Laboratory Investigation of Low-Tension-Gas (LTG) Flooding for Tertiary Oil Recovery in Tight Formations

APPROVED BY
SUPERVISING COMMITTEE:

Supervisor:

Quoc P. Nguyen

Gary A. Pope
Laboratory Investigation of Low-Tension-Gas (LTG) Flooding for Tertiary Oil Recovery in Tight Formations

by

Stefan Michael Szlendak, B.S.

Thesis
Presented to the Faculty of the Graduate School of
The University of Texas at Austin
in Partial Fulfillment
of the Requirements
for the Degree of

Master of Science in Engineering

The University of Texas at Austin
December 2012
Dedication

To my family.
Acknowledgements

I would like express my sincere gratitude to my supervising professor, Dr. Quoc Nguyen, for his continued support and guidance during my graduate study. His willingness to share his technical passion is infectious and hopefully reflected in my own work. I look forward to working with him in the future and observing the continued evolution of foam improved oil recovery.

I would also like to provide a special thanks to Nhut Nguyen and Dr. Sujeewa Palayangoda for their considerable help in teaching me the experimental and chemistry related aspects of my research. It was only through their considerable assistance that I was able to meet the aggressive research goals and timelines which were set. Additionally, I would like to show my appreciation to the countless people responsible for the continued success of the Chemical EOR research consortium, including Dr. Gary Pope, without which this research would not have been possible.

Moreover, I would like to acknowledge my many friends and colleagues which have supported me during my time at the University of Texas and helped to make for a more enjoyable experience. To Alexander Sweet, Adrian Rossi-Mastracci, Maddy Evans, Nabijan Nizamidin and Chris Shum, I would like to thank you for your enduring friendship and support as I pursued my long existent goal of entering the oil industry. And, to Dustin Walker, Arron Clark, Mazen Abdulbaki, Natalia Salies and Do Shin, I would like thank you for your comradery within the PGE department.

Finally, I would like to thank the Yates and Thurber families for their continued support of the PGE department and the University of Texas. Their financial support helped enabled me to attend UT and fulfill my goal of entering the industry.
Abstract

Laboratory Investigation of Low-Tension-Gas (LTG) Flooding for Tertiary Oil Recovery in Tight Formations

Stefan Michael Szlendak, M.S.E.
The University of Texas at Austin, 2012

Supervisor: Quoc P. Nguyen

This paper establishes Low-Tension-Gas (LTG) as a method for sub-miscible tertiary recovery in tight sandstone and carbonate reservoirs. The LTG process involves the use of a low foam quality surfactant-gas solution to mobilize and then displace residual crude after waterflood. It replicates the existing Alkali-Surfactant-Polymer (ASP) process in its creation of an ultra-low oil-water interfacial tension (IFT) environment for oil mobilization, but instead supplements the use of foam over polymer for mobility control. By replacing polymer with foam, chemical Enhanced Oil Recovery (EOR) methods can be expanded into sub-30 mD formations where polymer is impractical due to plugging, shear, or the requirement to use a low molecular weight polymer.

Overall results indicate favorable mobilization and displacement of residual crude oil in both tight carbonate and tight sandstone reservoirs. Tertiary recovery of 75-95% ROIP was achieved for cores with 2-15 mD permeability, with similar oil bank and other ASP analogous process attributes observed. Moreover, similar recovery was achieved
during testing at high initial oil saturation (56%), indicating high process tolerance to oil saturation and potential application for implementation at secondary recovery.

In addition, a number of tools and relations were developed to improve the predictive relationship between observed coreflood properties and actual mobilization or displacement mechanisms which impact reservoir-scale flooding. These relations include qualitative dispersion comparison and calculation of in-situ gas saturation, macroscopic mobility ratio at the displacement fronts, and apparent viscosity of injected fluids. These tools were validated through use of reference gas and surfactant floods and indicate that stable macroscopic displacement can be achieved through LTG flooding in tight formations.

Furthermore, to better reflect actual reservoir conditions where localized fractional flow of gas can vary substantially depending on mixing or gravity phenomenon, two additional sets of data were developed to empirically model behavior. Through testing of LTG co-injection at a number of discrete fractional flow values over a wide range, recovery was shown to achieve a relative maximum at 50% gas fractional flow which also corresponded with optimal observed mobility control as measured by the previously established tools. Likewise, through testing of surfactant-alternating-gas (SAG) injection cycling, displacement and overall recovery were shown to be improved versus reference co-injection flooding.

Finally, by comparing the observed displacement and mobility data among co-injection and surfactant-alternating-gas floods, a new displacement mechanism is introduced to better relate actual displacement conditions with observed macroscopic mobility data. This mechanism emphasizes the role of liquid rate in actual displacement processes and a mostly static gas saturation (independent of gas rate) in altering liquid relative permeability and diverting injected liquid into lower permeability zones.
# Table of Contents

List of Tables ........................................................................................................... xii

List of Figures .......................................................................................................... xiii

Chapter 1: Introduction.............................................................................................1

1.1 Overview ...........................................................................................................1

1.2 Research Methodology ....................................................................................2

1.3 Research Objectives .......................................................................................3

Chapter 2: Literature Review..................................................................................5

2.1 Overview—Low Tension Gas ..........................................................................5

2.2 Existing EOR Methods—Limitations & Select Applications .......................6

2.2.1 Description of Current State EOR Methods ............................................6

2.2.2 Limitations to Application of Current State EOR Methods .................8

2.2.3 Micellar-Polymer Flooding .......................................................................9

2.2.3.1 Application .........................................................................................9

2.2.3.2 Polymer Limitations .........................................................................11

2.2.3.3 Surfactant Chemistry & Design .......................................................13

2.3 Properties of Foam ..........................................................................................19

2.3.1 Introduction to Foam ...............................................................................19

2.3.2 Mechanisms Impacting Foam Stability .................................................23

2.3.2.1 Destructive Mechanisms ................................................................24

2.3.2.2 Stabilizing Mechanisms ..................................................................29

2.3.3 Mechanisms for Foam Generation ..........................................................31

2.3.4 Foam Rheology in Porous Media ............................................................36

2.3.4.1 Foam Regimes | Critical Capillary Pressure Theory .......................36

2.3.4.2 Impact of Rate and Foam Quality ....................................................40

2.4 Implementations & Limitations to Foam Flooding ......................................43

2.4.1 Existing Mobility Control & Conformance Research ..............................43

2.4.1.1 Gas-Liquid Co-injection ..................................................................44
4.5.2 Surfactant-Alternating-Gas (SAG) Investigation ..................168

4.5.2.1 Key Findings .................................................................168

4.5.2.2 Theoretical Significance: SAG Spreading Wave and Displacement Phenomenon..............................................171

Chapter 5: Summary and Recommendations.................................................................174

5.1 Summary ....................................................................................................................174

5.1.1 Initial Investigation: Proof of Concept, Development of Evaluation Tools—Chapter 3......................................................175

5.1.2 Further Investigation: Foam Mixing & Fractional Flow Behavior, Displacement Mechanisms—Chapter 4..............................177

5.2 Recommendations and Future Work ......................................................................180

Appendices .....................................................................................................................181

Appendix A: Experimental Setup and Additional Surfactant Phase Behavior Figures.................................................................181

Appendix B—Figures From Preparatory Flooding Process .........................183

Glossary ..........................................................................................................................191

References .......................................................................................................................194
## List of Tables

Table 3.1: Flood Objectives by Experiment .......................................................61
Table 3.2: Flood Injection Strategy ........................................................................62
Table 3.3: Notable Properties Prior to Chemical Flooding .................................63
Table 3.4: Gas saturation at tracer breakthrough ($tD1$). .................................95
Table 3.5: Observed mobility ratios ($R$) for experiment corefloods ..........105
Table 3.6: Calculated apparent viscosity and model input values ...........113
Table 4.1: Co-injection gas quality study attributes .......................................124
Table 4.2: Surfactant-alternating-gas (SAG) cycling study attributes ..........125
Table 4.3: Notable properties prior to chemical flooding ...............................126
Table 4.4: Gas saturation at tracer breakthrough ($tD1$) for co-injection floods.132
Table 4.5: Observed mobility ratios ($R$) for co-injection study corefloods. ....134
Table 4.6: Calculated apparent viscosity and contributing model values .......140
Table 4.7: Calculated apparent viscosity and contributing model values .......163
Table 4.8: Calculated apparent viscosity and contributing model values .......164
List of Figures

Figure 2.1: Trend of U.S. EOR projects ......................................................... 7
Figure 2.2: Viscous fingering in a quarter five-spot model ......................... 8
Figure 2.3: Schematic of Alkali-Surfactant-Polymer (ASP) injection process ... 10
Figure 2.4: Structure of a surfactant monomer ........................................ 14
Figure 2.5: Schematic liquid crystalline micelle structures .......................... 15
Figure 2.6: Interfacial tensions and solubilization parameters ........................ 17
Figure 2.7: Residual oil saturation as a function of capillary number (Nca) .... 18
Figure 2.8: A generalized foam system ................................................... 20
Figure 2.9: Foam lamella translating from left to right ................................ 22
Figure 2.10: Schematic of continuous and discontinuous gas flow regimes in porous media .......................................................... 23
Figure 2.11: Pressure differences across curved surfaces in a foam lamella ...... 25
Figure 2.12: Comparison of the total interaction energy (V, - - -) and the disjoining pressure (π, —) in a liquid lamella as a function of film thickness .... 30
Figure 2.13: Gibbs-Marangoni effect in the thin-film drainage process .......... 31
Figure 2.14: ‘Snap-off’ mechanism of lamella creation ............................... 33
Figure 2.15: Schematic of lamella creation by ‘leave behind.’ ...................... 34
Figure 2.16: Schematic of lamellae creation by ‘lamella division’ ............... 35
Figure 2.17: Schematic of minimum pressure gradient for ‘strong foam’ generation as seen in experiments at fixed flow rate that is steadily increased ...... 38
Figure 2.18: Minimum pressure gradient for ‘strong foam’ generation as a function of permeability for N2 and CO¬2 foams ................................. 38
Figure 2.19: Flow regime diagram—contours of pressure ......................... 42
Figure 2.20: Schematic of three uniform zones in model of Stone and Jenkins for
continuous co-injection of gas and water........................................45

Figure 2.21: Time-distance diagram for the idealized model of Shan and Rossen
(Shan 2002) for a SAG displacement ........................................46

Figure 3.1: Oil and water solubilization data for selected surfactant formulation (t=7
days) ..................................................................................................55

Figure 3.2: Oil recovery and fractional flow profile for LTG_Tert_#1. .........64

Figure 3.3: Sectional pressure profile for LTG_Tert_#1..............................66

Figure 3.4: Effluent salinity profile and microemulsion environment for
LTG_Tert_#1. ......................................................................................68

Figure 3.5: Oil recovery and fractional flow profile for LTG_Tert_#2 vs.
LTG_Tert_#1. ......................................................................................70

Figure 3.6: Cumulative oil recovery for LTG_Tert_#1, Surf_Tert_#3 and
Gas_Tert_#4..........................................................................................72

Figure 3.7: Oil cut for LTG_Tert_#1, Surf_Tert_#3 and Gas_Tert_#4. ..........73

Figure 3.8: Oil recovery and fractional flow profile for LTG_Oil_#5 and reference
waterflood. ..........................................................................................75

Figure 3.9: Idealized model for mobilization and displacement during secondary
recovery for chemical flooding with mobility control.......................77

Figure 3.10: Sectional pressure profile for LTG_Oil_#5 and reference waterflood.78

Figure 3.11: Corey-type relative mobility curves for Case 1. .....................81

Figure 3.12: Corey-type relative mobility curves for Case 2. .....................82

Figure 3.13: Schematic of model for mobilization and displacement during tertiary
recovery.............................................................................................84
Figure 3.14: Sensitivity study of pore volume available to mobile oil ($P_{V_{MO}} = S_{oi} - S_{orw}$) upon oil bank size ($\Delta S_{oil\ bank}$) and oil bank relative velocity ($v_{r\ oil\ bank}$) .................................................................85

Figure 3.15: Sensitivity study of crude oil viscosity ($\mu_o$) upon oil bank relative velocity ($v_{r\ oil\ bank}$), oil bank saturation $S_{oil\ bank}$, oil bank saturation change ($\Delta S_{oil\ bank}$), and non-dimensional oil bank water saturation ($S_{w^o}$) ........................................................................................................87

Figure 3.16: Effluent salinity profile for LTG_Tert_#1, Surf_Tert_#3, and GAS_Tert_#4........................................................................................................................89

Figure 3.17: Effluent salinity profile for LTG_Tert_#1 and LTG_Oil_#5. ..........92

Figure 3.18: Calculated $R_{vs\ brine}$ during LTG_Tert_#1. ..............................101

Figure 3.19: Calculated $R_{vs\ oil\ bank}$ during LTG_Tert_#1. .........................102

Figure 3.20: Calculated $R_{vs\ water\ residual\ oil}$ during LTG_Tert_#1.............103

Figure 3.21: Injected fluids profile ($1-S_{oi}$), and interpreted relative permeability ($k_r$ injected fluids) profile for apparent viscosity deconstruction of LTG_Tert_#1.................................................................111

Figure 3.22: Derived 2-phase relative permeability relationship for late-stage, high oil-water IFT tertiary recovery using an expanded Corey relationship. ................................................................................................................111

Figure 3.23: Sectional and overall calculated apparent viscosity for LTG_Tert_#1. Overall Surf_Tert_#3 & Gas_Tert_#4 floods are included as reference cases. ........................................................................................................112

Figure 4.1: Fractional flow and cumulative recovery for LTG_Coinj_0%, LTG_Coinj_30%, LTG_Coinj_50%, and LTG_Coinj_85% floods.128
Figure 4.2: Cumulative recovery at different flood periods with respect to liquid PV injected (PV\textsubscript{Liquid}) for various injected gas fractions......................129

Figure 4.3: Cumulative recovery at different flood periods with respect to total PV injected (PV\textsubscript{Total fluid}) for various injected gas fractions.............130

Figure 4.4: Effluent salinity profile for LTG\textsubscript{Coinj}_0\%, LTG\textsubscript{Coinj}_30\%, LTG\textsubscript{Coinj}_50\%, and LTG\textsubscript{Coinj}_85%........................................131

Figure 4.5: Calculated gas saturation for LTG\textsubscript{Coinj}_0\%, LTG\textsubscript{Coinj}_30\%, LTG\textsubscript{Coinj}_50\%, LTG\textsubscript{Coinj}_85\%, and (from previous study) LTG\textsubscript{Tert}_#2. .................................................................133

Figure 4.6: Calculated mobility ratios for LTG\textsubscript{Coinj}_0\%, LTG\textsubscript{Coinj}_30\%, LTG\textsubscript{Coinj}_50\%, LTG\textsubscript{Coinj}_85\% using total injection rate (q\textsubscript{Total}) for calculations. .................................................................135

Figure 4.7: Re-normalized calculated mobility ratios for LTG\textsubscript{Coinj}_0\%, LTG\textsubscript{Coinj}_30\%, LTG\textsubscript{Coinj}_50\%, LTG\textsubscript{Coinj}_85\% using liquid injection rate (q\textsubscript{Total}) for calculations. .................................................................138

Figure 4.8: Calculated apparent viscosity (\(\mu\textsubscript{app}\)) versus injected gas quality for LTG\textsubscript{Coinj}_0\%, LTG\textsubscript{Coinj}_30\%, LTG\textsubscript{Coinj}_50\%, LTG\textsubscript{Coinj}_85\%. Results use total fluid injection rate (q\textsubscript{Total \text{ liquid}}) for apparent viscosity calculations. .................................................................140

Figure 4.9: Calculated re-normalized apparent viscosity (\(\mu\textsubscript{app}\)) versus injected gas quality for LTG\textsubscript{Coinj}_0\%, LTG\textsubscript{Coinj}_30\%, LTG\textsubscript{Coinj}_50\%, LTG\textsubscript{Coinj}_85\%. Results use liquid injection rate (q\textsubscript{Liquid}) for apparent viscosity calculations. .................................................................141
Figure 4.10: Cumulative recovery at different flooding increments (PV_{Liquid}) versus calculated re-normalized apparent viscosity (\mu_{app}) using liquid injection rate (q_{Liquid}) for apparent viscosity calculations. Floods LTG_Coinj_0\%, LTG_Coinj_30\%, LTG_Coinj_50\%, and LTG_Coinj_85\% are represented .................................................................143

Figure 4.11: Fractional flow and cumulative recovery for LTG_SAG_2L:2G versus reference co-injection flood (LTG_Coinj_50%). .........................145

Figure 4.12: Sectional raw pressure behavior for LTG_SAG_2L:2G. ............147

Figure 4.13: Sectional averaged pressure behavior for LTG_SAG_2L:2G versus reference co-injection flood (LTG_Coinj_50%). .........................148

Figure 4.14: Sectional raw pressure behavior for LTG_SAG_2L:2G for a single late-stage liquid:gas cycle. .................................................................150

Figure 4.15: Normalized pressure gradient data for one late-stage liquid:gas cycle for LTG_SAG_2L:2G. .................................................................152

Figure 4.16: Comparison of effluent salinity for LTG_SAG_2G:2L and LTG_Coinj_50\%. .................................................................156

Figure 4.17: Raw pressure data for LTG_SAG_1L_3G. .........................158

Figure 4.18: Normalized pressure gradient profile for LTG_SAG_1L_3G......158

Figure 4.19: Raw pressure data for LTG_SAG_3L_31. .........................160

Figure 4.20: Normalized pressure gradient profile for LTG_SAG_3L_1G.......160

Figure 4.21: Overall (X_{D=0.1}) normalized pressure gradient for LTG_SAG_2L:2G, LTG_SAG_1L:3G, and LTG_SAG_3L:1G .........................161

Figure A1: Schematic of experimental setup used in coreflood experiments...182

Figure A2: Photo of surfactant phase behavior for the selected formulation used in corefloods..........................182
Figure B1: Steady-state pressure drop values used in brine permeability measurements. ................................................................. 183

Figure B2: Plot of the corrected pressure drop-flow rate relationship for section $X_{D=0.25}$ during Gas_Tert_#4 after transducer calibration. .......... 184

Figure B3: Saturation profile during Gas_Tert_#4 oilflood. .................. 185

Figure B4: Observed pressure profile for Gas_Tert_#4 during oilflood displacement. ........................................................................ 186

Figure B5: Observed oilflood mobility vs. reference brine mobility (mobility ratio) for Gas-Tert_#4. ................................................................. 187

Figure B6: Calculated fractional flow and water saturation data for Gas_Tert_#4 waterflood displacement. .............................................................. 188

Figure B7: Observed pressure profile for Gas_Tert_#4 waterflood displacement. 189

Figure B8: Observed waterflood mobility vs. reference brine mobility (mobility ratio) for Gas-Tert_#4. ................................................................. 190
Chapter 1: Introduction

1.1 Overview

Many tight sandstone and carbonate reservoirs under waterflood are considered unsuitable candidates for Enhanced Oil Recovery (EOR). These reservoirs represent large volumes of currently unproduced oil which cannot be economically extracted by current thermal, chemical, or miscible-gas EOR methods. A few of the economic and technical constraints which limit these technologies are low permeability, low or high reservoir thicknesses, reservoir depth and pressure, reservoir temperature, reservoir salinity, availability of miscible gas, and crude oil viscosity (Lake 1989; Taber 1997).

To scale chemical flooding to tight carbonate and sandstones of 2-35mD replacement of polymer is a required because of plugging and shear degradation of polymer (discussed later). The Low-Tension-Gas (LTG) process as described in this paper replaces polymer used in conventional Alkali-Surfactant-Polymer (ASP) flooding with low gas-quality nitrogen foam.

Existing foam research which focuses on the creation of high-strength, high gas-quality foam is poorly suited for tight reservoirs due to the ultra-high flow rates and pressure drops associated with the creation and propagation of high-strength foam. Further, the salinity and surfactant concentrations used by many authors to create stable foam are often poorly suited for oil mobilization through reduction of IFT.

A low-quality, low-rate injection strategy is tested based upon a mechanistic understanding of foam generation and propagation in porous media. It is believed that a “weak foam” regime exists with the desired rheological properties for stable displacement of light crudes (See LTG in Tight Formations). If this behavior exists, it
may reflect favorably upon the ability for LTG to economically produce residual crude oil in tight-reservoirs.

1.2 Research Methodology

A notable lack in foam literature for application in tight porous media results in a high degree of uncertainty in expected foam rheological parameters for this study. Additionally, because of differences in displacement phenomenon during three phase flow (oil-water-gas) versus two phase flow—which is encountered for polymer flooding (aqueous-gas)—exact relation between observed macroscopic foam rheology and actual displacement conditions was unknown. To establish that LTG can (or can’t) work for tertiary recovery in tight formations, a set of LTG proof of concept floods were employed. Critical emphasis for this work was towards improving formulation and strategy and achieving recovery profiles consistent with favorable oil mobilization and displacement.

In addition to initial observation of LTG as effective (or ineffective) in mobilizing and displacing light crude oil in tight formations, it is important to understand the critical process attributes and how they impact upscaling. This is especially important due to the mitigating impact that 1-D coreflood displacement can have upon unstable displacement, allowing poor mobility control floods to achieve uncharacteristically good (“untrue”) laboratory results. To better understand the LTG process and its potential for upscaling, a variety of parameters and deconstructions were studied to form high level conclusions towards process effectiveness.

Upon identification of critical process and stability parameters, empirical correlations and relationships are developed for flood optimization in a field setting. For this study, gas fractional flow is the primary parameter studied due to the importance that
that it can have upon foam rheology and the expected variability in gas fractional flow due to gravity segregation and gas-water cycling—among other factors. A series of floods are utilized over a range of both varied discrete gas fractional flow and gas-liquid cycle strategies to allow for observation of fractional flow and mixing affects.

From the expanded dataset developed as part of proof of concept and optimization work, important inter-flood properties are then studied. These observations are related to previously stated and hypothesized mechanisms for foam propagation and stability and a refined mechanism for foam propagation and displacement is then proposed.

1.3 **Research Objectives**

Chapter 2: Literature Review
- Identify mechanisms for and characteristics of foam propagation in porous media.
- Identify existing literature related to application of micellar foam flooding. Based upon observed results, determine previous process successes and pitfalls. Develop LTG injection strategy.
- Identify deviations in process behavior which may exist as a function of application in tight formations. Determine if LTG has potential application in tight formations.

Chapter 3: Proof of Concept | Low-Tension-Gas Flooding in Tight Formations
- Demonstrate that favorable LTG recovery can be achieved in tight formations.
- Develop a set of analytic parameters to evaluate results.
- Utilize analytic parameters to evaluate critical process aspects such as:
  - Stability and strength of dispersed gas drive
  - Overall displacement stability and mobility ratios
• Repeatability and process tolerance
• Effects of oil saturation; Potential for application at secondary recovery
• Consistency of results with proposed mechanisms and literature

Chapter 4: Effects of gas injection strategy upon LTG process in tight formations
  o Observe effects of varied fractional flow (co-injection testing).
  o Develop a correlation between in-situ fractional flow and apparent viscosity
  o Perform SAG flooding to replicate actual injection processes
  o Associate SAG results with co-injection results to interpret displacement contributions
  o Use expanded co-injection and SAG datasets to improve understanding of displacement mechanisms
Chapter 2: Literature Review

2.1 Overview—Low Tension Gas

The Low-Tension-Gas (LTG) process described in this paper is a chemical flooding alternative to Alkali-Surfactant-Polymer (ASP/SP) flooding. Oil mobilization is achieved through reduction in oil-water interfacial tension via a high performance synthetic surfactant. Well performing formulations can nearly eliminate oil-water interfacial tension and allow for theoretical complete recovery of swept crude oil.

To improve sweep efficiency and counteract potential instabilities associated with a lower mobility crude oil bank, co-injection or alternate injection of gas and surfactant/liquid is utilized to create a dispersed gas phase. Dispersed gas is bounded by liquid thin films called lamellae which span constrictions or pore throats and provide a resistance to flow. The degree and stability of produced lamellae has a strong impact on resistance to flow and can result in increased fluid apparent viscosity beyond that of the constituent phases.

An in depth understanding of LTG opportunity, mechanisms, existing work, and specific application is developed in sections 2.2 through 2.5. Descriptions of each section are provided below:

2.2 Existing EOR Methods—Establishes research opportunity by showing limitations in application of current methods to many tight reservoirs. In addition, factors affecting surfactant oil mobilization are discussed. ASP and other EOR literature is used to improve understanding of surfactant flooding and also provide a high level understanding of chemical flooding.

2.3 Properties of Foam—Provides a mechanistic understanding of foam rheology in porous media and its use for mobility control. Important parameters such as oil
microemulsions, flow rate & fractional flow, and flow geometry are discussed in the context of how they affect lamellae generation and stability.

2.4 Implementations & Limitations of Foam Flooding Research— Discusses current practice of foam flooding as applied to conformance (near wellbore, thief zones) and mobility control (foam co-injection, surfactant-alternating-gas). Previous research into micellar foam flooding, a precursor of LTG, is introduced with important contributions and pitfalls noted. Additionally, this section provides additional context for techniques used to model foam propagation in porous media.

2.5 LTG in Tight Formations—Expresses reasons for an existing lack of research on foam flooding in tight formations. These concerns are considered from a technical and practical perspective in order to determine if LTG has the potential to achieve favorable results. Based upon existing empirical results and an interpretation of existing foam theory, it is proposed that a “weak foam” regime may exist at experiment conditions which may exhibit desired flow properties.

2.2 Existing EOR Methods—Limitations & Select Applications

2.2.1 Description of Current State EOR Methods

Thermal, Miscible Gas, and Chemical methods constitute the extent of existing widespread application of Enhanced Oil Recovery. According to the Oil and Gas Journal’s Worldwide EOR Surveys (2012), volume of oil produced worldwide by EOR is 2.5MMBOPD, with 90% located within the United States, Canada, Venezuela, and China. Figure 2.1 (below), presents the number of historical EOR projects. Since 2008, an increase in Chemical EOR projects has been observed which is not apparent in the figure. This has been associated with an increase in oil price and manufacture of more cost effective chemicals. (Manrique 2010)
For each of these methods substantial increase in recovery is achieved by altering in-situ mobility of target reservoir fluids. The mechanism for increase in oil mobility varies among the three processes, but it is typically associated with a decrease in oil viscosity (Thermal) and/or a decrease in oil-water or oil-gas interfacial tension (Miscible Gas, Chemical). For the remainder of this paper, the term oil mobilization is given to associate increases in-situ mobility of target fluids which enable displacement.

Increased mobility of contacted in-situ fluids, although favorable for EOR processes, can amplify viscous instabilities between in-situ fluids and injected fluids. Figure 2.2 provides an illustration of viscous fingering due to unstable displacement. To reduce fingering of injected and/or contacted reservoir fluids through uncontacted fluids, it is desirable to reduce the mobility of the injected fluids. To reduce the mobility of the injected fluids, common methods include hydrolyzed polymer injection (section 2.2.3),
water alternating gas (section 2.4), or gas-surfactant (foam) injection (section 2.4). By controlling mobility of injected fluids (inversely related to apparent viscosity), increased oil contact and improved sweep efficiency can be achieved.

![Viscous fingering in a quarter five-spot model. M₀=17 (Habermann 1960)](image)

**2.2.2 Limitations to Application of Current State EOR Methods**

There are a number of technical and economic parameters which restrict application of Thermal, Miscible Gas, or Chemical EOR methods (Manrique 2010, Lake 1989, Taber 1997). Brief discussions of the limitations of each are expressed below. Together, these limitations demonstrate that tight reservoirs of sub ~40mD represent a large stranded resource when a suitable miscible gas is unavailable.

Thermal EOR— is most commonly applied to heavy and medium-heavy crudes within formations of Darcy-type permeability. Reservoirs have high remaining oil saturation and high remaining mobile oil saturations. In addition to permeability,
common limitations include formation depth, mineralogy, thickness, crude viscosity, heterogeneity, and oil saturation.

Miscible Gas—is applied to reservoirs with a wide range of permeability, although application in tighter reservoirs of 5-20mD is most common. Availability of an economic supply of gas of appropriate composition is the most common limitation. Other common limitations include formation depth & temperature (miscibility parameters), thickness, geometry, crude oil chemistry, permeability, and heterogeneity.

