Pressure Transient Behavior of Immiscible Water-Alternating-Gas (IWAG) Injection Well with and without Skin Effect

by

Abu Bakar bin Mustafa Bamadhaj
14732

Dissertation submitted in partial
fulfillment of the requirements for the
Bachelor of Engineering (Hons)
(Petroleum)

JANUARY 2015

Universiti Teknologi PETRONAS
Bandar Seri Iskandar
31750 Tronoh
Perak Darul Ridzuan

CERTIFICATION

CERTIFICATION OF APPROVAL

Pressure Transient Behavior of Immiscible Water-Alternating-Gas (IWAG) Injection Well with and without Skin Effect

by

Abu Bakar bin Mustafa Bamadhaj

14732

A project dissertation submitted to the

Petroleum Engineering Programme

Universiti Teknologi PETRONAS

in partial fulfillment of the requirement for the

BACHELOR OF ENGINEERING (Hons)

(PETROLEUM)

Approved by,

____

(Azeb Demisi Habte)

UNIVERSITI TEKNOLOGI PETRONAS

TRONOH, PERAK

January 2015

CERTIFICATION OF ORIGINALITY

This is to certify that I am responsible for the work submitted in this project, that the original work is my own except as specified in the references and acknowledgements, and that the original work contained herein have not been undertaken or done by unspecified sources or persons.

____

ABU BAKAR BIN MUSTAFA BAMADHAJ

ABSTRACT

Pressure transient analysis could provide valuable information on the characterization and evaluation of reservoir. Previous studies have shown critical analysis of injection and falloff tests of water or gas injection wells. Existing pressure transient study conducted on immiscible water-alternating-gas (IWAG) injection wells mainly focused on falloff test without considering the presence of skin near the wellbore region. The objective of this study is to analyze the pressure transient behavior of IWAG injection and falloff test with and without skin effect using simulated data. Presence of skin near the wellbore region could adversely affect the pressure behavior of reservoir. Likewise, the pressure transient behavior will provide useful information in reservoir characterization study. ECLIPSE 100 is used to simulate the reservoir model under different mobility condition with the presence of skin for a water-oil system only since gas-oil system is always unfavorable. Skin values are calculated using the Hawkin's equation. The Infinitely acting reservoir with radial composite system is considered in this study with an injection well placed at the center. Water and gas are injected alternately at constant injection rate. The reservoir is homogenous, isotropic and with no gravity and wellbore storage effects. However, hysteresis is included in order to simulate the real condition of an IWAG injection well. Effect of skin is dominant at early time for all skin cases. Presence of positive skin under unfavorable mobility condition shows the most significant result for injection test period. Pressure derivative curves during the first water injection period resulted in increasing pressure drop at early time thus increasing the pressure derivative value. However, the derivative of positive skin case drops to negative values when the transient reach the fluid boundary where mobility of water is higher. For the first gas injection, pressure change curve of positive skin case at early time region drops and causes negative derivative values. Positive pressure derivative values are observed at late time region due to high water mobility. Similar trend is observed during the second gas injection except at late time the pressure derivative for all skin cases coincide with each other. Flood front radius is estimated by observing the change on the average mobility profile generated from pressure falloff test data. Mobility after the flood front location for unfavorable condition decreased gradually due to low oil mobility region.

ACKNOWLEDGEMENTS

First and foremost I would like to express my gratitude and take immense pleasure in thanking Ms. Azeb Demisi Habte for her constant guidance and supervision throughout the project. Without her knowledge and assistance this project would not have been successful. Next, I would like to thank all those people who have contributed in any way for the success of this individual project. I would also like to express my gratitude to Dr. Ismail Bin Mohd Saaid, as the Chairman of Final Year Project (FYP) II and Dr. Syahrir Ridha, as the course coordinator for being very helpful in giving us assistance and advices during this project.

I would like to express my sincere gratitude to Universiti Teknologi PETRONAS (UTP) for providing us an opportunity to enhance my knowledge and research skills through this project.

Finally, I would like to express my heartfelt thanks to my beloved parents and family for their blessings and support throughout my study period, and my friends/classmates for their help and wishes for the successful completion of this project.

TABLE OF CONTENTS

CERTIFICATION .... **II**

ABSTRACT .... **IV**

ACKNOWLEDGEMENTS .... **V**

LIST OF FIGURES .... **VIII**

LIST OF TABLES .... **IX**

CHAPTER 1 .... **1**

INTRODUCTION **1**

1.1 Background 1

1.2 Problem Statement 1

1.3 Objectives 2

1.4 Scope of Study 2

CHAPTER 2 .... **3**

LITERATURE REVIEW **3**

2.1 Enhanced Oil Recovery (EOR) Methods and Applications 3

2.2 Water-Alternating-Gas (WAG) Process and Classifications 5

2.3 Mobility Ratio 7

2.4 Pressure Transient Behavior of Injection Wells 8

2.5 Skin Factor Effect on Pressure Behavior and its Derivative 10

CHAPTER 3 .... **11**

METHODOLOGY **11**

3.1 ECLIPSE 100 11

3.2 Pressure Transient Analysis 11

3.3 Gantt-Chart 12

3.4 Key Milestones....13
3.5 Flow Chart....14

CHAPTER 4 15

RESULTS AND DISCUSSION....15

4.1 Numerical Simulation Model....15
4.2 Result Analysis....17
4.3 Pressure and Pressure Derivative Responses (Favorable Condition)....19
4.3.1 1st Water Injection and Falloff Periods (M = 0.3) 19
4.3.2 1st Gas Injection and Falloff Periods (M = 0.3)....21
4.3.3 2nd Water Injection and Falloff Periods (M = 0.3) 23
4.3.4 2nd Gas Injection and Falloff Periods (M = 0.3)....25
4.4 Pressure and Pressure Derivative Responses (Unfavorable Condition)....27
4.4.1 1st Water Injection and Falloff Periods (M = 2.0) 27
4.4.2 1st Gas Injection and Falloff Periods (M = 2.0)....29
4.4.3 2nd Water Injection and Falloff Periods (M = 2.0) 31
4.4.4 2nd Gas Injection and Falloff Periods (M = 2.0)....33

CHAPTER 5 36

CONCLUSION AND RECOMMENDATION 36

5.1 Conclusion....36
5.2 Recommendation....37

REFERENCES....38

APPENDICES 39

Appendix 1 39
Appendix 2 40

LIST OF FIGURES

Figure 1: System Assisted Gravity Drainage (SAGD) Schematic Diagram by Thomas (2008) 4
Figure 2: Water-Alternating-Gas (WAG) Schematic Diagram by Zahoor et al. (2011) 6
Figure 3: 3D Radial Base Case Model from ECLIPSE 100 16
Figure 4: Well Bottomhole Pressure for IWAG Injection 17
Figure 5: Point-Centered Logarithmic Gridding (Habte & Onur, 2013) 18
Figure 6: Pressure change and pressure derivative responses for 1st water injection period with and without skin factor (M = 0.3) 20
Figure 7: Pressure change and pressure derivative responses for 1st water falloff period with and without skin factor (M = 0.3) 20
Figure 8: Average mobility profile from the pressure derivative response of the 1st water falloff test with and without skin factor (M = 0.3) 21
Figure 9: Pressure change and pressure derivative responses for 1st gas injection period with and without skin factor (M = 0.3) 22
Figure 10: Pressure change and pressure derivative responses for 1st gas falloff period with and without skin factor (M = 0.3) 22
Figure 11: Average mobility profile from the pressure derivative response of the 1st gas falloff test with and without skin factor (M = 0.3) 23
Figure 12: Pressure change and pressure derivative responses for 2nd water injection period with and without skin factor (M = 0.3) 24
Figure 13: Pressure change and pressure derivative responses for 2nd water falloff period with and without skin factor (M = 0.3) 24
Figure 14: Average mobility profile from the pressure derivative response of the 2nd water falloff test with and without skin factor (M = 0.3) 25
Figure 15: Pressure change and pressure derivative responses for 2nd gas injection period with and without skin factor (M = 0.3) 26
Figure 16: Pressure change and pressure derivative responses for 2nd gas falloff period with and without skin factor (M = 0.3) 26
Figure 17: Average mobility profile from the pressure derivative response of the 2nd gas falloff test with and without skin factor (M = 0.3) 27
Figure 18: Pressure change and pressure derivative responses for 1st water injection period with and without skin factor (M = 2.0) 28
Figure 19: Pressure change and pressure derivative responses for 1st water falloff period with and without skin factor (M = 2.0) 28
Figure 20: Average mobility profile from the pressure derivative response of the 1st water falloff test with and without skin factor (M = 2.0) 29
Figure 21: Pressure change and pressure derivative responses for 1st gas injection period with and without skin factor (M = 2.0) 30
Figure 22: Pressure change and pressure derivative responses for 1st gas falloff period with and without skin factor (M = 2.0) 30

Figure 23: Average mobility profile from the pressure derivative response of the 1st gas falloff test with and without skin factor (M = 2.0) 31
Figure 24: Pressure change and pressure derivative responses for 2nd water injection period with and without skin factor (M = 2.0) 32
Figure 25: Pressure change and pressure derivative responses for 2nd water falloff period with and without skin factor (M = 2.0) 32
Figure 26: Average mobility profile from the pressure derivative response of the 2nd water falloff test with and without skin factor (M = 2.0) 33
Figure 27: Pressure change and pressure derivative responses for 2nd gas injection period with and without skin factor (M = 2.0) 34
Figure 28: Pressure change and pressure derivative responses for 2nd gas falloff period with and without skin factor (M = 2.0) 34
Figure 29: Average mobility profile from the pressure derivative response of the 2nd gas falloff test with and without skin factor (M = 2.0) 35

LIST OF TABLES

Table 1: WAG Schedule 16
Table 2: Comparison of average mobility and flood front location value for favorable and unfavorable mobility condition 35
Table A1: Reservoir Rock and Fluid Properties – Input Data 39

CHAPTER 1

INTRODUCTION

1.1 Background

The demand for petroleum fluids nowadays has increased tremendously throughout the world. Kokal and Al-Kaabi (2010) stated that the daily oil production is not keeping pace with the growing energy demand. Average recovery factor from the world hydrocarbon reservoirs is in the mid-30 percent range. Prior to increase recovery, big oil companies have started to explore for oil in deeper part of the Earth. On the other side, this issue has also opened a great opportunity for enhanced oil recovery (EOR) technologies to boost the hydrocarbon recovery.

With that being said, one specific method of EOR that is widely used since the 1960's is water-alternating-gas (WAG) injection technique. It is an EOR method designed to inject water and gas in alternating cycles for specific period in order to increase recovery. The result is similar to gas or water injection individually which is to increase the sweep efficiency inside the reservoir thus increasing the mobility of the trapped oil and flow to the surface.

Injection and falloff tests are used to obtain useful reservoir information such as effective permeability, well-bore damage, flood front location, static reservoir pressure and data for PVT analysis. This information is usually obtained through interpretation of the pressure and pressure transient behavior of the injection well. Full understanding of pressure transient behavior is very important in measuring the efficiency and effectiveness of WAG injection.

1.2 Problem Statement

There are a number of studies on pressure transient test involving skin effect in water injection well. However, when gas injection is included, effect of the presence of skin is still ambiguous. Such injection usually occurs in immiscible water alternating gas (IWAG) injection well. Based on well test analysis, presence of skin affects the pressure behavior near the wellbore region due to altered permeability of the skin zone. Likewise the pressure transient test with presence of skin will provide information on pressure derivative behavior that is used to determine the presence of formation damage. This study will focus on pressure transient behavior of IWAG injection and falloff tests with and without skin effect using simulated pressure data.

1.3 Objectives

The objective of this study is as follows:

1. Study the pressure transient behavior of IWAG injection and falloff tests with and without skin effect.
2. Estimate the flood front location from pressure-derivative profile during falloff period.

1.4 Scope of Study

This study will focus on injection and falloff tests for IWAG injection process. The simulation model will be based on a cylindrical reservoir with homogeneous and isotropic properties. Gravity and well-bore storage effects are neglected. The reservoir is set to a constant temperature and injection rate (1:1 WAG ratio) throughout the simulation study and the well is fully perforated. Simulation study is focused on water-oil system only for both favorable and unfavorable condition since gas-oil system is always unfavorable.

CHAPTER 2

LITERATURE REVIEW

2.1 Enhanced Oil Recovery (EOR) Methods and Applications

During the production life of reservoir, there are basically three types of oil recovery. First is primary recovery where oil is produced through naturally occurring reservoir pressure such as solution gas drive and water drive. Second is the secondary recovery which usually involves water flooding and gas injection to provide external energy to push the remaining oil out. Then the third recovery would be the Enhanced Oil Recovery (EOR). Sunmonu and Onyekonwu (2013) stated that EOR which also referred to as Tertiary Recovery is a technique for increasing the oil recovery of a reservoir using chemical, thermal, gas injection or other preferred method such as microbial flooding.

There are many types of EOR techniques. They are distributed into two types which are thermal and non-thermal techniques. Thermal techniques provide heat to the reservoir thus vaporizing certain amount of oil. Therefore the viscosity of the fluid will reduce tremendously as well as the mobility ratio (Thomas, 2008). The most common thermal EOR are steam injection. It has been popularly applied in heavy oil sand reservoirs with ongoing projects in Alberta (Canada), Venezuela, California, Indonesia and Oman (Kokal & Al-Kaabi, 2010).

Steam Assisted Gravity Drainage (SAGD) is an example of thermal EOR. SAGD utilize gravity segregation of steam to push the oil out of the reservoir. Butler (1985) first established a study showing recovery of bitumen from Alberta in Canada. Referring to **Fig. 1**, steam injector is the top well and producer at the bottom. First, steam will condenses at the top formation creating a steam accumulation. Due to large viscosity reduction, this will allow the hydrocarbon whereby in this case, bitumen to mobilize which will be drained to the bottom of the well caused by gravity. Oil will flow through the producer up to the surface. If steam is injected continuously, the steam accumulation will expand and spread throughout the reservoir. SAGD works more efficient with bitumen and oil that has low mobility which is crucial for the formation of steam accumulation instead of steam channels. Success of SAGD depends on high vertical permeability. Even though SAGD is effective in enhancing oil recovery, it is not economic friendly due to its high energy requirements. Basically it requires large volumes of water and gas for steam generation (Thomas, 2008).

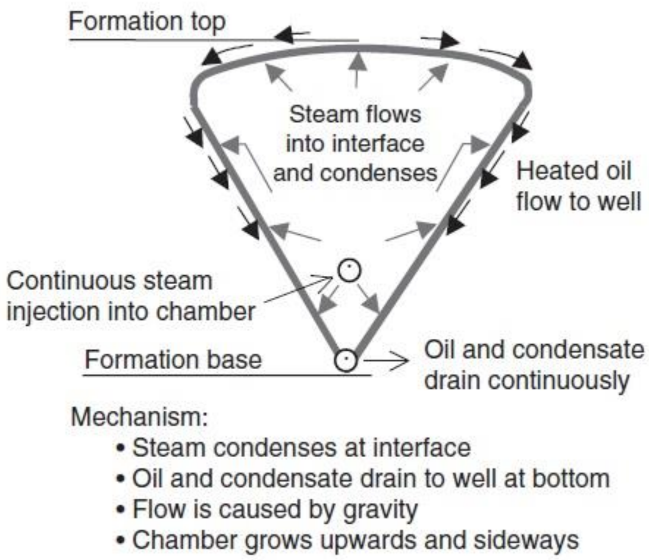


Figure 1: System Assisted Gravity Drainage (SAGD) Schematic Diagram by Thomas (2008)

Another type of thermal EOR is in situ combustion method. This method is carried out by injecting air or oxygen bearing gas in the reservoir. The gas is then ignited to burn a ratio (approx. 10%) of the oil in place to produce heat which will reduce the oil viscosity tremendously due to high temperature (Thomas, 2008). In situ recovery is recommended for reservoirs with high porosity and oil saturation, good permeability and moderate oil viscosity which usually found in heavy oil sandstone (Thomas, 2008; Tunio et al., 2011). Through THAI (Toe-To-Heel Air Injection) which is a type of in situ combustion method, 70-80% OIIP is estimated to be recovered.

