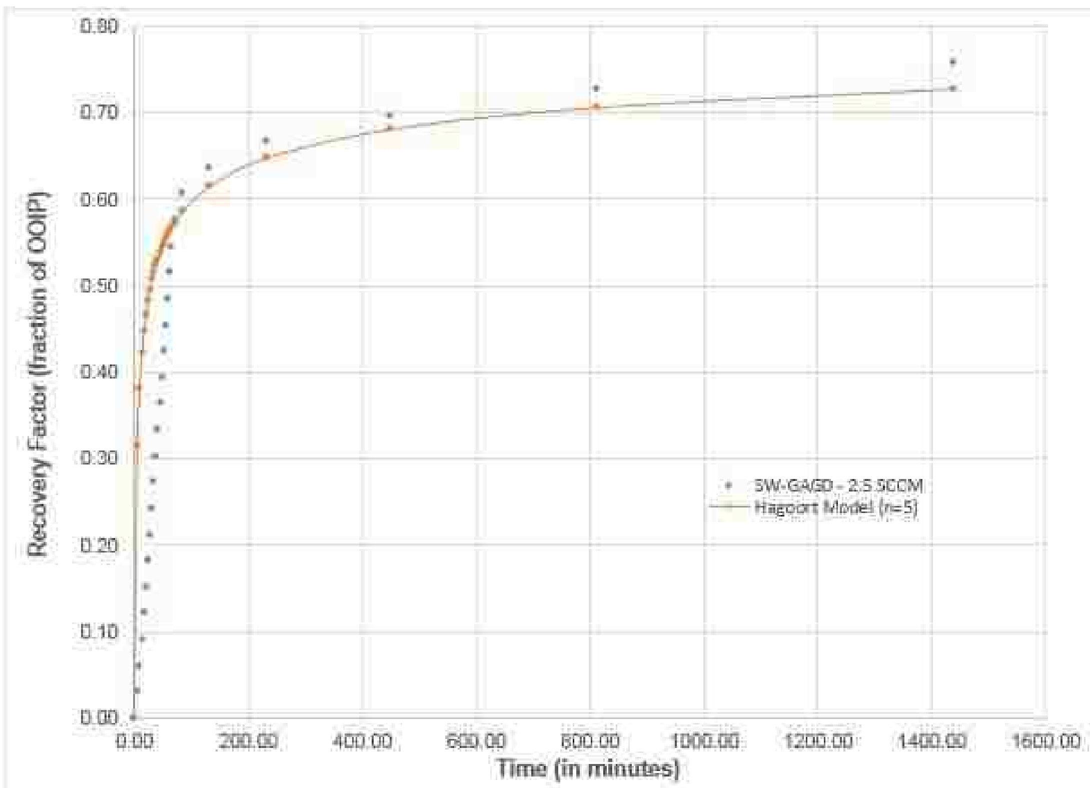

Figure 6.3: Comparison of SW-GAGD recoveries at 2.5 SCCM with that predicted by Hagoort model (n=5)

In case of oil-wet systems thick oil wetting films act as conduits for flow of oil phase and coupled with gravity drainage, this can lead to significant production. This effect is particularly pronounced for GAGD mode recoveries, firstly, because the length that oil films need to traverse is reduced considerably to just the thickness of the reservoir rather than well spacing for horizontal mode displacements and secondly, there is a positive gravity component of force which is pulling the oil downwards at all times.