Chemical EOR—is currently associated with Micellar-Polymer flooding, which is used to describe Surfactant (no polymer), Surfactant-Polymer (SP), Alkali-Polymer (AP), or Alkali-Surfactant-Polymer (ASP) flooding. It is most commonly applied after waterflood for reservoirs of moderate to high permeability. Attributes and limitations are discussed in great detail in section 2.2.3, where it is shown that Polymer tolerance is the primary concern and a lower permeability threshold of 50mD is asserted based upon experimental studies.

### 2.2.3 Micellar-Polymer Flooding

#### 2.2.3.1 Application

Well performing surfactants commonly lower the IFT to $10^{-3}$ dynes/cm, nearly eliminating IFT and allowing for theoretical oil recovery of nearly 100% Levitt (2006-b). However, high apparent viscosity of mobilized oil and oil-water microemulsions results in unfavorable mobility ratios and a corresponding decrease in displacement efficiency.

Micellar-polymer flooding utilizes low concentration (1000’s ppm) high molecular weight (MW) water soluble polymer to increase viscosity of injected fluids and ensure stable displacement. Current application of the process involves injection of a short (~0.15-0.3PV) high quality surfactant slug, which is then followed by 1-2PV of a
displacing drive. Addition of polymer to the slug can increase the volume of the reservoir which is contacted by injected chemicals, while inclusion of polymer to the injected drive helps increase displacement efficiency and increases the ability to produce out mobilized oil.

Successful ASP floods exhibit shock like displacement and the production of a large oil-bank at high oil cut (30-50%). For tertiary ASP flooding after waterflood, as is most common for ASP candidates, two shock fronts propagate as oil is mobilized and displaced (Figure 2.3). One shock front is associated with mobilization of oil by surfactant which is then displaced by injected aqueous fluids. Forward of this shock front is an oil bank. At the front of this oil bank, a second shock front forms as oil displaces a portion of in-situ water.

![Schematic of Alkali-Surfactant-Polymer (ASP) injection process for tertiary recovery (Tewari 2009)](image)

Figure 2.3  Schematic of Alkali-Surfactant-Polymer (ASP) injection process for tertiary recovery (Tewari 2009)

To ensure process stability, viscosity of injected fluids is designed to achieve a mobility ratio of slightly below or equal to 1 (Lake 1989). Mobility ratio is defined as relative mobility of injected fluids versus apparent mobility of displaced fluids (Eq. 2.1 & 2.2).
Use of a salinity gradient is another process parameter which has important application in ASP flooding. Most often, a negative salinity gradient is selected due to high reservoir brine salinity and surfactant phase behavior; however, some work is being done to apply surfactants which will respond favorably to a positive salinity gradient. For a negative salinity gradient, surfactant slug formulation is done at salinity below reservoir salinity. This is then followed by drive fluids which are at salinity below slug salinity. This creates a spectrum of salinity environments which progress from high to low salinity, and ensures that an optimal oil-water IFT environment is encountered in-situ. Additional details regarding the effects of salinity upon oil-water phase behavior are provided in section 2.2.3.3.

A systematic process for the screening and design of ASP floods is beyond the scope of this paper. Important factors as they pertain to LTG flooding are included in section 2.2.3.3, Surfactant Chemistry and Design. A discussion of other factors which affect design for ASP floods can be found in Flatten (2008), or Levitt (2006-a, 2006-b).

### 2.2.3.2 Polymer Limitations

Current application of ASP is limited primarily by scalability to adverse reservoir conditions and associated cost. Salinity, temperature, rock mineralogy, and moderately low permeability are characteristics which can partially affect the economics of a project but can often be designed for to achieve technical and economic success (Levitt 2006-a).
Tight reservoirs of sub 20 mD permeability represent a current limitation to ASP application which cannot be achieved even on a technical basis due to polymer plugging or shear degradation. Further, required use of low molecular weight (MW) polymers for formations of sub 100 mD permeability can negatively impact project economics. Experimental results from testing Hydrolyzed Polyacrylamide (HPAM) polymers are discussed below. HPAM polymers represent greater than 95% of field reported polymer floods (Manning 1983), providing a substantial decrease in cost versus other alternatives. Bio-polymers such Xanthan gum may provide additional capability for application in tight formations; however, for reasons of cost they are excluded from current application of polymer flooding.

Martin (1974, 1984) studied laboratory injection of Hydrolyzed Polyacrylamide (HPAM) into tight reservoirs of 4-67 mD permeability at 1.5-6 ft/day advance. During tests involving sub 15 mD cores, steady state pressure drop was not achieved which reflects substantial plugging. For cores of higher permeability, shear degradation of effluent polymer was observed. Degradation was dependent on permeability, flow rate, and MW of the polymer.

Maerker (1975) observed similar effects for shear degradation of HPAM in tight formations. High salinity and near wellbore effects were noted as of specific concern, with simulations indicating greater than 80% loss in mobility control in typical field injection situations. Other authors (Sorbie 1991, Taber 1997, Stavland 2010) have indicated shear degradation or plugging for both Acrylamido-Propyl-Sulfonate (AMPS) and/or HPAM when encountering high shear and/or low permeability.
2.2.3.3 Surfactant Chemistry & Design

As previously noted, the application of surfactants via either injection or in-situ generation has the potential to reduce oil-water IFT to below $10^{-6}$ dynes/cm. Such an environment can enable theoretically recovery of effectively all residual oil in a formation. As smaller molecules, surfactants are not impacted by the plugging, shear, thermal, or hardness to the extent of polymers. Nonetheless, careful control is required in order to reduce absorption, achieve favorable in-situ oil-water IFT, reduce microemulsion viscosity, and reduce equilibration time. These topics are discussed below.

**Surfactants**

Surfactants are groups of chemical compounds which act at the interface between two fluids. Use of surfactants is prevalent throughout almost every industry and includes such applications as detergents, paints, cosmetics, plastics, and others. A typical surfactant monomer is composed of a nonpolar (lypophile) portion, and a polar (hydrophile) portion (Figure 2.4). There are three classes of surfactants that have been used in EOR applications. They are defined based upon the charge of their respective “head” and “tail” groups: (Tadros 2005, Lange 1999)

Anionic—a negatively charged surfactant when in an aqueous solution (metal cation disassociates from the head group). Anionic surfactants are the most common in Micellar-Polymer flooding because they are resistant to retention and have low cost. Carboxolates, phosphates, sulfonates, and sulfates are common surfactants which are anionic.

Cationic—contain a positively charged polar head. They are used minimally for Micellar-Polymer flooding because of high absorption on anionic surfaces of interstitial clays.
Nonionic—does not form ionic bonds when dissolved in aqueous solutions but exhibit surfactant properties due to an electronegativity contrast between their constituents. They have high salinity tolerance and are commonly used as co-surfactants to shift phase behavior or increase solubility.

Figure 2.4: Structure of a surfactant monomer. (Tadros 2005)

**Controlling Microemulsion Environment**

Microemulsions are thermodynamically stable dispersions of one liquid phase in another. In Chemical EOR, they are achieved through the presence of surfactant micelles at the interface between two phases (Figure 2.5). Micelles form once a minimum critical micelle concentration is achieved (CMC) and will exhibit behavior depending upon the type of surfactant, and compositions of each of the fluids. Due to the hydrophobic-hydrophilic nature of a surfactant monomer, the surfactant will partition at an interface between oil-water, water-gas, or (uncommon) gas-oil. For oil mobilization, a surfactant that will mostly partition at the oil-water interface is considered favorable and is typically associated with balanced or increased weighting towards hydrophobicity. Co-surfactants are often more highly hydrophilic, and as such demonstrate greater aqueous stability. These surfactants are also better suited for propagation of stable foam lamellae (section 2.3). (Holmberg 2003)
For an anionic surfactant at high salinity, Winsor Type II(+) microemulsions will form (Figure 2.5b). Such a microemulsion is a water-in-oil (w/o) microemulsion, where oil is the continuous phase with oil microemulsion droplets dispersed within. Type II(-) microemulsion typically are associated with high bulk fluid viscosity and possible retention of surfactant within the aqueous phase. Winsor Type II(-) microemulsions, oil-in-water (o/w), will form at low salinity (not pictured). Bulk fluid viscosity is often the lowest of the microemulsion environments, and therefore Type II (-) environment is often most conducive to transport of oil within porous media. Winsor Type III microemulsions (Figure 2.5a) exhibit a planar or chaotic structure. It is considered to be a bi-continuous or middle phase, which may include a combination of micellar planes, w/o, o/w microemulsion. This environment is associated with the lowest oil-water interfacial tension and has a high degree of oil solubility relative to surfactant concentration. Design for achievement of Type III environment is a critical parameter for chemical flooding.

Figure 2.5: Schematic liquid crystalline structures (a) lamellar phase of double-tail surfactant, (b) cubic array of reverse micelles. (Lange 1999)
There is a strong relationship between microemulsion environment and interfacial tension. Figure 2.6 demonstrates reduction of oil-water IFT by 3 orders of magnitude as environment progresses to Type III from either Type II(-) or Type II(+). This environment is controlled by changing salinity (% NaCl) of the aqueous solution from a high or low value to a value which coincides with Type III behavior, which is also known as “optimum salinity.”

For application in oil reservoirs, it is important to note that chemical properties depend on concentration of specific ions rather than salinity only. The aqueous phase’s total divalent cation content (hardness) is usually more critical to chemical flood properties than the same TDS concentration. In addition, absorption of surfactant at the rock interface can change salinity (% NaCl) values associated with ultra-low IFT, causing deviations from ideal during actual field application.

Overall behavior of oil-water IFT as a function of salinity is often given the term “phase behavior.” During design, varied surfactant types and concentrations are tested to achieve favorable phase behavior. Favorable properties include: ultra-low IFT, a large ultra-low IFT salinity range (“phase window”), reduced microemulsion viscosity, and chemical stability of the surfactant (no precipitation).

The phase window is typically designed to be at a slightly lower salinity than reservoir salinity in order to allow for application of a negative salinity gradient. This causes a progression from Type II(+) → Type III → Type II(-) microemulsion environment for most currently used surfactant formations. Mixing during this progression ensures that Type III behavior is encountered during injection, something that may otherwise be difficult due to shifting optimal salinity (via absorption, ion exchange). In addition, progression from Type III & Type II(+) to Type II(-) reduces microemulsion viscosity and allows for easier displacement of mobilized crude oil.
Finally, many reservoirs have salinities which are too high for chemical flooding at optimum due to a lack of surfactant stability or appropriate phase window. By using a negative salinity gradient, chemical flooding can be applied to these reservoirs. A more detailed understanding of phase behavior design and injection strategies for ASP can be found in Anderson (2006), Healey (1997).

![Interfacial tensions and solubilization parameters](Reed 1977).

**Figure 2.6:** Interfacial tensions and solubilization parameters (Reed 1977).

**Results of IFT Reduction**

Reduction in oil-water interfacial tension decreases irreducible oil saturation by diminishing capillary effects. As reflected in Figure 2.7, decreases in capillary number correspond with decreases in irreducible oil saturation ($S_{or}$). Capillary number ($N_{ca}$) is defined as the viscous effects divided by the surface tension effects. This is expressed by Eq. 2.3 with $\gamma$=oil-water surface tension, $\mu$=water viscosity, and $v$=water interstitial velocity. A decrease in surface tension by several orders of magnitude will cause an
increase in capillary number by a proportional amount. For chemical flooding, capillary number is commonly increased several orders of magnitude, allowing for substantial reduction in residual oil saturation.

\[ Ca \equiv \frac{\mu \nu}{\gamma} \]  

(2.3)

Figure 2.7: Residual oil saturation as a function of capillary number \((N_{ca})\). Figure from Willhite (1986)
2.3 **Properties of Foam**

As described by Schramm (1994), foam is defined as a dispersion of gas in a bulk liquid. Gas, in the form of bubbles, is separated by thin films called lamellae. In porous media, these lamellae typically span the pore walls and are especially concentrated at constricted pore throats. During gas flow, the lamellae exhibit a resistance to flow due to both the viscous shear stresses in thin films between the pore walls and the gas-liquid interface, and the forces required to push lamellae through constricted pore throats. Foam strength is therefore a function of the stability and generation of these liquid lamellae.

Liquid lamellae are thermodynamically unstable. The steady-state presence of foam involves constant generation and destruction of foam lamellae. For oil and gas application, synthetic surfactants are used which act at the gas-liquid interface to stabilize the lamellae and thus foam. This section provides a detailed discussion of foam type, mechanisms for stability, mechanisms for generation, and characteristics & rheology. Specific focus is placed upon how the respective attributes impact displacement in porous media and oil reservoirs.

### 2.3.1 Introduction to Foam

**Bulk Foam**

For discussion in petroleum applications, foam is divided into two main groups: bulk foam and foam in porous media. Bulk foam, while not often a valid physical representation of foam in porous media, exhibits many of the same mechanisms. Bulk foam exists when the volume confining the foam has dimensions several times larger than those of the individual dispersed bubbles. For such foams, where bubble size is
typically no larger than several millimeters and usually much smaller, this limitation has little impact upon foam structure. As a result, foam structure will often resemble that of Figure 2.8, with an ordered matrix of dispersed gas bubbles separated by liquid films (polyhedral foam). A lower quality foam state known as “bubble foam,” however, also exists as discussed below.

![Figure 2.8: A generalized foam system (Schramm 1994)](image)

The depicted cross section in the figure identifies several components of foam which are discussed in this paper. A dispersed gas phase is separated by a liquid thin films or lamellae. Due to capillary pressure among the phases and the tendency for fluids to reduce the surface area at their interface, lamellae achieve a meta-stable thin film state where stabilizing forces impede further drainage—the individual forces being discussed in detail later. At the edges of the liquid lamellae are plateau borders. Due to curvature at the interface of the gas phase, liquid drains into these plateau borders. If oil microemulsions are present, they are often concentrated in the plateau borders due to their size relative to lamellae diameter. The overall structure of bulk foam is that of a
polyhedral (as pictured) or a lower gas quality “bubble foam,” both of which are associated with achieving a relative minimum in the energy state through reduction of gas-water surface area.

The preference for an ordered arrangement of dispersed gas bubbles and separating liquid lamellae causes a resistance to flow when a displacing shear is applied. The extent of the resistance to shear is a function of gas fraction or quality, bubble size, and lamellae stability and drainage, among other factors. The behavior of foam flow and the factors which contribute to rheology are discussed in other sections. In addition, the highly structured arrangement of liquid and gas phases causes the two phases to flow in approximate relation to one another. As such, bulk foam is often considered to be a single homogenous phase.

**Foam in Porous Media**

When foam is introduced into porous media, the dimensions of the confining pores or pore throats are usually of equivalent or smaller size to those of the bulk state of a dispersed gas bubble. This results in a restriction of bubble size in one or typically two directions. As the wetting fluid, the bulk aqueous phase lines the outer walls of the pore network. Liquid lamellae then span the individual pore bodies or more commonly pore throats to separate a dispersed gas phase.

At constrictions such as a pore throat, the wetting fluid may connect to form a liquid lamella. This liquid lamella will provide a resistance to flow as it is displaced into the larger pore network. Depending on the gradient applied, capillary pressure on the lamella and stability parameters of the lamella, the lamella may remain static, become a flowing lamella, or become unstable and rupture after a certain degree of displacement due to capillary pressure. Displacement of a liquid lamella through a pore series is shown in Figure 2.9.
In porous media, generation and propagation of liquid lamellae is not uniform but highly a function of geometry, fractional flow, and capillary pressure, among other factors—each is discussed in sections 2.3.2-2.3.4. This results in an uneven distribution of gas-liquid phases, which is depicted in Figure 2.10. For regions where liquid lamellae cannot be created due to geometry, rate, or gas fraction, a continuous gas phase will form. This continuous gas phase has high mobility due to the high relative permeability which accompanies high saturation and low gas viscosity. A discontinuous gas phase can also be present. If the in-situ pressure gradient is high enough to displace the liquid lamellae from the pore throats, the discontinuous gas will be flowing. On the other hand, if the pressure gradient is low or the capillary pressure too low, a discontinuous gas phase may be stationary or “trapped.” These individual flow regimes have important implications for resistance to flow of gas or liquid and mobility reduction. They are discussed in detail in remainder of section 2.3.
2.3.2 Mechanisms Impacting Foam Stability

Liquid lamellae lack true thermodynamic stability. As described below, liquid lamellae will drain until a critical thickness is achieved and eventually rupture. As such, the propagation of liquid lamellae or foam is strongly a function of the both the rate at which liquid drains from the liquid lamellae and the critical thickness at which the lamellae finally ruptures. Overviews of the key mechanisms which stabilize or destabilize lamellae are discussed in this section. Discussion is limited for this thesis because of the believed reduced relevance that lamellae stability has when compared to generation mechanisms. In addition, these stability mechanisms are well understood at a theoretical level and are beyond the scope of this paper’s contributions. Detailed descriptions of each of these mechanisms are provided within Schraam (1994), Weaire (1997), Djabbarah (1985), and Scheludko (1967).
As is discussed in section 2.3.2.1, destabilizing effects are driven largely from capillary drainage. This is attributed to higher liquid pressures at the lamellae than the plateau borders. Additionally, gravity drainage will also cause liquid to drain from the liquid lamellae. Upon drainage of the lamellae, the thin film will eventually reach a critical thickness and rupture. Other mechanisms which can raise the effective critical thickness or cause premature rupture are: gas diffusion, crude oil spreading, and shear.

As is discussed in section 2.3.2.2, stabilizing effects are driven largely by disjoining pressure between the two interfaces with Gibbs Marigoni also contributing by slowing lamellae drainage. Disjoining pressure can be considered to be the sum of forces from electrostatic repulsion, van der Waals attraction, and steric forces. High disjoining pressures can slow drainage or even allow for a meta-stable state to be achieved where drainage forces are perfectly balanced. Under such conditions, liquid lamellae have been observed to last for days or longer. Exhibited disjoining pressure is strongly a function of surfactant type and separation thickness, with disjoining pressure switching from positive to negative (and vice versa) several times as separation thickness decreases from a large value. As such, surfactants which are most suitable for foaming will demonstrate both a) high disjoining pressure states and b) a stable drainage process to such a state which does not cause rupture.

2.3.2.1 Destructive Mechanisms

Capillary Drainage

Drainage of the liquid lamellae through capillary drainage is considered to be the primary destabilizing mechanism for most foams (Schramm 1994), the exceptions to which are discussed later. Drainage through this mechanism is due to a potential in liquid lamellae pressure which induces drainage to the plateau borders. This pressure potential
is expressed in Figure 2.11. In this figure, the radius of curvature can be related to the specific capillary pressure and thus the liquid pressure at a given point. This relationship is discussed below.

![Diagram of pressure differences across curved surfaces in a foam lamella (Schramm 1994)](image)

Figure 2.11: Pressure differences across curved surfaces in a foam lamella (Schramm 1994)

This form of drainage is due to the interfacial phenomenon known as capillarity, where the lowest energy states are associated with reduced interface surface area. The desire for the interface to achieve such a state creates a force or pressure which is known as capillary pressure. The Young-Laplace equation is used to express capillary pressure as a function of interface curvature or radius of curvature (R), and interfacial tension (σ) (Eq. 2.4). According to this relationship, a liquid lamella which has a large radius of curvature (R_{1A}) will have a lower capillary pressure (P_{CA}) than the adjacent plateau border (P_{CB}) which has a smaller radius of curvature (R_{1B}). Because the gas pressure (P_G) is the same for both interfaces, the capillary pressure equations can be equated (Eq. 2.5).
This shows that because $P_{CA} < P_{CB}$, $P_{WA} > P_{WB}$, with $P_{W}$ representing the water or liquid pressure (shown in figure).

\[ P_c = P_g - P_w = \frac{2\sigma}{R} \]  \hspace{1cm} (2.4)

\[ P_{CA} + P_{WA} = P_{CB} + P_{WB} \]  \hspace{1cm} (2.5)

**Gravity Drainage**

Gravity causes liquid lamellae to drain which affects foam stability in a similar manner to that which was previously discussed. For oil reservoirs where capillary pressure is usually at least several orders of magnitude higher than the gravity potential, the impact upon the drainage of an individual lamella is likely insignificant unless the water saturation is very high and thus the capillary pressure low. The larger concern for gravity drainage arises during the steady-state propagation of foam away from the injector. During the displacement process, gravity effects will cause a steady increase in foam quality at the top of the reservoir with an accompanying decrease in quality at the bottom of the reservoir. This topic of gravity stratification of the phases is a concern due to the potential for loss of mobility control at the very top or bottom of the reservoir. This paper covers the topic in detail as part of section 2.4.1 _Existing Mobility Control and Conformance Research_, where the effects of gravity segregation are considered in the context of macroscopic displacement.

**Gas Diffusion**

Inter-bubble diffusion of trapped gas will take place due to the difference in pressures among small and large bubbles. This diffusion is driven by the higher gas pressure in small bubbles than large bubbles due to the interfacial relationship already described by Young-Laplace. This diffusion through the liquid lamellae will drain and
eventually eliminate small bubbles while growing larger bubbles. It can be considered as a process which reduces the number of liquid lamellae and has important significance in the context of lamellae mobilization (discussed in section 2.3.3, *Mechanisms for Foam Generation*) due to a) the reduction of lamellae which are resisting flow, and b) the repositioning of lamellae into flow channels of the network due to bubble growth and displacement (Rossen 1996).

**Lamellae Stretching and Displacement**

During displacement of liquid lamellae through a pore network, the lamellae are subject to stretching forces which cause the lamellae to thin. If the thinning of the liquid lamellae causes a reduction of the disjoining pressure (which is discussed in *Stabilizing Mechanisms*), then the liquid lamellae will rupture or achieve another thin film state where disjoining pressure is higher. The rupture of liquid lamellae when subject to high shear is an important macroscopic flow parameter and is discussed in section 2.4.2, Foam Rheology.

**Oil Effects**

Within current foam-oil stability literature, no content was found which tested the specific ‘low (foam) strength,’ low rate, low lamellae mobility regime which is the focus of this study (see sections 2.3-2.5 for details on differing foam states). Such an anticipated regime correlates poorly with the ‘high (foam) strength,’ high pressure gradient foams which have been studied. As such, this content is excluded from the thesis but can be found in detail in discussions by Schraam (1994), and Nguyen (2004). In general, authors have observed a highly variable destabilizing affect from crude oil. Destabilization effects are attributed, among other factors, to:
• Surfactant partitioning into the oil-water interface, resulting in reduced surfactant available for foam stabilization.

• Altered wettability of the porous medium, making it more difficult for foam to be generated and regenerated.

• Oil entering (emulsification) within the lamellae (plateau borders), allowing for eventual spreading to plateau (see below) or bridging of the pseudo-emulsion film within the plateau border (due to surface tension from large, rigid oil emulsions).

• Oil spreading over the two interfaces, allowing for eventual bridging of the aqueous phase.

Empirical models exist (Schramm 1993, Lau 1988) to relate the bulk surface tension of the phases to the entering ($W_E$) and spreading ($W_S$) coefficients (Eq. 2.6 and 2.7). They reflect the work required for oil to enter or spread along the interface. It is important to note that the bulk surface tensions cannot represent sufficiently the dynamic properties of the two interactive interfaces of aqueous lamella.

\[
W_E = \sigma_{gw} + \sigma_{wo} - \sigma_{og} \quad (2.6)
\]

\[
W_S = \sigma_{gw} - \sigma_{wo} - \sigma_{og} \quad (2.7)
\]

For purposes of this paper, empirical relations between microemulsion environment and salinity is instead used (and verified during testing). During work by Srivastava (2010) and Nguyen (2010), it was demonstrated that increased foam stability was associated with a lower type II(-) environment. As salinity increased to type III or type II(+), foam stability decreased, especially in the presence of crude oil. In the context of entering and spreading coefficients, this transition to type III environment from II(-)
environment also reflects a reduction in $\sigma_{wo}$, and causes a decrease in $W_E$ and an increase in $W_S$. This would reduce the barrier for oil to enter the liquid lamellae, and indicates that entering may be the primary mechanism in determining effective foam stability.

2.3.2.2 Stabilizing Mechanisms

Disjoining Pressure and DLVO Theory

Disjoining pressure ($\pi$) is the primary mechanism by which surfactants stabilize liquid lamellae and foams. Disjoining pressure forms as a result of diffuse double layers that form at the two gas-liquid interfaces on either side of the liquid lamellae and exerts a hydrostatic pressure that acts to keep the interfaces apart (or together in an unstable environment). The disjoining pressure concept represents the total of electrical, dispersion, and steric forces that operate across the lamellae. A brief overview of this important but well understood foam concept is developed below, with a more detailed description of disjoining pressure provided within Derjaguin (1939) and Kovscek (1994) or the previously cited Weaire (1997), Djabbarah (1985), and Scheludko (1967).

As stated, disjoining pressure is the total of electrical, dispersion, and steric forces. These forces will create several attractive and repulsive energy states concurrently which vary with separation distance. Electrical repulsive forces result in a repulsive energy ($V_R$) which decreases exponentially with increasing separation distance. Van der Waals attraction forces result in an attractive energy ($V_A$) which decreases inversely with the square of increasing separation distance, while steric forces are especially pronounced at atomic level distances but diminish rapidly with increases in thin film length. This relationship is expressed in Eq. 2.8, where $h$ is thickness, $V$ is net repulsive energy, and $V_1$, $V_2$, and $k$ are constants. Such a relationship is based upon DLVO theory for total interaction energy (Pashley 1981, Exerowa 1987).
\[ V = V_R - |V_A| = V_1 \exp(-kh) + V_{\text{steric}} - \frac{V_2}{h^2} \]  

(2.8)

Figure 2.12 illustrates how total interaction energy \((V)\) and disjoining pressure \((\pi)\) vary with respect to thin film thickness. The relationship between \(V\) and \(\pi\) can be expressed by taking the derivative of \(V\) with respect to film thickness as shown in Eq. 2.9. Because interfacial phenomenon are captured by DLVO theory, meta-stable states at which drainage does not take place correspond to the points where \(\pi=0\) or \(V\) is at a relative minima. The two meta-stable states which are shown below represent those of the “common black film” at larger \(h\) and the “Newton black film” at smaller \(h\). Successful stabilization of lamellae is therefore a function of: a) existence of such a meta-stable state, b) transitioning such a meta-stable state without rupture, and c) large energy minimum amplitude and width to tolerate perturbation during lamellae displacement which causes stretching.

\[ \pi = -\left(\frac{1}{A}\right) \frac{\partial V}{\partial h} \]  

(2.9)

Figure 2.12: Comparison of the total interaction energy \((V, \ -\ -\ -)\) and the disjoining pressure \((\pi, \ ---)\) in a liquid lamella as a function of film thickness \((h)\). From Tadros (1984)
**Gibbs-Marangoni**

Gibbs-Marangoni is an interfacial phenomenon unique to the use of surfactants. Because surfactant is contained largely within the aqueous phase, during convective flow of liquid to the plateau borders during drainage of liquid lamellae, surfactant is also partially carried with the bulk fluids. This results in a surfactant gradient with increased surfactant concentration at portions of the liquid lamellae near the plateau border. This will, according to the Young-Laplace relation, cause decreased capillary radius near the borders (vs. the center) of the lamellae and result in a partial constriction of the lamellae area available to drainage flow. In turn, drainage of liquid lamellae is reduced. It is worth noting that this phenomenon does not alter the final failure or meta-stable states but instead slows the rate at which these states are achieved. Figure 2.13 illustrates this phenomenon.

![Surface tension gradient opposes film flow](image)

**Figure 2.13.** Gibbs-Marangoni effect in the thin-film drainage process. Surfactant is swept to the Plateau borders by flow in the film and droplet phases, which thereby creates a surface concentration gradient which causes a surface tension gradient. (From Kovscek 1984)

### 2.3.3 Mechanisms for Foam Generation

It was previously indicated that liquid lamellae are thermodynamically unstable. This requires constant generation of foam for the steady-state presence of foam in porous
media, the three mechanisms for which are: gas ‘snap-off,’ lamella ‘leave behind,’ and ‘lamella division.’ These individual mechanisms for lamellae generation and destruction are described in the work by, Shen (2006) and Renkema (2007), among others.