Non-thermal EOR methods such as miscible and immiscible gas injection, chemical injection and others such as microbial EOR (MEOR) and foam injection are also applied in the field. This method is suitable for light oils; viscosity less than 100 cp and few cases for viscosity less than 2000 cp. Below these viscosity values, thermal methods are not effective. Two major focus when applying non-thermal techniques are reducing the interfacial tension (IFT) and increasing the mobility ratio. Generally, non-thermal techniques require laboratory work and study for process selection and optimization (Thomas, 2008).

Miscible flooding indicates that the displacing fluid is miscible with the displaced fluid (reservoir oil). A mixing zone (transition zone) will be developed between both fluids prompting a piston-like displacement with zero IFT. For example, carbon dioxide (CO_2) miscible flooding utilizes its low minimum miscibility pressure (MMP) with most crude oils and pushes it out of the reservoir. It is widely used due to the low-cost of CO_2 gas (Thomas, 2008). Apart from increasing the oil recovery, CO_2 miscible flooding is doing a favor to our planet by disposal of a greenhouse gas (Kokal & Al-Kaabi, 2010).

Another non-thermal EOR method is chemical flooding. This technique focused on two goals which are reducing the mobility of injected water by adding polymer and to reduce the IFT by injecting surfactants or alkalis (Kokal & Al-Kaabi, 2010). Surfactant flooding is an example of chemical flooding EOR. A study conducted by Santa et al. (2011) used alkyl polyglucosides (APGs) as surfactants based on natural raw materials. In this study, it is shown that APG is able to reduce the IFT of crude/ brine system even in high salinity brines. Other than that, APG is not affected by high temperature environment. Santa et al. (2011) have proved that surfactant flooding is capable of enhancing oil recovery.

2.2 Water-Alternating-Gas (WAG) Process and Classifications

WAG process is an EOR method basically designed to inject water and gas in alternating cycles in order to increase the oil recovery. **Fig. 2** shows a schematic diagram of a typical WAG process. It is a technique to increase sweep efficiency of gas injection by using water to control the displacement mobility and stabilizing the front because gas is more effective in microscopic displacement of oil than water. WAG injection is not a new method in the industry for it has been applied since the early 1960’s on fields located mostly in Canada and yielded a significant increase in oil recovery about 5-10% (Christensen et al., 2001).

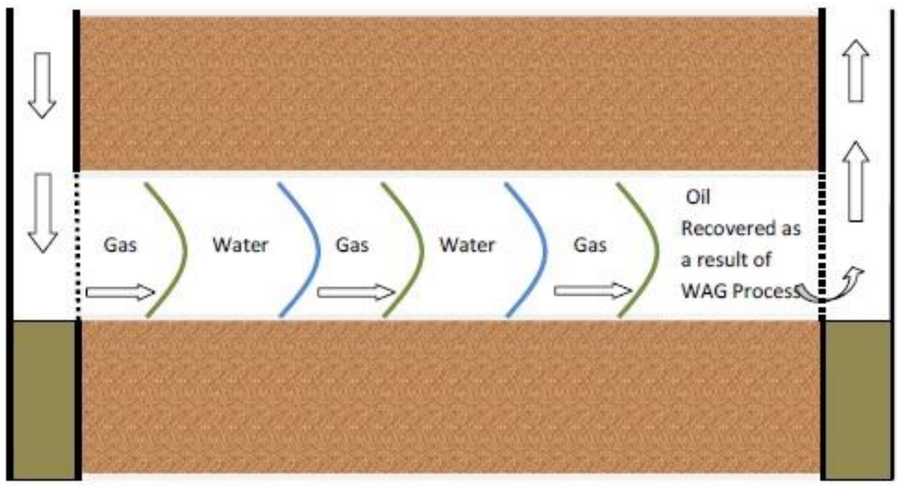


Figure 2: Water-Alternating-Gas (WAG) Schematic Diagram by Zahoor et al. (2011)

According to Christensen et al. (2001) , WAG injection process has been reported to have five classifications which are Miscible (MWAG), Immiscible (IWAG), Simultaneous (SWAG), Selective-Simultaneous (SSWAG) and Hybrid (HWAG). From a total of 59 WAG injection projects in Canada, 79% used MWAG, 18% IWAG and 3% utilized other methods. This proved that MWAG is the most widely used WAG injection technique.

In MWAG injection, miscibility is established along the gas slug as it displaces oil. Following gas injection, water is then injected to increase the volumetric sweep because the residual oil saturation will be low after the miscible front has passed (Skauge & Dale, 2007). MWAG injection resulted in decreased oil viscosity due to gas miscibility thus mobilizing the trapped oil (Zahoor et al., 2011). On the other hand, in IWAG injection process, the injected gas is not miscible with the reservoir oil and the oil is displaced while maintaining its gaseous phase, with a front between the two phases (Zahoor et al., 2011). Immiscible WAG takes place when the reservoir is below the minimum miscibility pressure (MMP). According to Christensen et al. (2001), IWAG is usually applied on reservoirs where gravity-stable gas injection cannot be applied due to limited gas resources, low formation dipping or strong heterogeneity.

Miscible WAG (MWAG) is sometimes confused with Immiscible WAG (IWAG) due to the MMP factor. According to Christensen et al. (2001), majority of the miscible projects reviewed are re-pressurized in order to increase the reservoir pressure above the fluids MMP. Due to failure in maintaining this pressure, real field cases may interchange between miscible and immiscible gas due to miscibility loss (below MMP). In certain cases Hybrid WAG (HWAG) could also take place where large volume of gas is injected, followed by a number of small volumes of water and gas.

Nangacovié (2012) mentioned that in Simultaneous WAG (SWAG) injection, water and gas are injected at the same time in the reservoir through a single injector well. When the water and gas reached the surface, they are mixed together and injected back into the reservoir thus completing a cycle. However, when the water and gas are pumped separately through a dual completion injector without any mixing of the two phases at the surface, it is called a Selective-Simultaneous WAG (SSWAG).

2.3 Mobility Ratio

According to Ahmed (2006) as mentioned by Touray (2013), the mobility of any fluid is the ratio of the effective permeability of the fluid to the fluid viscosity. This definition could be expressed as:

$$\lambda_o = \frac{k_o}{\mu_o} = \frac{kk_{ro}}{\mu_o}\ ; \quad \lambda_w = \frac{k_w}{\mu_w} = \frac{kk_{rw}}{\mu_w}$$

Where:

λ_o = mobility of oil [D/cP]

λ_w = mobility of water [D/cP]

k_o ,k_w = effective permeability to oil and water respectively [D]

k_{ro} ,k_{rw} = relative permeability to oil and water respectively [-]

Touray (2013) stated that the mobility of fluids (water and gas) injected during WAG process affects the stability of the displacement front thus enabling the volume of the reservoir to be contacted to be determined. Efficient mobility control could lead to larger reservoir pore volume being contacted during flooding. This mean more un-swept zone could be reached leading to higher recovery efficiency.

Based on the explanation and equations above, the mobility ratio could be defined as the ratio of the mobility of the injecting fluid which in this case, water and gas to the mobility of the fluid it is displacing oil.

Thomas (2008) also mentioned similar mobility definition. He stated that mobility ratio is defined as $M = \lambda_{ing} / \lambda_{ed}$, where λ_{ing} is the mobility of the displacing fluid such as water and λ_{ed} is the mobility of the displaced fluid such as oil. In the equation, lambda $\lambda = k/\mu$, where k is the effective permeability (m^2) and μ is the viscosity (Pa.s) of the fluid concerned. Based on his study, value of $M > 1$ indicate unfavorable condition due to displacing fluid flows more readily than the displaced fluid thus bypassing some of the residual oil. Therefore, mobility ratio, $M < 1$ is favorable and need to be achieved.

2.4 Pressure Transient Behavior of Injection Wells

There are two types off injection wells that are of interest in this section which are water injection well and gas injection well. Injection well is usually used to improve the recovery of oil by increasing the sweep efficiency. Injection wells are usually associated with pressure transient analysis called injection test and falloff test. According to Ahmed (2006), the time period where the reservoir boundary does not influence the pressure behavior is the transient or unsteady-state flow. This situation shows that the reservoir is infinite acting. While stating the same transient definition as Ahmed (2006), Pitzer (1964) mentioned that pressure transient tests are able to determine effective permeability, static reservoir pressure, well-bore damage and distances to boundaries or flow restrictions. Other applications of pressure transient tests are to measure reservoir pressure and temperature and obtain fluid samples for PVT analysis.

Falloff test is carry out by injecting water or gas into the injection well and then shut in the well. Pressure is then recorded when the injection is stopped. Falloff test is similar to a buildup test provided the properties of the injected fluid and reservoir fluid are the same. On the other hand, injection test has the same similarity with drawdown test in production well provided they have the same injection and reservoir fluid properties. The first step in injection test is to shut in the well in order to stabilize the pressure and later the injection is carried out at a constant rate. The bottom-hole pressure is then recorded. Banerjee et al. (1997) mentioned that difference in drawdown/ buildup test with injection/ falloff test is that the flow characteristics of the injected fluid are different from the reservoir fluids. In order to prove the similarity, multiphase reservoir flow has to be considered.

There have been many studies done for pressure transient behavior in water injection well. Levitan (2003) present a new analytical method for precise solution of the pressure transient problem. His study involved two-phase flow related with water injection/ falloff tests in appraisal of reservoir. The result is presented in a diagnostic derivative plot at mobility ratio of 0.3 and 4.0. The reservoir is homogeneous with radial flow geometry. Injection period shows that the bottom-hole pressure was affected by the water front movement. Late-time self-similar flow regime associated with constant rate injection is identified with constant derivative characterization. The value of the derivative is inversely proportional to the water mobility at residual oil saturation. The bottom-hole pressure behavior during a falloff period reveals the mobility distribution since the early stage of the falloff. At early time, the pressure behavior reflects the fluid mobility in the water zone and later time it shows the mobility in the oil zone ahead of the water front.

Another study conducted by Banerjee et al. (1997) on injection/ falloff testing in heterogeneous reservoir. They have derived an approximate analytical solution for water injection in a radially heterogeneous reservoir. Based on the theory developed, injection test shows the pressure derivative data reflect permeability of both at the flood front and in the un-flooded region. This concluded that in heterogeneous reservoir, it is possible to detect permeability changes ahead of the flood front. Apart from that, they have analyzed falloff test by using conventional single-phase method. They considered permeability-mobility product in place of permeability to estimate the mechanical skin factors.

There are not many study conducted on pressure transient behavior of a gas injection well. Most of the research conducted is related to water injection well due to its vast application in the industry for decades. However study involve the pressure transient behavior of both water and gas or water-alternating-gas (WAG) injection has been done and will be highlighted later in this paper.

2.5 Skin Factor Effect on Pressure Behavior and its Derivative

Skin is a formation damage formed in the wellbore during the production period of a reservoir. It is divided into two types which are negative and positive skin. The former skin type is preferred in any production wells for its higher permeability value. Skin factor is a value that is usually included in equations involving flow rate in a reservoir. Other than that, skin factor could affect the pressure behavior of a certain reservoir. In this section the effect of skin factor on pressure behavior only in injection well will be discussed.

According to Ali Asfak Hussain (2012), falloff pressure analysis could produce more accurate result than injection pressure analysis for the estimation of skin, permeability and mobility for flooded and un-flooded zones due to stationary fluid banks. When relating it to pressure behavior, presence of skin factor when compared to zero skin yield no effect on the derivative curve ΔP'. He concluded that only the pressure difference ΔP as a function of Δt are different for different skin effects.

Yeh and Agarwal (1989) determined the skin effect on pressure behavior in an injection well. They simulated the real skin effect by assigning an absolute permeability in the near wellbore region. Then the skin factor is calculated based on Hawkin's skin equation. Yeh and Agarwal (1989) mentioned a similar response where for both negative and positive skin cases, the pressure response ΔP as a function of Δt were different for each case. However, the derivative curves were identical for different skin factors (positive and negative) except at very early time.

Another study conducted by Habte and Onur (2013) focus on method for simulating pressure transient behavior of oil/-water flow associated with water injection/ falloff test. In their study, skin effect is incorporated to show the pressure behavior during the injection and falloff period. In injection period, the result showed that for positive skin case, the pressure drop increases at early time followed by a reduction as the flood front approaches the skin radius resulting in negative pressure derivative due to unfavorable mobility ratio. However, for negative skin case, the pressure will keep increasing and have positive derivative (favorable mobility ratio) throughout the test. On the other hand for falloff period, effect of skin on pressure derivative is negligible as mentioned by Yeh and Agarwal (1989) except at early time.

CHAPTER 3

METHODOLOGY

3.1 ECLIPSE 100

This project will use software application called Eclipse 100 which is delivered by Schlumberger in order to simulate the dynamic properties of a reservoir. This software will be used to generate a simulation model to demonstrate the IWAG injection and observe the pressure transient behavior. Input data (see **Table A1**) in Appendix 1 for the simulation in ECLIPSE 100 is obtained from Habte et al. (2015) study on pressure transient behavior of IWAG injection well with and without hysteresis and capillary pressure effect.

3.2 Pressure Transient Analysis

Result obtained from ECLIPSE 100 software will be interpreted and analyzed. The pressure transient behavior (pressure profile and pressure derivative profile) of IWAG injection with the presence of skin will be observed. Mobility profile is generated from pressure derivative of falloff test data in order to calculate the flood front location.

Once the literature study is completed, the objective of this project needs to be achieved by following the procedure below:

1. Simulation model is to be generated using ECLIPSE 100 software.
2. Simulation is carried out for IWAG injection well with and without skin effect under favorable and unfavorable mobility condition.
3. Pressure change (ΔP) and pressure derivative ($\Delta P'$) response are calculated and analyzed for injection and falloff period under different skin cases.
4. Mobility profile is generated, studied and compared using the pressure derivative plot for both skin cases.
5. Flood front location is estimated from mobility profile generated earlier.