6.5 A Relook at Gravity Drainage Reference Rate (GRR)

The criterion to gauge the effectiveness of gravity drainage process has been the gravity drainage reference rate (GRR). It's also known as the maximum rate of gravity drainage and is supposed to be the threshold value of rate beyond which the gravity drainage process suffers from adverse mobility of the gas phase and the recoveries are poor. A number of expressions for gravity drainage reference rate have been put forwarded by various authors (Dumore et al.[15], Hill et al.[26], Slobad et al.[61], etc.). In one of its earliest and basic forms (Terwilliger et al.[62]), it is expressed by the following equation:

$$GRR = \frac{K_L A}{\mu_L} g\, \Delta\rho \sin\alpha \qquad (4)$$

Where,

K_L = effective permeability to liquid at 100 percent liquid saturation

A = cross-sectional area through which flow occurs

μ_L= viscosity of liquid

g = gravitational constant

$\Delta\rho$ = density difference between liquid and gas

α = angle of dip of the system (+ for up)

This expression for GRR, as indicated in Equation 4, was often observed to be conservative in its requirement. Terwilliger et al. did not find the GRR as defined by equation (4) to be limiting in terms of his experimental recoveries. He reported overshooting the GRR by as much as 226% and still did not find any disruption in gravity drainage performance. We have also encountered similar results with our SW-GAGD runs, some of which exceeded this GRR but still had satisfactory recovery performance. That is why some later authors improved upon this definition of critical rate by adding porosity term in the denominator to account for interstitial velocity, which is higher than the superficial velocity. Two of the most popular expressions are that by Hill and Dumore, which are given below respectively in equations (5) and (6):

$$V_{ST} = \frac{2.741\ k\ sin\theta}{\phi}\left(\frac{\partial\rho}{\partial\mu}\right)_{min} \tag{5}$$

$$V_C = \frac{2.741\Delta\rho\ k\ sin\theta}{\phi\Delta\mu} \tag{6}$$

Where (includes both (4) and (5),

V_{ST} = Critical velocity for stable vertical flow of gas (ft/D)

V_C = Critical vertical injection velocity (ft/Day)

$\Delta\rho$ = Density difference (g/cc)

$\Delta\mu$ = Viscosity difference (cp)

K = Permeability (D)

ϕ = Porosity

θ = Dip angle

Dumore's expression is an improved version of Hill's[26] (1952) expression and was developed for miscible displacements. Since Hill's expression was developed for immiscible displacement, we have used Hill's expression for critical rate to compare with SW-GAGD rates. Table 5 lists the data used for calculation of GRR. Critical rate for our SW-GAGD model based on Hill's criteria was 68.74 ft/ day and all the SW-GAGD runs were well within Hill's criteria for the critical rate, ranging from 2.3ft/day for 2.5 SCCM run to 36.5 ft/day for 40 SCCM run. Even though higher rates did not affect the gravity drainage performance, breakthrough recovery was affected at higher rates. For example, at 2.5 SCCM, the breakthrough efficiency was 57% compared to less than 50% for 40 SCCM, even though both rates were below the critical rate. Overall (or ultimate) recovery efficiencies were, however, not affected. Thus Hill's criteria was not violated with our SW-GAGD experimental results and serves as a reasonably good, though less conservative, yardstick to ascertain the stability of vertical floods.

Table 5: Data required for gravity stable criteria calculations

Parameter	Value	Units
Density of Decane	0.73	g/cc
Density of Nitrogen gas at STP	0.034	g/cc
Viscosity of Decane	0.859	cp
Viscosity of Nitrogen gas	0.018	cp
Permeability, K	12	darcy
Porosity	0.396	-
Critical velocity, V_c	68.74	ft/day
Flow rate, SCCM	2.5	cm^3/min
Flow rate, ft^3/day @2.5 SCCM	0.127133	ft^3/day
Area of cross section for flow	0.055664	ft^2
Velocity, V @ 2.5 SCCM	2.28393	ft/day

There are instances in fields where even Dumore criteria was overshot and they too did not experience any shortfall in the performance of their gravity stable floods. Since, as a rule of thumb, the typical flood front velocity with horizontal floods range from 5-10 ft/day, it is anticipated to be even less for vertical floods, keeping the same rate with increased cross-sectional area. So, in view of that it can be reasonably stated that vertical floods will be more likely to be stable than not from operational perspective.