In brief, gas ‘snap-off’ creates lamellae at the constrictions created by pore throats. These lamellae are flow normal and can reside at the pore throat or be displaced out depending on the in-situ capillary pressure of the respective pore throats and induced flowing pressure gradient. Lamella ‘leave behind’ creates lamellae perpendicular to flow during drainage in porous media due to gas displacing liquid in two adjacent pores. ‘Lamella division’ creates multiple lamellae from a singular flowing lamella which is concurrently displaced into multiple flowing channels. More detailed descriptions of each mechanism are provided below. The criteria for these particular mechanisms to be present are also discussed in section 2.3.4 due to their contribution to effective foam rheology in porous media.

**Gas ‘Snap-off’**

Gas ‘snap-off’ occurs primarily as a function of pore geometry and displacement of gas through a medium. This is unlike ‘leave behind’ and ‘lamella division’ mechanisms which are largely dependent upon the presence of process drainage (‘leave behind’) or process pressure gradient (‘lamella division’). During displacement of gas through a porous medium, variability in pore throat size will cause a series of constrictions which may cause separation of a single flowing bubble into two or more gas bubbles. Figure 2.14 provides a schematic of this process.
Figure 2.14: ‘Snap-off” mechanism of lamella creation: (a) gas entry into liquid filled pores; (b) swelling of films to bridge the throat; (c) liquid lens bridging the throat after snap-off (Kovscek 1994).

The ability for this mechanisms to occur is dependent upon the ability for the displaced gas to first achieve a capillary pressure above the entry pressure ($P_c^*$), which allows the gas to enter the pore throat. As gas is displaced through the pore throat, the capillary pressure must then fall below the critical capillary pressure for ‘snap-off” ($P_{c\text{sn}}$). For straight cylindrical throats and bead packs, this relationship among the two is approximately $P_{c\text{sn}}=P_c^*/2$ (Falls 1988). A variety of flowing conditions can result in such conditions, all of which are related to a buildup in capillary pressure due to entry requirements and normalization of downstream capillary pressure for gas as it passes through the constriction (Rossen 1996).

Like lamella leave behind, this process can occur independent of the presence of surfactant. The addition of surfactant, however, is critical towards providing the required lens (or lamella) stability for the lamella to undergo displacement into the pore network. It is through displacement into the pore network that a high number (or density) of liquid lamellae can propagate and provide an effective resistance to flow. The stability parameters for such movable lamellae were discussed previously (Mechanisms for Foam
Stability), while the parameters for actual displacement are discussed as part of Critical Capillary Pressure Theory in section 2.4.

‘Leave behind’

Lamella ‘leave behind’ is the result of drainage processes which take place during gas flooding. As shown in Figure 2.15, the mechanism results in the propagation of flow parallel liquid lamellae as a result of capillary pressure and reduced flow perpendicular pressure gradient during the displacement process. As is discussed in section 2.4, because ‘leave behind’ results in flow parallel lamellae which are mostly stationary, lamellae produced through this mechanism result in substantially less resistance to flow than the other two mechanisms. These lamellae are likely only significant where the effects from the other two foam mechanisms are less significant, as is discussed in LTG in Tight Formations (section 2.5).

Figure 2.15: Schematic of lamella creation by ‘leave behind.’ Rock grains are represented in lined circles, liquid in gray color, and gas in white color. (Kovscek 1994)
‘Lamella division’

‘Lamella division’ is a secondary mechanism for generation of liquid lamellae because it relies upon the other two mechanisms for the initial germination lamellae which can then be divided. Figure 2.16 provides a schematic of the ‘lamella division’ mechanism. It shows that as a single fluid bubble is displaced through a porous media, concurrent flow into multiple flow networks can result in the production of additional liquid lamellae through the separation of the bubble. This mechanism is also unique in that it requires sufficient in-situ pressure gradient (or the related capillary pressure) to mobilize the liquid lamellae into a flowing state. This is expressed in critical capillary pressure theory (section 2.3.4.1) through the propagation of two different foam regimes, a ‘high strength’ and a ‘low strength’ foam regime. This section discusses how the presence of flowing lamellae results in much higher flow resistance due to the generation of much larger quantities of lamellae.

Figure 2.16: Schematic of lamellae creation by ‘lamella division’ method. (Kovscek 1994)
2.3.4 Foam Rheology in Porous Media

Foam resistance to flow in porous media can vary by several orders of magnitude depending upon the specific nature of rock geometry, fluids type, fluid fraction, and fluid rate, among other factors. Large differences in foam strength can be observed depending on the degree of lamellae creation and their respective stability. Critical Capillary Pressure Theory (See section 2.3.4.1 below) is often used to express a distinct difference between two foam regimes based upon conditions required for lamellae displacement and thus increased lamellae generation through ‘lamellae division’ and increased ‘snap off’ (mechanisms described previously). In addition, similar (albeit smaller) differences in foam resistance to flow can be observed for systems of consistent lamellae generation where fractional flow, rate, and/or other parameters are changed. These relations are described in Impact of Foam Quality and Rate where effects of fractional flow, relative permeability to liquid, and foam destabilization are discussed.

2.3.4.1 Foam Regimes | Critical Capillary Pressure Theory

Two foam regimes are believed to exist within porous media: a low-low quality regime, and a high-quality regime (Osterloh 1992; Nguyen (2000); Gauglitz 2002). Low-quality foams are also known as “coarse” or “weak” foams. For such foams, lamellae are generated through ‘snap off’ and lamella ‘leave behind.’ Due induced pressure gradients which are too low to overcome capillary forces at the pore throat constrictions, these generated lamellae remain static. This restricts the number of lamellae which are present and results in reduced resistance to flow and a ‘coarse’ or ‘weak’ foam state.

The second foam regime is the high quality regime which is also known as that of ‘strong foam.’ This foam regime is associated with mobilization of lamellae which were previously generated at the pore throats through ‘snap off’ or ‘leave behind.’ Upon displacement from these constrictions, these mechanisms are capable of generating
additional lamellae. In addition, mobilized lamellae can reproduce through ‘lamella division’ as they flow through the pore network. This is of particular importance due to the limited pore throat geometries which enable the other two mechanisms. A much greater degree of pore network throats and constrictions are capable of forming lamellae under these conditions.

Figure 2.17 shows the abrupt transition in pressure gradient which can occur once a critical pressure gradient ($\Delta P^{\text{min}}$) is achieved. This transition is affected by a sufficient number of pore throats with static lamellae achieving the required pressure gradient to displace these lamellae. This causes additional lamellae to be generated which further increases resistance to flow and pressure gradient, eventually causing a ‘high strength’ to be achieved. Once this mode is achieved, a high degree of hysteretic properties are demonstrated, with ‘high strength’ foam behavior still exhibited at reduced flow rates (Shi 1996).
Figure 2.17. Schematic of minimum pressure gradient for ‘strong foam’ generation as seen in experiments at fixed flow rate that is steadily increased (a) Increase in pressure drop upon foam generation. (b) Relation between pressure gradient and interstitial velocity. From Gauglitz (2002)

![Figure 2.17](image)

Figure 2.18. Minimum pressure gradient for ‘strong foam’ generation as a function of permeability for N2 and CO–2 foams. All of the N2 foams were conducted with \( f_w = 0.1 \) and 1.0 wt % surfactant. CO2 tests were conducted with \( f_w = 0.2 \) and 0.5 wt % surfactant. From Gauglitz (2002)

![Figure 2.18](image)
The required pressure gradient for lamellae mobilization is directly related to the in-situ capillary pressure for the pore throats at which the static lamellae exist. Figure 2.18 presents the required pressure gradient for creation of a ‘strong foam,’ which is directly associated with mobilization of liquid lamellae. By presenting a model based upon percolation theory with beadpack data (Rossen 1990), the plot shows that reduction in permeability is associated with an increase in $\Delta P_{\text{min}}$ according to the relationship $\Delta P_{\text{min}} \sim k^{-1}$.

This relationship can also be explained according to the Young-Laplace equation where capillary pressure is inversely proportional to interface radius. This indicates that lower permeability sands, which have a smaller pore throat radius, will have a larger capillary pressure which must be overcome. This relation is used in the construction of a limiting capillary pressure ($P_c^*$) which associates Darcy’s law with capillary number in order to determine macroscopic flow parameters required for lamellae mobilization. Eq. 2.10 presents this relationship, and using an observed $N_c=8$ for lamellae mobilization shows that $\Delta P_{\text{min}}$ scales as $k^{-1/2}$ (Ransohoff, 1988). In the described equation, $\mu_{nw}$ is the viscosity of the non-wetting (gas) phase, $v_t$ total interstitial velocity, $\phi$ porosity, $L$ is the length of the core, $R_g$ the grain radius, $\sigma$ gas-liquid surface tension, $k_{rnw}$ the relative permeability of the non-wetting (gas) phase, and $f_{nw}$ the fractional flow of the non-wetting (gas) phase (Gauglitz 2002).

$$N_c \equiv \frac{\mu_{nw} v_t L R_g}{\phi k R_{rnw}} = \frac{v_p L R_g}{f_{nw} \phi \sigma}$$

The exact nature of the $n$ exponent which dictates the $\Delta P_{\text{min}}$ versus $k$ relationship is beyond the scope of this study. It is considered to be of lesser importance due to forecast $\Delta P_{\text{min}}$ values for either relation which would be several orders of magnitude
higher than feasible in formations of 10mD. In addition, the empirical data used to develop these models is most commonly that of micromodels, beadpacks, sandpacks, or high permeability rock outcrop cores. The permeability range used in this study falls outside of the range dictated by these experiments. This is further amplified by the increased variability in pore size (and throat) distribution for tight formations, causing a diminished correlation between macroscopic permeability and actual in-situ conditions at the pore throats.

2.3.4.2 Impact of Rate and Foam Quality

Foam Displacement Rate Impacts

The relationship between the rate that foam is displaced through porous media and observed apparent viscosity is highly complex. It was previously described how high displacement rates or pressure gradients could positively impact foam strength through creation of a ‘high strength’ foam regime. Because the achievement of such a regime is commonly considered by literature to be favorable, high flow rates quite often receive considerable weight in the understanding of foam rheology. There are however, a number of settings under which foam can also exhibit shear thinning behavior. These conditions are described below.

Foam is known to exhibit shear thinning behavior near many injection points of oil reservoirs. This relationship is related to individual lamellae stability and can be described by the impact that high flow rate has upon lamellae stability. Within specific flow regimes, increases in flow rate (gas quality or other conditions also being a factor) can cause destabilization of liquid lamellae. High rate has the effect of either: a) mobilizing un-mobilized liquid lamellae which are unstable during displacement, or more commonly b) through stretching of the lamellae, decreasing temporarily decreasing the
thin film thickness to an unstable thermodynamic state. These mechanisms are described in greater detail by Nguyen (2004), Rossen (1996), and Osterloh (1992). Additionally, from an economic perspective shear thinning behavior can be considered favorably due to: a) the positive impact that it has upon injectivity, and b) associations to lamellae stretching which temper shear thinning effects in fractures or high permeability channels (less variability in channel size).

**Foam Quality Relations**

Foam quality is defined as the fractional flow of gas fluids injected (surfactant-water as the other phase). Because foam quality has a substantial impact on the gas saturation and relative velocity of the phases, it has the potential to have a substantial impact upon the apparent viscosity of foam. It is important to know, however, that this relationship is complicated by the effects that varying foam regimes (‘weak foam’ versus ‘strong foam’) and shear thinning behavior can have upon foam strength. These complicating effects are partially dependent on foam quality, as discussed in the respective sections, and thus necessary in the discussion of foam quality impacts. Because these topics are discussed in other sections, this section is used to describe foam quality effects as they pertain to a singular flow regime in absence of shear thinning behavior.

Changes in gas fractional flow can cause foam flow in porous media to have two characteristic regions. In one region, high liquid fractional flow results in a small number of dispersed gas bubbles (‘bubble flow’). In such a regime, the flow of rigid gas bubbles through pore throats results in the primary resistance to flow. Accordingly, the resistance to flow in such a regime is primarily a function of gas flow rate or fractional flow. As gas rate is increased to high levels, a second flow regime exists. In this regime, gas is the primary flowing phase and liquid occupies the boundaries of the pores with lamellae
spanning the pore throats. The high gas saturation and relative rate results in reduced resistance to gas flow but high resistance to liquid flow. On a macroscopic level, the pressure gradient in this region is shown to be primarily a function of liquid rate. Work by Alvarez (2001), Nguyen (2004), and Osterloh (1992) further describes this relationship.

Figure 2.19 shows the above described relationship. At high gas rate, observable pressure gradient is primarily a function of liquid flow; while at high liquid rate, observable pressure gradient is primarily a function of gas rate. This manifests a mobility minimum with respect to both injected phases, where the maximum pressure gradient is observed.

Figure 2.19: Flow regime diagram—contours of pressure. Osterloh (1992)
It is also important to note that many gas or foam injection strategies do not involve the steady-state presence of a singular gas-liquid fractional flow relationship. Drainage or surfactant-alternating-gas (SAG) injection processes result in substantial changes in gas-liquid or foam mobility during the flooding process. For surfactant-alternating-gas, in-situ mixing of gas and liquid to create low mobility foam is often modeled through use of a ‘spreading wave’ concept. This concept is described below in section 2.4.1 and is related to a progression from a high gas fractional flow state to a high liquid fractional flow state or vice versa.

2.4 IMPLEMENTATIONS & LIMITATIONS TO FOAM FLOODING

2.4.1 Existing Mobility Control & Conformance Research

Use of foam in the oilfield was first proposed by Bond and Helbrook (1958) and has since been used to decrease the mobility of injected gas. Significant applications in the petroleum industry include: acid diversion in well stimulation, well drilling and fracturing, environmental remediation, and enhanced oil recovery.

Of the stated applications, near wellbore methods requiring a ‘high strength’ foam, which can propagate in high permeability medium (See 2.3.3_Mechanisms for Foam Generation), are considered beyond the scope of this paper due to very different rate, permeability, apparent viscosity, and distance from the wellbore. Far wellbore methods for mobility and conformance control are a much better process analogy to LTG for EOR and are currently used as part of successful gas (CO2, N2, hydrocarbon, air) or thermal flooding.

Such far wellbore methods as: a) the injection of aqueous-phase foaming surfactant during water-alternating-gas processes (WAG), which is titled “surfactant-alternating-gas” (SAG), and b) gas/liquid co-injection processes have been shown to
substantially reduce the mobility of the injected fluids and improve ultimate oil recovery through increased sweep efficiency (Blaker 2002; Shi 1998). This is significant because for gas injection in the absence of mobility control, gravity override, channeling, and/or viscous fingering can negatively alter otherwise acceptable sweep efficiency (via waterflood) and cause early breakthrough of high mobility free gas. Upon breakthrough of high mobility free gas, it is common for there to be minimal increases in sweep efficiency (Renekema 2007).

A significant number of field trials of gas-liquid (foam) co-injection and surfactant-alternating-gas (SAG) injection have been conducted. These trials include more than 11 foam field trials with N2, CO2, air or hydrocarbon gas in the North Sea which are described together by Shan (2001) and Rossen (2004). In these studies, a variety of injection strategies and surfactants were used. Results varied, however, large increases in oil production and reductions in produced gas were observed for a number of pilots. This behavior can be attributed to increases in mobility control and sweep efficiency.

2.4.1.1 Gas-Liquid Co-injection

A schematic of a gas-liquid mixing zone which takes place during gas-liquid injection is shown below (Figure 2.20). Within this mixing zone, moderate gas and liquid fractional flow is associated with a trend towards a mobility minimum. This relationship, however, is only valid for approximately proportional gas and liquid fractional flow states (in the absence of foam), and it quickly breaks down due to gas fingering or gravity segregation which cause high concentration flows of the respective phases (as described previously). As such, (absent foam) gas-liquid co-injection provides poor mobility control for the non-near wellbore region.
Through addition of surfactant to the aqueous phase, increased stability of the dispersed gas phase allows for an expanded low mobility mixing zone. This is accomplished through the propagation of foam, with mechanisms for which described previously. The results of this enlarged mixing zone include: a) increased gas contact and b) increased displacement of contacted/mobilized crude oil. Experimental observation of foam propagation through use of surfactant-gas co-injection is included in chapter 4 where the strategy is contrasted with surfactant-alternating-gas (SAG) strategies suggested by other authors.

![Figure 2.20: Schematic of three uniform zones in model of Stone and Jenkins for continuous co-injection of gas and water (From Rossen 2004).](Image)

**2.4.1.2 Surfactant-Alternating-Gas (SAG)**

Surfactant-alternating-gas (SAG) is often used in place of surfactant-gas co-injection to avoid high pressure gradients associated with foam propagation near the wellbore. By alternate injection of single phase surfactant-liquid with gas, foam generation can be suppressed until mixing takes place further into the reservoir. Mixing further along the reservoir will create an expanding low mobility region due to foam
propagation as expressed by Figure 2.21. The increased injectivity via reduced near-well foaming reduces effects of gravity segregation and results in increased mobility control. Further, a greater portion of the well-to-well pressure drop can be dissipated in the non near-well region, helping to displace additional oil (Shan 2002).

Figure 2.21: Time-distance diagram for the idealized model of Shan and Rossen (Shan 2002) for a SAG displacement. It shows a narrow low-mobility region with thickness ($\tau$) and total-relative mobility ($\lambda_{rt}$). $\tau$ increases with distance from the well.

SAG injection process is also used prevent gas breakthrough associated with surfactant absorption. During co-injection of gas and surfactant-liquid, surfactant surface absorption and preferential partitioning at the oil-water interface will result in a diminished rate of advance of an available surfactant front (for gas-liquid lamellae production). Gas which may otherwise advance at the same rate as other injected fluids may then become uncontacted by surfactant as the surfactant front advances at a slower rate. Lacking available aqueous phase surfactant, early slug gas may then lose mobility control and finger through the core. Free gas which fingers through the core will
establish high gas saturation for more permeable channels and prevent lamellae production during later portions of the displacement process.

### 2.4.2 Micellar Foam Flooding

Some limited work towards surfactant oil mobilization with coupled foam mobility control flooding exists. Such work is given the term micellar foam flooding for purposes of this review, although it may be referred to differently by the authors. Results of these mostly experimental studies and one field pilot indicate that design for oil mobilization, ideal foam viscosity, process stability, and overall effectiveness is not well developed. These individual studies are described in depth below. Common process pitfalls during these studies are:

- Poor control of microemulsion environment to mobilize and displace crude oil, typically achieved through a progression from Windsor Type III to Windsor Type II( ) microemulsion environment (ASP process analogy).
- Poor control and understanding of destabilizing effects of crude oil and microemulsions upon foam strength.
- Reliance upon unrealistic flow-rates or high gas quality to achieve ‘high strength’ foam state. Accompanying unrealistic pressure gradient due to ‘high strength’ foam.
- Improper use of ultra-high permeability sandpacks or other porous media where foam generation, stability, and rheology will deviate from that of actual reservoir permeabilities. Characteristic lack of fundamental study of foam flooding in tight formations.

Initial micellar foam flooding studies by Kamal and Marsden (1973) and Lawson and Reisberg (1980) demonstrated that during flooding in a porous medium, injected
foam (Kamal) and alternate gas/dilute foaming surfactant injection (Lawson) could effectively displace a .05, 0.1, and 0.25 PV concentrated (5%) surfactant slug. Tertiary recovery during the Kamal study was poor (20-50% incremental) when compared to benchmark Surfactant-Polymer (SP) flooding and likely reflects poor foam stability for mobility control. In addition, the ultra-high sandpack permeability of 23.6D is a poor analogy for actual reservoir conditions.

Better overall recovery was observed during the Lawson study and was strongly correlated with both observed pressure drop and residual gas saturation. Alternate gas/dilute foaming surfactant injection resulted in ultra-strong foam strength which is likely untenable for field-type applications. Gas/liquid co-injection resulted in weaker foam which exhibited desirable, albeit highly variable, foam strength. These results indicate both the importance of foam strength for flood success, and the ability for the micellar foam flooding to generate foam of sufficient strength in situ. Compelling recovery profiles were observed with high oil cut, which is indicative of an oil bank; however, remaining oil saturation after flooding of 10-20% indicates that ideal oil-water IFT may not have been achieved. In addition, the body of the study encompasses more permeable rock outcrop cores of 450-500mD where foam rheology and propagation likely differ.

The single known micellar foam flood pilot is described by Wang (2001) for the Northern Daquing Oilfield. Poor laboratory recovery of below 50% ROIP was observed for micellar foam and micellar polymer (ASP) flooding, indicating an apparent poor understanding and control of microemulsion environment. Further, a designed gas-liquid ratio of 3:1 was unachievable in field setting due to poor injectivity, forcing the reduction to 0.34:1 during injection. Nonetheless, ultimate recovery of 33% ROIP current and 44%
ROIP forecast is comparable to laboratory data and reflects the ability for the process to upscale effectively.

Srisvastava (2009, 2010) is the first systematic study of micellar foam flooding which incorporates effects of microemulsion environment. The concept of salinity gradient is introduced as a process analogy to current ASP flooding. Further, the effects of salinity and microemulsion environment upon foam stability are studied to best optimize the micellar flooding process. This work resulted in good tertiary recovery (60-90%) and ASP process characteristics—shock front and oil bank. However, the 5:1 gas-liquid ratio used requires greater than 8 PV injected fluid for process completion. In addition, the core outcrops utilized exhibited higher permeability (100-250mD) where foam mechanisms likely differ.

Li (2008) and Hua (2011) provide additional experimental studies of micellar foam flooding. High flow rates (>20ft/day) and permeability (>1 Darcy) associated with these sandpack floods (Li) and corefloods (Hua) make these floods poor analogies for flooding in tight reservoir rock. Both Li and Hua place an emphasis upon the creation of a ‘strong foam’ environment which is poorly suited for flooding in tight rock.
2.5 LTG in Tight Formations

Current foam mobility control research has an emphasis upon achieving a ‘high strength’ foam state. ‘High strength’ foam is associated with high in-situ pressure gradients due to the large scale generation and displacement of stable lamellae. Previously noted resistance factors associated with ‘high strength’ foam ($RF=200-500$) which make design for highly permeable sands difficult, would be untenable for tight rock (<20mD), the objective of this study.

Further, as described previously in Relevant Foam Theory, conventional foam theory indicates an inverse relationship between minimum critical pressure gradient for creation of ‘high strength’ foam and rock permeability. This is based upon an understanding of lamellae mobilization as the critical factor in achieving large populations of in-situ liquid lamellae which impede flow. As such, a conventional ‘high strength’ foam state may not be achievable for tight formations under practical conditions, even if such a state were considered to be desirable.

Based upon the empirical data from Chou (1991), Friedmann (1991) and relevant foam theory (as described previously), it is believed that a ‘weak foam’ region exists which can provide a desirable flow resistance factor for displacement of light crudes in tight porous media. In this regime, lamellae generation is primarily driven by ‘snap off’ and ‘leave behind’ mechanisms which are only poorly dependent upon pressure gradient or capillary pressure. These lamellae will primarily be of the immobile variety due to the high in-situ capillary pressures demonstrated at the small pore throats and should provide a reduced but still sufficient resistance to flow. Balan et al (2012) has shown that gas relative permeability is exponentially reduced with trapped gas saturation.

In addition, preferential flow and partitioning of mobile lamellae (‘lamella division’) may be present in the higher permeability channels where capillary pressures
are reduced. If present, this could favorably impact displacement efficiency by preferentially impeding flow in the higher permeability regions. This characteristic of widely varied pore throat size distribution and related capillary pressures in tight formations would be characterized on a macroscopic level by a critical pressure gradient transition zone. Instead of a critical capillary pressure causing a discontinuity in foam strength as lamellae are mobilized throughout the medium, pore volume available to lamellae mobilization would be a function of induced capillary pressure. As pressure is increased, smaller and smaller channels would exist which allow for mobilization of liquid lamellae. This would indicate that foam strength is a function of pressure gradient or other factors affecting in-situ capillary number such as gas saturation.
Chapter 3: Proof of Concept and Analytic Tools

3.1 INTRODUCTION

This study tests the ability for the LTG process to effectively mobilize and displace tertiary oil in tight formations at economic rates and pressure drop. A chemical formulation is designed and a series of corefloods are performed to evaluate overall process effectiveness and potential for economic application in tight reservoirs. A total of five corefloods are included within this study.

Data from oil recovery and fractional flow; salinity and mixing, sectional pressure drop; and microemulsion and surfactant production are used to evaluate LTG flooding (Ch. 3.3). Reference floods are used to establish repeatability and determine the relative process contributions of gas flooding and surfactant flooding (Ch. 3.4.1 & 3.4.2). In addition, effects of high initial oil saturation are tested to determine process tolerance to oil and evaluate potential for application during secondary recovery (Ch. 3.4.3).

High oil saturation has the potential to destabilize the liquid lamellae which provide the resistance to gas flow via separation of a dispersed gas phase. Reduced apparent viscosity and gas fingering are typically associated with unstable lamellae environments and can result in critical failure during reservoir displacement processes. A high degree of process tolerance towards initial oil saturation also would indicate favorably for application at secondary recovery. Such application has the potential to improve reserve capture and payback by accelerating recovery and reducing high pressure gradients typically associated with flooding tight reservoirs.

Using the data provided by these five floods, additional physical process attributes are studied (Ch. 3.5) and macroscopic stability parameters analyzed (Ch. 3.6). Physical process attributes which are studied include: gas breakthrough, oil bank elongation, liquid dispersion, and gas saturation. Macroscopic stability parameters which are analyzed are:
displacement front mobility ratio and apparent viscosity of displaced and displacing fluids.

3.2 **EXPERIMENT DESCRIPTION**

3.2.1 **Materials**

The chemicals used in LTG corefloods were already identified in previous ASP studies (Mohammad 2009; Flaaten 2008; Zhang 2006), comprehensive ASP/foam studies (Hirisaki 2004, 2005, and 2006), and micellar foam floods (Srivastava 2009; Li 2008; Hua 2011). Selection is based upon their respective effectiveness in residual oil mobilization and foam mobility control. Brief description of the chemicals utilized in this study is expressed below. A synthetic soft brine and consistent alkali concentration were incorporated into design to improve control during this study. More detailed description of the chemicals and their selection can be found in the cited proceeding literature; however, process design during this study, and accordingly results, is consistent with practices suggested by other researchers.

*Surfactants and Co-solvents*—Two surfactants were used, an alcohol propoxy sulfate (with C_{16-17} branched alcohol hydrophobe and seven propylene oxide groups) and an internal olefin sulfonate (with C_{15-18} twin-tailed hydrophobe). The combination of these two surfactants has been shown to give the best results in ASP corefloods conducted with light oil at low temperature (Levitt 2006-b). Further, IOS has been shown to demonstrate good foaming behavior at low concentration. The co-solvent Triethylene Glycol Monobutyl Ether (TEGBE) was added to improve equilibration time during this study and could likely be removed during field study, as observed microemulsions viscosity was low.
Alkali and Synthetic Brine—Alkali reduces surfactant adsorption on rock surfaces, can generate soap in the presence of a reactive crude oil, and can speed microemulsion equilibration (Hirasaki 2004). Sodium carbonate (Na$_2$CO$_3$) is a common alkali and is used in this flood. For formations with concentrations of divalent cations in solution (Ca$^{2+}$ and Mg$^{2+}$), undesirable precipitation of sodium carbonate can take place in the form of insoluble salts (carbonates). To minimize and ensure consistent absorption for all corefloods, 1% Na$_2$CO$_3$ was added to synthetic brine and injected chemical formulations. In addition, to prevent carbonate precipitation, divalent cations were excluded from all injected fluids. NaCl was added to achieve the brine composition of 1.00% Na$_2$CO$_3$, 3.46% NaCl (wt %). Brine viscosity was measured at ~0.9cP.

Outcrop Cores—Texas Cream Limestone cores exhibited the permeability type and consistency desired for this study. Four cores cut parallel to the bedding plane (LTG 1-4) exhibited 10.8mD-14.2mD permeability to brine. One core cut for flow almost perpendicular to the bedding plane (LTG 5) exhibited 2.6mD permeability. Core dimensions were 1.5”x12”. For preparation, cores were aged dry at 120°C after cutting.