3.3 Gantt-Chart

Final Year Project

Title: Pressure Transient Behavior of Immiscible Water-Alternating-Gas (IWAG) Injection Well with and without Skin Effect

Student: Abu Bakar bin Mustafa Bamadhaj (14732)

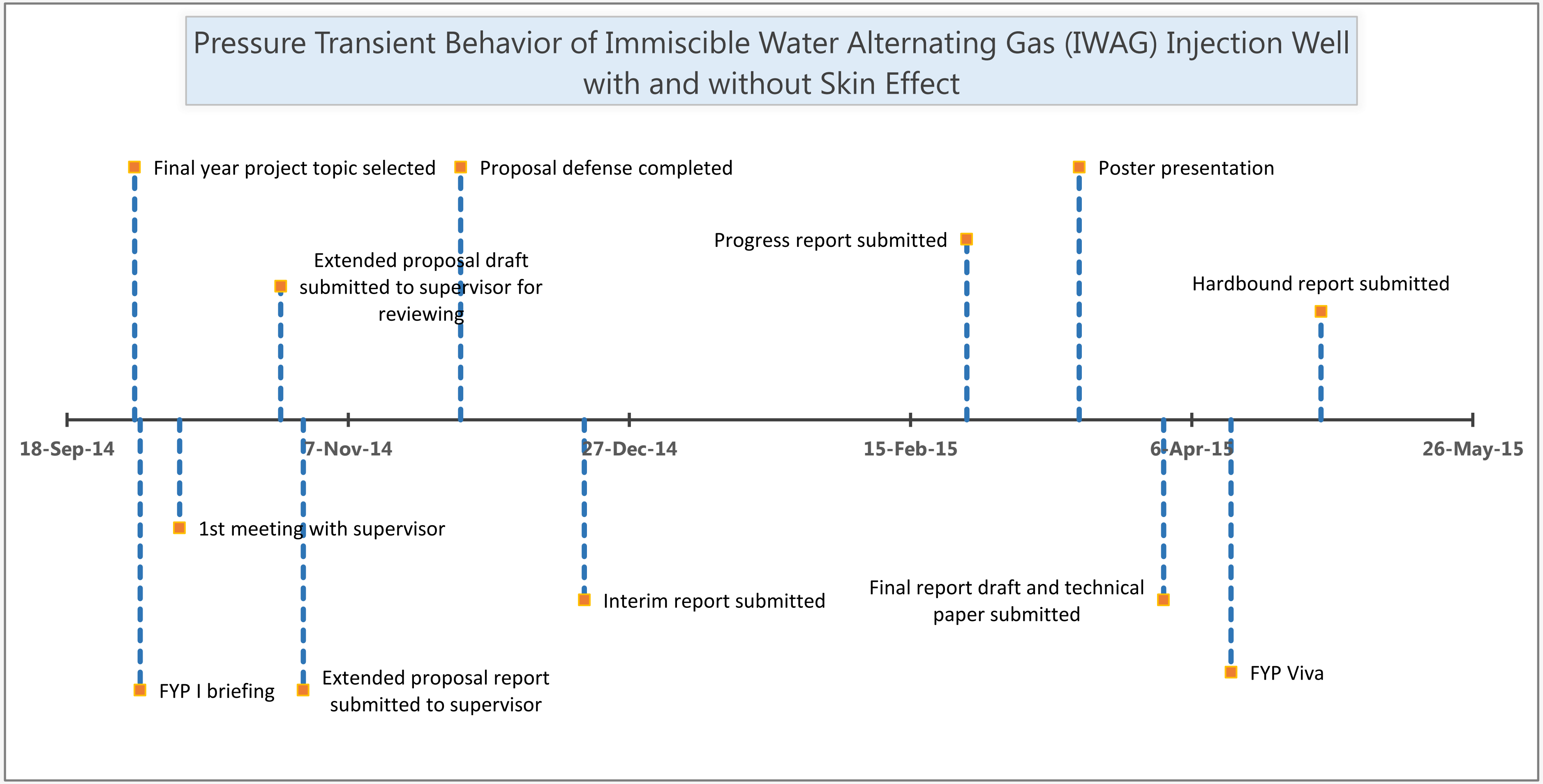
Supervisor: Ms. Azeb Demisi Habte

Objectives		2014														2015														
		Sep		Oct			Nov				Dec					Jan			Feb				Mac					Apr		
A.	**Deliverables**	1	2	3	4	5	6	7	8	9	10	11	12	13	14	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
1	**Report Writing**																													
1.1	Proposal Defense						■	■	■	■																				
1.2	Interim Report									■	■	■	■																	
1.3	Progress Report																	■	■	■	■									
1.4	Draft Report																						■	■	■	■				
1.5	Dissertation																							■	■	■	■			
1.6	Technical Paper																									■	■			
2	**Data Gathering**																													
2.1	Technical Paper References	■	■	■	■	■																								
2.2	Data File Creation	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■									
3	**Simulation**																													
3.1	Simulation trial	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■									
3.2	Simulation of different cases																					■								
4	**Data Analysis**																													
4.1	Different cases analysis																					■	■	■	■					
4.2	Interpretation																						■	■	■	■				
B.	**Presentation**																													
1	Proposal Defense										■																			
2	Pre-SEEDX																									■				
3	Oral Presentation																												■	
C.	**Report Submission**																													
1	Proposal Defense									■																				
2	Interim Report													■																
3	Progress Report																					■								
4	Draft Report																										■			
5	Dissertation (Soft Bound)																											■		
6	Technical Paper																											■		
7	Dissertation (Hard Bound)																													■

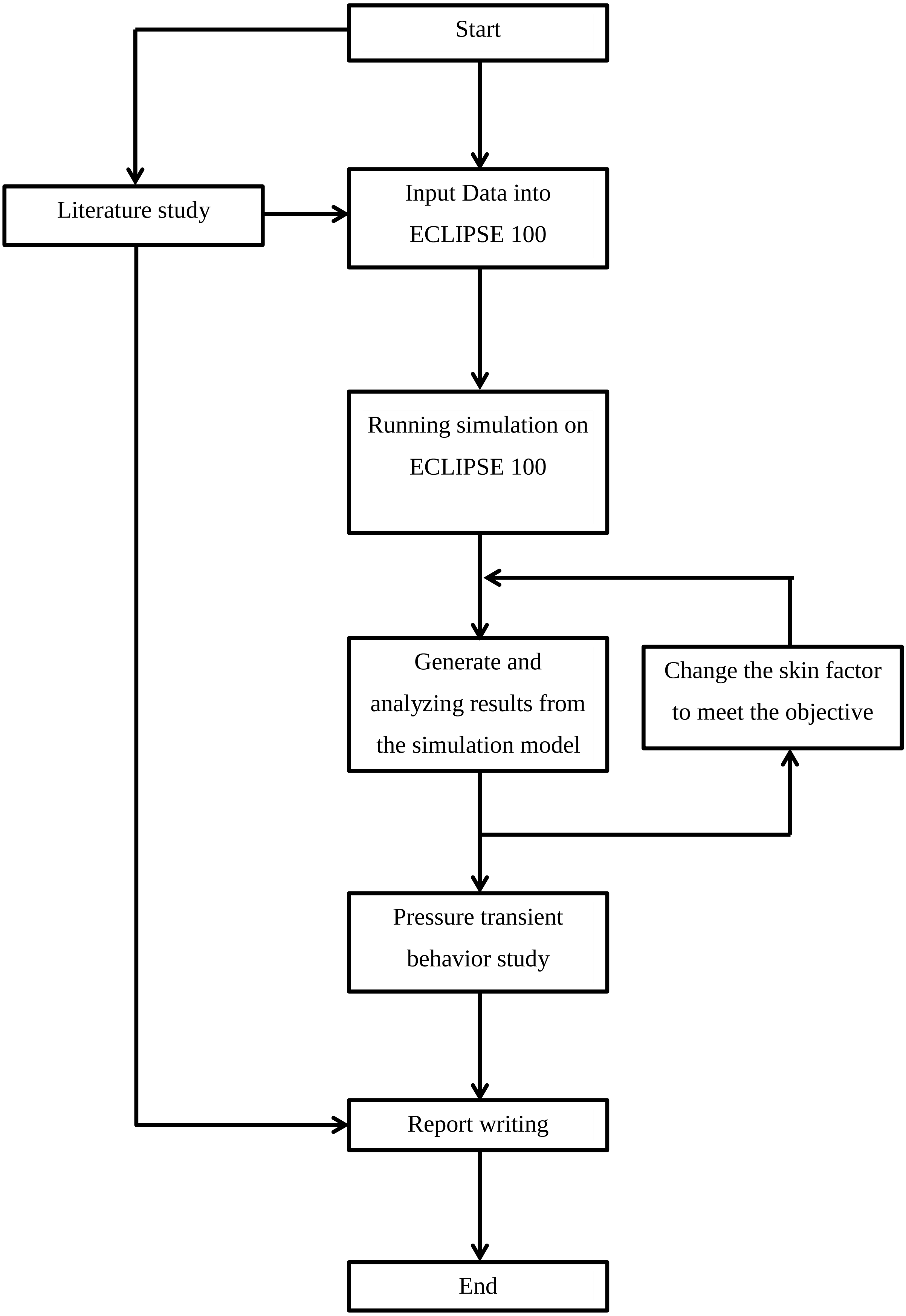
Completed

Projected

3.4 Key Milestones



3.5 Flow Chart



CHAPTER 4

RESULTS AND DISCUSSION

4.1 Numerical Simulation Model

A one-dimensional radial composite model is developed in order to carry out the simulation studies. The synthetic reservoir description is based on actual producing field. Equal sized small grids are placed in the r direction near the well bore up to the outer radius of the wellbore. 1 injection well was placed at the center, penetrating the whole layer. Gravity and wellbore storage effects are neglected and the model is generated using ECLIPSE 100. Hysteresis effect is included due to the cyclic process during WAG injection which results in the presence of both imbibition and drainage (Habte et al., 2015). Therefore, treatment of three-phase relative permeability hysteresis for gas is essential. The hysteresis effect is activated using WAGHYSTER keyword in the PROP section. The external reservoir radius is 10000 ft. in order to simulate an infinite acting reservoir. Absolute permeability and porosity is constant throughout the reservoir since it is homogenous. Capillary pressure was assumed to be zero. Initial reservoir pressure is 3200 psia. The depth to the top of the reservoir is approximately 1500 ft. subsea. Since the scope of interest is pressure transient study, only injection well is available with no production well. The injection well is located in the cell (1, 1, 1). The reservoir is fully penetrated with perforation thickness equal to the reservoir thickness of 56 ft. There is no aquifer at the bottom of the oil zone and the brine in the reservoir is connate water. **Fig. 3** shows the radial 1D model used for numerical simulations.

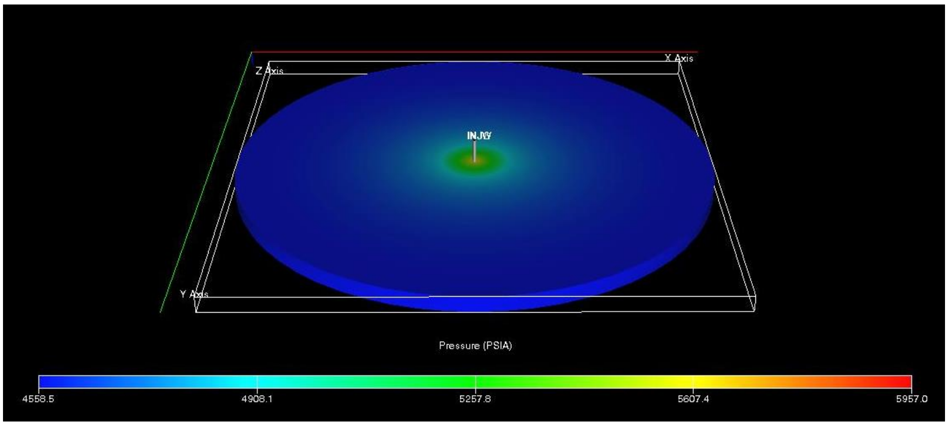


Figure 3: 3D Radial Base Case Model from ECLIPSE 100

Water and gas are injected alternately and simulated in the software using the keyword WCONINJE following the schedule shown in **Table 1**.

Table 1: WAG Schedule

Time period, days	Test
0-10	1st Water injection
10-30	1st Water falloff
30-40	1st Gas injection
40-60	1st Gas falloff
60-70	2nd Water injection
70-90	2nd Water falloff
90-100	2nd Gas injection
100-120	2nd Gas falloff

Two cycles are simulated in this study which made up a total of 120 days for both injection and falloff period. The reservoir is pressurized initially during the injection period with a constant water and gas injection rate (1:1 WAG ratio) of 4500 stb/day and 4432 scf/day respectively. **Fig. 4** shows the well bottomhole pressure for alternate water and gas injection. **Fig. 4** proved the validation of input data file (Appendix 2) for the base case scenario without skin effect for unfavorable condition (M = 2.0).

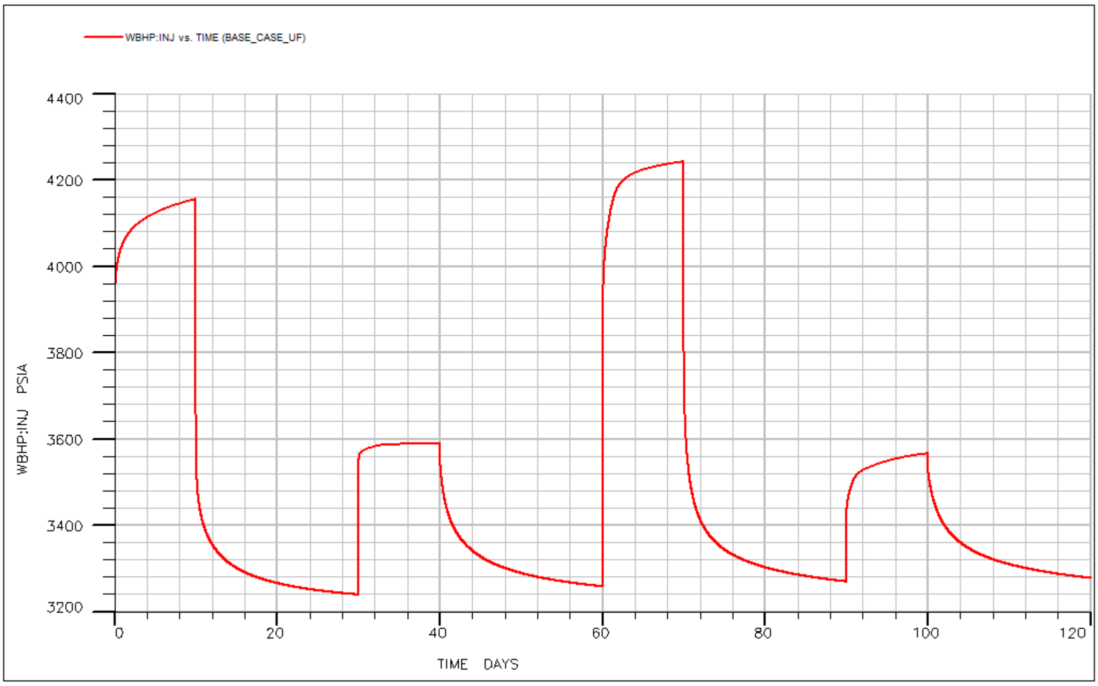


Figure 4: Well Bottomhole Pressure for IWAG Injection

Input data for the simulation was mainly taken from Habte et al. (2015) study as mentioned in methodology. **Table A1** in Appendix 1 shows the reservoir rock and fluid properties data used for simulation. Two phase relative permeability data is obtained from experiment conducted by Oak et al. (1990) on Berea sandstone.

4.2 Result Analysis

Pressure and pressure derivative profile is generated for each case for both unfavorable and favorable condition with and without skin effect. Base case model for both unfavorable and favorable cases are also plotted in order to analyze the change in the pressure derivative plot when comparing with different skin values. The pressure derivative is calculated using Eq. 1.

$$\Delta P' = t_i \left(\frac{d\Delta p}{dt}\right)_{t_i} = t_i \left[\frac{\left(\frac{\Delta P_i - \Delta P_{i-1}}{t_i - t_{i-1}}\right)(t_{i+1} - t_i) + \left(\frac{\Delta P_{i+1} - \Delta P_i}{t_{i+1} - t_i}\right)(t_i - t_{i-1})}{(t_i - t_{i-1}) + (t_{i+1} - t_i)}\right] \quad \text{...........................(1)}$$

Pressure-derivative during the injection period is calculated using normal elapsed time (Δt). For pressure-derivative calculation during the falloff period, Yeh and Agarwal (1989) equivalent time (denoted as Δt_e) is used to reduce the effect of injection time. However, elapsed time (Δt) is used when plotting the pressure-derivative of falloff period (Habte et al., 2015). The pressure change and time difference for both injection and falloff period is described in Eq. 2.

$$\Delta P' = \frac{d\Delta p}{d\ln(T)} \text{ ....(2)}$$

where

$\Delta p = p_{wf} - p_i$ and $T = \Delta t$, for injection period

$\Delta p = p_{wf}(\Delta t = 0) - p_{ws}$ and $T = \Delta t_e$, for falloff period

The graph for water injection, water falloff, gas injection and gas falloff period are plotted individually on a log-log plane for each case in order to analyze the effect of skin on the pressure change and pressure derivative. The most encountered situation which is the unfavorable condition (M > 1) will be studied first followed by the favorable condition (M < 1) which is highly unlikely to occur in real reservoir condition.