6.6 Salient Observations and Suggestions for Future Modeling Endeavor

1. Modeling for gravity drainage, particularly forced gravity drainage, is still a nascent area even though this mechanism of oil production has been in existence for a very long time.
2. Modeling for gravity drainage, particularly forced gravity drainage, is still a nascent area even though this mechanism of oil production has been in existence for a very long time.
3. The perception that gravity drainage is an extremely slow process, is still pervasive within the industry despite emergence of forced gravity drainage processes like GAGD. This is partly the reason why the industry is slow to welcome the process into its fold and consequent lack of modeling effort.
4. With coming of age of high performance computing, even solution of complex non-linear partial differential equations have ceased to be a challenge and we are no longer limited by mathematics but by our understanding of the physics of various multi-phase mechanisms, that necessitates resorting to simplistic empirical correlations to fill the gap. Renewed stress needs to be placed in understanding of the physics of such processes which will go a long way in bolstering the modeling efforts. In case of gravity drainage, thin film flow, coupling of film flow with gravity drainage, capillary effects, heterogeneity effects, wettability and their various interactions are a few such areas.
5. Predictions from Hagoort model[25], a semi-analytical model, was found to be a relatively good match with experimental SW-GAGD data than modified LH[36], an empirical model. So, still there is hope for analytical modeling and we need not resort to purely statistical modeling techniques that do not explain the physics of the problem. As mentioned earlier, we would

need to gain a better understanding of the physics of the process like film flow and it's coupling with gravity drainage to improve the predictions.

6. Heterogeneity effects, particularly permeability layering, was found to have a strong influence on SW-GAGD recoveries in this experimental study. Even though permeability is a well-studied area but this aspect of permeability-layering that aids in improving the recovery efficiency of a gravity drainage process like SW-GAGD is new. Further work in this area so as to be able to quantify this effect would be worthwhile.
7. For injection processes alike including gravity drainage processes, it matters when the intervention is made. For example, it will matter a great deal whether the intervention point for injection of gas is above the bubble point or below or at abandonment of primary depletion. Unless field data is shared with the researchers and there is active interest on the part of the industry to foster research in this area, we will not be able to develop a good knowledge base in this area.
8. In view of the earlier effort by various authors and a few dedicated works on forced gravity drainage like Hagoort[23], Terwilliger et al.[62] and Kulkarni et al.[36] and the current study, following specific comments on forced gravity drainage modeling can be made with relative confidence.
9. Forced gravity processes, like SW-GAGD is a much faster process compared to free or pure gravity drainage processes. Production from the process is immediate and this has been reported earlier by various authors (Mahmoud et al.[42], Silva et al.[56]).
10. Until before breakthrough of the injected gas, the rate of oil production is equal to the gas injection rate. Hagoort also discussed this in his paper and it has been observed in our current

work. Even though free fall gravity drainage plays a role but compared to forced gravity drainage, that is a much slower process and hence forced gravity drainage takes over.

11. Capillary forces are often ignored for absence of reliable experimental data or to simplify the solutions but they can have a significant effect on modeling performance, as shown by the mismatch during early stage of production as in Figure 6.3.
12. Film flow aided by gravity drainage is important, especially, post-breakthrough period. This is supported by higher recoveries for oil-wet case than water-wet case in the earlier work of Mahmoud et al.[42] (2007) and Paidin et al.[47] (2007) on GAGD performance. Under prediction of SW-GAGD recovery performance through Hagoort's model, which did not take into account the film flow component, also points to this fact. Nenniger and Storrows'[44] work appears to be the only work acknowledging the effect of film flow on gravity drainage by incorporating the film flow component.
13. Reservoir heterogeneity layering has a pronounced effect on forced gravity processes. We have found almost 6-7% enhancement in recovery factor with a low permeability layer overlying the horizontal production compared to the opposite case. Though we currently do not have studies looking into this aspect of such processes, it will be worthwhile to keep this in mind while trying to match experimental data.

CHAPTER 7: SUMMARY, CONCLUSIONS AND RECOMMENDATIONS

7.1 Summary of Results

Following points summarize the main findings based on the discussion in the previous chapter on Results and Discussion.