Crude Oil—The crude oil used for floods had a viscosity of 1.9 cP and a density of 45 API. Phase behavior tests indicate that mixing of the crude with Na$_2$CO$_3$ resulted in no observable production of microemulsions or soap, indicating the crude is minimally/not reactive.

3.2.2 Experimental Procedure

3.2.2.1 Aqueous stability and phase behavior tests

Aqueous stability and phase behavior tests were carried out to determine the ideal chemical formulation for chemical slug injection. Criteria and process for screening are described in detail by Flaaten (2008), Jackson (2006) and Levitt (2006-a). Several
surfactant/co-solvent concentration pairings were tested across a salinity spectrum to select a ratio which exhibited the desired microemulsion phase window, high oil solubility, and surfactant stability. The selected chemical formulation had the properties 1.25% surfactant at 3:1 propoxylated sulfate to IOS with 1.0% TEGBE.

Figure 3.1 depicts the oil-surfactant solubility ratio as a function of total dissolved solids, with actual phase behavior photo’s available in Appendix A. TDS is the sum of a consistent 1.0% Na$_2$CO$_3$ and a variable NaCl concentration. Optimum salinity was observed at approximately 35,000ppm TDS with a solubization ratio of $\sigma^*=32$ (cc/cc) and implied oil-water interfacial tension of $3*10^{-4}$ dynes/cm according to the Chun Huh equation.

![Figure 3.1: Oil and water solubilization data for selected surfactant formulation (t=7 days). Optimal salinity solubilization ratio of 32 corresponds to oil-water IFT of $3*10^{-4}$ dynes/cm (Huh, 1979)](image)

Higher salinity values correspond water in oil Windsor Type II (+) microemulsions while lower salinity values correspond with oil in water Windsor Type II (-) microemulsion. Through use of a negative process salinity gradient, as is common with ASP flooding, a progression across optimum salinity is induced. This is done to
introduce favorable salinity tolerance, reduction of microemulsion viscosity, and decreased surfactant absorption. Further, when injecting surfactant-gas (foam), synergistic effects between the Type II (-) and foam stability are observed (Srivastava 2009).

3.2.2.2 Drive Chemical Selection and Testing

Foam stability tests are commonly carried out to determine the extent to which the injected surfactant solution is able to stabilize foam. Bulk foam tests which are commonly undertaken test the rate at which a high quality bulk solution of foam decays as described by Hua (2011) and Nguyen (2010). These tests; however, often diverge with available data for flow in porous media due to different foam rheological properties and the importance of foam generation mechanisms upon creation of a high in-situ population of liquid lamellae. For purposes of this study, bulk foam tests were used on a purely qualitative basis to indicate the presence of stable foam. Surfactant type and concentration was derived from previous authors, which observed favorable drive apparent viscosity during gas-surfactant displacement with nitrogen. The selected drive composition was 0.10% IOS with 1.0% Na$_2$CO$_3$.

Bulk foam tests were conducted for both injected slug and drive chemical solutions in the presence of experiment crude oil and without experiment crude oil. For injected slug solution, stable foaming was observed for aqueous only samples; however, diminished foaming was observed during testing with crude oil included. This is due to the destabilizing affects associated with Windsor Type III microemulsion upon foam stability. Depending on the extent of destabilization, this attribute can be considered to have favorable implications for process conformance. Through diminished stability in
unswept zones with respect to already swept zones, preferential flow of injected fluids to unswept zones may take place.

For injected drive solution, stable foam was observed for samples both with and without crude oil. This can be attributed to reduced salinity and a lower Windsor Type II (-) microemulsion environment where microemulsions are not believed to correlate with a high degree of lamellae destabilization. Presence of stable drive apparent viscosity due to foam is critical for process stability, and therefore it is desired for drive fluid to exhibit foaming properties throughout a wide range of crude oil saturations.

3.2.2.3 Coreflood Apparatus and Procedures

The coreflood apparatus used in this experiment is described by the schematic (See Appendix A). Overall design is consistent with that of coreflood experiments conducted by other researchers. Two back pressure regulators were utilized at the coreholder effluent to maintain elevated experiment pressure. This is required to minimize the effects of gas expansion which is induced via a pressure gradient as gas flows through the core. A pressure of 580 psi was selected for N₂ flooding as a compromise between the desire to minimize gas expansion and the desire to minimize nitrogen miscibility effects, which are both outside the scope of this study.

Liquid rates were controlled via a Jasco PU-2080 HPLC pump which was tested to show ±1% accuracy over the range of rates used in the experiment. Gas rate was controlled via a Brooks Sla5850 mass flow controller with regulated upstream (gas supply) and downstream (via BPR) pressures of 1150 and 1100 psi respectively. Good control of mass rate (±3%) was shown down to rates equivalent to 0.25 ft/day gas interstitial velocity. Average core pressure at waterflood completion was used as the pressure for required gas flow calculations. This was shown to be a good approximation,
with average experiment pressure deviating by less than 1.5% for all points during chemical flooding. Pressure was observed at $X_d =$ $0.00$, $0.25$, $0.75$ and $1.00$.

Synthetic brine and limestone cores were prepared as described in Materials. Injected chemical slug and chemical drive were prepared to the specifications determined in phase behavior testing. Samples from prepared batches were taken, mixed with study crude oil, and compared to reference phase behavior to ensure that fluid properties were consistent with desired composition and properties.

Injected slug, drive, crude oil, and brine were placed in individual accumulators located inside the oven to eliminate the effects of thermal expansion during injection. Chemical slug and drive were placed in volumetric accumulators and were displaced by a lower density immiscible mineral oil. Partitioning of surfactant into mineral oil was not observed. Crude oil was placed in a volumetric accumulator and displaced via a higher density DI water. Synthetic brine was placed in a piston accumulator and displaced via DI water. Aqueous solutions demonstrated minimal thermal expansion, while crude oil was measured to expand 2.5% during heating from standard conditions to 45 Deg C. This was corrected for during volume balances which were used to calculate in-situ saturations.

Limestone cores were enclosed in aluminum and heat-shrunk plastic liner with ends exposed. End pieces were not required due to coreholder influent/effluent dispersion grid patterns which reduce flow convergence effects. The core was placed in the core holder and holes were drilled at 3” and 9” to accommodate coreholder pressure taps. Mineral oil was used to fill the confining sleeve and set confining pressure at 1300psi. The setup was leak tested with nitrogen at 800 psi.
After preparation and installation of experiment fluids and core, the following procedures are used to describe the experiment:

1) Brine Saturation: The setup and core were vacuumed for 12 hours and then saturated at low rate to 100% brine. Material balance calculations were used to calculate brine pore volume. Results were consistent with calculated pore volume via salinity tracer testing which was done for two experiments. Flooding for this step was at ambient temperature of 21°C.

2) Core Aging: Oven temperature was set to experimental temperature of 45°C and 10 PV brine was displaced through the core at low rate over a period of 5 days. High sodium carbonate concentrations in the displacing brine (1.0%) were used to establish a low absorption environment for later chemical flooding.

3) Permeability: Permeability to brine was measured at several discrete flow rates over a wide range. Results were used to determine sectional permeability and also establish an improved transducer calibration. Linear regression of measured sectional pressure drop versus flow rate was used to normalize to a zero flow rate pressure drop of zero. Apparent $R^2$ of >.999 and good inter-experiment consistency of transducer calibration factor were observed.

4) Oil Saturation: Oil injection was carried out at 10 cc/hr (~6 ft/day) for 2 PV, at which point fractional flow of water ($f_w$) ~0. Irreducible water saturation ($S_{wi}$), initial oil saturation ($S_{oi}$), and relative permeability of oil at residual water saturation ($k_{ro}^*$) were calculated.

5) Waterflood: Oil was displaced by injecting brine at 2ft/day, which is consistent with chemical flood injection rate. 2 PV brine was injected, at which point $f_w$ varied between 97% and 100%. Remaining oil saturation ($S_{or@2PV\ waterflood}$), water saturation
(S_{w @ 2PV \text{ waterflood}}), and relative permeability of brine at 2 PV water injected (k_{rw @ 2PV \text{ waterflood}}) were calculated.

6) Slug Injection: After waterflood, 0.3 pore volume (PV) previously prepared chemical slug was co-injected with nitrogen at 50% gas fraction—0.6 PV total fluid (PV_{\text{Total fluid}})—at a liquid rate (q_L) of 1 ft/day which was equivalent to total fluid injection rate (q_{\text{Total}}) of 2 ft/day. This was consistent with waterflood injection rate. Use of a T-valve for mixing resulted in ~0.0025 PV gas/liquid alternate injection which was determined visually from 1.5in gas/liquid slugs at the influent (known tubing ID). Flow streams for injected fluids were pressurized to match in-situ core conditions before commencing pressure communication in order to remove pressure shock and improve material balance.

7) Drive Injection: Drive injection followed slug injection at identical rate and gas quality. Injection proceeded until either 100% water cut or 3.5 PV_{\text{Total fluid}}.

- Fluids Processing and Measurement: A fractional collector and burette were used to measure volumes of produced fluids for procedures 4-7 and 4-5, respectively. Production of microemulsion during certain portions of Slug and Drive injection required heating of select samples to elevated temperature of 80 °C to break microemulsion. Results were recorded previous to and post microemulsion breaking, with small quantities of highly stable microemulsion still present for select samples. Salinity was measured for a clean aqueous phase (if present) via salinity probe and calibrated to reference salinities of batch reservoir brine, chemical slug, and chemical drive.
- Material balance—was used for all recovery and saturation because of the presence of gas which negated the use of aqueous phase tracers for oil saturation. In addition, use
of X-ray imaging was discounted due to high experimental pressures and likely saturation changes during transportation at lower pressures.

### 3.2.3 Coreflood Study Attributes

Five corefloods were used in this study to establish process effectiveness and determine contributing factors. Additional flooding in more permeable sandstone (135mD) and limestone (115mD, oil wet) cores achieved similar results and indicate the ability for the process to be expanded to additional reservoir candidates; however, due to the desire to examine a single rock type and permeability range, these floods are excluded from discussion.

The objectives of each flood are described in Table 3.1 (below). LTG_Tert_#1 is contrasted with floods 2-5 to establish: (a) repeatability and ability to scale to lower permeability (LTG_Tert_#2), (b) relative contributions from surfactant flooding (Surf_Tert_#3) and gas flooding (Gas_Tert_#4), and (c) impact of high initial oil saturation upon LTG oil mobilization and displacement. In addition, reference floods were used to validate models used to evaluate important process attributes such as apparent drive viscosity, displacement efficiency, and stability of displacing fluids.

<table>
<thead>
<tr>
<th>Experiment ID:</th>
<th>Description/Objective</th>
</tr>
</thead>
<tbody>
<tr>
<td>LTG_Tert_#1</td>
<td>Base case LTG flood</td>
</tr>
<tr>
<td>LTG_Tert_#2</td>
<td>Reference LTG repeatability and low perm flood</td>
</tr>
<tr>
<td>Surf_Tert_#3</td>
<td>Reference surfactant flood (no gas)</td>
</tr>
<tr>
<td>Gas_Tert_#4</td>
<td>Reference brine-gas coinjection flood (no surfactant)</td>
</tr>
<tr>
<td>LTG_Oil_#5</td>
<td>Effect of high initial oil saturation</td>
</tr>
</tbody>
</table>

Table 3.1: Flood Objectives by Experiment
The injection strategy to conduct these five floods is expressed below in Table 3.2. Consistent liquid formulations were used for all floods except Gas_Tert_#4, where surfactant was removed from formulation, and LTG_Tert_#2, where lower surfactant concentration was utilized to potentially reduce chemical costs.

<table>
<thead>
<tr>
<th>Experiment ID:</th>
<th>Res (%wt)</th>
<th>Slug (%wt)</th>
<th>Drive (%wt)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Salts (same in all experiments)</td>
<td>1.00% Na₂CO₃ 3.46% NaCl</td>
<td>1.00% Na₂CO₃ 1.73% NaCl</td>
<td>1.00% Na₂CO₃ 0.0% NaCl</td>
</tr>
<tr>
<td>Surf. &amp; Alcohols</td>
<td>+ + +</td>
<td>+</td>
<td>+</td>
</tr>
<tr>
<td>LTG_Tert_#1</td>
<td>None</td>
<td>1.25% Surf (3:1, S82:IOS) 1.00% TEGBE</td>
<td>0.10% IOS</td>
</tr>
<tr>
<td>LTG_Tert_#2</td>
<td>None</td>
<td>1.00% Surf (3:1, S82:IOS) 1.00% TEGBE</td>
<td>0.10% IOS</td>
</tr>
<tr>
<td>Surf_Tert_#3</td>
<td>None</td>
<td>1.25% Surf (3:1, S82:IOS) 1.00% TEGBE</td>
<td>0.10% IOS</td>
</tr>
<tr>
<td>Gas_Tert_#4</td>
<td>None</td>
<td>None</td>
<td>None</td>
</tr>
<tr>
<td>LTG_Oil_#5</td>
<td>None</td>
<td>1.25% Surf (3:1, S82:IOS) 1.00% TEGBE</td>
<td>0.10% IOS</td>
</tr>
</tbody>
</table>

Table 3.2: Flood Injection Strategy

Prior to chemical flooding, the five floods exhibited properties expressed in Table 3.3. These values were calculated from volume and pressure measurements at the steps described by procedures 1-5. Permeability is consistent (10.8mD-14.6mD) for cores cut parallel to the bedding plane, while it is lower for LTG_Tert_#2 which was cut normal to the bedding plane in order to achieve a lower flowing permeability. Porosity (\(\phi\)), \(S_{oi}\), and \(S_{or@2PVwaterflood}\) are all similar across floods.

Similar relative \(k_{ro}\) was observed across all three sections in each of the floods (not apparent), indicating uniformity in oil saturation. This is likely due to very favorable mobility ratios during initial oil saturation. Substantial variation in \(k_{rw@2PVwaterflood}\) was
observed across the three sections with dimensionless distance \((X_D)=0-.25\) demonstrating the highest \(k_{rw}\). This is consistent with diminished displacement efficiency and discussed in detail in the results section. Higher relative permeability to oil in LTG_Tert_#2 is believed to be due to the higher \(\Delta P\) during oil saturation. Likewise, the higher \(k_{rw}\) is believed to be due to the lower permeability of \(X_D=0-.25\) (1.2 mD), which resulted in an increased weighting for section 1 \(k_{rw}\) in the overall average.

<table>
<thead>
<tr>
<th>Experiment ID:</th>
<th>k</th>
<th>(\phi)</th>
<th>(S_o)</th>
<th>(S_{oil}) water</th>
<th>(k_{co}) (X_d=0-1)</th>
<th>(k_{rw}) @2PV water injected</th>
</tr>
</thead>
<tbody>
<tr>
<td>LTG_Tert_#1</td>
<td>10.8mD</td>
<td>21.2%</td>
<td>56%</td>
<td>29%</td>
<td>0.35</td>
<td>(X_d) = 0-0.08 (X_d) = 0.08 (X_d) = 0.17</td>
</tr>
<tr>
<td>LTG_Tert_#2</td>
<td>2.6mD</td>
<td>20.9%</td>
<td>51%</td>
<td>30%</td>
<td>0.44</td>
<td>(X_d) = 0.12 (X_d) = 0.15</td>
</tr>
<tr>
<td>Surf_Tert_#3</td>
<td>14.2mD</td>
<td>22.4%</td>
<td>53%</td>
<td>33%</td>
<td>0.33</td>
<td>(X_d) = 0.09 (X_d) = 0.13</td>
</tr>
<tr>
<td>GAS_Tert_#4</td>
<td>11.7mD</td>
<td>20.7%</td>
<td>56%</td>
<td>27%</td>
<td>0.35</td>
<td>(X_d) = 0.09 (X_d) = 0.22</td>
</tr>
<tr>
<td>LTG_Oil_#5</td>
<td>14.6mD</td>
<td>22.4%</td>
<td>51%</td>
<td>n/a</td>
<td>0.35</td>
<td>n/a</td>
</tr>
</tbody>
</table>

Table 3.3: Notable Properties Prior to Chemical Flooding

3.3-3.6 RESULTS AND DISCUSSION

3.3 ESTABLISH HIGH TERTIARY RECOVERY DURING LTG FLOODING

3.3.1 Recovery Profile

Tertiary recovery of 91% of residual oil in place (ROIP) was achieved during LTG_Tert_#1 flooding. Including waterflood, resulting total recovery was 95% of oil initially in place (OOIP) with remaining oil saturation after chemical flooding of \(S_o=3\%\). Figure 3.2 presents recovery and fractional flow information versus dimensionless liquid injected \((t_D\text{ liquid})\) for LTG_Tert_#1. Consistent oil cut \((f_o)\) of 20-30% was observed from 0.2PV\text{ Liquid}-0.8PV\text{ Liquid}. This resulted tertiary recovery of 73% ROIP by 0.8PV\text{ Liquid} and 79% ROIP by 1.0 PV\text{ Liquid}.
In addition, microemulsion production reflected only 30% of recovered oil at room temperature and pressure. Of the 30% microemulsion production, 20% (two thirds) of recovered oil reflected microemulsions that were easily broken by raising temperature to 75°C for a period of two days. These microemulsions are likely to be broken in a cost effective manner during field emulsion breaking activities.

Observed results are similar to successful conventional ASP floods where high fractional flow of oil is observed during a period of production corresponding with an oil bank. Elongation of the oil bank at lower (but consistent) oil cut is believed to be a function of low oil viscosity and low pore space available to mobile oil (capillary effects in low permeability), and is discussed in detail in Expansion of Oil Bank. It is not believed to be as a result of diminished displacement efficiency.
Secondary increase of oil production starting at 0.7 $P_{V\text{Liquid}}$ coincided with production of a microemulsion bank. Successful ASP tests at high permeabilities (not possible for low permeability) often exhibit similar behavior with secondary microemulsion production observed at $\sim1$ PV injection. For LTG flooding, by accounting for in-situ gas saturation at microemulsion breakthrough (19%, discussed later) microemulsion production was shown to take place at 0.9-1.2 PV (liquid injected/liquid in-situ). This is consistent with conventional ASP Flooding in high permeability rocks.

3.3.2 Pressure Profile

Observed pressure drop during LTG Tert #1 is shown in Figure 3.3. Pressure drop increases during displacement as residual oil is mobilized and an oil bank is formed. This is attributed to decreases in total apparent fluid mobility as oil saturation increases from residual oil saturation until a relative minimum apparent fluid mobility is achieved (relationship is discussed further in Mobility Ratio and Apparent Viscosity). As the oil bank progresses out of the section, oil saturation decreases and a pressure drop is observed. A progression from section 1 ($X_D=0.0-0.25$) $\rightarrow$ section 2 ($X_D=0.25-0.75$) $\rightarrow$ section 3 ($X_D=0.75-1$) is observed, with a decrease in the pressure drop for the upstream section being accompanied by a rise in the pressure drop for the following section.
Figure 3.3: Sectional pressure profile for LTG_Tert_#1. Progression of an oil and microemulsion bank from section to section is apparent.

Elongation of the pressure wave is apparent for section 3. This is believed to be a product of an elongate oil bank, a characteristic already noted and discussed in detail in Elongation of Oil Bank.

Steady state pressure drop is achieved in all three sections by 0.85 PV_{Liquid}, with upstream sections reaching steady state pressure drop at earlier periods. This was shown to correspond with a substantial reduction in oil fractional flow as measured by the fractional collector. Accounting for in-situ gas and oil saturation at breakthrough (18% and 12% respectively), steady state pressure drop was achieved at liquid injection of 1.14x in-situ water volume. Completion of the process at a value near 1.00x in-situ water volume indicates that favorable ‘shock like’ displacement was observed.
Steady-state pressure drop of 25 psi was stable over the measured $3\text{PV}_{\text{Liquid}}$ period. The high pressure gradient (25 psi/ft) is a function of the high rate of advance used ($q_{Total\,fluid}=2\,\text{ft/day}$), which was done for experimental convenience and to accelerate flood timelines. In addition, the observed steady-state pressure drop is actually below that of waterflooding steady state pressure drop. This is due to diminished displacement efficiency for later sections of the core which take place during unstable waterflood displacement which results in reduced relative permeability to water. As is discussed in detail later (See *Macroscopic Stability Parameters*), through more even displacement efficiency, LTG reduces observed pressure gradient while maintaining stable displacement.

Similar displacement properties were observed during flooding at $q_{Total\,fluid}=0.5\,\text{ft/day}$ (not included), and it is believed that comparable displacement can be achieved at substantially lower rates. Rate independence of this process is contrary to ‘strong foam’ literature which predicates the existence of a critical minimum flow rate. However, flow rates used in this study are several orders of magnitude below that required to achieve a critical flow rate for propagation of ‘strong foam’ in 10mD rock.

### 3.3.3 Salinity Profile

As previously described, there is a strong relationship between microemulsion environment and interfacial tension. A reduction of oil-water IFT by 3 orders of magnitude or more can be observed as environment progresses to Type III from either Type II(-) or Type II(+). Further, optimal salinity which corresponds with such an environment can be deviate substantially from observed results during phase behavior pipette testing due to absorption of surfactant, degradation of surfactant, activity of crude oil, and ion exchange or mixing of salt ions (among other factors).
As a design consideration, a negative salinity gradient is often employed to ensure that optimal salinity is achieved within the reservoir. Figure 3.4 presents the observed effluent salinity for LTG_Tert_#1. Salinity is strongly correlated with microemulsion environment, and therefore can be used as a powerful tool to evaluate the conditions encountered during flooding. Early effluent salinity (0-0.65PV_{Liquid}) is attributed to in-situ reservoir brine and corresponds with a lower Type II(+), upper Type III microemulsion environment.

Figure 3.4: Effluent salinity profile and microemulsion environment for LTG_Tert_#1. 0.70PV_{Liquid} injected corresponds to period at which midpoint reservoir/slug salinity is achieved. Results are used to calculate aqueous phase salinity.
This is followed by a sharp decrease in salinity until injected slug salinity is achieved. This transition crosses the optimal Type III microemulsion environment and ensures ultra-low IFT behavior is observed. Because most oil exists as part of a single phase oil bank which precedes the microemulsion front, a short period of ultra-low IFT is sufficient for oil mobilization if effective mobility control is present (Nelson 1978).

As the flood continues, the salinity continues to decrease until injected drive salinity is achieved. Low salinity has the advantage of decreasing microemulsion viscosity associated with Type III environment, which enables more effective displacement of mobilized oil. In addition, Type II(-) microemulsion environment corresponds with more stable foam propagation in the presence of crude oil. This allows for increased apparent viscosity of displacing fluids and more effective process stability and displacement of preceding fluids.

3.4 Utilize Reference Floods to Determine Repeatability and Process Contributions

3.4.1 Reference Flood: LTG Process Repeatability

Application of LTG to tighter rock (LTG_Tert_#2) resulted in similar process attributes to LTG_Tert_#1. In addition to reduction in permeability (2.6mD vs. 10.6mD), slug surfactant concentration was reduced from 1.25% to 1.00% (wt) to test the threshold for reduced surfactant. Comparable data was observed for recovery, fractional flow, observed pressure profile and apparent drive viscosity, and in-situ gas saturation. Results are mostly shown as part of comparison tables included in later portions of this paper.

Figure 3.5 presents recovery data for LTG_Tert_#2 versus recovery data for the LTG_Tert_#1 flood which was discussed previously. Overall recovery is slightly lower at 75% vs. 91%, which is believed to be a function of: (a) LTG_Tert_#2 was aligned
perpendicular to the bedding plane, while all other floods were aligned parallel to the bedding plane. This may have prevented oil displaced by gas from being displaced forward and instead sideways. In addition, (b) reduced flood length, (c) experimental error in oil material balance, and/or (d) reduced surfactant injection at lower permeability may have also contributed.

Similar high oil cuts were observed which constituted a large oil bank (during 0.15 PV_{Liquid} to 0.6 PV_{Liquid}). Oil bank production was for a slightly shorter period of time than for LTG_Tert_#1, which appears to be a function of reduced oil mobilization in the last section of the core due to factors noted above. This is described in greater detail later, where pressure derived mobility data is used to visualize this relationship.

Figure 3.5: Oil recovery and fractional flow profile for LTG_Tert_#2 vs. LTG_Tert_#1.
3.4.2 Reference Floods: Gas-coinjection and Surfactant Injection

Surfactant and gas tertiary flooding were used to compare effectiveness and establish relative contribution of these related processes. As noted in Table 3.2, \text{Surf\textunderscore Tert\textunderscore #3} used the same injection strategy as \text{LTG\textunderscore Tert\textunderscore #1} with the notable exception that gas injection fraction was reduced from 50\% to 0\%. During \text{Gas\textunderscore Tert\textunderscore #4} surfactant was removed from the formulation and all other parameters were held constant to \text{LTG\textunderscore Tert\textunderscore #1}.

Results from surfactant injection (\text{Surf\textunderscore Tert\textunderscore #3}) reflect the relative effectiveness and contribution of oil/water IFT reduction. This is considered an unstable displacement process due to the lower relative mobility of mobilized oil versus injected brine. Results from gas-coinjection (\text{Gas\textunderscore Tert\textunderscore #4}) reflect contributions from gas injection at the initial reservoir IFT environment. This flood captures recovery contributions from immiscible gas displacing oil filled pores and increases (or decreases) in mobility control during gas-liquid flow. Increased mobility control due to lamellae production is not captured by either reference flood. In addition, effects of increased gas displacement of oil at low IFT are not captured by the selected reference floods.

Recovery and fractional flow discussions and figures within this section provide a high-level understanding of the respective processes and floods. More extensive analysis of these floods is presented later in this paper where they are used to compare results and evaluate models in examining physical attributes and studying macroscopic process stability.

Figure 3.6 presents the cumulative oil recovery versus dimensionless total fluid injected (\(t_D^{\text{total fluid}}\)) for reference Gas-coinjection, surfactant injection, and LTG flooding. Total fluid injected is a different metric than liquid injected (\(t_D^{\text{Liquid}}\)) which is used for previous plots in this paper. Total liquid injected is more directly correlated with mixing
and displacement due to low gas saturation and gas/liquid mixing; however, total fluid injected is more closely correlated with allowable injection rate and therefore actual economics. Because of different gas injection fraction during surfactant flooding, it is believed that $t_{D_{\text{total fluid}}}$ is a better metric for initial discussion.

The figure shows that recovery via LTG was approximately equal to the sum of surfactant and gas injection floods until $t_{D_{\text{total fluid}}}= 0.75$. After this point, total recovery via LTG continues to increase while surfactant and gas flood recovery remain mostly constant.

Figure 3.6: Cumulative oil recovery for LTG_Tert #1, Surf_Tert #3 and Gas_Tert #4. LTG flooding is shown to substantially improve recovery over combined surfactant and gas co-injection floods after 0.50PV_{Total fluid} injected. LTG flooding is delayed with respect to PV_{Total fluid} due to the 50% gas quality utilized. Potential exists to accelerate recovery (shift left) by reducing gas fraction.
Figure 3.7 presents the fractional flow of oil versus $t_{D_{\text{total fluid}}}$. Comparison of LTG flooding versus the combined oil recovery of gas and surfactant (G+S) flooding yields several notable results. Initially higher G+S oil production (~0.05PV$_{\text{Total fluid}}$) is due to oil production ahead of early gas breakthrough during the gas flood. Later gas breakthrough during LTG flooding results in a delayed and larger quantity of oil production ahead of this breakthrough (~0.2PV$_{\text{Total fluid}}$). From 0.25-0.50PV$_{\text{Total fluid}}$, combined G+S oil production is greater than LTG flooding. This is primarily due to accelerated production during surfactant flooding with respect to total fluid injected. This is because $q_L$ is the primary contributor to displacement, and $q_L$ is 2x higher during the surfactant flooding than the LTG flood due to the 50% gas quality used in LTG flooding ($q_{\text{Total}}$ is held constant).

![Comparison of Observed Oil Cut (Tertiary)](image)

Figure 3.7: Oil cut for LTG Tert #1, Surf Tert #3 and Gas Tert #4.
After 0.50PV_{Total \ fluid}, LTG oil production is substantially higher than the combined G+S production. This is a result of higher overall recovery and production delay due to injection of a gas fraction. If reduced gas quality during LTG flooding can achieve similar mobilization and displacement properties to that of tested gas fraction, the potential exists to accelerate LTG recovery with respect to $t_{D \ total \ fluid}$. In figures 3.6 and 3.7 this would be expressed by a shifting of the recovery and fractional flow curves to the left.