The skin effect is simulated by creating zone of altered permeability using logarithmic gridding method in ECLIPSE 100 as shown in **Fig. 5**.

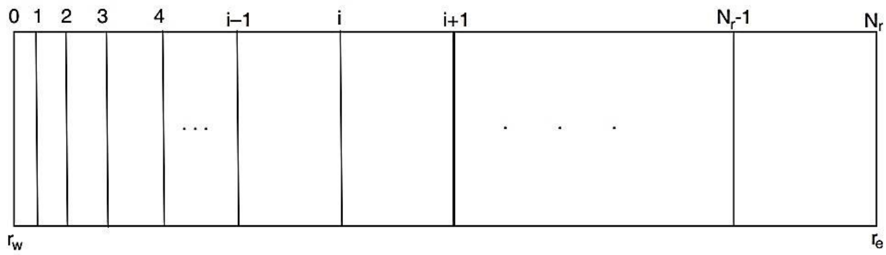


Figure 5: Point-Centered Logarithmic Gridding (Habte & Onur, 2013)

The skin zone permeabilities are calculated using the Hawkin's formula shown in Eq. 3. Positive and negative skin values, which are 4 and -2 respectively and skin radius of 1.52 ft are assumed (see **Table A1**). The values of respective skin zone permeability are 53 md for positive skin and 534 md for negative skin. These permeabilities values are incorporated inside the data file for simulation.

$$S = \left(\frac{k}{k_s} - 1\right)\ln\frac{r_s}{r_w} \text{ ....(3)}$$

The average mobility profile behind the flood front can is calculated using the fall-off pressure derivative response. Consequently, the location of the flood front is estimated directly by choosing the radial distance corresponding to a minimum mobility value. The average mobility (λ_t, cp^{-1}) against radial distance (r, ft) is plotted on a log-log scale. Eq. 5 and Eq. 6 are used to calculate the value of average mobility and radial distance travelled respectively.

$$\lambda_t = k\left(\frac{k_{rw}}{\mu_w} + \frac{k_{ro}}{\mu_o}\right) \quad (4)$$

$$\lambda_t = 70.6\,\frac{q_w B_w}{h\Delta P'} \quad (5)$$

$$r = 0.024\sqrt{\frac{\lambda_t \Delta t_e}{\phi c_t}} \quad (6)$$

4.3 Pressure and Pressure Derivative Responses (Favorable Condition)

4.3.1 1st Water Injection and Falloff Periods (M = 0.3)

Figure 6 shows the pressure and pressure derivative for the 1st water injection period. Similar to Habte et al. (2015) findings, value of the pressure derivative at initial injection period is lower than that of the pressure derivative at late times due to the higher mobility of oil than water for zero skin case. However, presence of positive skin (4) resulted in higher derivative thus higher pressure change values at early time due to zone of altered permeability (53md) near the wellbore region which dominate the effect of mobility. As time increased, steep drop is observed on the positive skin case derivative curves as the transient moves out of the zone of reduced permeability into higher permeability zone (200md) which reflect the end-point mobility of water. Negative skin (-2) case derivative curve has lower values at early time due to dominant effect of skin (534md) thus reduced pressure drop. As it entered the zone of lower permeability (200md), the derivative increased, reflecting the mobility of water zone.

Figure 7 shows the pressure change and its derivative for the 1st water falloff period. Zero skin case shows similar result as Habte et al. (2015) study which stated that the early time region reflects the end-point mobility of water. However, pressure derivative values at early time show positive skin with higher derivative values compared to negative skin case due to reduced permeability around the wellbore. At late time region, the effect of skin on the derivative curve is insignificant.

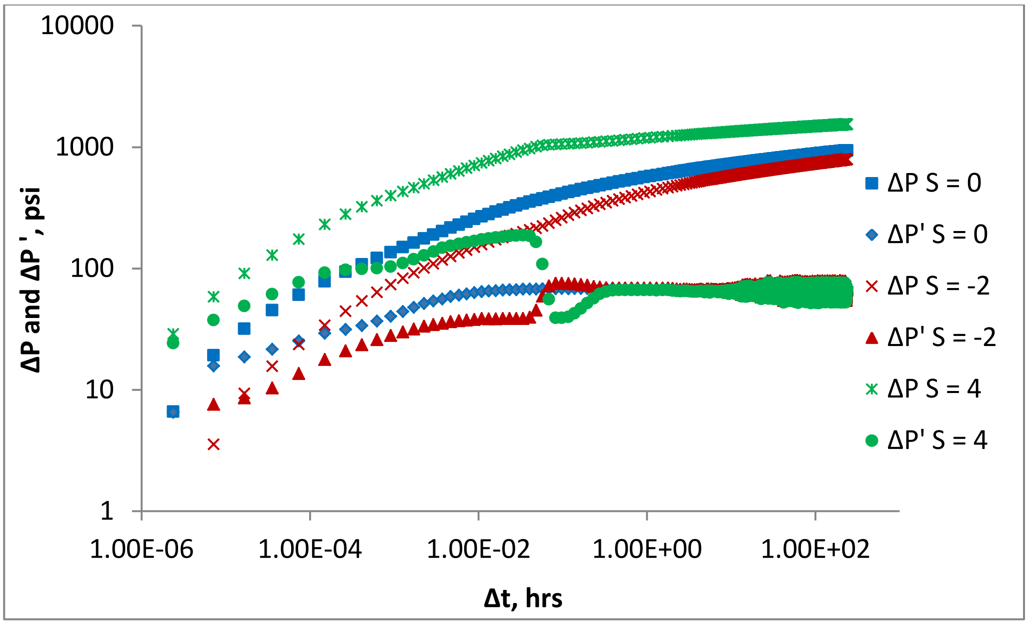


Figure 6: Pressure change and pressure derivative responses for 1st water injection period with and without skin factor (M = 0.3)

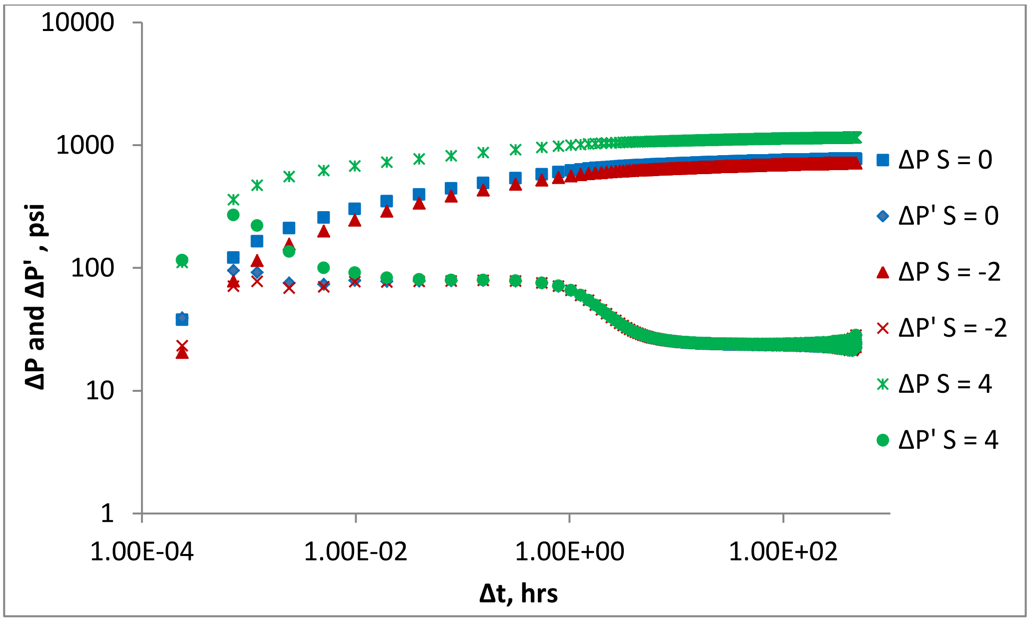


Figure 7: Pressure change and pressure derivative responses for 1st water falloff period with and without skin factor (M = 0.3)

Based on **Fig. 8** the estimated flood front location is at 53.65 ft with average mobility value of 73.81 cp^{-1}. High oil mobility enable water to create a sharp oil sweep zone, resulting in the average mobility value increased with a steep slope after the flood front location and later reached a stabilized oil mobility region.

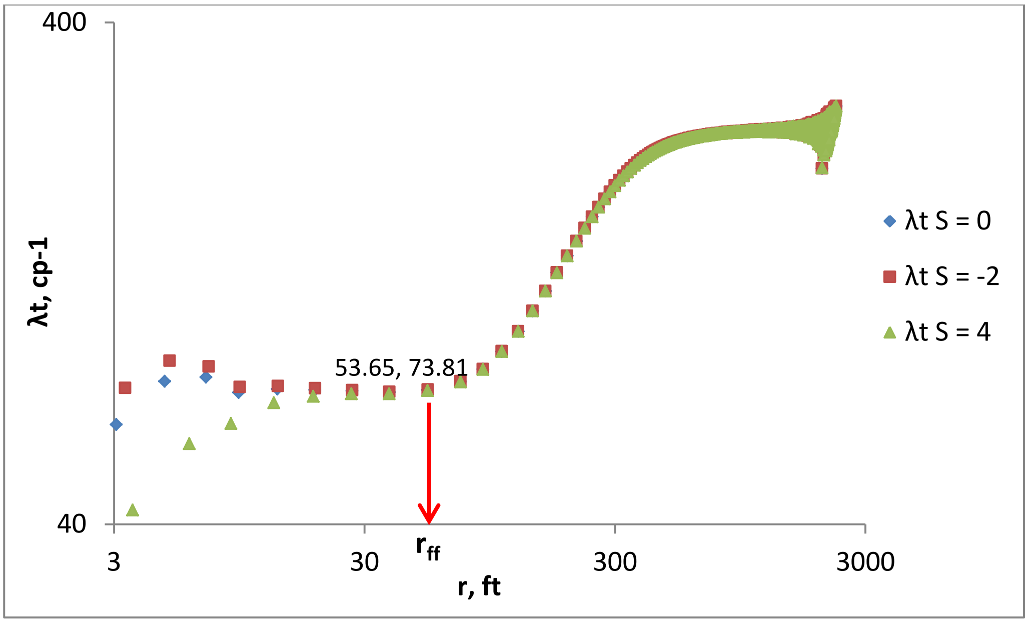


Figure 8: Average mobility profile from the pressure derivative response of the 1st water falloff test with and without skin factor (M = 0.3)

4.3.2 1st Gas Injection and Falloff Periods (M = 0.3)

Figure 9 shows the pressure and pressure derivative of the 1st gas injection period which is dominated by the effect of skin. Positive skin case reduced the gas mobility at early time thus resulting in higher pressure change and pressure derivative. As the pressure transient moves out of the skin zone, gas injectivity is increased but as it reached the low water mobility zone, high gas compressibility caused the pressure change to drop drastically thus resulting in negative derivative values. In negative skin case, lower but increasing pressure drop is observed at early time maybe due to high mobility gas flowing through the skin boundary. High permeability (534md) region near the wellbore caused the gas flooded region to be felt longer, thus the horizontal derivative line, before descending into negative derivative values as it entered a lower permeability (200md) region. High compressibility and mobility of gas cause an increase in gas injectivity. Therefore, the pressure change starts to decrease after some time which results in negative pressure derivative values for negative skin and base case.

Figure 10 shows the pressure and pressure derivative curve of the 1st gas falloff period. The falloff pressure derivative curve at early time reflects the gas zone property for all cases. It is then followed by a long transition period due to mixing of gas with water (lower mobility) before entering the stabilized oil zone. No significant change on the derivative curve at late time for presence of skin.

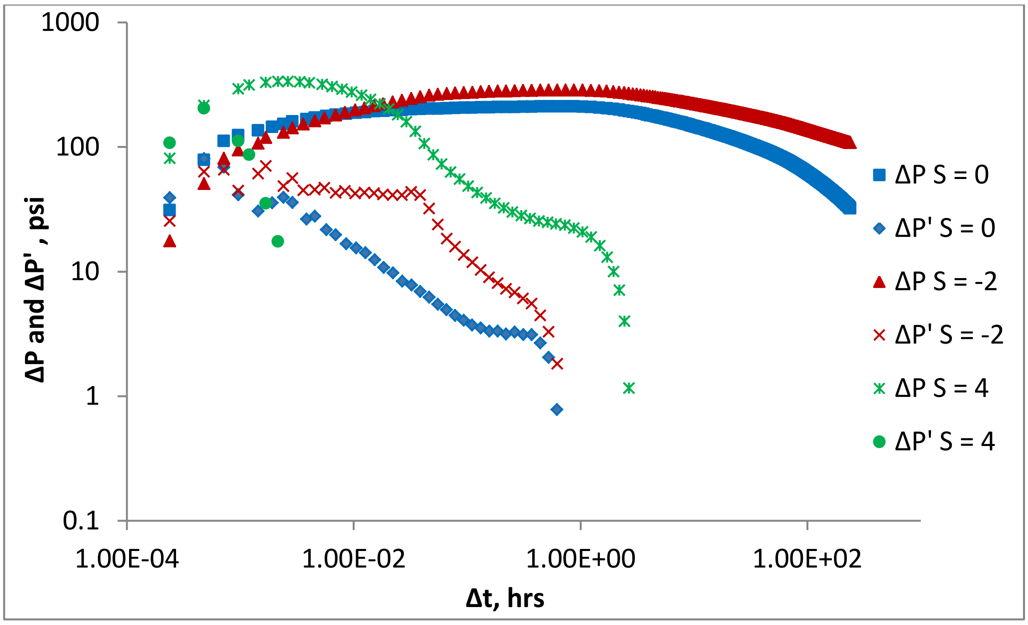


Figure 9: Pressure change and pressure derivative responses for 1st gas injection period with and without skin factor (M = 0.3)

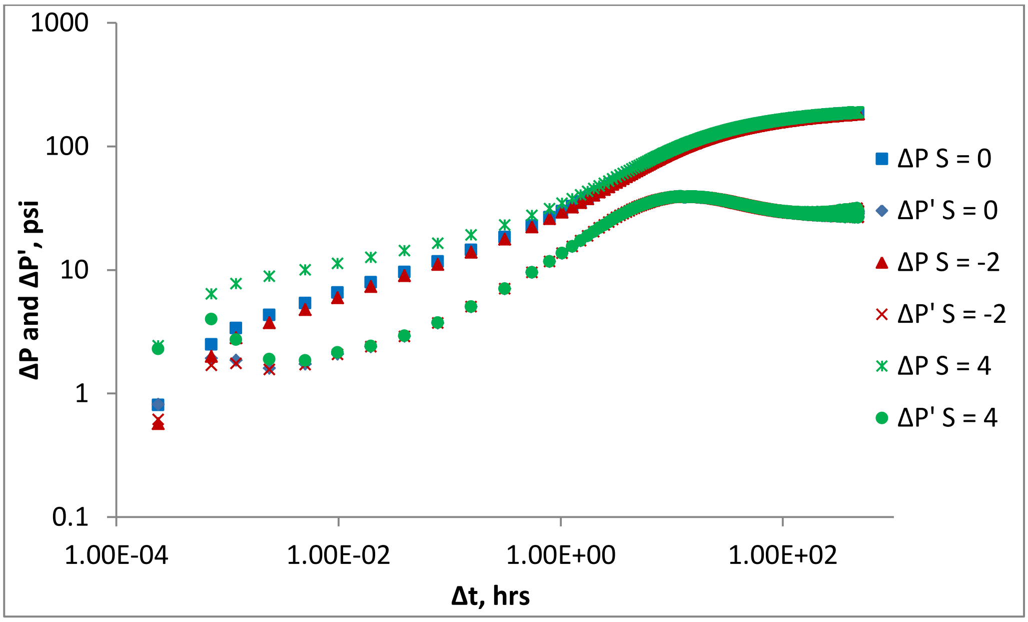


Figure 10: Pressure change and pressure derivative responses for 1st gas falloff period with and without skin factor (M = 0.3)

Based on **Fig. 11**, the estimated flood front location is at 302.33 ft with average mobility value of 203.48 cp^{-1}. The average mobility increased after the flood front location due to higher oil mobility in favorable condition.