1. SW-GAGD process far outperforms natural gravity drainage process in terms of recovery factor and rate of recovery. Even a minimal gas injection rate of 2.5 SCCM was 23 times faster than naturally gravity drainage to reach recovery factor of 61% OOIP (Ultimate recovery for naturally gravity drainage for the model). A rate of 20 SCCM was on the other hand 93 times faster.
2. Increase in the rate of injection of the SW-GAGD process, increases the recovery rate. However, recovery factor in terms of PV of gas injected gets affected in the short run. For example, at 1 PV injected, recovery factor is higher for lower rates. But the recovery factor catches up at higher PVs injected.
3. Before the arrival of gas-oil displacement front at the horizontal producing well, the production is primarily through displacement at the gas-oil interface. Post arrival, there is no clear displacement front and the production continues through interplay of gravity, capillary and inertial forces.
4. Miscible SW-GAGD process is capable of producing 100% of the OOIP, similar to a miscible GAGD process.
5. As long as the point of injection is within the same layer, bottom injection seems to perform a tad better than top injection. This is as a result of boost in inertial forces at bottom of the layer, where most of the trapping occur.

6. A comparison between SW-GAGD and GAGD, established exact equivalence between the two processes in terms of progression of displacement front as well as recovery profile.
7. Toe-to-Heel configuration or any other configuration involving bottom point injection of the gas is fraught with the risk of severe short-circuiting of the injected gas to the production well, if the injected layer has a higher permeability than the upper layers. This may leave behind a lot of unswept oil in the upper layers. Hence, layering of the reservoir is critical factor while consideration bottom injection including Toe-to-Heel configuration.
8. Top point injection seems to be the safest bet as a choice of injection point as it is immune to layering of the reservoir.
9. In case of a Bi-layer model with low permeability in the bottom layer, the location of the Toe-to-Heel well within the bottom layer facilitated flattening of the gas-oil displacement front compared to a Toe-to-Heel well located at the bottom of a single layer model.
10. In such a Bi-layer Toe-to-Heel model with low permeability in the bottom layer, the gas oil displacement front first preferred to sweep the upper higher permeable layer than to move into the bottom lower permeable layer. This is because of higher frictional resistance for the gas to flow in the low permeable layer. This preference of the injected gas leads to much better sweep of the upper high permeable layer.
11. Armed with the above knowledge, if we have a top point injection SW-GAGD well configuration with the bottom horizontal well completed within a low permeable layer, then first of all it will be immune to reservoir layering and secondly, it will lead to excellent sweep of the upper layers. Extending it further, if we are able to create a low permeable sand-pack of sorts using micro/nano sized particles or any other completion framework imparting lower

permeability near the bottom horizontal well, we should be able to enhance greatly the sweep of the upper layers.

12. Vertical fractures do not any adverse impact on SW-GAGD performance.
13. Reservoir dip doesn't affect SW-GAGD performance to a great extent. But recovery performance of SW-GAGD process gets enhanced when the gas injection is up dip and the production horizontal well is placed at the lowest point in the reservoir, taking into account reservoir heterogeneity.
14. Performances of the same SW-GAGD model in horizontal orientation simulating horizontal gas and waterfloods points out the limitations of conventional horizontal floods. Gravity has a tremendous effect on the recovery and so does reservoir layering. Hence, gravity stable SW-GAGD process is the safest bet, not only immuned but enhanced by forces of gravity and reservoir heterogeneities.

7.2 Conclusions

1. SW-GAGD process has shown recoveries in the range of 70-80% in the immiscible mode and close to 100% in miscible mode.
2. SW-GAGD process has been shown to be immuned to reservoir heterogeneities like vertical fractures, reservoir dip and permeability layering. Reservoir layering with low permeability layer at the bottom (commonly observed in reservoir) acted to improve the sweep efficiency and hence recoveries.
3. Novel SW-GAGD process performs equivalently with GAGD process and thus can be transported to deepwater Gulf of Mexico to substitute conventional GAGD process.
4. Model results matched semi-analytical Hagoort model for forced gravity drainage reasonably well.