Gas flooding (no surfactant) is negatively impacted by the high relative mobility of a free gas phase which will occur after gas breakthrough when surfactant is not present for mobility control. Almost no increase in oil recovery is observed after 0.50PV_{Total \ fluid}. Surfactant flood oil production mostly terminates after 1.00 PV_{Total \ fluid}. This coincides with approximate effluent arrival of type II(-) microemulsion environment for the flood. Such an environment has higher oil/water IFT relative to type III microemulsion environment which will have preceded this environment. This may cause previously mobilized oil to again become trapped by capillary forces if sufficient mobility control is not present to displace the fluids out before this happens. In effect, lack of effective mobility control during surfactant flooding causes large volumes of oil to be mobilized but not displaced before the oil/water IFT environment again becomes unfavorable for oil mobilization.

3.4.3 Reference Flood: Oil Effect and Secondary Recovery

LTG flooding was tested for a core at initial oil saturation to determine the affects of high initial oil saturation on the LTG process. This is of considerable importance to this study due because of the opportunity to capture additional recovery from flooding and to accelerate payback. This is particularly relevant for LTG flooding where, unlike
ASP flooding where reservoir permeability tends to be high, LTG flooding has the potential to be applied to reservoirs of 10-50mD where application of waterflooding is less mature.

As noted in Table 3.2, LTG_Oil_#5 used the same injection strategy as LTG_Tert_#1. Figure 3.8 presents results for recovery and fractional flow for LTG_Oil_#5 and a reference waterflood. The reference waterflood was selected because it exhibited similar petrophysical properties— $k \pm 3\%$, $S_{ol} \pm 2\%$.

![Figure 3.8](image)

Figure 3.8: Oil recovery and fractional flow profile for LTG_Oil_#5 and reference waterflood.

Results show that production at high oil cut (>85%) is extended from $t_D^{total\ fluid}=0-0.25PV$ observed during waterflooding to $t_D^{total\ fluid}=0-0.45PV$ during LTG injection.
Production of water during this period is due to remaining water mobility because of the experiment preparation process used, and it not believed to be a characteristic of early breakthrough during either waterflood or LTG flooding. By extending the period of high oil cut production, LTG flooding is able to produce 53% of OOIP before breakthrough. This is contrasted with 32% of OOIP for waterflooding recovery before breakthrough.

For this LTG flood, additional oil production occurs at 10-25% cut until 2.0PV_{Total fluid} (1.0 PV_{Liquid}) where ultimate recovery is 80% of OOIP. Production during this period may correspond with production of a diminished tertiary oil bank in a manner similar to tertiary recovery floods discussed previously. Fractional flow during this oil bank is slightly below that of tertiary recovery floods and is reflective of higher final oil saturation after chemical flooding (which was observed through material balance).

The higher final oil saturation after LTG flooding for secondary application (LTG_Oil_#5) is believed to be a function of reduced aqueous phase mixing between reservoir brine and injected slug at higher oil saturation ($S_o$ vs. $S_{orw}$). For the type II(-) microemulsion slug injection strategy used, reduced mixing during LTG_Oil_#5 will result in reduced type III optimal chemical solution after mixing. This will result in a higher oil-water IFT and increased residual oil saturation. The recovery could be improved if injected slug salinity were at optimum instead of at the upper type II(-) boundary.

In addition, partitioning of the surfactant at the oil-water interface may cause some production of surfactant. This is due to higher relative interstitial velocity of the oil bank as it expands. This causes mobilized oil to flow forward from the chemical front as it is displaced by additional oil. For LTG_Oil_#5, this mechanism is amplified by higher initial oil saturation. Nonetheless, because (a) partitioning will likely be proportional to the portion of contacted mobile oil and (b) high recovery was still achieved, it is not
believe that this mechanism will cause in significant depletion of surfactant during upscaling which would impact displacement stability.

Figure 3.9 is an idealized schematic of the interpreted displacement process during LTG_Oil_#5 flooding. One shock front is formed with two distinct spreading saturation waves which reflect that of: (a) conventional waterflood displacement of oil at initial oil saturation ($S_{oi}$), and (b) low-tension surfactant flooding with mobility control.

![Idealized model for mobilization and displacement during secondary recovery for chemical flooding with mobility control. A singular shock front will characterize two separate spreading saturation waves: that of a conventional water flood and that of a low-tension surfactant flood.](image)

Figure 3.9: Idealized model for mobilization and displacement during secondary recovery for chemical flooding with mobility control. A singular shock front will characterize two separate spreading saturation waves: that of a conventional water flood and that of a low-tension surfactant flood.

Figure 3.10 presents the pressure profile for LTG_Oil_#5 and reference waterflood. Pressure response for LTG_Oil_#5 is similar to that of LTG_Tert_#1. One notable exception is that LTG_Oil_#5 has an initially lower pressure gradient. This is due to an unusually high endpoint relative mobility for oil due to low oil viscosity ($\mu=1.9\text{cP}$),
which results in an average total relative mobility which is higher at $S_{oi}$ than it is after 2PV waterflood $S_{w@2PV waterflood}$.

High oil endpoint relative mobility also enables LTG flooding to reduce observed pressure gradient versus waterflood. Average pressure gradient at 2PV Total fluid for the waterflood is approximately 3x greater than it is for LTG flooding. In addition, LTG flood initial and final pressure gradient are approximately equal. This is indicative of an ideal mobility ratio of R=1 with respect to the oil bank and injected fluids. Maximum mobility ratio of R=1.4 is observed and is due to an apparent minimum in total mobility during displacement of oil with injected fluids.

Figure 3.10: Sectional pressure profile for LTG_Oil_#5 and reference waterflood.
3.5 **EXAMINE PHYSICAL ATTRIBUTES**

3.5.1 **LTG Gas Breakthrough**

Early production of oil at 0.1\textsubscript{Liquid} (LTG\textsubscript{Tert\#1} and LTG\textsubscript{Tert\#2}) was likely associated with displacement of crude oil by slight increases in gas saturation from fingering gas—gas breakthrough was observed at 0.15 PV\textsubscript{Liquid} (0.3 PV\textsubscript{total fluid}). High recovery, consistent and high oil fractional flow, pressure data, and high in-situ gas saturation (discussed later) indicate that a stable dispersed gas phase was present during injection. Flow of free gas is believed to be the result of diminished rate of advance for the surfactant front relative to injected gas (described below). Of importance is that neither of the described mechanisms indicates that production of a free gas is due to breakdown of foam.

One factor which is believed to contribute to free flow of gas is a maximum in-situ gas saturation, which is a function of capillary number, may be lower than injected gas fraction (50%). Maximum gas saturation will occur where gas occupies the largest and most permeable pores for immiscible (gas-liquid) displacement. An approximate quantification of these large pores can be determined based upon calculation of pore volume available to mobile oil which is determined during oil/waterflood (Eq. 2). During oil/water flood, the low permeability zones is saturated by a wetting water phase, a medium permeability zone is that of immobile oil, and a high permeability zone is that of mobile oil. For LTG\textsubscript{Tert\#1}, \textit{PV\textsubscript{MO}} is 27%. If the maximum gas saturation is related to \textit{PV\textsubscript{MO}}, with Gas Saturation Calculations (below) appearing to validate this assumption, then 50% injection gas quality will flow in gas filled pores which occupy 27% of PV. On the other hand, injected liquid fraction of 50% will flow in liquid filled pores which occupy 73% of PV (~60-70% if we consider only water). This will result in a required
higher interstitial velocity for injected gas versus injected liquid which is manifest in free
gas evolving out of the front of the surfactant bank.

\[ PV_{MO} = S_{oi} - S_{orw} \]  
(3.2)

As a second factor, during co-injection processes, surfactant surface absorption and
preferential partitioning at the oil-water interface will result in a diminished rate of
advance of an available surfactant front (for gas-liquid lamellae production). Gas which
may otherwise advance at the same rate as other injected fluids may then become un-
contacted by surfactant as the surfactant front advances at a slower rate.

3.5.2 Elongate Oil Bank | Tertiary Recovery

During tertiary recovery, a mobile oil bank forms due to diminished oil relative
mobility versus water relative mobility at high water saturation. As a result of surfactants
mobilizing residual oil, oil saturation ahead of the surfactant front will increase until oil
achieves a greater mobility than water. Once this is achieved, oil will advance at a faster
rate than displaced water. This is expressed through an expanding oil bank which has an
oil saturation that corresponds with oil achieving mobility required to advance at the
correct relative velocity for material balance. The oil saturation which corresponds with
required oil mobility for material balance is determined in the Oil Bank Sensitivity Study
(below)

Figures 3.11 and 3.12 present the Corey-type (Eqs. 3-8) relative mobility profiles
for two example cases. Corey exponents of \( n=2 \) (oil) and \( m=3 \) (water) were used for both
cases. Case 1 reflects interpreted petrophysical data for LTG_Tert_#1 while Case 2 has
higher crude oil viscosity (40cP vs. 1.9cP) and higher pore volume available to mobile oil (45% vs. 27%). Pore volume available to mobile oil is often positively correlated with formation permeability. As such, Case 2 reflects displacement of medium-heavy crude in a more permeable formation which is common for ASP flooding.

**Figure 3.11:** Corey-type relative mobility curves for Case 1. Values represent actual physical parameters of LTG_Tert_#1

$$\text{Case 1 relative mobility: } \mu_o=1.9\text{cP}, \mu_w=0.9\text{cP}, S_{oi}=56\%, S_{or}=29\%$$

Water Saturation ($S_w$)

$\lambda_w$ (n=3)

$\lambda_o$ (n=2)

$\lambda_{total}$

$\Delta S_w=9\%$
Elongation of the oil bank is a function of low oil viscosity and low pore volume available to mobile oil (capillary effects in low permeability). Low oil viscosity results in higher apparent mobility for the oil phase ($\lambda_o$). This reduces the required increase in oil saturation for oil relative mobility to surpass water relative mobility ($\lambda_{rw}$) and results in a smaller amplitude but longer oil bank. Low pore volume available to mobile oil compresses the saturation profile and amplifies effects that changes in saturation can have upon petrophysical properties such as relative permeability. Numerically, low oil viscosity has the effect of shifting the dimensionless water saturation ($S_w^*$) (Eq. 8) value which corresponds with the oil bank, while low pore space has the effect of amplifying the impact that a change in $S_w$ has upon $S_w^*$.

A basic analytical simulation for Case 1 and Case 2 indicates that an oil saturation increase of 9% and 31%, respectively, will correspond with creation of an oil bank. For
Case 1, an oil bank will exhibit oil saturation ($S_{oil \_bank}$) of 38% versus residual oil saturation ($S_{orw}$) of 29%. For Case 2, an oil bank will exhibit $S_{oil \_bank}$=56% versus $S_{orw}$=25%. An approximate inverse relationship between oil bank saturation change ($\Delta S_{oil \_bank}$) and oil bank length ($X_{oil \_bank}$) indicates that Case 1 will exhibit an oil bank of greater than 3x that of Case 2. This can be considered favorable due to earlier breakthrough of an enlarged oil bank, albeit at slightly lower oil fractional flow. Effects of individual physical properties upon oil bank attributes are discussed next.

Corey-type relative permeability equations:

\[
S_w^* = \frac{S_w - S_{wi}}{1 - S_{wi} - S_{orw}} 
\]

(3.3)

\[
k_{rw} = k_{rw} * (S_w^*)^n
\]

(3.4)

\[
k_{ro} = k_{ro} * (1 - S_w^*)^m
\]

(3.5)

\[
\lambda_w = \frac{k_{rw}}{\mu_w}
\]

(3.6)

\[
\lambda_o = \frac{k_{ro}}{\mu_o}
\]

(3.7)

\[
\lambda_{total} = \lambda_o + \lambda_w
\]

(3.8)

### 3.5.2.1 Oil Bank Sensitivity Study—Tertiary Recovery | Results

To identify the effect that oil viscosity ($\mu_o$) and saturation available to mobile oil ($PV_{MO}$) have upon oil bank properties, several sensitivity tests were performed. This study utilized a simple displacement model for tertiary recovery which assumes perfect oil mobilization, uniform displacement, and no microemulsion phase (Figure 3.13). By performing an oil mass balance at the chemical shock front, oil bank properties such as oil saturation of the oil bank $S_{oil \_bank}$, oil bank saturation increase versus residual oil
saturation $\Delta S_{oil\ bank}$, and oil bank relative velocity \(v_{r\ oil\ bank} = \frac{v_{oil\ bank}}{v_{inj}}\) can be determined.

Figure 3.13: Schematic of model for mobilization and displacement during tertiary recovery. Tertiary displacement model used in oil bank sensitivity study assumes perfect mobilization and/or displacement at shock fronts and no microemulsion contributions.
Figure 3.14 presents the effects of varied PV$_{MO}$ upon $v_{roil\text{ bank}}$ and $\Delta S_{oil\text{ bank}}$. Residual ($S_{orw}$) and initial ($S_{oi}$) oil saturations were defined as linear functions of pore volume available to mobile oil (Eqs. 9 and 10). The selected relationship results in $S_{orw}=28\%$ and $S_{oi}=58\%$ ($PV_{MO}=30\%$) or $S_{orw}=23\%$ and $S_{oi}=63\%$ ($PV_{MO}=40\%$), which is consistent with values observed for flooding in water wet rocks. Increases in PV$_{MO}$ correspond with increases in $\Delta S_{oil\text{ bank}}$. This is attributed to the expanded range for $S_w^*$ and diminished affect that a change in $S_w$ has upon $S_w^*$. With increases in $PV_{MO}$, there is an accompanying decrease in $v_{roil\text{ bank}}$. Increased PV$_{MO}$ is also correlated with decreased $S_{orw}$ in this model. This reduces the oil available for mobilization and decreases the volume rate of oil.
mobilization. $S_w^*$ remains mostly constant with respect to $PV_{MO}$ due to consistent oil/water relative mobility curves.

\[ S_{orw} = 43\% - PV_{MO}/2 \]  
\[ S_{oi} = 42\% + PV_{MO}/2 \]  

Figure 3.15 presents the affects of varied crude oil viscosity ($\mu_o$) upon $\nu_{oil\ bank}$, $\Delta S_{oil\ bank}$, and $S_w^*$. Increases in crude oil viscosity will result in a lower $S_w^*$ to achieve desired oil relative mobility (as noted in the Cases 1 and 2 apparent mobility curves). Because $S_w^*$ is initially at 1 before displacement, lower $S_w^*$ will correspond with a larger saturation change. This larger saturation change is captured by $\Delta S_{oil\ bank}$, which increases with increases in viscosity. In addition, larger $\Delta S_{oil\ bank}$ results in more volume available for mobilized oil. This increased volume diminishes the rate of advance for $\nu_{oil\ bank}$. Note that the calculations of $\nu_{oil\ bank}$, $\Delta S_{oil\ bank}$, and $S_w^*$ are based on the following assumptions: (a) Uniform residual oil saturation ($S_{orw}$) present at the start of the flood, (b) Homogenous porous media, (c) Immediate mobilization of 100% of $S_{orw}$ upon chemical front contact, (d) Uniform displacement of mobilized crude oil, and (e) No effects of microemulsion viscosity or mixing upon displacement. A more detailed description of these calculations is shown in Appendix A.
3.5.2.2 Oil Bank Sensitivity Study—Tertiary Recovery | Calculations

Detailed Oil Bank Calculations—See Figure 3.13 or in-text discussion for detailed discussion regarding physical model used. Mass balance for oil was performed at the trailing shock front (surfactant/chemicals displacing residual oil) to determine volume rate of oil mobilization. From this, the relative velocity of the oil bank versus injected fluids velocity was determined which corresponded with no oil volume accumulation at this front (Eq. 3.11). This equation has two unknowns, \( \frac{\nu_{oil \ bank}}{\nu_{inj}} \) and \( S_{o \ oil \ bank} \). An additional relationship was introduced to relate \( \nu_{oil \ bank} \) to the superficial velocity of the two phases forward of the mobilization front (Eqs. 3.12 and 3.13). These superficial velocities are related to the relative phase mobilities (Eq. 3.15) by using a 1-D Darcy’s relationship (Eq. 3.14). The relative phase mobilities (\( \lambda_o \) and \( \lambda_w \)) are already know as
functions of \( S_w^* \), which is a direct relationship of \( S_{oil \_bank} \) and other known petrophysical parameters (\( S_{orw} \) and \( S_{oi} \)). Substitution is then used to determine Eqs. 3.16 and 3.17. This results in a relationship with 3 equations (Eq. 3.17, and Corey parameters for \( \lambda_o \) and \( \lambda_w \)) and 3 unknowns (\( S_{oil \_bank} \), \( \lambda_o \) and \( \lambda_w \)). Because \( S_{oil \_bank} \) is directly related to \( S_w^* \) and known parameters, a value of \( S_w^* \) is determined which solves Eq. 3.17. A unique solution for \( S_w^* \) is achieved when applying the criteria \( 0 \leq S_w^* \leq 1 \).

\[
\sum M_o = 0 = V_{oil \_in} * \rho_o - V_{oil \_out} * \rho_o = (v_{oil \_in} * A_{oil \_in} - v_{oil \_out} * A_{oil \_out}) * \rho_o
\]

\[
0 = (v_{oil \_bank} - v_{inj}) * (S_{oil \_bank} - S_{or}) - v_{inj} * (S_{orw})
\]

\[
\frac{v_{oil \_bank}}{v_{inj}} = \frac{S_{oil \_bank}}{(S_{oil \_bank} - S_{orw})}
\]

(11)

Given:

\[
u_o = v_{oil \_bank} * (S_{oil \_bank} - S_{orw}) => S_{oil \_bank} * v_{inj}
\]

(12)

\[
u_w = v_{inj} - u_o => v_{inj} - S_{oil \_bank} * v_{inj}
\]

(13)

From 1-D Darcy’s Law:

\[
q = \frac{\Delta P * k * k_r * A}{\mu * L} => u = \frac{q}{A} = \frac{\Delta P * k * k_r}{\mu * L}
\]

(14)

\[
u_o = \frac{\Delta P * k * k_r \rho_o}{\mu_o * L} = \frac{k_{ro} \rho_o}{\mu_o} \frac{k_{rw} \rho_w}{\mu_w} = \frac{\lambda_o}{\lambda_w}
\]

(15)
3.5.3 Effluent Salinity Tracers for Dispersion

In addition to data on microemulsion environment and IFT, salinity acts as an effective tracer which can be used to provide important information on dispersion and phase saturation. Sharp transitions of effluent salinity from one injected or in-situ fluid salinity to salinity of another injected fluid reflect reduced dispersion and sharper shock front propagation. Comparison of effluent salinity profile for different injection strategies for tertiary recovery is shown in Figure 3.16 to provide a qualitative understanding of dispersion.

\[
\frac{u_o}{u_w} = \frac{S_{oil\ bank} \cdot v_{inj}}{v_{inj} - S_{oil\ bank} \cdot v_{inj}} = \frac{S_{oil\ bank}}{1 - S_{oil\ bank}} \quad (16)
\]

\[
\frac{\lambda_o}{\lambda_w} = \frac{S_{oil\ bank}}{1 - S_{oil\ bank}} \quad (17)
\]

![Comparison of Effluent Salinity, Mixing, & Microemulsion Environment](image)

Figure 3.16: Effluent salinity profile for LTG_Tert_#1, Surf_Tert_#3, and GAS_Tert_#4. Results were used to qualitatively compare dispersion among the three floods.
Effluent salinity concentration is shown to initially reflect reservoir brine. At $t_{DLiquid} = 0.60-0.95\ PV$ the effluent salinity makes a transition from initial brine to injected slug salinity. The $t_{DLiquid}$ at which this takes place is shown to correspond with aqueous phase saturation, as is described in detail during ‘gas saturation.’ As injection continues, effluent salinity will continue to progress until it approaches that of injected brine.

The rate at which salinity transitions from one fluid to another is a function of salinity difference and in-situ dispersivity. Unfavorable mobility of an injected fluid relative to a displaced fluid (mobility ratio $>1$) can further amplify dispersion through viscous instabilities and fingering of the less viscous phase.

This is expressed by contrasting gas-coinjection with surfactant or LTG flooding processes. During gas-coinjection for tertiary recovery (Gas_Tert_#4), gas will occupy a small number of pores. Once gas breakthrough is observed, displacement of oil mostly ceases and oil remains an immobile phase. Injected brine displaces in-situ brine which has consistent and equal viscosity. This is reflected in figure 3.16, where a steady progression from reservoir salinity $\rightarrow$ slug salinity $\rightarrow$ drive salinity is observed.

During injection of surfactant (surfactant or LTG flooding), creation of oil/water microemulsions results in increased viscosity of the in-situ displaced phase. This is especially pronounced for type II(+) and type III microemulsion environments, the latter being achieved in this study. Increased viscosity of oil-water microemulsions has the potential to increase dispersion by creating an unstable displacement environment.

For surfactant flooding (Surf_Tert_#3), an unfavorable mobility ratio ($>1$) exists for injected fluids displacing a microemulsion or oil bank. This results in an elongate salinity profile during drive injection when compared to gas injection (Gas_Tert_#4). Fingering of injected fluids through the microemulsion or oil bank will result in increased...
dispersion. In addition, microemulsions in the type III environment have large aqueous phase solubization. As oil/water microemulsions are bypassed by fingering of injected fluids, large quantities of higher salinity fluids will be retained. These effects are further amplified by preferential displacement of high permeability zones which leaves tighter zones with disproportionate microemulsion trapping and amplifies affects of heterogeneity upon dispersion.

LTG flooding exhibited an improved salinity profile when compared to surfactant flooding during early stage process. Increased salinity shock strength during progression from reservoir to slug salinity is indicative of improved displacement of fluids during production of reservoir brine and oil bank. Once slug salinity is achieved, similar dispersion between Surfactant and LTG flooding is apparent. This indicates that oil/water microemulsion creation, which amplifies dispersion during surfactant flooding, also amplifies dispersion during LTG flooding. It is important to note that the presence of increased apparent dispersion during LTG flooding is concerning because it can be associated with increased instability of fluid displacement (mobility ratio >1) and possible fluid fingering.

However, it is not the belief at this time that unstable displacement is the primary factor contributing towards increased dispersion. Observed macroscopic mobility (via pressure) indicates near parody in mobility ratio (~1), as is discussed in Examining Macroscopic Stability Attributes. In addition, temporary trapping of higher salinity aqueous fluids in a type III microemulsion phase can also be determined to be a positive, as it may reflect increased microemulsion production and oil mobilization via improved fluid contact or control of IFT environment. Displacement of the previously trapped aqueous phase later in the process will result in apparent increases in dispersion. For highly unstable displacement (no mobility control), these fluids may remain trapped even
after injection of several PV_{Liquid}, allowing the higher salinity fluids to never be produced and resulting in decreased apparent dispersion (when analyzing the salinity profile).

Salinity can also be used as a tool to evaluate the effect that high oil saturation has upon LTG flooding. As shown in Figure 3.17, LTG flooding at residual oil saturation (LTG_Tert_#1) and initial oil saturation (LTG_Oil_#5) result in nearly identical effluent salinity. This indicates that similar oil mobilization and displacement is achieved for the two floods and that the process is mostly independent of initial oil saturation.

![Comparison of Effluent Salinity, Mixing, & Microemulsion Environment](image)

**Figure 3.17:** Effluent salinity profile for LTG_Tert_#1 and LTG_Oil_#5. Similar salinity profile indicates similar dispersion among floods.
3.5.4 Effluent Salinity Tracers for Gas Saturation

Aqueous phase concentration can also be determined by using salinity as a conserved single-phase tracer. Consider binary injection of a single phase conservative tracer displacing an in-situ fluid of different tracer concentration. Measurement of tracer concentration versus \( t_D \) will show a characteristic progression from initial tracer concentration to final tracer concentration. Assuming complete contact between injected and initial tracer bearing fluids, as is typically the case for a wetting aqueous phase, the dimensionless time at which the transition takes place (half-way point) will correspond with phase saturation at breakthrough.

To apply this methodology to LTG flooding, several assumptions are made. They are: 1) salinity is a conservative tracer, 2) perfect contact is achieved between the displacing and displaced aqueous phase, and 3) injected drive fluids do not affect initial brine/injected slug mixing. Because a sharp transition in salinity is observed from reservoir brine to injected slug salinity (\( \Delta t_D^{\text{liquid}}=0.1 \)), it is believed that reduced dispersion was present during LTG flooding. Because of the large slug size (\( \Delta t_D^{\text{liquid}}=0.3 \)) it is not believed that injected drive substantially affected reservoir brine/injected slug mixing. Other assumptions regarding tracer conservation and perfect contact of displaced fluids are consistent with existing tracer applications.

The salinity profile for LTG_Tert_#1 (Figure 3.4) shows that transition between initial reservoir salinity and injected slug salinity takes place at \( t_{D1}=0.70PV_{\text{Liquid}} \). This indicates that water saturation is 70% at 0.7PV_{\text{Liquid}}. Using additional data for oil saturation at this point \( (S_{oil} @ t_{D1}) \) which is determined from material balance, gas saturation at \( t_{D1} \) can be determined (Eqs. 3.18-22). Table 3.4 presents dimensionless time of tracer transition (\( t_{D1} \)), oil saturation at this time \( (S_{oil} @ t_{D1}) \), calculated gas saturation
\(S_{\text{gas}@t_{D1}}\), and gas saturation versus pore volume available to mobile oil \(S_{\text{gas}}/PV_{MO}\) for the five study floods.

It is unknown how strongly gas saturation at \(t_{D1}\) corresponds with early stage displacement gas saturation. However, it is believed that gas saturation has achieved a steady-state value by \(t_{D1}\) and is reflective of ultimate gas saturation attainable during flooding. Changes in gas saturation during this process would result in either: 1) increased apparent viscosity due to foam propagation, or 2) decreased apparent viscosity due to increased relative mobility of the gas phase (‘gas fingering’). Both mechanisms would result in changes in observed pressure gradient, and it is deemed highly unlikely that the two would achieve perfect balance required for steady-state pressure gradient behavior. Other literature [Rossen 2004] affirms this conclusion, with minimal increases in displacement efficiency and gas saturation observed after gas breakthrough.

Results show consistent measured gas saturation (21\%, 18\%, and 22\%) for the three LTG floods, signifying tolerance for increased oil saturation, decreased permeability, and/or surfactant concentration. In-situ gas saturation was approximately equal to \(PV_{MO}\) and is reflective of gas occupying most of the high permeability pore regions. LTG saturation contrasts with measured gas saturation of 5\% for gas-coinjection and indicates that the presence of surfactant in LTG flooding was effective in stabilizing an increased dispersed gas phase. Gas saturation of 5\% corresponds to 9\% of OOIP, 18\% of ROS, or 16\% of \(PV_{MO}\) and is similar to results obtained in WAG/gas-coinjection studies. Surfactant flooding was used to validate the methodology. Obtained result of \(S_{\text{gas}@t_{D1}}=0.7\%\) contrasts with actual gas saturation of \(S_{\text{gas}@t_{D1}}=0\%.\) This falls within the interpreted experimental error of ±2\% and is thus consistent with the model.
Gas Saturation Calculation Results:

<table>
<thead>
<tr>
<th></th>
<th>$t_{\text{D liquid}}$ @ tracer midpoint ($t_{D1}$)</th>
<th>$S_{\text{oil}}$ @ $t_{D1}$</th>
<th>$S_{\text{gas}}$ @ $t_{D1}$</th>
<th>$S_{\text{gas}}/\text{PV}_{\text{MO}}$</th>
</tr>
</thead>
<tbody>
<tr>
<td>LTG_Tert_#1</td>
<td>0.68</td>
<td>0.11</td>
<td>0.21</td>
<td>0.77</td>
</tr>
<tr>
<td>LTG_Tert_#2</td>
<td>0.69</td>
<td>0.13</td>
<td>0.18</td>
<td>1.08</td>
</tr>
<tr>
<td>Surf_Tert_#3</td>
<td>0.74</td>
<td>0.25</td>
<td>&lt;.01</td>
<td>0.03</td>
</tr>
<tr>
<td>Gas_Tert_#4</td>
<td>0.72</td>
<td>0.23</td>
<td>0.05</td>
<td>0.16</td>
</tr>
<tr>
<td>LTG_Oil_#5</td>
<td>0.67</td>
<td>0.11</td>
<td>0.22</td>
<td>n/a</td>
</tr>
</tbody>
</table>

Table 3.4: Gas saturation at tracer breakthrough ($t_{D1}$).