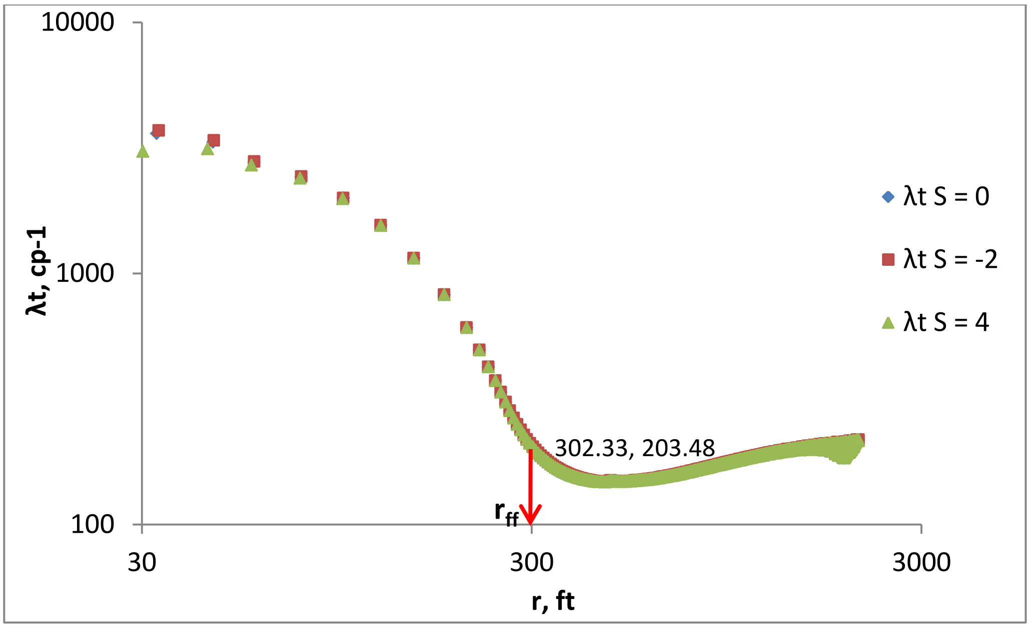


Figure 11: Average mobility profile from the pressure derivative response of the 1st gas falloff test with and without skin factor (M = 0.3)

4.3.3 2nd Water Injection and Falloff Periods (M = 0.3)

Figure 12 shows the pressure and pressure derivative curve of the 2nd water injection period. Pressure and pressure derivative curves for all cases are having positive values and showing similar trend as the 1st water injection (**Fig. 6**) period at early time. However, derivative of positive skin case is having a steep reduction at time about 1.87 minutes due to the presence of trapped gas (high mobility) caused by the 1st gas injection which resulted in reduced water injectivity. The derivative curves of positive skin increased back as the transient moves through the 1st water injection region. At late time region, derivative for all skin cases drop through a steep transition period before arriving at a region reflecting the property of the oil zone.

Figure 13 shows the pressure and pressure derivative response of the 2nd water falloff period which has the same trend as in the 1st water falloff period (**Fig. 7**). However, in this case, the derivative curve is having a longer horizontal line that reflected the end-point mobility of water before entering the oil zone.

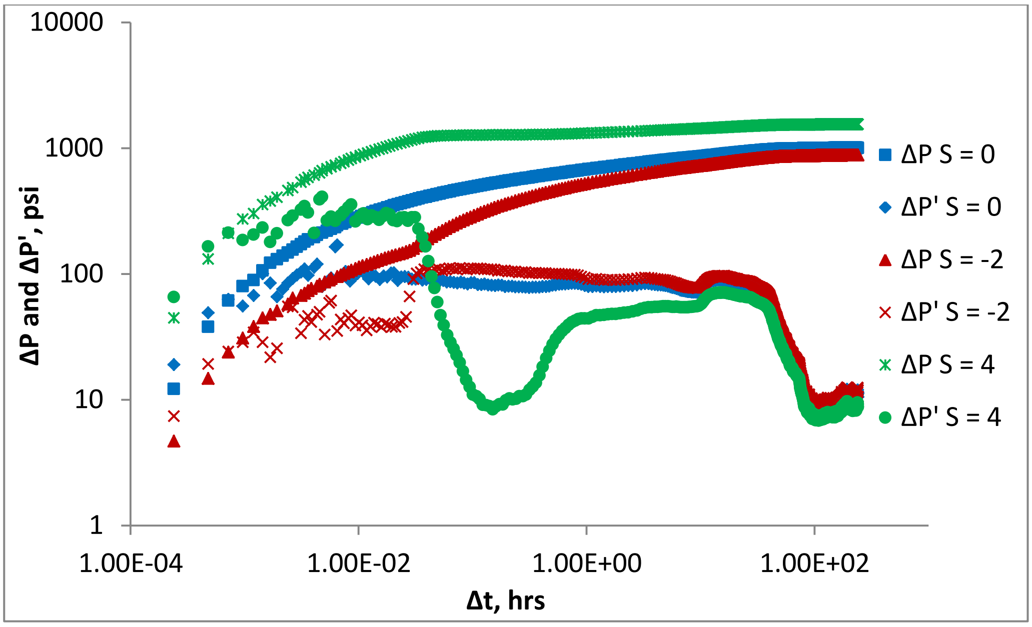


Figure 12: Pressure change and pressure derivative responses for 2nd water injection period with and without skin factor (M = 0.3)

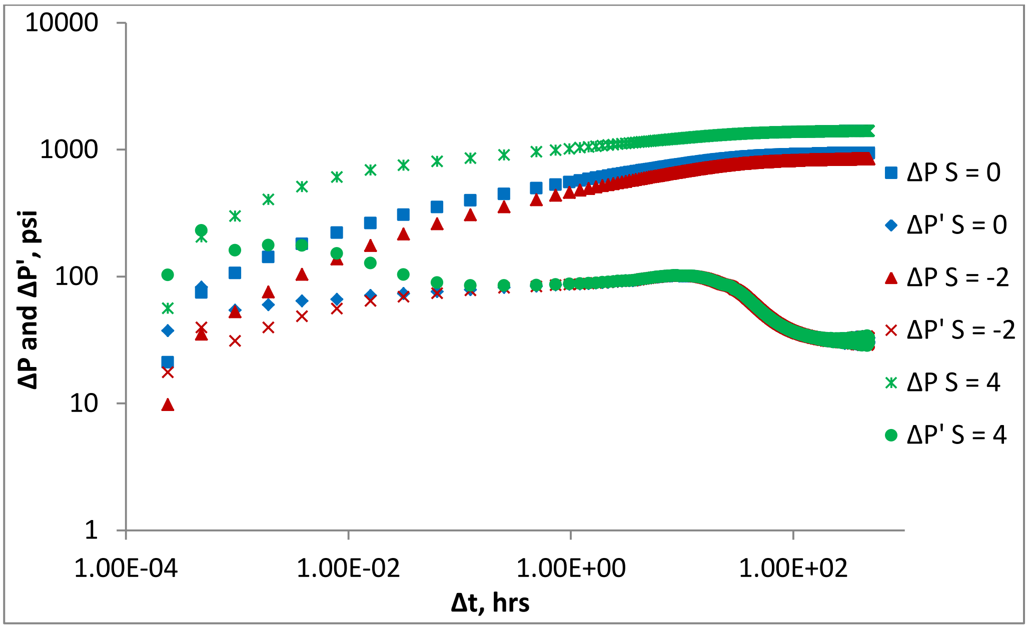


Figure 13: Pressure change and pressure derivative responses for 2nd water falloff period with and without skin factor (M = 0.3)

Based on **Fig. 14**, the flood front location is estimated to be at 360.7 ft with average mobility value of 61.8 cp^{-1}. There is a clear distinction of mobility near the wellbore region for each skin cases. Positive skin case shows the lowest average mobility and negative skin shows the highest average mobility due to zone of altered permeabilities near the wellbore region.

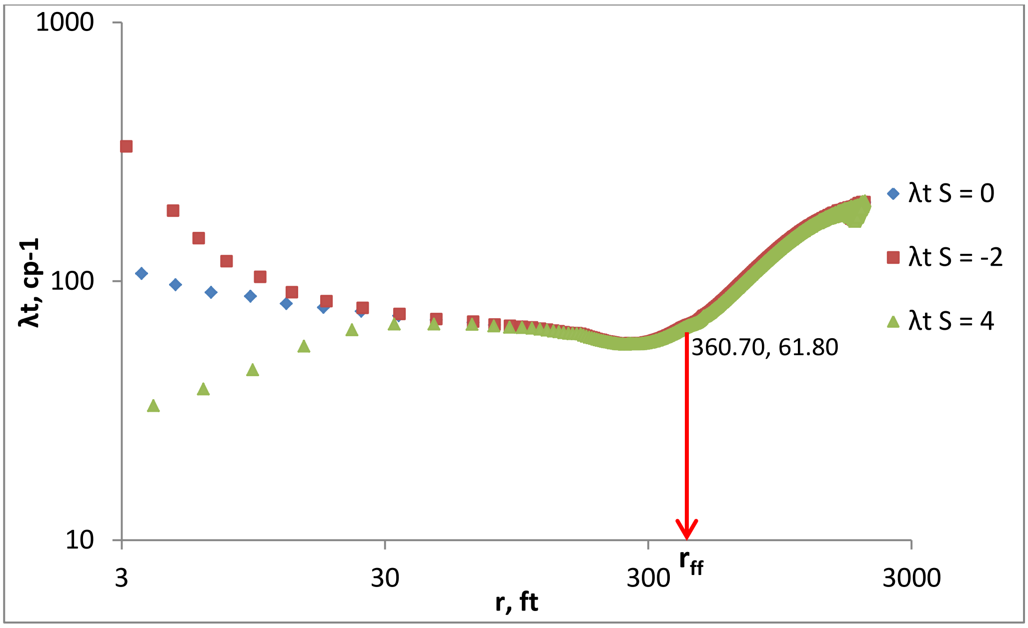


Figure 14: Average mobility profile from the pressure derivative response of the 2nd water falloff test with and without skin factor (M = 0.3)

4.3.4 2nd Gas Injection and Falloff Periods (M = 0.3)

Figure 15 shows the pressure and pressure derivative curves for 2nd gas injection period in favorable condition for all cases. In this period, pressure drop for positive skin case shows similar trend only at early time as the 1st gas injection (**Fig. 9**). As time increased, the pressure change does not drop to negative but instead it drops below the negative and zero skin case proceeding with a horizontal line. This behavior is observed due to presence of water flooded region (low mobility) in front of the injected gas. The pressure change drop of positive skin at early time resulted in negative derivative values maybe due to the movement of gas, a high compressible fluid through a reduced permeability zone which resulted in a gas zone buildup at the positive skin boundary. The pressure drop for all skin cases begin to increase up to 20.7 hours before decreasing. This pressure change behavior is reflected in the derivative curve where at intermediate time in increases up to 20.7 hours which it gives negative pressure derivative values.

Figure 16 shows the pressure and pressure derivative curve for 2nd gas falloff period with and without skin factor. The result shows identical trend as in the 1st gas falloff period (**Fig. 10**). Estimation of the flood front location from **Fig. 17** gives a value of 473.28 ft with average mobility of 173.48 cp^{-1}.

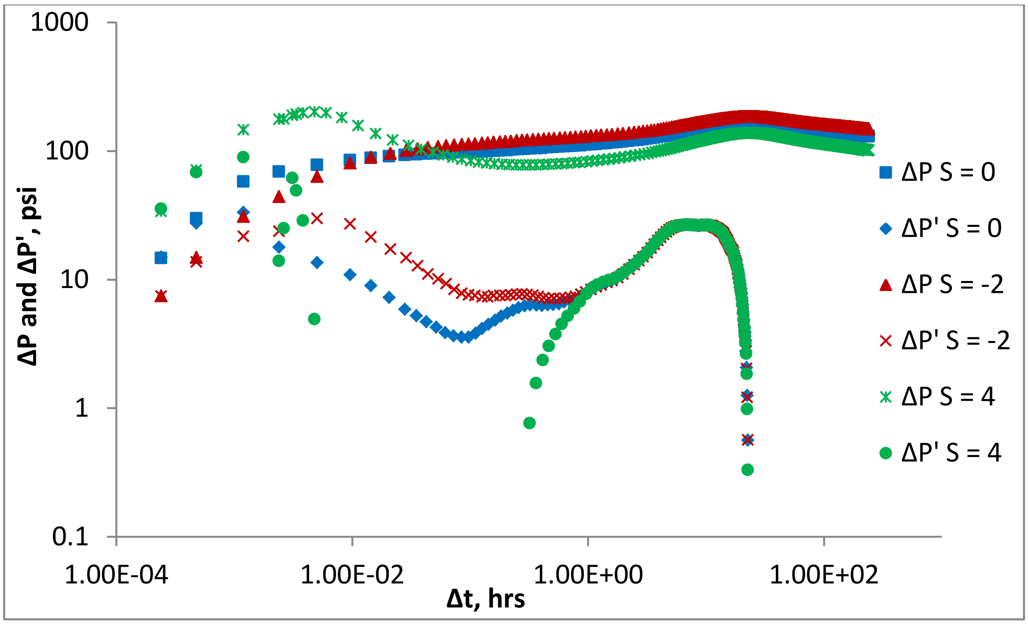


Figure 15: Pressure change and pressure derivative responses for 2nd gas injection period with and without skin factor (M = 0.3)