7.3 Recommendations for Future Work

Following work are proposed to be completed in future towards the objective:

i. Lateral Length Limitation: Even though SW-GAGD and GAGD mode performances were exactly the same and as discussed the aspect ratio (length) is not expected to play a significant role, as injected gas moved to the top in both in laboratory and field setting, still it would be worthwhile to put any doubt to its performance to rest by having a SW-GAGD run in a model with a very high aspect ratios.

ii. Effect of Consolidation: Numerous sand-pack models have proven beyond doubt the efficacy of SW-GAGD and for that matter GAGD process. However, it will be interesting to check the performance of the process in presence of consolidation.

iii. Modeling of SW-GAGD process: Modeling work has remained lacking in case of gravity drainage processes, both free and forced. Renewed emphasis needs to be put on gravity drainage modeling, especially because of the emergence of effective forced gravity drainage processes. Concerted efforts need to be placed on both modeling and experimental fronts to understand and quantify some of the less explored areas like film drainage, drainage across layers in heterogenous layered system etc.,

REFERENCES

1. Advanced Resources International (2006), "Basin Oriented Strategies for CO_2 Enhanced Oil Recovery: Onshore Gulf Coast", Prepared for US DOE.

2. Aronofsky, J.S., Masse, L., Natanson, S.G., "A Model for the Mechanism of Oil Recovery from the Porous Matrix Due to Water Invasion in Fractured Reservoirs", 1958, Vol. 213, Petroleum Transactions, AIME.

3. Bangia, V.K., Yau, F.F., Hendricks, G.R., "Reservoir Performance of a Gravity-Stable Vertical CO2 Miscible Flood: Wolfcamp Reef Reservoir, Wellman Unit", November 1993, SPE Reservoir Engineering Journal.

4. Bilozir, D.E., and Frydl, P.M., "Reservoir Description and Performance Analysis of a Mature Miscible Flood in Rainbow Field, Canada", October, 1989, SPE 19656, Presented at SPE Annual Technical Conference and Exhibition, San Antonio, U.S.A.

5. Buckley, S.E. and Leverett, M.C., "Mechanism of Fluid Displacement in Sands", May 1941, TP1337, Petroleum Technology.

6. Cardwell, W.T. and Parsons, R.L., "Gravity Drainage Theory", November 1948, TP 2464, Petroleum Technology.

7. Carlson, L.O., "Performance of Hawkins Field Unit Under Gas Drive-Pressure Maintenance Operations and Development of an Enhanced Oil Recovery Project", April 1988, Presented at SPE/DOE Enhanced Oil Recovery Symposium, Tulsa, USA.

8. Caudle, B.H., and Dyes, A.B., "Improving Miscible Displacement by Gas-Water Injection", October 1957, Vol. 192, Presented at SPE Annual Fall Meeting of SPE Dallas, Tx, U.S.A.

9. Choudhary, M.K., Parekh, B., Dezabala, E., Marks, D., Zambrano, P., "Design, Implementation and Performance of a Down-dip WAG Pilot", February 2012, Paper Presented at IPTC, Bangkok, Thailand.

10. Christensen, J. R., Stenby, E. H., Skauge, A., "Review of the WAG field experience", SPE 71203-PA, April, 2001, SPE Reservoir Evaluation and Engineering.

11. Crogh, N. A., Eide, K., Morterud, S.E., “WAG Injection at the Statfjord Field, A Success Story”, October, 2002, Presented at SPE 13th European Petroleum Conference, Aberdeen, UK.

12. Cubillos, H., Stright, D. and Navarro, J.M., “Successful Peripheral Miscible Gas Injection in RKF Field, Berkine Basin, Algeria – Field Case History”, June 2005, Presented at SPE Europe/EAGE Annual Conference, Madrid, Spain.

13. Davis, T.L., Benson, R.D., “Weyburn Field Seismic Monitoring Project”, October 2004, Presented at SEG International Exposition, Denver, Colorado.