Equations:

\[ C_{\text{tracer midpoint}} = \frac{C_{\text{reservoir}} + C_{\text{slug}}}{2} \quad (3.18) \]

\[ S_{\text{water}}@t_{D1} = [t_{D \text{ liquid}}]@c_{\text{tracer midpoint}} \quad (3.19) \]

\[ S_{\text{total}} = 1 = S_{\text{water}} + S_{\text{gas}} + S_{\text{oil}} \quad (3.20) \]

\[ S_{\text{gas}}@t_{D1} = 1 - S_{\text{water}}@t_{D1} + S_{\text{oil}}@t_{D1} \quad (3.21) \]

\[ S_{\text{oil}}@t_{D1} = S_{\text{oil}}@2\text{PV water flood} - \Delta S_{\text{chemical flood}}@t_{D1} \quad (3.22) \]
3.6 Examine Macroscopic Stability Attributes | Mobility Ratio and Apparent Viscosity

One dimensional displacement has the potential to mitigate effects from poor displacement efficiency and unstable displacement with respect to actual reservoir application. As previously described, this concern is especially relevant for chemical flooding where mobility of oil-water microemulsion and mobilized crude is often substantially lower than that of injected brine. This can cause amplification of existing instabilities and cause injected fluids to bypass regions of high remaining oil saturation or remain in-situ if contacted by crude oil.

LTG process effectiveness is therefore closely tied to the ability for injected dispersed gas drive to displace producible crude oil. Additionally, mobility and/or conformance control is desired during slug injection in order to increase contacted oil and thereby increase displaceable crude oil.

As previously described, two shock fronts propagate during ASP or LTG flooding for tertiary or secondary/tertiary recovery. Figures 3.9 and 3.13 were introduced to illustrate ideal propagation of the two shock fronts, with description provided previously in this paper. For tertiary flooding, a forward shock front is characterized by an oil bank displacing mobile water, while a secondary shock is characterized by injected fluids mobilizing residual oil and forming an advancing oil bank. For secondary flooding, a forward shock front is characterized by oil at initial oil saturation being displaced by previously displaced residual water. This is followed by a secondary shock where injected fluids mobilize residual oil to form an oil bank which connects the two fronts. This oil bank will have higher interstitial velocity and result in increased volume of oil at initial oil saturation. In addition, for actual displacement where displacement of residual
water will be minimal and slow, the two fronts will blend or be located very close to one another.

3.6.1 Mobility Ratio and Apparent Viscosity of Displaced Fluids

3.6.1.1 Models and Calculations

Given by a dimensionless ratio called the mobility ratio (M), a ratio of displacing and displaced fluid motilities can characterize displacement efficiency and process stability (Eq. 3.23). A mobility ratio less than or equal to one indicates favorable displacement (Lake 1989; Habermann 1960).

\[ R = \frac{\lambda_{\text{displacing}}}{\lambda_{\text{displaced}}} \] (3.23)

Three relative mobility values are used evaluate displacement across floods. They are the relative mobility of: injected fluids (\( \lambda_{\text{injected}} \)), oil bank (\( \lambda_{\text{oil bank}} \)), and displaced water at residual oil (\( \lambda_{\text{wro}} \)). These values correspond with the relative mobility of the displacing and/or displaced fluids. For calculation of \( \lambda_{\text{oil bank}} \) and \( \lambda_{\text{wro}} \), endpoint relative permeability values from oilflood and waterflood were used to calculate mobility, respectively. This is consistent with methods described by Levitt (2006-b). It is worth noting that this method is an oversimplification for \( \lambda_{\text{oil bank}} \) because it assumes \( S_o \) oil bank is equal to \( S_o \) for mobility calculations. As described in Elongate Oil Bank, the oil bank will elongate at lower \( S_o \) which will result in reduced \( \lambda_o \) according to a Corey Relation. Calculation of \( \lambda_{\text{injected}} \) is based upon observed pressure gradient during chemical flooding. This calculated mobility will have moderate error during early stage displacement because of the high contribution of mobility of displaced fluids to overall observed pressure gradient. However, for late stage processes where injected fluids are the primary
flowing phase, this assumption should be valid. Calculation of relative mobility and mobility ratios during flooding are based upon 1-D Darcy’s law as described in Eqs. 3.24 and 3.25.

\[ \lambda = \frac{k_r}{\mu} = \frac{k^*q*L}{A^*\Delta P} \quad \text{(From 1-D Darcy’s law)} \]  

\[ R = \frac{\lambda_1}{\lambda_2} = \frac{[k^*q*L/A^*\Delta P]_1}{[k^*q*L/A^*\Delta P]_2} = \frac{[q/\Delta P]_1}{[q/\Delta P]_2}; \quad k_1 = k_2, \ L_1 = L_2, \ A_1 = A_2 \]  

For propagation of the forward shock front during tertiary recovery, \( \lambda_{\text{injected}} \) is used in place of the more physical representation of \( \lambda_{\text{oil \ bank}} \) for fluids displacing water at residual oil (\( \lambda_{\text{wro}} \)). This is attributed to an approximation for oil bank mobility (discussed below) and a requirement for \( \lambda_{\text{oil \ bank}} \leq \lambda_{\text{wro}} \). \( \lambda_{\text{oil \ bank}} \gg \lambda_{\text{wro}} \) would be accompanied by elongation of the oil bank and diminished oil saturation until \( \lambda_{\text{oil \ bank}} \approx \lambda_{\text{wro}} \). Elongation of the oil bank is a topic which was previously discussed.

For the second shock front during tertiary recovery (floods 1-4) and the approximated shock front during secondary recovery (LTG_Oil_#5), injected fluids (\( \lambda_{\text{injected}} \)) are considered to displace an oil bank (\( \lambda_{\text{oil \ bank}} \)). This is physically valid for tertiary recovery other than the overestimation of \( \lambda_{\text{oil \ bank}} \) which was already noted. For secondary recovery under practical displacement conditions, the two shock fronts should blend together due to mixing and reduced displacement for the low permeability water bearing zone. As such, a high saturation (\( S_{\text{oil}} \)) front is displaced by injected chemicals (\( \lambda_{\text{injected}} \)) with a mixing zone in between. The mobility of the displaced oil is known from previous oilflood and is exactly equal to \( \lambda_{\text{oil \ bank}} \).
To determine $\lambda_{wro}$, $k_{rw}^o$ from the influent section ($X_D=0-0.25$) was used to establish $\lambda_{wro}$ for all sections. This is consistent with normalizing to true residual oil conditions if $X_D=0-0.25$ is taken to be at such conditions (Eqs. 3.26 and 3.27). This selection was done due to poor displacement efficiency during waterflood where $k_{rw}^o(X_D=0.25-1) < 0.5 \times k_{rw}^o(X_D=0-0.25)$. This results in diminished in-situ $k_{rw}^o$ and diminished reference mobility. This is manifest in higher calculated macroscopic mobility ratios for $X_D=0.25-1$ if in-situ conditions are used instead of true residual conditions.

Use of in-situ conditions for later sections to determine $\lambda_{wro}$ is, however, not believed to be physically valid during tertiary recovery involving surfactant. The diminished $k_{rw}^o$ for later sections which causes this behavior is not present during actual displacement due to remobilization of crude oil in an oil bank (trailing shock front). This oil bank re-establishes high oil saturation and negates the effects of differences in initial displacement efficiency across sections which result in this different $k_{rw}^o$. Sections of mostly uniform oil and water saturation, and relative mobility will form which correspond to the point at which the oil bank achieves required relative mobility for stable propagation.

Determination of $\lambda_{oil \ bank}$ was straightforward due to the near uniform $\lambda_o^o$ values which were observed across all cores. This is due to the very low mobility ratio ($M \sim .15<<1$) which was present during initial oil saturation. As such, overall average endpoint relative mobility, $\lambda_o^o(X_D=0-1)$, was used. Although, very similar results would have been observed if $\lambda_o^o(X_D=each \ section)$ was used instead.

$$\lambda_{wro}(X_D=each \ section) = \lambda_w^o(X_D=0-0.25) \quad (3.26)$$

$$\lambda_{w@2PV \ waterflood \ (X_D=each \ section)} = \lambda_w^o(X_D=each \ section) \quad (3.27)$$
\[ \lambda_{\text{oil bank \ (X_D=\text{each section})}} = \lambda_0^\alpha(X_{D=0-1}) \equiv \lambda_0^\alpha(X_{D=\text{each section}}) \quad (3.28) \]

The mobility ratios which were utilized are shown below. Mobility versus brine \((R_{\text{vs \ brine @100\%}})\) does not have a physical representation but is used to provide an understanding of foam strength (Eq. 3.29). On the other hand, \(R_{\text{vs \ oil bank}}\) and \(R_{\text{vs \ water at \ residual \ oil}}\) (Eqs. 3.30 and 3.31) are physically related to stability of the process. For calculation of \(R_{\text{vs \ water at \ residual \ oil}}\), in-situ mobility ratio was calculated based upon the relative mobility observed at 2PV water injection \((\lambda_{\text{2PV \ Waterflood}})\). This was then normalized by endpoint relative permeability to water to better align with actual petrophysical properties and eliminate the impact of originally poor displacement efficiency, as was already noted above.

\[
R_{\text{vs \ brine @100\%}} = \frac{\lambda_{\text{Chem \ flood}}}{\lambda_{\text{brine \ flood \ @ \ Sw=100\%}}} \quad (29)
\]

\[
R_{\text{vs \ oil \ bank}} = \frac{\lambda_{\text{Chem \ flood}}}{\lambda_{\text{Oil \ flood \ Endpoint}}} \quad (30)
\]

\[
R_{\text{vs \ water \ at \ residual \ oil}} = \frac{\lambda_{\text{Chem \ flood}}}{\lambda_{\text{Waterflood}}} = \frac{\lambda_{\text{Chem \ flood}}}{\lambda_{\text{2PV \ Waterflood}}} \cdot \frac{[k_{\text{water}}]_{X_D=\text{analyzed \ section}}}{[k_{\text{water}}]_{X_D=0.25}^{\text{2PV \ Waterflood}}} \quad (31)
\]

### 3.6.1.1 Using Mobility Ratio to Evaluate LTG_Tert_#1

**Figure By Figure Analysis**

Figure 3.18 presents observed chemical flood mobility versus brine flood mobility \((R_{\text{vs \ brine @100\%}})\) for LTG_Tert_#1. Brine mobility at \(S_w=100\%\) does not have a physical
representation in the propagation of a shock front, but it is useful in examining mobility behavior during the flood. The same mobility behavior which is exhibited through use of a reference brine mobility value will also be exhibited when using other reference mobility values. Any differences will be attributed to different scalar reference mobility values which have the effect of changing the magnitude of the y-axis values.

Figure 3.18: Calculated $R_{\text{vs brine}}$: Mobility injected fluids versus brine ($S_w=100\%$) mobility during LTG_Tert_#1. Mobility control is apparent given the low final oil saturation ($S_0=3\%$) and interpreted $k_{r,\text{injected fluids}} \sim 1$.

As fluid is displaced from the core, a slight drop in mobility ratio is followed by a rise to sectional steady-state values. This behavior is shown to progress along the core, with a fall in mobility being attributed to microemulsion viscosity and diminished mobility associated with formation of an oil bank. The accompanying rise in mobility is associated with displacement of oil out of the measured section. A final steady-state mobility value is achieved which corresponds to the relative mobility of the injected drive at final in-situ phase saturations and interfacial tensions. This behavior is consistent with that already discussed when introducing LTG_Tert_#1.
Consistent steady-state mobility ratio of $R \sim 0.20$ is exhibited for all sections by approximately $t_D=1.1\text{PV}_{\text{Liquid}}$. This would correspond with an apparent viscosity of $\sim 4.5\text{cP}$ based upon a final $k_r$ injected fluids$=1.0$. The assumption that $k_r$ injected fluids$=1.0$ is based upon the high overall flood recovery, resulting in $S_o \sim 3\%$ upon completion. At this point, remaining oil will occupy only sections with ultra-low permeability which should contribute minimally to permeability. This is affirmed by the fact that observed pressure drop does not appreciably change after $t_D=0.85\text{PV}_{\text{Liquid}}$, a period where oil saturation was measured to drop from 7\% to 3\%.

Figure 3.19 presents the chemical flood mobility versus oil bank mobility ($R_{\text{vs oil bank}}$). Overall behavior is identical to that of $R_{\text{vs brine}}$, which is consistent with the only change being that of a singular reference mobility value. The magnitude of the y-axis is, however, adjusted. Steady-state mobility ratio of $R_{\text{vs oil bank}} = 1.3$ is slightly above ideal ($R \leq 1$) but still within the range which would likely accompany successful flooding.

![Graph](image)

Figure 3.19: Calculated $R_{\text{vs oil bank}}$: Mobility of injected fluids versus interpreted oil bank mobility during LTG_Tert_#1. A final mobility ratio of R$\sim1.3$ was achieved.

102
Figure 3.20 presents the chemical flood mobility versus water mobility at true residual oil saturation ($R_{vs\ water\ at\ residual\ oil}$). Steady-state mobility ratio is the same as that of $R_{vs\ oil\ bank}$ at $R_{water\ at\ residual\ oil} = 1.3$. As previously noted, this is slightly above ideal ($R \leq 1$) but still within the range which would likely accompany successful flooding.

Figure 3.20: Calculated $R_{vs\ water\ residual\ oil}$: mobility of injected fluids versus water mobility at true residual oil during LTG_Tert_#1. A final mobility ratio of $R \sim 1.3$ was achieved.

**Overall LTG_Tert_#1 Mobility Ratio Analysis**

Uniformity in steady-state mobility ratio across sections, rapid progression to steady state behavior, and lack of a mobility overshoot were found to be of particular interest. Uniformity across sections indicates that mobility control did not deteriorate during progression of the chemical front, with dispersed gas likely exhibited similar rheological properties throughout the core.
Rapid progression to steady state behavior and a lack of mobility overshoot indicate a high degree of process tolerance to crude oil. Potentially destabilizing crude-water microemulsions have the potential to result in diminished mobility control. This would be observable through mobility overshoot (a rise above steady state behavior followed by a fall) and a long period of time required to achieve steady state behavior.

Mobility ratios of $R=1.3$ with respect to both water at true residual oil and the oil bank are within the range which would likely accompany successful flooding. The sharp fronts exhibited by pressure derived mobility, and high, rapid recovery indicate that additional mobility control may be present which is not captured by mobility ratio. This could be due to foam rheology in porous media being different than that of polymer flooding, allowing for favorable displacement at slightly diminished macroscopic mobility ratio.

### 3.6.1.2 Mobility Ratio for Other Floods

Table 4.5 presents the steady-state mobility ratio values for each of these floods. Discussion of each of the floods is presented below. Direct comparison among floods is complicated by differing relative permeability to injected fluids which is strongly a function of oil saturation. Because tertiary recovery varies from 14%-92% among the five floods presented, relative permeability to injected fluids will substantially vary among the floods. Floods with lower recovery will exhibit comparatively favorable apparent macroscopic mobility ratio when contrasted to higher recovery floods.
Table 3.5: Observed mobility ratios (R) for experiment corefloods.

<table>
<thead>
<tr>
<th>Experiment ID:</th>
<th>$k_w$ used</th>
<th>$k_w^*$ used</th>
<th>$R_{vs\ brine}$ @S_W=100%</th>
<th>$R_{vs\ oil\ bank}$</th>
<th>$R_{vs\ displaced\ water}$ [A]</th>
</tr>
</thead>
<tbody>
<tr>
<td>LTG_Tert_#1</td>
<td>0.35</td>
<td>0.17</td>
<td>0.22</td>
<td>1.3</td>
<td>1.3</td>
</tr>
<tr>
<td>LTG_Tert_#2</td>
<td>0.44</td>
<td>0.15</td>
<td>0.15</td>
<td>0.7</td>
<td>1.0</td>
</tr>
<tr>
<td>Surf_Tert_#3</td>
<td>0.33</td>
<td>0.13</td>
<td>0.28</td>
<td>1.7</td>
<td>2.8</td>
</tr>
<tr>
<td>Gas_Tert_#4</td>
<td>0.35</td>
<td>0.22, 0.07, 0.10 [B]</td>
<td>0.13</td>
<td>0.8</td>
<td>0.9</td>
</tr>
<tr>
<td>LTG_Oil_#5</td>
<td>0.35</td>
<td>n/a</td>
<td>0.26</td>
<td>1.5</td>
<td>n/a</td>
</tr>
</tbody>
</table>

[A] $R_{vs\ displaced\ water}$ is $R_{vs\ water\ at\ residual\ oil}$ for floods #1-3, and #5. $R_{vs\ water}$ is $R_{vs\ water\ at\ 2PV\ water\ flood}$ for flood #4. This is due to minimal saturation change during flood #4 which makes initial conditions more reflective of displacement conditions than residual (oil) conditions.

[B] Sectional $k_w^*$ values were used which correspond with initial conditions instead of residual (oil) conditions. 0.22 corresponds with section 1, 0.07 with section 2, and 0.10 with section 3.

LTG_Tert_#2—Similar mobility ratio behavior and profile was observed to that of LTG_Tert_#1, although mobility ratios were slightly below that of LTG_Tert_#1. Two factors may have contributed to this behavior: 1) reduced oil recovery during this flood resulted in lower relative permeability to injected fluids and more favorable observed macroscopic mobility ratio; and 2) strength of dispersed gas drive is slightly high for propagation in tight formations.

Other observations include that $R_{vs\ oil\ bank}$ is disproportionately low. This is due to a higher $k_w^*$ for this flood which is likely caused by the higher pressure gradient during oil flooding (due to lower permeability). In addition, mobility ratio is slightly lower for the last section than the other two sections. This may indicate that the lower injected surfactant concentration for this flood was not present in sufficient quantity in this last section to fully mobilize the oil. This would result in higher oil saturation, reduced relative permeability to injected fluids, and increased apparent mobility control.
Surf_Tert_#3—Larger mobility ratios were observed for this flood than LTG floods. This is consistent with reduced mobility control. Macroscopic calculated mobility ratio is smaller for later floods. This is likely due to diminished displacement efficiency which results in a reduced relative permeability to injected fluids. This relationship is discussed in greater detail in the next section where relative permeability is compensated for to allow for direct comparisons across floods of apparent viscosity of injected fluids.

Gas_Tert_#4—Unlike other floods, $\lambda_{w@2PV \text{ waterflood}}$ was used for evaluation due to the minimal displacement of crude oil and minimal notable change in saturation distribution across the core during tertiary displacement. As such, initial conditions are believed to more representative of fluid behavior than residual (to oil) conditions (which were used for other floods). Nonetheless, some increase in $R_{vs \text{ water}}$ was observed for later sections which indicates that this flood did impact displacement efficiency. Resulting mobility ratio is approximately $\sim 1$ for the first section and rises slightly for later sections. This is due to displacement of mobile but previously undisplaced crude oil in the later sections which had been negatively impacting $k_{rw}$. As some of this oil is displaced and $k_{rw}$ increases, the apparent mobility ratio will increase above 1. Beyond this intuitive understanding, this is likely a purely mathematical relationship and does not indicate that displacing fluids have reduced apparent viscosity. Assuming that displacement of oil is minimal in section 1 and $k_{rw}$ is similar before and after tertiary flooding, approximate co-injection viscosity of 1cp is achieved.

LTG_Oil_#5—Results were similar to other LTG floods for $R_{vs \text{ brine} @ 100\%}$ and $R_{vs \text{ oil bank}}$. This is consistent with high initial oil saturation not having a substantial impact upon process displacement. $R_{vs \text{ displaced water}}$ was not available due to a lack of a waterflood derived $k_{rw}$ value because the core was not waterflooded.
3.6.2 Apparent Viscosity Calculations

Apparent viscosity of injected fluids ($\mu_{\text{app \ injected}}$) is an important gauge of foam strength and ability for injected fluids to displace in-situ crude oil or oil-water microemulsions. Conventional coreflood measurement of apparent viscosity in porous media utilizes steady state displacement where the relative (and absolute) permeability to the injected fluids is both known and constant. By doing so, the macroscopic pressure drop can be used to directly calculate the apparent viscosity of the injected fluids.

During tertiary recovery which takes place for the five discussed floods, relative permeability to the injected phases is neither known nor constant. Additional recovery during the flooding, usually due to an ultra-low o/w IFT environment, will result in an increase in relative permeability to water from the known endpoint relative permeability. As such, any calculations of apparent viscosity based upon the initial relative permeability will be incorrect and result in apparent viscosity which is below actual.

A deconstruction is required in order to determine the relative permeability to the injected fluids and thus the apparent viscosity (Eqs. 3.32-38). This deconstruction is based upon an expansion of the Corey-equation beyond residual oil saturation. It is considered only valid for late stage displacement processes (1.5PV$_{\text{Liquid+}}$) due to its assumptions of: 1) uniform oil saturation, and 2) high oil-water IFT environment, which are described in greater detail below. Application of the Core-equation to beyond residual oil saturation by using these assumptions is likely not entirely valid and may only provide approximate values for apparent viscosity. Assumptions and possible sources of error are included below. Examples seem to validate this model as effective at calculating apparent viscosity with moderate to high error ($\pm 15\%$).
3.6.2.1 Assumptions and Calculation Method

Assumptions:

- Corey-equation is mostly valid and has a singular n-exponent which achieves the fitting parameters. \( k_{rw} \) vs. \( S_w \) exhibits behavior consistent with figure 3.22 (discussed below).
- Core achieves uniform oil saturation. This is required due to the use of material balance to determine in-situ oil saturation. Propagation of an oil bank negates use of the model for early-flood calculations. In addition, model is affected by non-uniform oil saturation (as expressed in examples)
- A high oil-water IFT environment is present during late stage flooding. This is consistent with lower type I microemulsion environment and is a requirement for use of a Corey relationship. If oil-water IFT is low, accompanying low capillary number will result in increased relative permeability to oil.
- Two-phase (oil-water) relative permeability is utilized to calculate relative permeability, with gas is considered part of the water phase. This is consistent with treating a gas-water (foam) mixture as a single phase and allows for comparison to aqueous phase displacement (polymer flooding, brine flooding)

Model and Derivation:

\[
\text{Normalized Apparent Viscosity} = \frac{\mu_{\text{tertiary flood}}}{\mu_{\text{brine}}} \quad (3.32)
\]

- From 1-D Darcy’s Law:

\[
\Delta P = \frac{\mu \cdot q \cdot L}{k \cdot k_r \cdot A} \Rightarrow \mu = \left(\frac{\Delta P \cdot A}{q \cdot L}\right) \left(\frac{k \cdot k_r}{k_{w}}\right) \quad (3.33)
\]
• Using a relative mobility relation:

\[
\lambda = \frac{q * L}{\Delta P * A} \Rightarrow \mu = \left(\frac{1}{\lambda}\right) * k_r
\]  

(3.34)

• Results in:

\[
\frac{\mu_{\text{tertiary flood}}}{\mu_{\text{brine}}} = \frac{(k_r)_{\text{tertiary}}}{(k_r)_{\text{brine}}}
\]  

(3.35)

**Determining Values for Calculation:**

• \( k_{r, \text{brine}} = 1 \) → brine permeability measurements at \( S_w = 100\% \)

• \( \lambda_{\text{brine}} = \text{known} \) → brine permeability measurements at \( S_w = 100\% \)

• \( \lambda_{\text{tertiary}} = \text{calculated} \) → from \( q \) and \( \Delta P \) values (Eq. 34) during flooding

• \( k_{r, \text{tertiary}} = k_{r, \text{injected fluids} \odot SS} \) → derived below: from Corey relation and material balance

**Calculation of \( k_{r, \text{injected fluids}} \):**

1) Use material balance to determine in-situ oil saturation—From the material balance, \( S_{\text{injected fluids}} \) is determined according to Eq. 36. This results in an injected fluids profile captured in Figure 3.21 (see next page).

\[
S_{\text{injected fluids}} = S_{\text{gas}} + S_{\text{water}} = 1 - S_{\text{oil}}
\]  

(3.36)
2) Develop a relationship for $k_r$ injected fluids as a function of $S_{\text{injected fluids}}$—A relative permeability curve is developed according to an expansion of the Corey-equation (Eq. 4) to fit the three known $k_{rw}$ values:

$$k_{rw}=0 \quad \text{at } S_{wi}$$
$$k_{rw}=k_{rw}^{\circ} \quad \text{at } S_{w@2PV \text{ Waterflood}}$$
$$k_{rw}=1 \quad \text{at } S_{w}=100\%$$

$k_r$ injected fluids $(S_{\text{injected fluids}}) \sim k_{rw}(S_{\text{injected fluids}})$ according to assumption #4 (gas is treated as a water phase for relative permeability measurements). In addition, it is important to note that this model uses a $S^{\circ}$ which is greater than 1 for tertiary recovery.

$$S_{\text{injected fluids}}^{\circ} = \frac{S_{\text{injected fluids}}-S_{wi}}{1-S_{wi}-S_{orw}} > 1 \text{ during tertiary recovery} \quad (3.37)$$

$$k_{r \text{ injected fluids}} = k_{rw} \times (S_{\text{injected fluids}}^{\circ})^n \quad (3.38)$$

Figure 3.22 presents the interpreted relative permeability curve for injected fluids for LTG_Tert_#1. Markers represent the interpreted relative permeability to injected fluids and injected fluid saturation for Gas_Tert_#4, Surf_Tert_#3, & LTG_Tert_#1 (left to right). The profile of the transition at $S>S^{\circ}$ is unknown and could result in error between calculated and actual $k_r$ values. However, potential error is reduced by the fact that the three floods lie close to known relative permeability values of $S_{\text{injected fluid}}=100\%$ (LTG) or $S_{\text{injected fluid}}=S_{w@2PV \text{ Waterflood}}$ (Gas, Surf).
Figure 3.21: Injected fluids profile (1-S_o), and interpreted relative permeability (k_r injected fluids) profile for apparent viscosity deconstruction of LTG_Tert_#1.

Figure 3.22: Derived 2-phase relative permeability relationship for late-stage, high oil-water IFT tertiary recovery using an expanded Corey relationship. Endpoint oil saturation values during flooding are near known endpoint saturation/relative permeability values, indicating reduced error.
3.6.2.2 Results From Apparent Viscosity Deconstruction

Figure 3.23 presents the calculated sectional apparent viscosity for LTG_Tert_#1. It is contrasted with calculated apparent viscosity for Surf_Tert_#3 and Gas_Tert_#4. Results show a substantial deviation in apparent viscosity during earlier portions of the flooding. This is attributed to non-uniform oil saturation (oil bank) which results in non-uniform relative permeability to injected fluids. As such, this model is considered only valid for after $t_D=1.0\, PV_{\text{Liquid}} (=2.0\, PV_{\text{total}} @50\% \text{ gas quality})$.

Figure 3.23: Sectional and overall calculated apparent viscosity for LTG_Tert_#1. Overall Surf_Tert_#3 & Gas_Tert_#4 floods are included as reference cases. Consistent with assumptions, $t_D = 0-1.0\, PV_{\text{Liquid}} (0-2.0\, PV_{\text{total\ fluid}} \text{ in plot})$ provides invalid sectional apparent viscosity due to non-uniformity in oil saturation across the core.

Once steady state behavior is attained $t_D>2.0\, PV_{\text{total}}$, LTG_Tert_#1 shows a consistent apparent viscosity of approximately 4.0cP across all sections. This is contrasted with an apparent viscosity of approximately 1.0cP for both Surfactant and Gas.
(co-injection) floods. Apparent viscosity of 1.0cP for surfactant flooding helps to validate the model.

With respect to LTG flooding, surfactant flooding achieves steady-state behavior at an earlier \( t_{D_{\text{total}}} \) due to a higher liquid fraction and resultant doubling of liquid rate with respect to \( t_{D_{\text{total}}} \). In addition, the temporary rise in apparent viscosity to 1.6cP depicts the relative contribution of oil mobilization and the microemulsion bank to overall average flowing apparent viscosity. Gas flooding exhibits near constant apparent viscosity at all points during the flood. This is consistent with minimal oil mobilization which is achieved by this process.