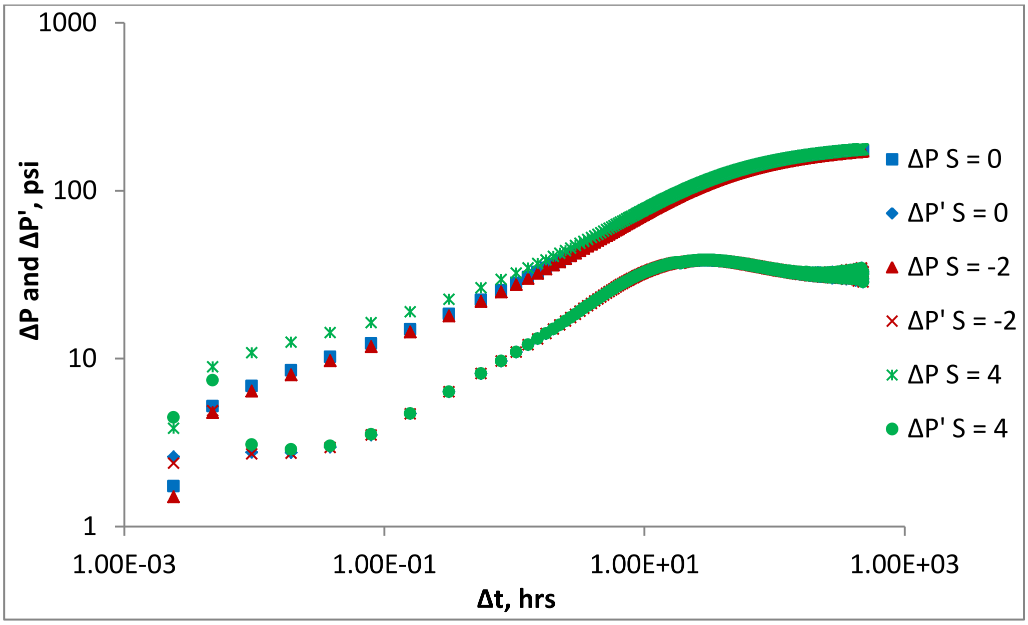


Figure 16: Pressure change and pressure derivative responses for 2nd gas falloff period with and without skin factor (M = 0.3)

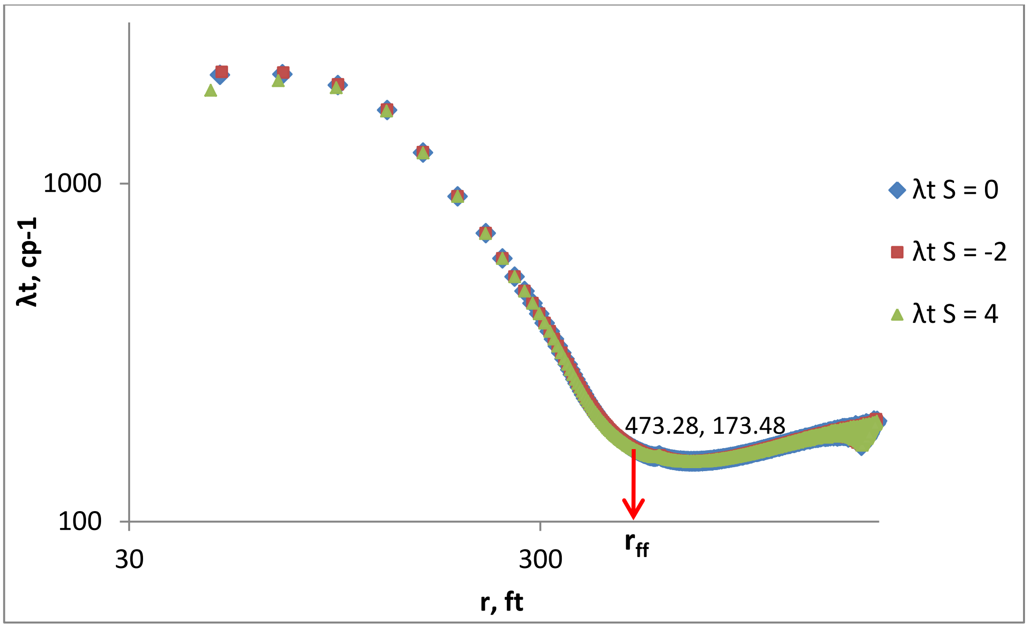


Figure 17: Average mobility profile from the pressure derivative response of the 2nd gas falloff test with and without skin factor (M = 0.3)

4.4 Pressure and Pressure Derivative Responses (Unfavorable Condition)

4.4.1 1st Water Injection and Falloff Periods (M = 2.0)

Figure 18 shows the pressure and pressure derivative curves of the 1st water injection for unfavorable condition with and without the presence of skin. Pressure derivative trend at early time reflects the effect of skin zone near the wellbore region where positive skin case has the highest derivative values due to lower mobility region compared to other skin cases with higher mobility value. The derivative at early time also reflects the mobility of the oil zone due to large amount of oil present near the wellbore region. As time increases, the pressure derivative of positive skin case starts to descend into the water zone but only for a short period of time. It is then further drop to negative derivative values due to unfavorable mobility condition where water has high mobility and also due to flow of water from low to high permeability region. The derivative of positive skin is later increased to positive values which reflect the property of the water zone. On the other hand, negative skin case at the middle time region has higher derivative values compare to base case.

Pressure and pressure derivative for the 1st water falloff period is presented in **Fig. 19** for unfavorable condition. The effect of skin is only visible at early time region for the pressure derivative curve as mentioned in previous study (Yeh & Agarwal, 1989). However, at late time region, the pressure derivative curve still exhibit the end-point mobility of water compared to 1st water falloff period for favorable condition (**Fig. 7**). This behavior is observed due to higher water mobility which cause the water flooded region to be felt longer.

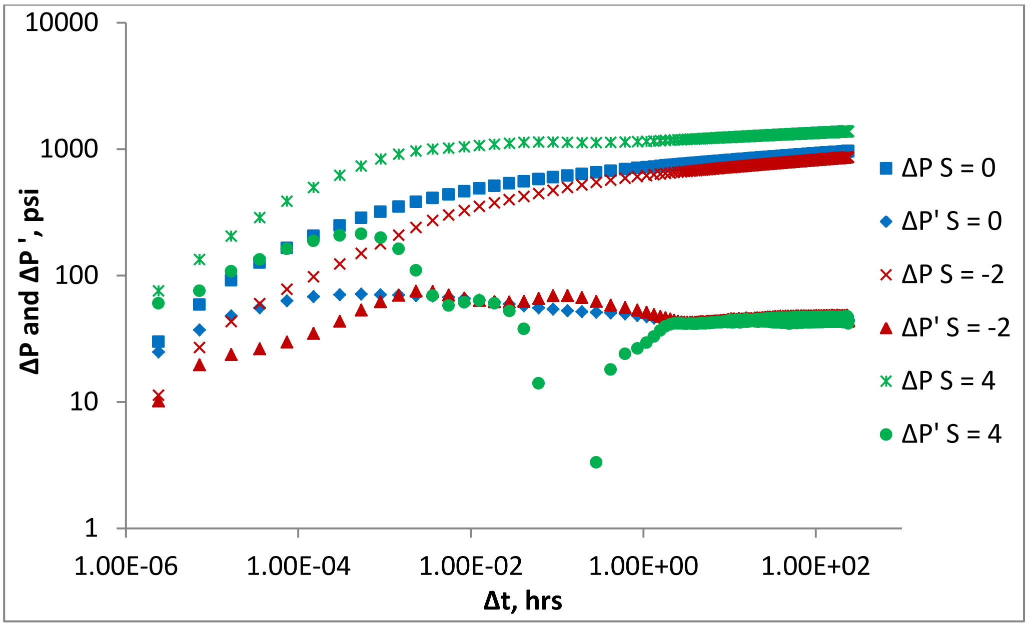


Figure 18: Pressure change and pressure derivative responses for 1st water injection period with and without skin factor (M = 2.0)

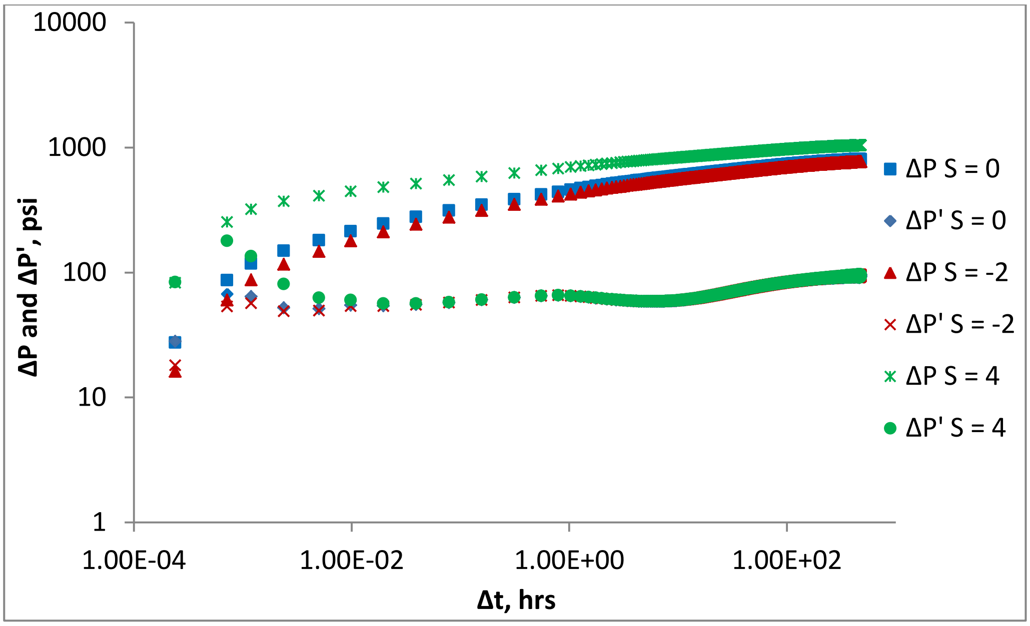


Figure 19: Pressure change and pressure derivative responses for 1st water falloff period with and without skin factor (M = 2.0)

Figure 20 shows the average mobility profile generated from the 1st water falloff pressure derivative data for unfavorable condition. Based on **Fig. 20**, the estimated flood front location is at 93.34 ft with average mobility value of 88.62 cp^{-1}. **Fig. 20** also shows that after the flood front location, the average mobility value start to increase up to approximately 275 ft before experiencing a gradual mobility drop due to low oil mobility in the stabilized zone.

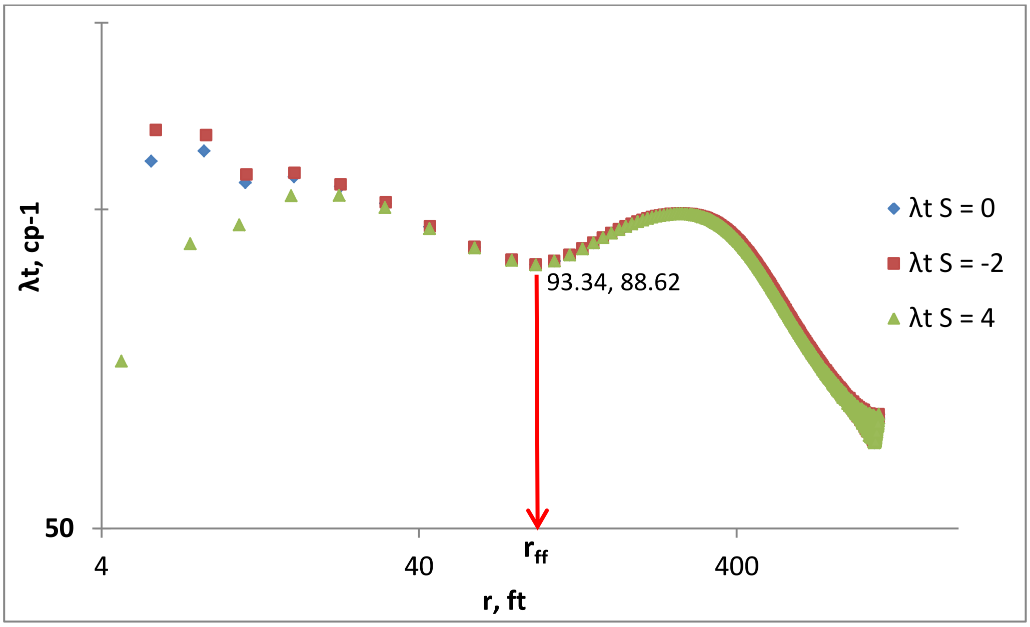


Figure 20: Average mobility profile from the pressure derivative response of the 1st water falloff test with and without skin factor (M = 2.0)

4.4.2 1st Gas Injection and Falloff Periods (M = 2.0)

Figure 21 displays the result of the 1st gas injection period for unfavorable mobility condition. Shortly after injection begins, the pressure change of positive skin case begins to decline thus the pressure derivative becomes negative and cannot be shown on a log-log plot. However, due to high water mobility, effect of high gas compressibility is not shown here thus the pressure change is increased. It takes about two log-log cycles (approximately from 7 seconds to 14 minutes) before the pressure derivative values begin to increase. On the other hand, negative skin case and base case behave similarly to the 1st gas injection period for favorable condition (**Fig. 9**) except at late time where the pressure derivative values are positive due to high water mobility.

Figure 22 shows the pressure and pressure derivative response of the 1st gas falloff period for unfavorable condition. Except at early time, effect of skin on pressure derivative cure is insignificant for all skin cases. The falloff derivative curve at late time shows similar trend as the 1st gas falloff period of favorable condition (**Fig. 10**) but with a positive slope.

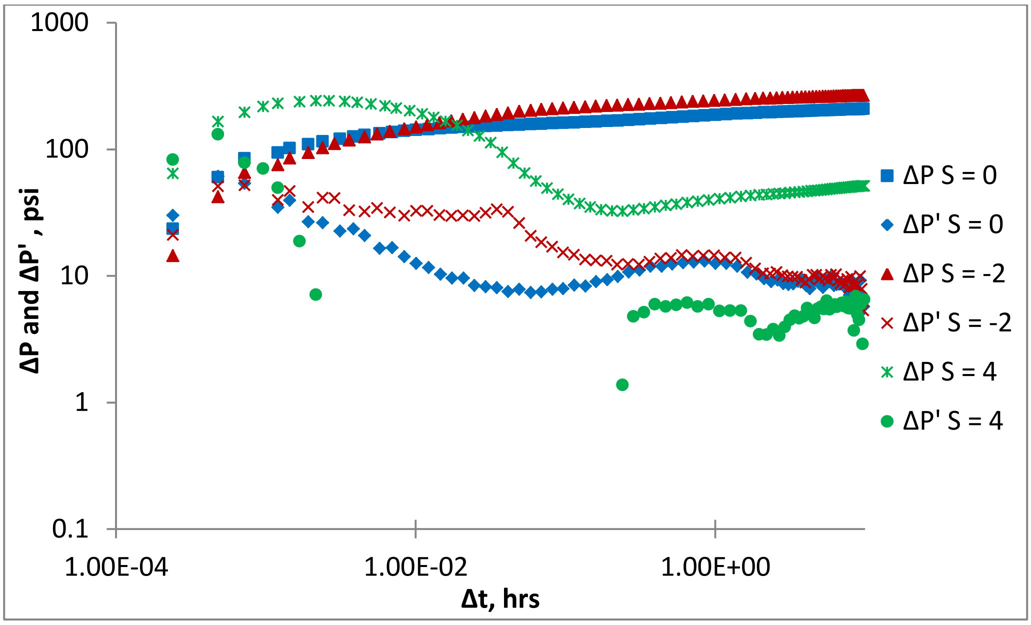


Figure 21: Pressure change and pressure derivative responses for 1st gas injection period with and without skin factor (M = 2.0)

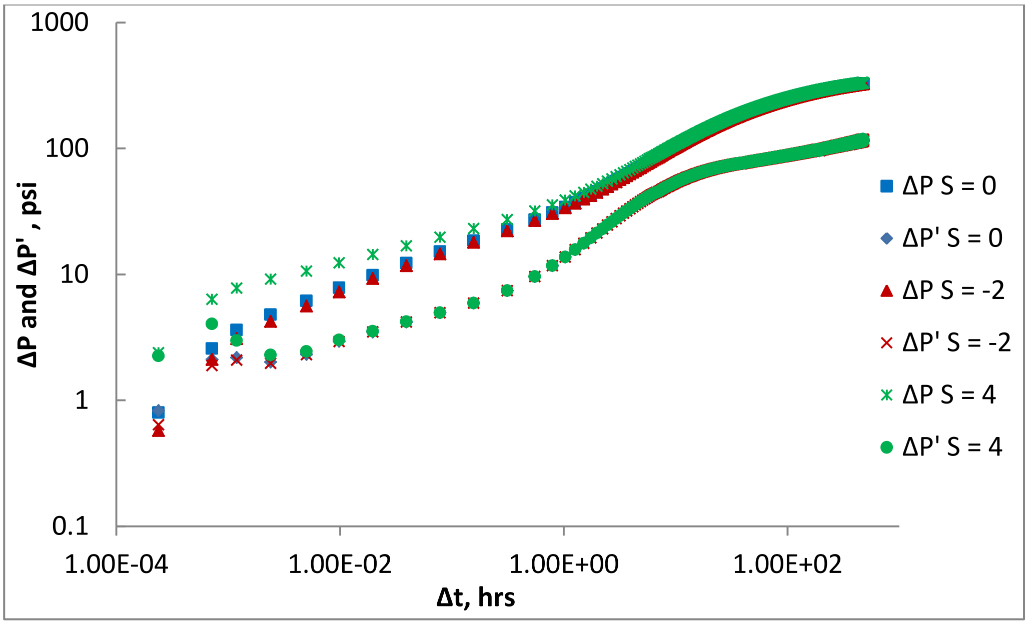


Figure 22: Pressure change and pressure derivative responses for 1st gas falloff period with and without skin factor (M = 2.0)

Based on **Fig. 23**, the flood front location is estimated to be at 289.27 ft with average mobility value of 175.03 cp^{-1}.