14. DOE website : http://energy.gov/fe/science-innovation/oil-gas/enhanced-oil-recovery

15. Dumore, J.M., “Stability Considerations in Downward Miscible Displacements”, December, 1964, Society of Petroleum Engineers Journal.

16. Dykstra, H., “The Prediction of Oil Recovery by Gravity Drainage”, May 1978, Journal of Petroleum Technology.

17. Erbas, D., Dunning, M., Nash, T.M., Cox, D., Stripe, J.A., Duncan, E., “Magnus WAG Optimization Through Data Integration”, April 2014, Presented at SPE IOR Symposium, Tulsa, USA.

18. Geertsma, J., Croes, G.A., Schwarz, N., “Theory of Dimensionally Scaled Models of Petroleum Reservoirs”, 1956, Vol. 207, Petroleum Transactions, AIME.

19. Ghahfarokhi, R.B., Pennell, S., Matson, M., Linroth, M., “Overview of CO2 injection and WAG sensitivity in SACROC”, April 2016, Presented at SPE IOR Conference, Tulsa, USA.

20. Gharbi, R., Peters, E.J. and Elkamel, A., “Scaling Miscible Fluid Displacements in Porous Media”, June, 1998, Energy Fuels 12 (4).

21. Gharbi, R.B.C., “Dimensionally Scaled Miscible Displacements in Heterogenous Permeable Media”, 48: 271-290, 2002, Transport in Porous Media.

22. Gonzalez, D.L., Mahmoodaghdam, E., Lim, F. and Joshi, N., “Effects of Gas Addition to Deepwater Gulf of Mexico Reservoir Oil: Experimental Investigation of Asphaltene Precipitation and Depositions”, October 2012, Presented at SPE ATCE, San Antonio, Texas.

23. Grattoni, C.A., Jing, X.D., Dawe, R.A., "Dimensionless Groups for Three-Phase Gravity Drainage Flow in Porous Media", October, 2000, 29 (2001) 53-65, Journal of Petroleum Science and Engineering.

24. Gunawan, S. and Caie, D., "Handil Field: Three Years of Lean Gas Injection into Waterflooded Reservoirs", April 2001, SPE Reservoir Evaluation & Engineering Journal.

25. Hagoort, J., "Oil Recovery by Gravity Drainage", June 1980, Society of Petroleum Engineers Journal.

26. Hill, S. "Channeling in Packed Columns", August, 1952, Chemical Engineering Science, Vol. 1, No. 6.

27. Hsie, J.C. and Moore, J.S., "The Quarantine Bay 4RC CO2 WAG Pilot Project: A PostFlood Evaluation", August 1988, SPE Reservoir Engineering Journal.

28. http://www.geographic.org/deepwater_gulf_of_mexico/production_rates.html

29. Huijgens, R.J.M. and Hagoort, J., "Interfacial Tension of Nitrogen/Volatile Oil Systems", October 1993, Presented at SPE ATCE, Houston, Texas.

30. Hyatt, J.H., Hutchison, D.A., "Enhanced Oil Recovery in East Texas", March, 2005, Presented at SPE Middle East Oil & Gas Show and Conference, Bahrain, Kingdom of Bahrain.

31. Jadhawar, P.S., Sharma, H.K., "Scaling and Sensitivity Analysis of Gas-Oil Gravity Drainage EOR", October, 2008, Presented at SPE Asia Pacific Oil & Gas Conference and Exhibition, Perth, Australia.

32. Johnston, J.R., "Weeks Island Gravity Stable CO2 Pilot", April, 1988, SPE/DOE 17351, Presented at SPE/DOE Enhanced Oil Recovery Symposium, Tulsa, USA.

33. Kane, A.V., "Performance Review of a Large Scale CO2-WAG Enhanced Recovery Project, SCAROC Unit – Kelly Snyder Field", February 1979, Presented at SPE-AIME Symposium on Improved Methods for Oil Recovery, Tulsa, USA.