Table 3.6 shows additional results for calculated apparent viscosity for the 5 floods. Large differences across floods of the \( n \)-exponent to fit the three known \( k_{rw} \) values \((n=2.7-3.6)\) indicate that substantial error may exist. This is especially relevant for high recovery (LTG floods) where the exponential relationship amplifies uncertainty associated with oil material balance. As such, the apparent viscosity values demonstrated by LTG_Tert_#1, LTG_Tert_#2, and LTG_Oil_#5 are considered experimentally inseparable.

![Table 3.6: Calculated apparent viscosity and model input values]

[A] = Inferred values. Actual determination not possible due to lack of waterflood during trial.
Overall, LTG flooding demonstrated improved apparent viscosity of 3.2-5.0cP, above that of reference Gas co-injection and Surfactant flooding. This indicates the presence of mobility control with approximate drive viscosity of 4cP.

In addition, due to averaging of oil saturation across the core, sections of below average oil saturation will have underestimated relative permeability to injected fluids and therefore lower apparent viscosity. For late-stage Gas co-injection and Surfactant flooding where the viscosity is assumed to be constant across sections, differences between apparent viscosities across sections can be related to in-situ oil saturation. Poorly swept sections will demonstrate higher oil saturation, lower relative permeability, and thus higher apparent viscosity than the other sections, and vice-versa.

Surf_Tert_#3 & Gas_Tert_#4 exhibit lower apparent viscosity for section one ($X_d=0-.25$) than the overall average. This indicates diminished displacement efficiency is exhibited by later sections of the core. On the other hand, no trend is observed in apparent viscosity across the sections during LTG flooding. This indicates that uniform oil saturation is achieved and that oil mobilization and displacement do not diminish as the process progresses along the core. This is indicative of improved mobility control and favorable displacement of in-situ fluids.
3.7 Key Findings

- Low-quality, low-rate co-injection of gas (N₂) and surfactant enriched brine (known as LTG) was effective in mobilizing and displacing residual oil to waterflood. Final LTG tertiary recovery of 91% was achieved (95% OOIP), with recovery of 73% ROIP by \( t_D=0.8PV_L \) and 79% ROIP by 1.0PV liquid injected.

- LTG flooding exhibited many of the properties characteristic of successful ASP floods. These include the production of a large bank of free oil at high oil cut prior to the production of oil-water microemulsion. In addition, pressure data indicate the sharp progression of a microemulsion or mobile oil phase through the core.

- LTG process repeatability was demonstrated via testing at reduced permeability and surfactant concentration, with similar process attributes achieved. These include similar propagation of injected and mobile fluids, observed apparent viscosities and mobility ratios, production profile, and overall recovery.

- LTG recovery was shown to achieve substantially higher recovery (47% greater) than the combined recoveries achieved by individual 1) surfactant injection and 2) gas co-injection floods. These reference floods constitute elements of the LTG process and were used for further comparison and model validation.

- Application of LTG flooding at secondary recovery demonstrated results consistent with other LTG floods. This indicates that potentially destablizing effects of high initial oil saturation upon lamellae stability and foam strength did not noticeably affect displacement and other mechanisms. In addition, LTG flooding was shown to
decrease pressure drop associated with secondary recovery when compared to waterflood. This is a consequence of high relative mobility of the oil phase ($\mu_o=1.9$) and the diminished overall relative mobility which occurs due to incomplete displacement during waterflood. As such, stable tertiary displacement can occur at pressure gradients below that of waterflood. These findings are of especially high significance due to the potential to: 1) capture additional recovery during tertiary flooding and 2) reduce the high pressure gradients associated with waterflooding—a concern for application of waterflood in tight formations.

- Early gas breakthrough, which was observed ($t_D \sim 0.3PV_{\text{Total}}$) is believed to be a function of diminished rate of advance for a surfactant relative to gas. This is attributed to the presence of free gas which evolves ahead of an injected surfactant front. It is not believed that this is a function of unstable foam propagation or failure but is instead likely caused by: 1) diminished rate of advance of free surfactant relative to bulk injected fluids due to absorption and partitioning at the oil-water interface, and 2) higher interstitial velocity of injected gas versus injected surfactant-liquid due to reduced pore volume available for a third gas phase.

- An elongate oil bank was exhibited by LTG flooding in this study. This is shown to be a characteristic of low oil viscosity ($\mu_o=1.9\text{cP}$) and tight saturation window ($\frac{dS_w}{dS_w^*} \gg 1$), which are within the proposed scope for this process. This is a potentially favorable attribute of this process because for floods exhibiting stable displacement, an elongate oil bank will allow for earlier oil production and more immediate payback.
• Effluent salinity was shown to be an effective tracer for measurement of dispersion and gas saturation when using a salinity gradient. Early stage LTG displacement exhibited reduced dispersion relative to other flooding methods, indicating favorable displacement of in-situ fluids and mobilized oil. Late stage LTG displacement exhibited similar, albeit slightly improved, dispersion to that of surfactant flooding. Temporary water trapping within a type II(+) or III microemulsion phase is believed to cause this observed dispersion. Later mobilization of this higher salinity trapped water will result in amplified apparent dispersion.

• LTG gas saturation of 18-22% was observed during slug breakthrough through use of material balance and effluent salinity tracers. This is contrasted with 5% gas saturation observed by gas-coinjection and indicates that a high degree of dispersed gas was present during LTG flooding. This is consistent with propagation of stable foam, as increased dispersed gas saturation is often associated with lamellae production.

• Approximate equality in mobility ratios between bulk injected fluids and oil bank or displaced water at true residual oil was observed during LTG flooding. This indicates that LTG flooding can achieve stable displacement of light crude oil in tight formations. Displaced water at true residual oil relative mobility \( (\lambda_{wro}) \) was used in favor of in-situ water relative mobility at the end of waterflood \( (\lambda_{w@2PV\text{waterflood}}) \) due to the impact that poor waterflood displacement efficiency has upon observed endpoint water relative mobility. \( \lambda_{w@2PV\text{waterflood}} \) was believed to be invalid due to the formation of an oil bank during LTG injection which will re-establish oil/water saturations in a
more uniform manner. This will greatly negate the impact of initial water mobility and make the use of $\lambda_{w@2PV\text{ waterflood}}$ as a stability parameter incorrect.

- Steady-state apparent viscosity of injected fluids was calculated to be \( \sim 4.5\text{cP} \) during late stage LTG flooding based upon observed mobility ratios and implied $k_{r\text{ injected fluids}}$ of approximately 1. This is contrasted with apparent viscosity near 1cP for gas-coinjection flooding (no surfactant) and indicates that a degree of foaming was present which restricted mobility of injected fluids. This affirms that foam can propagate in low permeability porous media and also give a quantitative benchmark for the capability of foam for mobility control in such formations.
Chapter 4: Investigation of Localized Behavior and Surfactant-Alternating-Gas (SAG) Injection

4.1 INTRODUCTION

Previous Relevant Work

It was previously shown that through co-injection of surfactant and gas, favorable mobilization and displacement of residual and initial \((1-S_w)\) oil saturation could be achieved for tight carbonate cores of 2-15mD (Chapter 3). By utilizing this injection process, titled Low-Tension-Gas (LTG) and discussed in the Literature Review, tertiary recovery as high as 92% of ROIP was achieved. Floods exhibited a characteristic large oil bank, which is associated with production of single phase oil at moderate and consistent oil cut for an extended period. This is similar to results observed by successful ASP floods at higher permeability and favorably indicates the likelihood that LTG can extend chemical flooding to tight reservoirs.

During the previous study, a number of deconstructions and tools were also developed to better understand the mechanisms which impact oil mobilization and/or displacement during LTG flooding. Reference gas (no surfactant) flooding, reference surfactant (no gas) flooding, and reference ultra-low permeability LTG flooding (2.6mD) were used to establish repeatability, determine relative process contributions, and validate models.

Earlier arrival and production of an elongate oil bank, with positive economic implications, was shown to be an attribute of the low crude oil viscosity and low formation permeability. Additionally, salinity was shown to be a valuable tracer tool for the interpretation of a) dispersion and b) in-situ gas saturation. Further, a number of mobility ratios and apparent viscosity constructions were utilized to model the macroscopic stability of the process and determine approximate foam strength. These
tools helped to form the opinion that under the steady-state conditions represented by co-injection, LTG flooding at the tested gas fractional flow (50%) exhibited the stability mechanisms required to (likely) effectively displace mobilized crude oil.

**Established Study Need**

However, true application of foam flooding within an oilfield is not captured by a single steady-state displacement condition. Actual foam quality and fractional flow will vary considerably based upon gravity segregation, in-situ mixing, reservoir permeability distribution and geometry, and injection strategy (among other factors). Basic foam theory (See chapter 2) and studies by a number of authors (Nguyen 2004, Osterloh 1992, Alvarez 2001) have shown that mobility reduction (inverse relationship to apparent viscosity) through foam is highly dependent upon the fractional flow of the respective phases.

The considerable existing experimental and theoretical work towards understanding this fractional flow-mobility reduction relation for the flow of gas-liquid (foam) in porous media is restricted to permeability, which is at least 1-2 orders of magnitude higher than the tight (5-10mD) formations that are investigated in this study. As presented in *LTG in Tight Formations* (Section 2.5), it is believed that a different interpretation of the relative importance of foam generation mechanisms is necessary for application in tight formations. Such interpretation places reduced emphasis upon the existing ‘strong foam’ literature which has been the focus of substantial experimental micro-models, bead packs, sand packs, and Darcy-type corefloods in addition to other mechanistic research. It instead proposes that a reduced ‘weak foam’ state exists with the desired rheological properties for stable displacement of low viscosity crude in tight formations. Such an interpretation was affirmed for LTG flooding at 50% gas fraction (chapter 3); but, the impact of higher or lower gas flowing fraction is not yet known.
In addition, beyond the overall ability for foam to demonstrate effective steady-state mobility reduction at a variety of flowing gas qualities in tight formations, it is also important to understand how the properties vary during process oil mobilization and displacement. High crude oil or microemulsion saturation can be highly destructive for foam stability in the conventional ‘high strength’ foam regimes (Schramm 1993, Lau 1988), with such behavior having the potential to substantially alter displacement efficiency and ultimate recovery. This behavior is highly dependent upon a number of factors, including oil-water microemulsion environment, crude oil and surfactant chemistry, brine composition and surface wettability (Schramm 1994). It also presents an important complicating factor in relating gas fractional flow and expected mobility reduction or displacement efficiency.

**Overview of Co-injection Study**

A series of 4 LTG (Co-injection) tertiary recovery corefloods are presented at differing gas fractional flow—\( f_g = 0 \), \( f_g = 0.30 \), \( f_g = 0.50 \), and \( f_g = 0.85 \). These floods represent the initial drainage followed by steady-state displacement of sections with specific gas fractional flow. They are used to observe both a) steady-state foam strength, which is of considerable importance for injected drive, and b) local mobilization and displacement phenomenon for portions of the reservoir with specific gas fractional flow.

Data from oil recovery and fractional flow (4.3.1); salinity and mixing (4.3.2-a), sectional pressure drop (used for 4.3.3 and 4.3.4); and microemulsion and surfactant production (4.3.2-b) is used to evaluate the respective floods. This direct data is coupled with additional derived gas saturation, mobility ratio (4.3.3), and apparent viscosity relations (4.3.4) to study overall mobilization and displacement mechanisms.

Through comparison of these observable process attributes among the floods, important understanding of the impact of gas fractional flow can be formed. For this
study, such observation is assigned significance according to: a) the ability to empirically
determine if critical instabilities are or may be present during flooding, b) better optimize
and model the displacement processes on a macroscopic and megascopic scale, and c)
investigate displacement mechanisms to establish consistency (or disparities) with theory
and anticipate future results by understanding which parameters are most significant.

**SAG Investigation | Established Need and Overview**

Co-injection of surfactant and gas was utilized in order to model mobilization and
displacement under specific local conditions where gas and liquid are both flowing as a
set volume fraction. Actual reservoir application of foam flooding typically requires the
use of a surfactant-alternating-gas (SAG) injection to mitigate near wellbore pressure
drop and increase injectivity. Mixing further along into the reservoir will create an
expanding low mobility region due to foam generation and propagation. This mixing
region will exhibit a range of gas fractional flow and gas saturation values which may
exhibit varying apparent viscosity.

This relationship is moderately well understood for highly permeable medium
(Shan 2002, Rossen 2004); however, minimal literature exists for foam generation and
displacement in tight formations. To better understand this relationship and to scale it to
LTG flooding, LTG_SAG corefloods using three different cycling strategies are
performed. Cycle strategies were selected to enable comparison to LTG co-injection
floods and/or amplify the effects of large gas or liquid cycle size. The cycle strategies
selected were 2L:2G, 1L:3G, and 3L:1G over a total cycle length of 0.20PV (gas and
liquid).

Displacement through SAG flooding was first tested (LTG_SAG_2L:2G) and
contrasted with observed results from co-injection at identical average gas injected
fraction of 50% (LTG_Coinj_50%). The same tools as described previously were used to
interpret oil mobilization and displacement during the two floods, with particular emphasis placed upon properties related to differences in oil displacement and mobility of injected fluids.

Additionally, cycle specific mobility behavior was observed and contrasted using additional SAG floods (LTG_SAG_1L:3G and LTG_SAG_2L:2G). By re-normalizing pressure gradient to account for differences in sectional permeability and length, accurate understanding of period dependent mobility phenomenon can be understood. This allows for important representation of progression of the respective shock fronts and other aspects tied to a gas-liquid (foam) spreading wave, a key aspect of SAG flooding (as discussed in section 2.4.1). Furthermore, it allows calculation of cyclic variability in gas saturation and an overall improved understanding of the specific displacement mechanism which dictate foam mobility reduction in tight formations.

4.2 EXPERIMENT DESCRIPTION

4.2.1 Materials and Methods

All experimental materials and formulations are identical to those used in the previous study (chapter 3). The experimental methods used for both preparation and injection are also identical with the notable exception that differing gas co-injection quality or gas/liquid alternate injection strategies were used. These differences are reflected in section 4.2, below. All floods were conducted under tertiary conditions after 2PV of waterflood (unlike LTG_Oil_#5 in chapter 3), and as such the term “Tert” was dropped from name describing each flood.

4.2.2 Study Attributes

The first series of experiments involved gas co-injection at differing gas fraction (quality) but identical overall total fluid injection rate ($q_{total\ fluid}=2$ft/day). The four floods
which constitute this study are expressed below in Table 4.1. As shown, gas injection quality of 0%, 30%, 50% and 85% was used. Attempts were made for 15% gas co-injection fraction; however, the low gas rate resulted in unstable control by the gas mass flow controller. Two floods (0% and 50% fraction) are taken from the previous study (chapter 3) and reflect Surf_Tert_#3 & LTG_Tert_#1, respectively. These floods have been renamed LTG_Coinj_0% & LTG_Coinj_50% (respectively) for this analysis to make them consistent with other floods.

<table>
<thead>
<tr>
<th>Experiment ID:</th>
<th>Description</th>
<th>Objective</th>
</tr>
</thead>
<tbody>
<tr>
<td>LTG_Coinj_0% (LTG_Surf_#3)*</td>
<td>Gas co-injection at 0% gas fraction (surfactant flood)</td>
<td>Recovery, dispersion, mobility</td>
</tr>
<tr>
<td>LTG_Coinj_30%</td>
<td>Gas co-injection at 30% gas fraction</td>
<td>Recovery, dispersion, mobility</td>
</tr>
<tr>
<td>LTG_Coinj_50% (LTG_Tert_#1)*</td>
<td>Gas co-injection at 50% gas fraction</td>
<td>Recovery, dispersion, mobility</td>
</tr>
<tr>
<td>LTG_Coinj_85%</td>
<td>Gas co-injection at 85% gas fraction</td>
<td>Recovery, dispersion, mobility</td>
</tr>
</tbody>
</table>

* Indicates that flood was previously used in chapter 3 and renamed for analysis in chapter 4.

Table 4.1: Co-injection gas quality study attributes.

The second series of experiments involved gas-liquid alternate injection (SAG cycling). Three different SAG cycle strategies were tested at a 3:1, 2:2, and 1:3 liquid-to-gas cycle size ratio over a total (liquid and gas) cycle period of 0.20PV. LTG_SAG_3L:1G corresponds to a 3:1 liquid to gas ratio (0.15PV_{Liquid injected} followed by 0.05PV_{Gas injected}), with a similar relationship for the other floods (see Table 4.2).

It is important to note that only one actual coreflood was performed to measure oil mobilization and displacement, LTG_SAG_2L:2G. LTG_SAG_3L:1G and LTG_SAG_1L:3G were performed at the end of LTG_SAG_2L:2G flooding to measure steady-state foam strength (and other foam properties). Due to the ultra-high tertiary recovery in LTG_SAG_2L:2G of >90% ROIP (S_o<3%) within 1.5PV_{Liquid injected} (with
additional production in unmeasured microemulsions after $t_D=1.5PV_{\text{Liquid injected}}$, it is assumed that steady-state foam results for all three floods were similar and reflected minimal/consistent remaining oil in the core. Late stage production of a “clean” aqueous phase and later visual inspection of the core further validated this conclusion. Additionally, the injected drive solution which will characterize the aqueous phase for these late stage cycle comparison tests was shown to have almost no oil microemulsion solubility and exhibited foaming which was minimally impacted by the presence of the tested crude oil. The exact formulation, phase behavior, and bulk foaming behavior are described in chapter 3, with the injected drive shown to be (/wt) 0.15% IOS surfactant, 1.0% Na$_2$CO$_3$ and 0% NaCl.

<table>
<thead>
<tr>
<th>Experiment ID:</th>
<th>Description</th>
<th>Objective</th>
</tr>
</thead>
<tbody>
<tr>
<td>LTG_SAG_2L:2G</td>
<td>SAG injection at 1:1 Liquid:Gas (0.1PV$<em>{\text{Liquid}}$:0.1PV$</em>{\text{Gas}}$)</td>
<td>Recovery, dispersion, mobility</td>
</tr>
<tr>
<td>LTG_SAG_1L:3G</td>
<td>SAG injection at 1:3 Liquid:Gas (0.05PV$<em>{\text{Liquid}}$:0.15PV$</em>{\text{Gas}}$)</td>
<td>Mobility</td>
</tr>
<tr>
<td>LTG_SAG_3L:1G</td>
<td>SAG injection at 3:1 Liquid:Gas (0.15PV$<em>{\text{Liquid}}$:0.05PV$</em>{\text{Gas}}$)</td>
<td>Mobility</td>
</tr>
</tbody>
</table>

Table 4.2: Surfactant-alternating-gas (SAG) cycling study attributes.

Prior to chemical flooding, the floods from the two sets of experiments exhibited properties expressed in Table 4.3. These values were calculated from volume and pressure measurements at the steps described in chapter 3. Other than these exceptions noted below, porosity ($\phi$), $S_{oi}$, and $S_{or@2PV}$ waterfloods, $k_{rw}$, and $k_{rw @2PV}$ water injected are all similar across floods.

<table>
<thead>
<tr>
<th>Experiment ID:</th>
<th>$k$</th>
<th>$\phi$</th>
<th>$S_{oi}$</th>
<th>$S_{or@2PV}$ water</th>
<th>$k_{rw}$</th>
<th>$k_{rw @2PV}$ water injected</th>
</tr>
</thead>
<tbody>
<tr>
<td>LTG_Coinj_0%</td>
<td>14.2mD</td>
<td>22.4%</td>
<td>53%</td>
<td>33%</td>
<td>.33</td>
<td>.09 .13 .08 .10</td>
</tr>
<tr>
<td>LTG_Coinj_30%</td>
<td>4.1mD</td>
<td>20.5%</td>
<td>52%</td>
<td>31%</td>
<td>.42</td>
<td>.09 .29 .09 .08</td>
</tr>
</tbody>
</table>

125
Table 4.3: Notable properties prior to chemical flooding.

Lower permeability values were observed for LTG_Coinj_30% and LTG_SAG versus other floods. This corresponded with lower porosity values and was likely due to heterogeneity in the carbonate outcrop block which was used for all core floods discussed in this thesis. This heterogeneity has already been noted (chapter 3.2).

LTG_Coinj_30% demonstrated higher $k_{rr}$ (overall) and $k_{rw}$ @2PV water injected ($X_d=0$-0.25) versus other floods. The different $k_{rw}$ value is likely due to the unusually high section 1 permeability (8.7mD) versus section 2 and 3 permeability (5.5mD and 2.1mD), which may have resulted in increased displacement efficiency of section 1 during waterflood. Higher $k_{ro}$ may be attributed to increased pressure gradient due to lower permeability.
**4.3–4.4 Results and Discussion**

## 4.3 Observe Effects of Varied Fractional Flow (Co-injection Testing)

*Note*—The tools and figures presented in this analysis were all previously developed in chapter 3 unless otherwise noted. For more detailed discussion of the specific models, relations or calculations presented below, please see said chapter.

### 4.3.1 Overall Recovery

Figure 4.1 presents the recovery and fractional flow profiles for all four steady-state co-injection tests within this study. Basic behavior was shown to be similar for all floods while magnitude (E.g. recovery) varied among floods. All floods exhibited early production of a small displaced oil bank (due to displacing gas) followed by an elongate oil bank. Such behavior was already described in detail as part of the previous study (See section 3.3 for additional details). Oil bank period was shown to be strongly dependent upon $P_{V_{\text{Liquid injected}}}$, with similar oil bank period exhibited for all floods. This is consistent with the previously proposed theory (chapter 3) of in-situ fluids mostly being displaced by injected aqueous phase during steady-state conditions.

Oil cut during the oil bank (percent oil of liquid production) was shown to be strongly correlated with final cumulative tertiary recovery. Recovery was shown to increase with an increase in gas injection quality from 0% to 50%, with LTG_Coinj_0%, LTG_Coinj_30%, and LTG_Coinj_50% floods demonstrating final tertiary recovery of 28%, 48%, and 92% (respectively). Further increases in gas injection quality to 85% (LTG_Coinj_85%) were associated with a decrease in final tertiary recovery to 74%. Reasons for this decrease are discussed later in this chapter through use of dispersion, mobility, and apparent viscosity data.
To better compare the recovery across floods, several discrete periods of flooding were selected and the cumulative recovery compared. Figure 4.2 presents recovery versus PV_{Liquid} injected at t_{D_Liquid}=0.25, 0.50, 0.75 and 1.00. This is the same information presented in the above figure 4.1. As noted previously and developed further in this chapter, it is believed that PV_{Liquid injected} is the most accurate metric to model the physical aspects of injection.

Figure 4.3 instead presents recovery for the floods versus total fluid PV injected (PV_{Total Fluid}) at t_{D_Total Fluid}=0.5, 1.0, 1.5, and 2.0. By re-normalizing to total fluid instead of liquid injected, this figure should more accurately reflect the economics of a project where injection rate and supplied fluid are restricted. Comparison of the two figures (4.2
and 4.3) shows that with respect to $\text{PV}_{\text{Total fluid}}$, diminished or delayed recovery is experienced by high gas injection quality floods and accelerated recovery is experienced for low gas injection floods. This is especially pronounced for 0% gas quality and 85% gas quality where the flood rapidly reaches completion (0% gas quality) or is still far from achieving final recovery (85% gas quality). Such behavior is important when considering actual injection strategies where, in addition to final recovery, rate of recovery is an important concern.

Figure 4.2: Cumulative recovery at different flood periods with respect to liquid PV injected ($\text{PV}_{\text{Liquid injected}}$) for various injected gas fractions.
4.3.2 Salinity Relationships: Dispersion and Gas Saturation

Dispersion and Mixing

The measured effluent salinity profiles for the four LTG_Coinj floods are shown in Figure 4.4. LTG_Coinj_0% and LTG_Coinj_50% salinity profiles were previously examined as part of chapter 3 (respectively known as Surf_Tert_#3 and LTG_Tert_#1). That analysis shows how LTG_Coinj_50% demonstrated reduced apparent dispersion relative to surfactant flooding (no gas). This was especially pronounced during the initial progression from reservoir to slug salinity and indicates substantially improved mobility control in this region.

Comparison of LTG_Coinj_30% to these floods shows that salinity breakthrough was substantially earlier than with the other floods. This is a result of high remaining oil saturation and moderate gas saturation that results in reduced pore volume occupied by
water. In addition, the progression from reservoir to slug salinity is substantially longer ($\Delta t_D=0.4P_{V_{Liquid}}$), which is indicative of increased mixing and reduced mobility control.

The salinity profile for LTG_Coinj_85% is very similar to that of LTG_Coinj_50% and indicates that similar displacement mechanisms were present. Notable differences are a) that salinity breakthrough is slightly to later, which is believed to be due to lower gas saturation (discussed later), and b) slightly increased apparent dispersion, which may be an attribute of the high gas rate increasing dispersion through an increased velocity contrast (high permeability channels which are mostly gas versus low permeability channels which are liquid).

![Comparison of Effluent Salinity, Mixing, & Microemulsion Environment](image)

**Figure 4.4:** Effluent salinity profile for LTG_Coinj_0%, LTG_Coinj_30%, LTG_Coinj_50%, and LTG_Coinj_85%. Results were used to qualitatively compare dispersion among the three floods or calculate in-situ gas saturation.
Gas Saturation

Gas saturation was calculated for the floods in the same manner as that described in section 3.5.4. Results are presented in Table 4.4 and Figure 4.5. An additional data point was included in the figure which represented LTG_Tert_#2 from the previous study (chapter 3). Results show that similar gas saturation was observed for all floods where gas was injected. Due to the larger error associated with this calculation method, it is not possible to conclusively distinguish among these data points other than to say that they exhibited gas saturations of approximately 20%. However, the lower gas saturation which occurred during LTG_Coinj_85% may be due to the lower permeability and associated reduction in large pores (related to PVMO). Or, this may indicate that the increased capillary pressure from increased gas injection fraction resulted in diminished lamellae stability and as such, diminished gas saturation. This is consistent with theory as described in section 2.3 and described empirical results where foam has been shown to be shear thinning (possible lamellae failure). Lower observed recovery and decreased mobility control (vs. LTG_Coinj_#50%) are also consistent with this interpretation (results discussed later).

<table>
<thead>
<tr>
<th></th>
<th>tD_{liquid} @ tracer midpoint (tD1)</th>
<th>S_{oil} @ tD1</th>
<th>S_{gas} @ tD1</th>
<th>S_{gas}/PV_{MO}</th>
</tr>
</thead>
<tbody>
<tr>
<td>LTG_Coinj_0%</td>
<td>.74</td>
<td>.25</td>
<td>&lt;.01</td>
<td>.03</td>
</tr>
<tr>
<td>LTG_Coinj_30%</td>
<td>.56</td>
<td>.22</td>
<td>.21</td>
<td>.98</td>
</tr>
<tr>
<td>LTG_Coinj_50%</td>
<td>.68</td>
<td>.11</td>
<td>.21</td>
<td>.77</td>
</tr>
<tr>
<td>LTG_Coinj_85%</td>
<td>.71</td>
<td>.12</td>
<td>.17</td>
<td>1.00</td>
</tr>
</tbody>
</table>

Table 4.4: Gas saturation at tracer breakthrough (tD1) for co-injection floods.
4.3.3 Mobility Relationships

As developed in chapter 3, macroscopic mobility ratio can provide an important understanding of displacement stability of the LTG process. Three mobility ratios are used in this paper, $R_{vs\ \text{brine}}$, $R_{vs\ \text{oil\ \text{bank}}}$, and $R_{vs\ \text{displaced\ water}}$. $R_{vs\ \text{brine}}$ is calculated from reference initial flooding at $S_w=100\%$ and does not have physical significance. $R_{vs\ \text{oil\ \text{bank}}}$ uses endpoint oil relative mobility observed during oilflood and is physically representative of the middle displaced phase (trailing shock front). $R_{vs\ \text{displaced\ water}}$ is calculated from section 1 ($X_D=0.025$) relative permeability observed during waterflood and is representative of the forward displaced phase at true residual oil saturation (forward shock front).