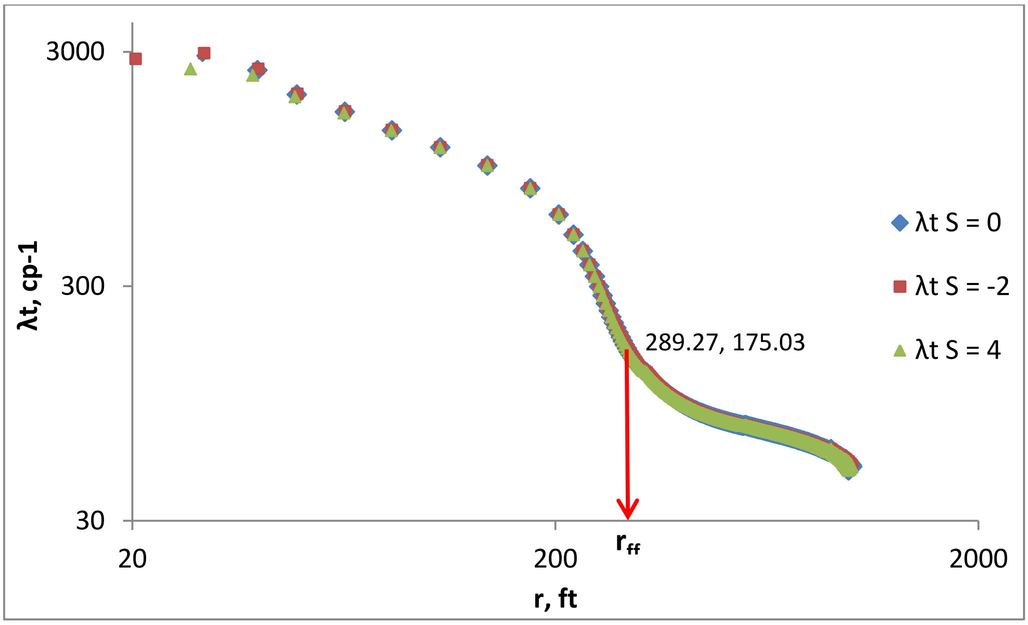


Figure 23: Average mobility profile from the pressure derivative response of the 1st gas falloff test with and without skin factor (M = 2.0)

4.4.3 2nd Water Injection and Falloff Periods (M = 2.0)

Figure 24 and **25** shows the pressure and pressure derivative response of the 2nd water injection and falloff period for unfavorable condition respectively with and without skin effect. The pressure and pressure derivative behavior of the 2nd water injection (**Fig. 24**) is very similar to the 2nd water injection for favorable condition (**Fig. 12**)**.** However, the reduction of positive skin case pressure derivative is not as steep as in **Fig.12** due to higher water mobility in unfavorable condition. **Fig. 25** shows the pressure and pressure derivative curve for 2nd water falloff period for unfavorable condition. The pressure and pressure derivative shows similar trend as in the 1st water falloff period (**Fig. 19**) except at early time where positive skin shows higher derivative values for a longer period of time compared to the 1st water falloff period. The effect of skin is again insignificant at the late time region.

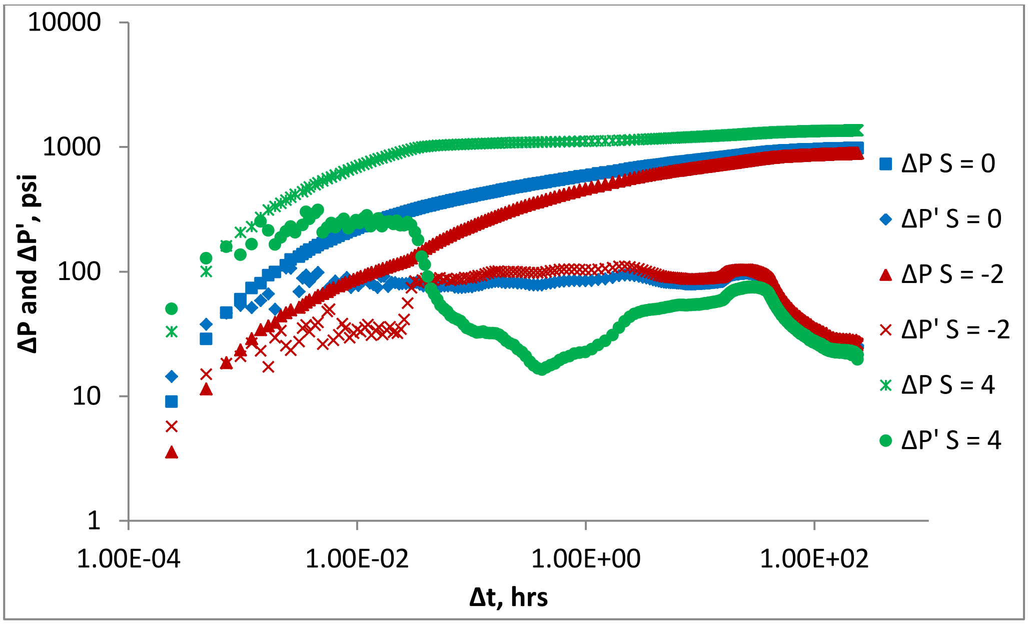


Figure 24: Pressure change and pressure derivative responses for 2nd water injection period with and without skin factor (M = 2.0)

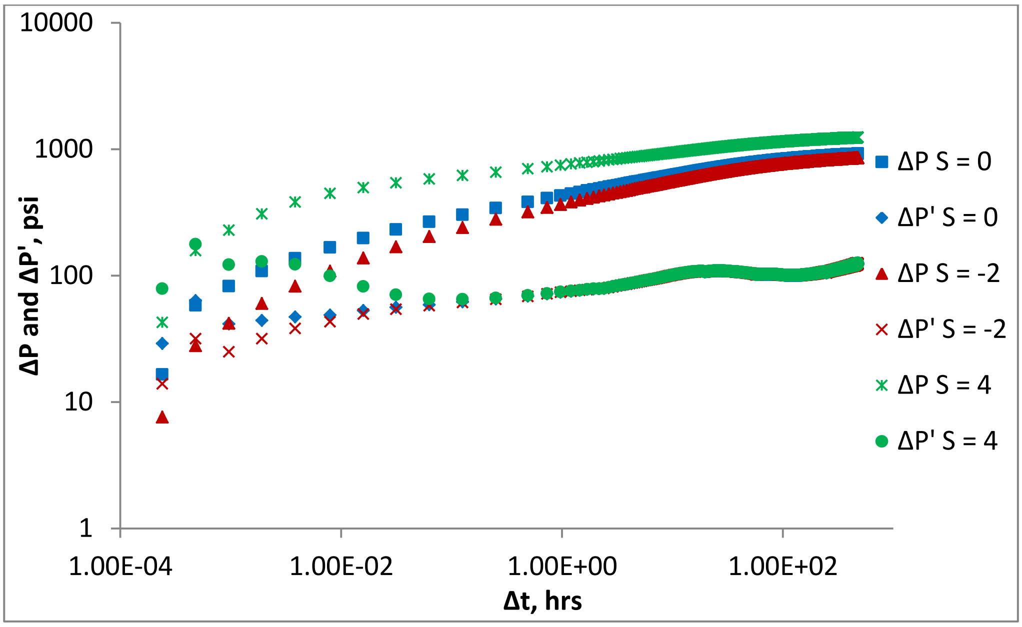


Figure 25: Pressure change and pressure derivative responses for 2nd water falloff period with and without skin factor (M = 2.0)

Figure 26 shows the average mobility profile generated from the 2nd water falloff derivative. Based on **Fig. 26**, the estimated flood front location is at 321.73 ft with average mobility value of 53.80 cp^{-1}.

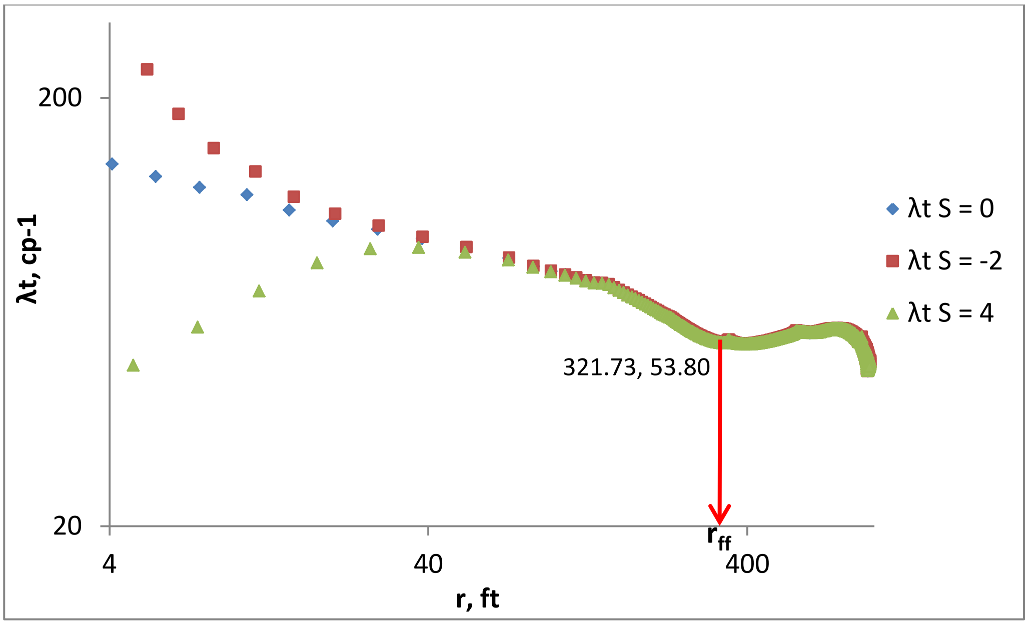


Figure 26: Average mobility profile from the pressure derivative response of the 2nd water falloff test with and without skin factor (M = 2.0)

4.4.4 2nd Gas Injection and Falloff Periods (M = 2.0)

Figure 27 shows the pressure and pressure derivative response of the 2nd gas injection period for unfavorable condition. The plot trend is similar as the 2nd gas injection period for favorable condition (**Fig. 15**) except at late time due to high water mobility causing the pressure derivative to show positive values. Positive skin case shows reduced pressure change at early time compared to negative skin and base case which result in negative pressure derivative values. It takes approximately 2 log-log cycle (9 seconds to 11 minutes) in order for the wellbore pressure to increase and show a positive derivative values. Negative skin case show a longer transition period compared to base case due to zone of increased permeability before entering the zero skin zone.

Figure 28 shows the 2nd gas falloff pressure and pressure response for unfavorable condition. Presence of skin does not have any significant effect on the pressure derivative curves except at really early time due to high gas mobility.

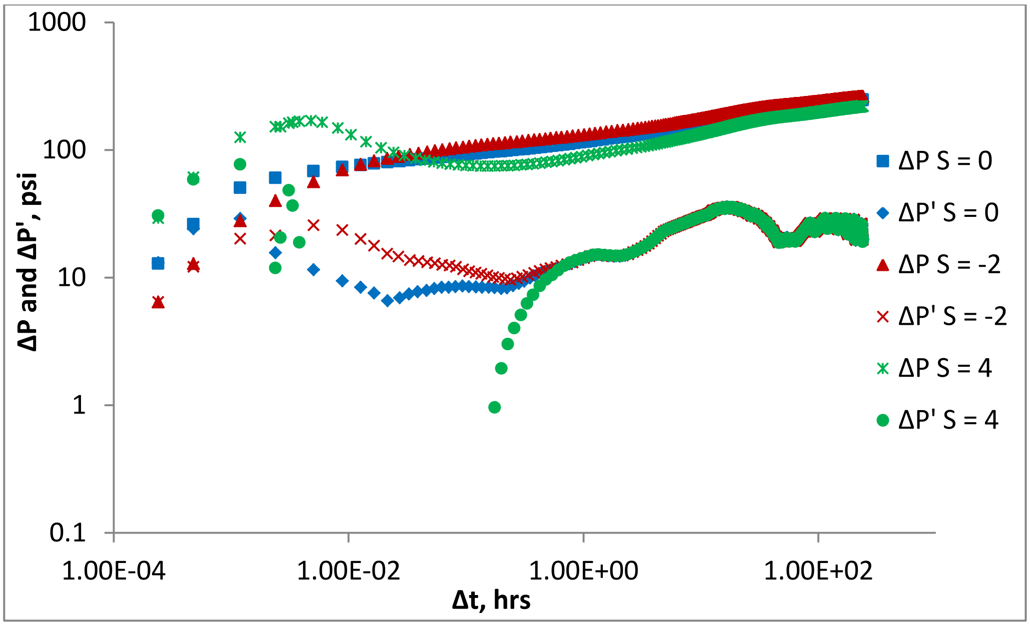


Figure 27: Pressure change and pressure derivative responses for 2nd gas injection period with and without skin factor (M = 2.0)

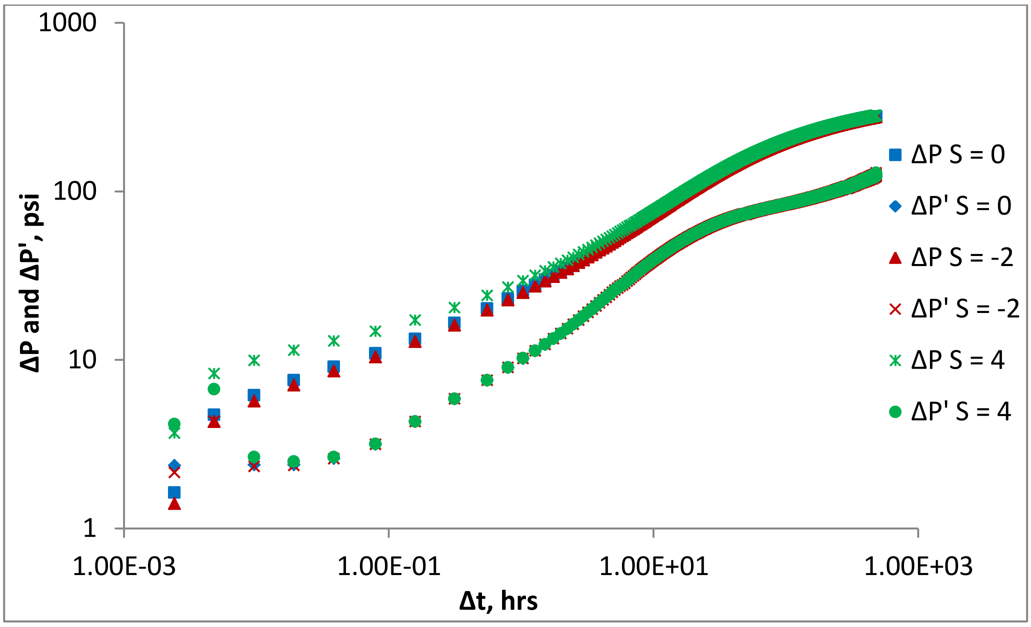


Figure 28: Pressure change and pressure derivative responses for 2nd gas falloff period with and without skin factor (M = 2.0)

Based on **Fig. 29**, the estimated flood front location is at 408.18 ft with average mobility value of 164 cp^{-1}.