34. Kokal, S., Modiu, S., Almohannad, "Design and Implementation of the First CO_2-EOR Demonstration Project in Saudi Arabia", September 2016, Paper Presented at SPE ATCE, Dubai, UAE

35. Koottungal, L., "2014 Worldwide EOR Survey", April 2014, Oi & Gas Journal.

36. Kulkarni, M.M. and Rao, D.N., "Analytical Modeling of Forced Gravity Drainage GAGD process", November 2006, AIChE 72361, AIChE Annual Meeting, San Francison, CA.

37. Kulkarni, M.M. and Rao, D.N., "Characterization of Operative Mechanisms in Gravity Drainage Field Projects Through Dimensional Analysis", September, 2006, SPE 103230, Presented at SPE Annual Technical Conference and Exhibition, San Antonio, U.S.A.

38. Kulkarni, M.M. and Rao, D.N., "Experimental Investigation of Miscible Secondary Gas Injection", October, 2005, SPE 95975, Presented at SPE Annual Technical Conference and Exhibition, Dallas, U.S.A.

39. Lach J., "IOR for Deepwater Gulf of Mexico", Knowledge Reservoir, December, 2010.

40. Langenberg, M.A., Henry, D.M., Chlebana, M.R., "Performance and Expansion Plans for the Double-Displacement Process in the Hawkins Field Unit", November 1995, SPE Reservoir Engineering Journal.

41. Lee, J.I., Astete, E.L., Jerhoff, T.F., "Performance Review of Brazeau River Nisku Dry-Gas Miscible-Flood Project", February 1994, SPE Reservoir Engineering Journal.

42. Li, D. and Lake, L.W., "Scaling Fluid Flow Through Heterogenous Porous Media", 1995, SPE Advanced Technology Series, Vol. 3, No. 1.

43. Li, K. and Firoozabadi, A, "Experimental Study of Wettability Alteration to Preferential Gas-Wetting in Porous Media and its Effects", April, 2008, Vol. 3, No. 2, SPE Reservoir Eval. & Eng.

44. Li, K. and Horne, R., "Prediction of Oil Recovery by Gravity Drainage", October, 2003, SPE 84184, Presented at SPE Annual Technical Conference and Exhibition at Denver, Co, U.S.A.

45. Loomis et al., "Theory and Application of Dimensional and Inspectional Analysis to Model Study of Fluid Displacements in Porous Media", Report of Investigations 6546, 1964, US Dept. of the Interior, Bureau of Mines.

46. Mahmoud, N. N. T. (2007), "Development and Performance Characterization of the Gas Assisted Gravity Drainage (GAGD) Process Using a Visual Model" (Master's Thesis), Louisiana State University.

47. Martin, W.E., “The Wizard Lake D-3A Pool Miscible Flood”, March, 1982, Presented at the International Petroleum Exhibition and Technical Symposium, Beijing, China.

48. Nenniger, E. and Storrow, J.A., “Drainage of Packed Beads in Gravitational and Centrifugal-Force Fields”, September, 1958, Vol. 4, Issue 3, AIChE Journal.

49. Oren, P.E., Billiotte, J., Pinczewski, W.V., “Mobilization of Waterflood Residual Oil by Gas Injection for Water-Wet Conditions”, March 1992, SPE Formation Evaluation.

50. Oren, P.E., Pinczewski, W.V., “Effect of Wettability and Spreading on Recovery of Waterflood Residual Oil by Immiscible Gasflooding”, June 1994, SPE Formation Evaluation.

51. Paidin, W.R. and Rao, D.N., “Physical Model Experiments to Evaluate the Effect of Wettability and Fractures on the Performance of Gas Assisted Gravity Drainage (GAGD) Process”, prepared for poster presentation at the International Symposium of the Society of Core Analysts, Calgary, 2007.

52. Pedrera, B., Bertin, H., Hamon, G., Augustin, A, “Wettability Effect on Oil Relative Permeability During a Gravity Drainage”, April, 2002, Presented at SPE/DOE Symposium on Improved Oil Recovery, Tulsa, USA.

53. Rao, D.N., Ayirala, S.C., Kulkarni, M.M. and Sharma, A.P., “Development of Gas Assisted Gravity Drainage (GAGD) process for improved light oil recovery”, April, 2004, SPE 89357, Presented at SPE/DOE IOR symposium, Tulsa, U.S.A.

54. Rapoport, L.A., “Scaling Laws for Use in Design and Operation of Water-Oil Flow Models”, August, 1955, Vol. 204, Petroleum Transactions, AIME.

55. Richardson, J.E. and Blackwell, R.J., “Use of Simple Mathematical Models for Predicting Reservoir Behavior”, September 1971, Journal of Petroleum Technology.

56. Salathiel, R.A., “Oil Recovery by Surface Film Drainage in Mixed-Wettability Rocks”, October 1973, Journal of Petroleum Technology.

57. Schechter, D. S., and Guo, B., “Mathematical Modeling of Gravity Drainage after Gas Injection into Fractured Reservoirs”, SPE 35170, SPE Permian Basin Oil and Gas Recovery Conference, Midland, TX, Mar, 1996.

58. Sharma, A.P. and Rao, D.N., "Scaled Physical Model Experiments to Characterize Gas-Assisted Gravity Drainage EOR process", April, 2008, SPE 113424, Presented at SPE/DOE IOR Symposium, Tulsa, USA.

59. Shook, M., Li, D. and Lake, L.W., "Scaling Immiscible Flow through Permeable Media by Inspectional Analysis", 1992, In Situ, Vol. 6, No. 4.

60. Silva, R.R.C and Maini, B., "Evaluation of Gas Assisted Gravity Drainage GAGD in Naturally Fractured Reservoirs NFR", April, 2016, SPE 179585, Presented at SPE IOR Symposium, Tulsa, USA.

61. Slobod, R.L. and Howlett, W.E., "The Effects of Gravity Segregation in Laboratory Studies of Miscible Displacement in Vertical Unconsolidated Porous Media", March, 1964, Society of Petroleum Engineers Journal.

62. Terwilliger, P.L., Wilsey, L.E., Hall, H.N., Bridges, P.M. and Morse, R.A., "An Experimental and Theoretical Investigation of Gravity Drainage Performance", February 1951, Vol. 192, AIME, Petroleum Transactions.

63. Thomas, F.B., Erin, A., Zhou, X., Bennion, D.B., Bennion, D.W., Okazawa, T., "Does Miscibility Matter in Gas Injection?", May, 1995, Presented at Annual Technical Meeting of the Petroleum Society of CIM in Banff, Alberta, Canada.

64. US EIA (2016), "Trends in U.S. Oil and Natural Gas Upstream Costs", US Department of Energy.

65. Vilela, M.J., Gharsalla, M., Elghmari, M., Majdoub, A., "Performance Evaluation of a Reservoir Under EOR Recovery: Intisar "D" Reef, Concession 103, Libya", March, 2007, Presented at SPE Middle East Oil & Gas Show and Conference, Bahrain, Kingdom of Bahrain.

66. Vizika, O., Lombard, J.M., "Wettability and Spreading: Two Key Parameters in Oil Recovery with Three-Phase Gravity Drainage", February 1996, SPE Reservoir Engineering.

67. Wang, G.C., "Microscopic Investigation of CO_2 Flooding Process", August, 1982, Journal of Petroleum Technology.

VITA

Born in a small oil town, oil and gas business was quite familiar to me. After my high school, joined National Institute of Technology in Karnataka, India and obtained my Bachelor's degree in Chemical Engg. Fascination towards oil and gas business led me to join the premier national oil and gas major in India. After a couple of years at work, joined master's program here at LSU in fall, 08 and obtained my degree in fall, 10. I expect to have the degree of Doctor of Science in Petroleum Engineering conferred in May 2017.