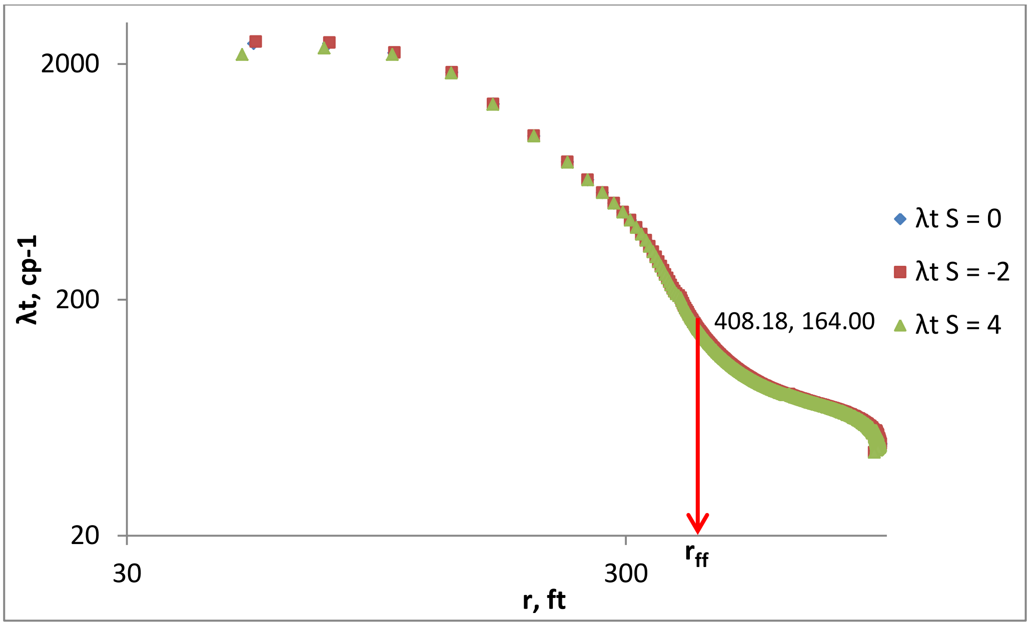


Figure 29: Average mobility profile from the pressure derivative response of the 2nd gas falloff test with and without skin factor (M = 2.0)

Based on **Table 2,** favorable condition shows further flood front location and higher average mobility value compared to unfavorable condition due to higher oil mobility.

Table 2: Comparison of average mobility and flood front location value for favorable and unfavorable mobility condition

Mobility Condition	Favorable Condition (M = 0.3)		Unfavorable condition (M = 2.0)	
Pressure Falloff Test	Average Mobility, λ_t (cp^{-1})	Flood front, r (ft)	Average Mobility, λ_t (cp^{-1})	Flood front, r (ft)
1st Water Falloff	73.81	53.65	88.62	93.34
1st Gas Falloff	203.48	302.22	175.03	289.27
2nd Water Falloff	61.80	360.70	53.80	321.73
2nd Gas Falloff	173.48	473.28	164.00	408.18

CHAPTER 5

CONCLUSION AND RECOMMENDATION

5.1 Conclusion

Pressure transient behavior of immiscible water alternating gas (IWAG) injection with and without skin effect is studied. Based on the result obtained, it could be generalized that presence of skin does not have any significant effect on the transient behavior of the pressure falloff tests except at early time. However, the pressure falloff data is useful when generating the mobility profile in order to estimate flood front location.

On the other hand, presence of skin has a highly significant effect on the pressure injection test. In the 1st water injection of favorable condition, pressure derivative of positive skin case shows higher derivative values at early time region whereas negative skin case displays lower derivative values as expected. This behavior is cause by zone of altered permeability near the wellbore region. For unfavorable mobility condition, derivative at the middle time region drop to negative values due to higher water mobility and flow of water from low to high permeability region.

1st gas injection of unfavorable condition show positive pressure derivative values at late time region due to high water mobility thus, there is no effect of high gas compressibility observed here. Pressure change of positive skin case in unfavorable condition does not drop to negative values compared to favorable condition due to higher water mobility in unfavorable condition.

Positive skin case shows similar behavior in 2nd water injection period for both favorable and unfavorable mobility condition where derivative of positive skin case at the middle time region drop due to presence of trapped gas inside the reduced permeability zone caused by the 1st gas injection which results in reduced water injectivity.

2^{nd} gas injection in both favorable and unfavorable condition shows the similar trend. Pressure derivative of positive skin case reflect the property of the gas zone at really early time and immediately drop to negative derivative values which is not visible on the log-log plot. This negative derivative values are caused by drop in pressure change of the positive skin case. Negative skin case has the highest derivative values at early time and immediately followed by a transition period into the oil zone.

Flood front radius is estimated by observing the change on the average mobility profile generated from pressure falloff test data. For favorable condition, average mobility values are showing an increasing trend after the flood front location due to higher oil mobility compared to water. However for unfavorable condition, the mobility values reduced drastically after the flood front location due to lower oil mobility. Positive skin shows lower mobility value near the wellbore region compared to negative skin and base case. However, this behavior can only be clearly observed for water falloff period. It can be concluded that the presence of skin affect the average mobility of water near the wellbore region. Mobility during the gas falloff period does not show any significant change near the wellbore region due to high gas compressibility.

5.2 Recommendation

Behavior of positive and negative skin case during the gas injection period are successfully observed and explained in detail. However, further justification is needed in order to explain the reason behind such behavior. Besides that, the mobility value for both favorable and unfavorable condition should be further reduced ($M < 1$) and increased ($M > 1$) respectively in order to improve the result accuracy.

REFERENCES

Ahmed, T. (2006). *Reservoir engineering handbook*: Gulf Professional Publishing.

Ali Asfak Hussain, H. (2012). *Pressure Transient Analysis in Injection Wells.* Universiti Teknologi PETRONAS.

Banerjee, R., Reynolds, A., & Thompson, L. (1997). *Injection/falloff testing in heterogeneous reservoirs.* Paper presented at the SPE annual technical conference.

Butler, R. (1985). A new approach to the modelling of steam-assisted gravity drainage. *Journal of Canadian Petroleum Technology, 24*(03).

Christensen, J. R., Stenby, E. H., & Skauge, A. (2001). Review of WAG field experience. *SPE Reservoir Evaluation & Engineering, 4*(02), 97-106.

Habte, A. D., & Onur, M. (2013). Laplace-Transform Finite-Difference and Quasistationary Solution Method for Water-Injection/Falloff Tests. *SPE Journal*(Preprint).

Habte, A. D., Onur, M., & Saaid, I. M. (2015). Pressure transient behavior of immiscible water alternating gas (IWAG) injection well with and without relative permeability hysteresis and capillary pressure effects. *Journal of Petroleum Science and Engineering, 127*, 169-178.

Kokal, S., & Al-Kaabi, A. (2010). Enhanced oil recovery: challenges & opportunities. *World Petroleum Council: Official Publication*.

Levitan, M. M. (2003). Application of water injection/falloff tests for reservoir appraisal: New analytical solution method for two-phase variable rate problems. *SPE Journal, 8*(04), 341-349.

Nangacovié, H. L. M. (2012). Application of WAG and SWAG injection Techniques in Norne E-Segment.

Oak, M., Baker, L., & Thomas, D. (1990). Three-phase relative permeability of Berea sandstone. *Journal of Petroleum Technology, 42*(8), 1054-1061.

Pitzer, S. (1964). Uses of transient pressure tests. *Drilling and Production Practice*.

Santa, M., Alvarez-Jürgenson, G., Busch, S., Birnbrich, P., Spindler, C., & Brodt, G. (2011). *Sustainable surfactants in enhanced oil recovery.* Paper presented at the SPE Enhanced Oil Recovery Conference.

Skauge, A., & Dale, E. I. (2007). *Progress in immiscible WAG modelling.* Paper presented at the SPE/EAGE Reservoir Characterization and Simulation Conference.

Sunmonu, R. M., & Onyekonwu, M. (2013). *Enhanced Oil Recovery using Foam Injection; a Mechanistic Approach.* Paper presented at the SPE Nigeria Annual International Conference and Exhibition.

Thomas, S. (2008). Enhanced oil recovery-an overview. *Oil & Gas Science and Technology-Revue de l'IFP, 63*(1), 9-19.

Touray, S. (2013). EFFECT OF WATER ALTERNATING GAS INJECTION ON ULTIMATE OIL RECOVERY.

Tunio, S. Q., Tunio, A. H., Ghirano, N. A., & El Adawy, Z. M. (2011). Comparison of different enhanced oil recovery techniques for better oil productivity. *International Journal of Applied Science and Technology, 1*.

Yeh, N., & Agarwal, R. (1989). *Pressure transient analysis of injection wells in reservoirs with multiple fluid banks.* Paper presented at the SPE Annual Technical Conference and Exhibition.

Zahoor, M., Derahman, M., & Yunan, M. (2011). Wag Process Design–an Updated Review. *Brazilian Journal of Petroleum and Gas, 5*(2).

APPENDICES

Appendix 1

Table A1: Reservoir Rock and Fluid Properties – Input Data

Initial reservoir peressure, P_i	3200 psi
Reservoir temperature, T	250°F
Initial water saturation, S_{wi}	0.31
Connate gas saturation, S_{gc}	0.06
Residual oil saturation in water-oil system, S_{orw}	0.373
Residual oil saturation in gas-oil system, S_{org}	0.125
Reservoir external radius, r_e	10000 ft
Wellbore radius, r_w	0.35 ft
Reservoir thickness, h	56 ft
Porosity, ϕ	0.33
Absolute permeability, k	200 md
Oil relative permeability at initial water saturation, $k_{ro(@Swi)}$	0.88
Water relative permeability at residual oil saturation, $k_{rw(@Sor)}$	0.09
Density: oil, ρ_o water, ρ_w gas, ρ_g	36.70 lbm/ft^3 70.00 lbm/ft^3 0.05 lbm/ft^3
Formation volume factor: gas, B_g oil, B_o water, B_w	1.035 scf/stb 1.530 rb/stb 1.020 rb/stb
Compressibility: oil, c_o water, c_w rock, c_f	1.50 ×10^{-5} psi^{-1} 2.30 ×10^{-6} psi^{-1} 3.00×10^{-6} psi^{-1}
Viscosity: favorable (M = 0.3) oil, μ_o water, μ_w unfavorable (M = 2.0) oil, μ_o water, μ_w	0.72 cp 0.22 cp 3.00 cp 0.15 cp
Injection cycle: water/ gas injection water/ gas falloff	10 days 20 days
Injection rate: water, q_w gas, q_g	4500 stb/day 4432 scf/day
Skin: negative skin/ permeability positive skin/ permeability skin radius (r_s)	-2/ 534 md 4/ 53 md 1.52 ft

Appendix 2

Data File of Base Case Scenario (Unfavorable mobility condition)

```
RUNSPEC
TITLE
Pressure Transient Analysis of Water alternating gas Injection Well
DIMENS
   300    1    1 /
RADIAL
OIL
GAS
WATER
FIELD
TABDIMS
    1    1  100    50       2     /
WELLDIMS
    2     1    1      2 /
REGDIMS
    2    1    0    0 /
SATOPTS
 2* HYSTER/
START
   05  AUG  2013  /
NSTACK
    50 /
UNIFOUT
UNIFIN
-----------------------------------------------------------------------------------------------------
-------------------
GRID
INIT
INRAD
 0.35 /
OUTRAD
10000/
DTHETAV
 360.0 /
DZ
 300*56 /
TOPS
 300*1500 /
PERMR
 300*200 /
PORO
 300*0.33 /
COPY
 PERMR PERMTHT /
 PERMR PERMZ /
/
```

```
RPTGRID
 'DR' /
------------------------------------------------------------------------------------------------------------------------
--------------------
PROPS
STONE1
SOMGAS
0          0.373
0.05     0.351053097
0.1       0.329106195
0.15     0.307159292
0.2       0.285212389
0.25     0.263265487
0.3       0.241318584
0.35     0.219371681
0.4       0.197424779
0.45     0.175477876
0.5       0.153530973
0.55     0.131584071
0.565   0.125/
INCLUDE
   Relative_perm.INC  /
WAGHYSTR
0.78  0.01/
/
PVTW
    3200.0  1.02  2.30E-06  0.15  0.0 /
PVCDO
   3200.0  1.53  1.5E-05  3.0   0.0 /
PVDG
3200    1.035065956   0.020096236
3300    1.005968448   0.020351453
3400    0.978897047   0.020608062
3500    0.953474417   0.02086781
3600    0.929761172   0.02112831
3700    0.907329724   0.021392662
3900    0.866557549   0.021924018
4100    0.830197805   0.022462552
4500    0.768362316   0.023554962
4800    0.729621442   0.024383762/
ROCK
    3200.0   3.0E-6 /
DENSITY
    36.7  70  0.0499424 /
RPTPROPS
  SOF3/
------------------------------------------------------------------------------------------------------------------------
--------------------
REGIONS
EQUALS
```

```
SATNUM
   1 1 300 1 1 1 1 /
/
FIPNUM
  300*1 /
IMBNUM
  300*1/
RPTREGS
  SATNUM FIPNUM /
----------------------------------------------------------------------------------------------------
-------------------
SOLUTION
PRESSURE
  300*3200.0 /
SWAT
  300*0.31 /
SGAS
  300*0.0 /
RPTSOL
  RESTART=1  FIP=2  /
RPTRST
'BASIC=2' 'VELOCITY' 'RK' 'VISC' /
----------------------------------------------------------------------------------------------------
-------------------
SUMMARY
WBHP
/
WPI
/
TCPU
EXCEL
----------------------------------------------------------------------------------------------------
-------------------
SCHEDULE
RPTSCHED
 'FIP=1' 'WELLS'  'SUMMARY=2'  /
TUNING
 1e-7    1e-2   1e-8   1.5e-8     2     0.3    1e-8  1.25 /
/
/
WELSPECS
   INJ    G1      1  1    1500      WATER/
/
COMPDAT
   INJ    1*   1*   1  1   OPEN    1*    1*   0.7   /
/
WCONINJE
    INJ     WATER     OPEN   RATE   4500    1*   100000 /
  /
TSTEP
```

```
 10/
INCLUDE
'Water_falloff1.INC' /
INCLUDE
'Gas_injection1.INC' /
INCLUDE
'Gas_falloff1.INC' /
INCLUDE
'Water_injection2.INC' /
INCLUDE
'Water_falloff2.INC' /
INCLUDE
'Gas_injection2.INC' /
INCLUDE
'Gas_falloff2.INC' /
END
```