Mobility was calculated according the previously developed relation based upon Darcy’s law where injected fluids are treated as a single phase. This equation is again presented below (Eq. 4.1) with; $k$ representing sectional permeability, $q$ representing total
fluid injection rate \((q_{\text{Total fluid}})\), \(L\) representing sectional length, \(A\) representing core cross sectional area, and \(\Delta P\) representing observed sectional pressure drop. The overall equation is reflective of displacing fluids mobility divided by displaced fluids mobility, where a mobility ratio greater than 1 reflects higher mobility of displacing fluids than that of displaced fluids. For additional details on other calculations used, see chapter 3, otherwise important input values and calculated results are shown in Table 4.5.

\[
R = \frac{\frac{L_1}{A_1 \Delta P_1}}{\frac{L_2}{A_2 \Delta P_2}} = \frac{q_1}{q_2}; \quad k_1 = k_2, \quad L_1 = L_2, \quad A_1 = A_2
\]  

(4.1)

<table>
<thead>
<tr>
<th>Experiment ID:</th>
<th>(k_{ro}^*) used</th>
<th>(k_{rw}^*) used</th>
<th>(R_{vs \ brine \ \text{@S}=100%}^{ro})</th>
<th>(R_{vs \ oil \ bank}^{ro})</th>
<th>(R_{vs \ displaced \ water}^{ro})</th>
</tr>
</thead>
<tbody>
<tr>
<td>LTG_Coinj_0%</td>
<td>0.33</td>
<td>0.13</td>
<td>0.28</td>
<td>1.7</td>
<td>2.8</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>1.9</td>
<td>1.8</td>
</tr>
<tr>
<td>LTG_Coinj_30%</td>
<td>0.41</td>
<td>0.29</td>
<td>0.21</td>
<td>1.05</td>
<td>0.65</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>0.65</td>
<td>0.65</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>0.65</td>
<td>0.65</td>
</tr>
<tr>
<td>LTG_Coinj_50%</td>
<td>0.35</td>
<td>0.17</td>
<td>0.22</td>
<td>1.3</td>
<td>1.3</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>1.3</td>
<td>1.3</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>1.3</td>
<td>1.3</td>
</tr>
<tr>
<td>LTG_Coinj_85%</td>
<td>0.36</td>
<td>0.18</td>
<td>0.9</td>
<td>5.2</td>
<td>4.9</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>3.6</td>
<td>6</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>5</td>
<td></td>
</tr>
</tbody>
</table>

Table 4.5: Observed mobility ratios (R) for co-injection study corefloods.

The results from this analysis are also presented in Figure 4.6. The same trend is observed for all three mobility ratios with variability observed on a flood to flood basis. Deviations in the behavior \(R_{vs \ oil \ bank}^{ro}\) or \(R_{vs \ displaced \ water}^{ro}\) versus \(R_{vs \ brine}^{ro}\) are due flood dependent variability in \(k_{ro}^*\) and \(k_{rw}^*\) values during flood preparation (oilflood and waterflood), the reasons for which are discussed in section 4.2.2 with actual values shown in the above table. The overall trend in mobility ratios shows an approximate maximum in mobility control between 30% and 50% gas injection quality. This mobility control diminishes as gas quality is reduced further or increased further, with especially pronounced decreases in mobility control due to further increases in gas quality (85%).
This overall trend is consistent with that observed by previously stated authors and is consistent with foam theory, as discussed in detail in the preceding literature review (section 2.4).

![Figure 4.6: Calculated mobility ratios for LTG_Coinj_0%, LTG_Coinj_30%, LTG_Coinj_50%, LTG_Coinj_85% using total injection rate (q_{Total}) for calculations.]

**Re-normalizing mobility ratio to liquid injection rate**

The substantial decrease in apparent mobility control at high gas fractional flow is likely due to the minimal effects that the additional $f_g$ has upon liquid saturation and thus relative permeability. Foam theory indicates that for higher gas fractional flow foams, the pressure gradient (and displacement process) is a function of the liquid rate and relative permeability. Gas has the effect of decreasing liquid saturation by occupying the larger pores. This causes liquid relative permeability to go down and also forces liquid to better flow into the lower permeability regions. Injection of larger quantities of gas—beyond a
certain threshold—can result in minimal decreases in liquid saturation. As such, it will only minimally (or not at all) impact liquid relative permeability, while the low gas viscosity results in minimal gas rate dependent pressure drop (within this flow regime).

Because injected liquid provides the actual contact and displacement mechanism for displacing in-situ crude oil and water, a model based upon total fluid injection rate to calculate mobility ratio is inaccurate. Such a model will overstate the impact of high in-situ gas velocity by implying a higher displacing fluids injection rate. In actuality, liquid injection rate (and rate of advance) will be substantially lower than that of gas when at a higher gas injection rate. Based upon the calculated in-situ gas saturation of ~20% during flooding, it can be implied that this phenomena takes place at injected gas quality values >20% (via material balance). To correct for this relationship, the previously calculated mobility ratios are normalized to liquid injection quality (which is directly related to liquid rate). This mobility ratio will reflect the mobility ratio observed by the injected liquid which contacts and displaces in-situ oil and water. Eq. 4.2 presents this normalization factor. The normalization factor can also be viewed in the context of adjusting the 1-D Darcy’s law equation that was used for the previous mobility ratio calculation (Eq. 4.1) to use liquid injection rate ($q_{\text{Liquid}}$) instead of total fluid injection rate ($q_{\text{total fluid}}$).

$$ (R)_{\text{liquid normalized}} = (R)_{\text{total fluid injection rate}} \times (1 - \text{Injected Gas Quality}) \quad (4.2) $$

Figure 4.7 presents the mobility ratios re-normalized to liquid injection rate ($q_{\text{Liquid}}$) as described above. The re-normalized mobility ratio profile is similar to that observed by the non-normalized mobility ratios (figure 4.6), where a minimum in mobility occurs at approximately 50% injection quality. However, in the case of the re-
normalized mobility ratios, an improvement in high injection quality calculated mobility ratio is observed. This results in mobility ratios for LTG_Coinj_85% which are much more in line with other moderate injection quality floods (LTG_Coinj_30% and LTG_Coinj_50%). It also is more consistent with observed recovery values, where LTG_Coinj_85% performed second best to LTG_Coinj_50% and thus should have second best mobility ratio values to represent displacement phenomenon.

Calculated apparent macroscopic mobility values were unusually good for low recovery floods in relation to observed recovery when using both total rate (q_{Total}) and liquid rate (q_{Liquid}) relations. This is explained by the use of steady-state (late stage) properties to measure injected fluid mobility, which is coupled with higher final oil saturation during LTG_Coinj_30% and LTG_Coinj_0% floods. This will result in higher steady state oil saturations for low recovery floods and lower relative permeability to injected fluids. In sum, this results in decreased apparent mobility for such low recovery floods when compared to high recovery floods, which is reflected in improved apparent mobility ratios for low recovery floods (LTG_Coinj_30% and LTG_Coinj_0%) when compared to higher recovery floods (LTG_Coinj_50% and LTG_Coinj_85%). For more correct comparison of mobility ratios among floods, relative permeability must be accounted for, as is done in the calculation of apparent viscosity (below).
4.3.4 Apparent Viscosity Relationships for Mobility

It was previously shown (section 3.6) that observed apparent mobility ratio derived from steady state pressure data is impaired by high remaining oil saturations and their impact upon relative permeability to injected fluids. The methodology described in section 3.6 uses a relative permeability deconstruction (Corey relationship) to calculate the true apparent viscosity ($\mu_{app}$), which is a value independent of relative permeability to injected fluids or oil saturation. The basic relation that this deconstruction is based off of is presented below in Eq. 4.3. Relative permeability ($k_r$) is determined from a Corey relation and material balance, while sectional absolute permeability ($k$), sectional length ($L$), and cross sectional area ($A$) are already known. Injection rate ($q$) and pressure drop ($\Delta P$) are based upon the specific flood parameters. Both total fluid injection rate ($q_{Total}$) and liquid injection rate ($q_{Liquid}$) are used to represent $q$ and are discussed below. $q_{Total}$ is
discussed first and \( q_{\text{Liquid}} \) later, where it is used for the calculation of what is given the term “re-normalized” apparent viscosity.

\[
\mu = \left( \frac{\Delta P_{\text{A}}}{q_{\text{L}}} \right) (k * k_f) \tag{4.3}
\]

The values used for this expanded Corey model and accompanying results are presented in Table 4.6, with results also presented in Figure 4.8. These results indicate a maximum apparent viscosity of bulk injected fluids is achieved at approximately 50% gas injection quality, with accompanying decreases in apparent viscosity observed with further increases in either liquid or gas fraction. Such results are consistent with theory (section 2.4) and those the authors described in the introduction. As noted with apparent viscosity discussions in chapter 3, it is important to understand the effects that oil saturation averaging (due to material balance) have upon calculated sectional apparent viscosity. To summarize, relative permeability to injected fluids is calculated from oil material balance and used to calculate apparent viscosity (equations in chapter 3.6). For floods with poor displacement efficiency, uneven oil saturation distribution (lower in upstream sections) will result in underestimation of upstream relative permeability to injected fluids and overestimation of downstream relative permeability to injected fluids. This is manifest in incorrect calculation of lower upstream apparent viscosity and higher downstream apparent viscosity. Flooding at 0% gas fraction (LTG_Coinj_0%) is an example of this phenomenon where upstream apparent viscosity is underestimated for section 1 and overestimated for trailing sections.
Table 4.6: Calculated apparent viscosity and contributing model values

<table>
<thead>
<tr>
<th>Experiment ID:</th>
<th>$S_w$</th>
<th>$S_{w@2PV}$</th>
<th>$K_w^*$</th>
<th>n-exp</th>
<th>$S_o$ @1.5PVL</th>
<th>$S_{<a href="mailto:f@1.5PVL">f@1.5PVL</a>}$</th>
<th>$\mu_{app}$ @X=0-0.25</th>
<th>$\mu_{app}$ @X=0.25-0.75</th>
<th>$\mu_{app}$ @X=0.75-1.0</th>
<th>$\mu_{app}$ @X=0-1.0</th>
</tr>
</thead>
<tbody>
<tr>
<td>LTG_Coinj_0%</td>
<td>47%</td>
<td>68%</td>
<td>0.09</td>
<td>2.8</td>
<td>23%</td>
<td>77%</td>
<td>0.8cP</td>
<td>1.0cP</td>
<td>1.1cP</td>
<td>0.95cP</td>
</tr>
<tr>
<td>LTG_Coinj_30%</td>
<td>48%</td>
<td>68%</td>
<td>0.09</td>
<td>2.5</td>
<td>17%</td>
<td>83%</td>
<td>2cP</td>
<td>2.1cP</td>
<td>2.1cP</td>
<td>2.1cP</td>
</tr>
<tr>
<td>LTG_Coinj_50%</td>
<td>44%</td>
<td>71%</td>
<td>0.08</td>
<td>3.4</td>
<td>4%</td>
<td>96%</td>
<td>4.2cP</td>
<td>4cP</td>
<td>3.8cP</td>
<td>4cP</td>
</tr>
<tr>
<td>LTG_Coinj_85%</td>
<td>53%</td>
<td>70%</td>
<td>0.11</td>
<td>2.4</td>
<td>8%</td>
<td>92%</td>
<td>1.1cP</td>
<td>0.7cP</td>
<td>0.8cP</td>
<td>0.9cP</td>
</tr>
</tbody>
</table>

Figure 4.8: Calculated apparent viscosity ($\mu_{app}$) versus injected gas quality for LTG_Coinj_0%, LTG_Coinj_30%, LTG_Coinj_50%, LTG_Coinj_85%. Results use total fluid injection rate ($q_{Total fluid}$) for apparent viscosity calculations.
**Liquid Rate Re-normalized Apparent Viscosity**

In a manner similar to that discussed in *Re-normalizing mobility ratio to liquid injection rate* (section 3.3.3), use of total injection rate to determine effective mobility ratio (section 3.3.3) or apparent viscosity (above) may not effectively represent the actual displacement process. To correct this, the results from total rate calculated apparent viscosity are re-normalized to liquid rate ($q_{\text{Liquid}}$) from total fluid rate ($q_{\text{Total fluid}}$) in a manner consistent with using $q_{\text{Liquid}}$ for apparent viscosity calculations instead of $q_{\text{Total fluid}}$ (Eq. 4.4). Results from the re-normalized apparent viscosity are presented in Figure 4.9. These results indicate substantial improvement in apparent viscosity for fluid injection at 85%, which is in much greater agreement with observed recovery results.

*\[ (\mu_{\text{app}})_{\text{liquid normalized}} = (\mu_{\text{app}})_{\text{total fluid injection rate}} \times (1 - \text{Injected Gas Quality}) \]  (4.4)*

![Normalized Liquid Rate (q_{Liquid}) Calculated Apparent Viscosity](image)

**Figure 4.9:** Calculated re-normalized apparent viscosity ($\mu_{\text{app}}$) versus injected gas quality for LTG_Coinj_0%, LTG_Coinj_30%, LTG_Coinj_50%, LTG_Coinj_85%. Results use liquid injection rate ($q_{\text{Liquid}}$) for apparent viscosity calculations.
Displacement Relationships: Recovery vs. Liquid Rate Re-normalized Apparent Viscosity

A strong correlation was observed between re-normalized apparent viscosity $\mu_{app}$ calculated from $q_{Liquid}$ and cumulative oil recovery during flooding. This relationship is presented below in Figure 4.10 for the four floods at five discreet flood periods. The five periods selected were 0.13, 0.25, 0.50, 0.75, and 1.00 PV$_{Liquid}$, with PV$_{Liquid}$ used in place of PV$_{Total \ fluid}$ because PV$_{Liquid}$ was shown to better represent displacement processes, as discussed previously.

The figure shows very strong correlation between cumulative recovery and flood apparent viscosity for all four floods. This relationship is diminished for early stage flooding where floods with diminished mobility control are not adversely affected by the higher rate of advance of injected fluids. This is especially the case when initial oil production ahead of early free flow gas, which was discussed in chapter 3.5.1, is not considered (cumulative production through $t_0=0.13PV_{Liquid}$). Such exclusion is based upon the non-tertiary, non-mobility reduction mechanism for this oil production and the fact that floods at low gas injected quality (LTG Coinj 30% & 0%) will not exhibit this behavior.

For late stage flooding, however, the relationship between flood apparent viscosity and cumulative recovery is especially pronounced, with an almost linear relationship. This indicates the importance of injected fluid apparent viscosity upon preventing fingering of injected fluids and achieving high recovery. Additionally, as discussed below in *(Note Regarding Displacement and Upscaling)*, 1-D displacement has a tendency to mitigate effects from unstable displacement.
Figure 4.10: Cumulative recovery at different flooding increments (PV_{Liquid}) versus calculated re-normalized apparent viscosity (\mu_{app}) using liquid injection rate (q_{Liquid}) for apparent viscosity calculations. Floods LTG_Coinj_0%, LTG_Coinj_30%, LTG_Coinj_50%, and LTG_Coinj_85% are represented.

**Note Regarding Displacement and Upscaling**

Co-injection flooding was utilized to model local behavior of specific gas fractional flow during LTG flooding. In addition to the empirical correlations relating overall recovery or apparent viscosity (and its inverse mobility reduction) to injected gas quality, a mechanistic understanding of the displacement mechanisms for LTG flooding was developed. This understanding of liquid rate as that which determines LTG displacement at moderate and high gas fractional flow within tight formations is critical for design and modeling of the LTG process on a mega-scopic level. This understanding is also deployed (below) to further our understanding of LTG_SAG efficacy and the specific process attributes which will impact SAG flooding success.
It is important to note that localized behavior expressed through this study cannot be fully scaled to the megascopic (inter-well) scale. The below SAG study attempts to improve this understanding by studying mixing parameters; nonetheless, impacts from complex reservoir geometry, complex permeability distributions, fracture networks, and instabilities which are manifest only on a megascopic scale are not entirely expressed through this experimental data.

4.4 STUDY OF SURFACTANT-ALTERNATING-GAS (SAG) INJECTION STRATEGIES

4.4.1 Observing Effectiveness of SAG injection

The recovery and fractional flow profile for LTG_SAG_2L:2G and reference LTG_Coinj_50% are presented in Figure 4.11. Both floods use the same flood average injected gas fraction (50%) but differing injection strategies. Although observed production attributes and final recovery were similar for both floods, in several respects they were better for LTG_SAG_2L:2G. Through use of SAG injection, the production profile was accelerated via increased early stage oil bank production and higher oil bank oil cut (percent oil fraction of produced liquids). This has favorable economic implications, with 65% ROIP tertiary recovery by 1.00 PV_{Total Fluid Injected} versus 45% for co-injection.

Additionally, increased early stage production of “clean oil” and diminished production of oil-water microemulsions was observed. This could be attributed to reduced mixing as a result of more effective displacement. Actual differences in final recovery comparison between floods is considered to be statistically insignificant due to errors associated with oil material balance—conventional tracer methods not possible due to 3-phase flow. This is especially concentrated for high recovery floods where oil
segregation into system tubing may result in measured recovery values several percent below actual recovery values. As such, it is entirely possible that recovery for LTG_SAG_2L:2G was higher than comparable co-injection (LTG_Coinj_50%) and resulted in nearly 100% tertiary recovery. This is consistent with the minimal/no oil staining that was observed upon visual inspection of this core.

Overall, these results are consistent with increased recovery through improved mobility control during SAG injection. This conclusion is affirmed and results better understood through use of: a) overall pressure and mobility data, b) overall salinity dispersion and derived gas saturation data, c) cycle specific gas saturation change, and d) overall and cycle specific apparent viscosity data. This information is presented in this section where it is also used to contrast various SAG injection strategies in order to enable optimization and further improve mechanistic understanding for foam displacement.

Figure 4.11: Fractional flow and cumulative recovery for LTG_SAG_2L:2G versus reference co-injection flood (LTG_Coinj_50%).
**Observed Pressure Behavior**

The observed (raw) pressure behavior for LTG_SAG_2L:2G is presented by Figure 4.12, with similar behavior also observed by other SAG floods (discussed later). Highly variable pressure fluctuations were observed and are functions of: a) normal mobilization and displacement processes during LTG tertiary recovery, and b) cycle dependent pressure fluctuations due to injected spreading foam waves as a result of gas-liquid alternate injection. To better depict this behavior, two differing techniques were used: a) averaging techniques (for overall displacement processes), and b) raw data period selection (for cycle dependent processes) were utilized. This information is discussed below.

It is important to note that several gas or liquid half cycles are larger (or smaller) than most half cycles. This is especially notable for a) an extended gas cycle at ~0.10PV_{Total fluid} with an accompanied shortened trailing liquid cycle and b) an extended liquid cycle at ~0.40PV_{Total fluid} with an accompanied shortened trailing gas cycle. The former is attributed to operator error in allowing lapse in gas-liquid changeover, while the latter was added to balance this error and ensure equality in gas-liquid injection. By doing so, equal parts gas and liquid were injected during slug injection. As such, quantities of slug injected (0.30PV_{Liquid}) were consistent with that of co-injection floods, and it is believed that recovery, salinity and overall mobility aspects were not adversely affected. The uneven cycle size during late stage flooding (~1.60PV_{Total fluid}) is not believed to have impacted the overall mobilization and displacement process (as it was almost entirely complete). It was also not selected for cycle specific investigation of behavior.

Additionally, because of gas compressibility, actual injected gas rate and volume will vary during flooding. For the floods described below (as with all other floods), a consistent gas mass flow rate was used during flooding. Mass flow rate for initial
displacement (LTG_SAG_2L:2G flooding until 2PV_{Total fluid}) was set to achieve volume flow using average experiment pressure during waterflood, which was shown to closely approximate LTG average experiment pressure during initial flooding (chapter 3). Due to the reduction in observed ∆P (and thus average pressure) after displacement of crude oil, mass rate was re-calculated according to the average ∆P observed from 1.5PV_{Total fluid}–2.0PV_{Total fluid}. This set calculated rate at 605psi (= effluent pressure + 0.5*average ∆P) is contrasted with the range of actual experiment pressures during cycle-testing of 590psi-635psi, resulting in a maximum deviation of ~5%.

Figure 4.12: Sectional raw pressure behavior for LTG_SAG_2L:2G.

Figure 4.13 shows the averaged pressure data (±0.07PV_{Total fluid}) for LTG_SAG_2L:2G and reference LTG_Coinj_50%. Averaging was used to mitigate the effects of cycle dependent pressure fluctuations. This assists in visualizing the actual mobilization and displacement process on a flood timescale. The averaged pressure data
shows a similar displacement profile to that of co-injection, with creation and mobilization of an oil bank being associated with an increase in pressure drop, which is then followed by a decrease in pressure drop as the oil is displaced outside the measured section or core.

One notable difference is the delayed and amplified peak in pressure drop. This is partially a result of lower permeability in section 3 (1/2 of that of the other sections) which gives it increased weighting for overall pressure drop. Because section 3 will exhibit the most delayed displacement, increased weighting will also delay the overall displacement profile. This, however, does not account for a substantial portion of the delayed and amplified peak pressure drop. Section 2 also exhibits a delayed rise during this peak period, and thus also contributes to this behavior. This is likely due to increased mobilization or displacement of oil during this late period. This is consistent with the larger oil bank which was observed for this flood and indicates more favorable displacement efficiency for SAG flooding.

![Graph showing sectional averaged pressure behavior for LTG_SAG_2L:2G versus reference co-injection flood (LTG_Coinj_50%).](image)

Figure 4.13: Sectional averaged pressure behavior for LTG_SAG_2L:2G versus reference co-injection flood (LTG_Coinj_50%).
Cycle Specific Pressure Behavior: Normalized Pressure Gradient

For SAG flooding, the increased apparent displacement efficiency demonstrated by the recovery profile is likely not captured entirely by the averaged pressure profile and associated displacement processes. To better understand the impact of gas-liquid cycling, an individual cycle is investigated. Figure 4.14 presents one gas-liquid cycle for the LTG_SAG:2L:2G flood. A late stage cycle with minimal further oil production was selected to remove the impact of oil mobilization and displacement (changes in oil saturation and oil fractional flow) upon observed pressure data. The figure shows a high degree of variability in observed pressure drop, which is dependent upon the respective period during liquid or gas injection. The profile shows that upon commencement of liquid injection, a slight fall and then characteristic rise in pressure drop is observed.

Upon gas injection, this rise is continued until high gas fractional flow (likely) occurs and the pressure drop begins to decline again. Increased pressure drop should be associated with increased foam stability through either: a) reduction of free gas saturation during liquid injection, or b) increased dispersed gas saturation during gas injection. Because of differing permeability values at different sections of the core, direct comparison of pressure drop at the specific sections is, however, invalid in this figure. The next figure presents a normalized pressure gradient which corrects for differing sectional permeability and length.
As noted, analysis of cycle specific displacement processes is complicated by the uneven permeability distribution across sections. A corrective normalized pressure gradient is implemented for each section which normalizes to the average core permeability according to Eq. 4.5. Sections 1 & 3 are 3” in length ($\Delta x_{\text{Section}}$), while section 2 is 6” in length. In addition, for overall average normalized pressure gradient, the relation presented in Eq. 4.6 was used.

\[
\left( \frac{\Delta P}{dX} \right)_{\text{normalized}} = \frac{\Delta P}{\Delta x_{\text{Section}}} \cdot \frac{k_{\text{Section}}}{k_{\text{overall}}} \tag{4.5}
\]

\[
\left( \frac{\Delta P}{dX} \right)_{\text{overall average}} = \frac{1}{4} \left[ \left( \frac{\Delta P}{dX} \right)_{XD=0.25-0.75} + 2 \left( \frac{\Delta P}{dX} \right)_{XD=0.75-1} \right] \tag{4.6}
\]

Figure 4.14: Sectional raw pressure behavior for LTG_SAG_2L:2G for a single late-stage liquid:gas cycle.
The results of the normalized pressure gradient for the selected LTG_SAG_2G:2L late stage cycle versus reference waterflood are presented in Figure 4.15. It shows the same general behavior is observed as with the unadjusted cycle pressure behavior, but with additional clarity. During early stage liquid injection, pressure gradient continues to drop or has a delayed rise. This may be due to:

a) A slightly larger upstream dead volume (liquid not reaching $X_{D=0}$ when anticipated) which could cause an unaccounted for additional delay. Volume of 0.03PV would be approximately 2cc in additional upstream volume. Methods for calculation of gas saturation (discussed below) seem to indicate that used upstream dead volume was correct, reducing the likelihood and magnitude of contributions from this factor.

b) A required minimum saturation change from previous final gas cycle injection (where mobility reduction is minimal) for foam propagation to begin by imbibition or displacement. This may create a transition zone ahead of the observed pressure wave associated with foam generation.

c) Impacts of a spreading (foam) wave or possible water fingering which may cause initially minimal foam generation near the injection point. Induced pressure gradients downstream of the injection point may allow for (delayed) upstream foaming (See Critical Capillary Pressure Theory in Lit. Rev.) or measured mobility reduction may only be for later portions of section 1.
As liquid injection progresses, section 1 ($X_D=0.25$) shows a rapid rise in pressure gradient, which is associated with rapid foam propagation and mobility reduction. Pressure gradient begins to rise shortly after in section 2 ($X_D=0.25-0.75$) and is then followed by a rise in the final section ($X_D=0.75-1$). The spreading pressure wave from the inlet of section 1 to inlet of section 3 ($X_D=0.75$) is observed over a period of approximately $0.0375 PV_{\text{Total fluid}}$, indicating rapid propagation of the forward portion of the mixing front. This indicates that the change in gas saturation during cycling is quite small. This is discussed below (see Cycle Change in Gas Saturation).

A unique result of this SAG injection strategy is that the maximum pressure gradient for trailing sections is higher than forward sections. More than likely this indicates the impact of a spreading wave upon mobility reduction, with later sections exhibiting a larger mixing zone and therefore more foam propagation. This may help to explain the increased displacement efficiency which was not captured (entirely) in
averaged flood pressure data. Propagation of foam mixing fronts will create regions of ultra-low mobility that will be very effective in displacing previously mobilized (via surfactants) crude oil and microemulsions. This is compounded by the amplification of these fronts in the trailing portions of the flood ($X_{D>0.5}$) where flood displacement efficiency often breaks down. This is especially significant for field scale displacement and may have favorable macro-scale implications (although it does not account for gravity segregation and other megascopic displacement processes or heterogeneity). Additionally, this may better explain reduced microemulsion production, whereby improved displacement efficiency resulted in reduced mixing (reduced microemulsion creation) and diminished available oil for microemulsion production (oil already displaced).

**Cycle Change in Gas Saturation**

The change in gas saturation during cycling can be measured several ways. Both described methods are related to progression of the mobility shock front and assume that saturation for the portions of the core upstream of the pressure tap have achieved steady-state saturation upon arrival of the front. It is believed that the first methodology is more correct if error in upstream dead volume measurement is not significant. Both methodologies are described below:

a) Measurement of the lag between gas injection (start) and maximum foam pressure gradient for section 3. This assumes that gas saturation is at or near its peak at maximum foam strength. This is consistent with observed results (section 4.3) and the understanding that liquid is the displacing phase which undergoes alteration in liquid relative permeability as a result in increases (or decreases) in gas saturation. This methodology also requires careful control of upstream “dead volume” to ensure that gas reaches the core at the exact point in flooding. Using this methodology and these
assumptions indicates an approximately $0.05\,\text{PV}_{\text{Total Fluid}}$ or 5% increase in gas saturation during cycling.

b) Measurement of the lag between shock front arrival at sections 1 and 3 ($X_D=0.75$). The measured delay of $\sim 0.0375\,\text{PV}_{\text{Total Fluid}}$ over $X_D=0.75$ would indicate a gas saturation change of approximately 5%. This method is not influenced by incorrect calculation in upstream dead volume; however, it will not account for additional increases in gas saturation for $X_D=0.75$ after wave arrival at the pressure tap. In addition, it does not account for possible changes in gas saturation before observable changes in mobility (via pressure taps) are observed—although, this mechanism would likely cancel for sections 1 and 3 (delays in one would be accompanied by delays in the other). The combination of the two mechanisms indicates that this method is more conservative (low case). Interestingly, these measurements validate the other calculation method ($S_g=5\%$) which would also indicate that upstream dead volume error is minimal.

**Salinity Analysis: Dispersion and Gas Saturation**

The measured effluent salinity for LTG_SAG_2L:2G and reference LTG_Coinj_50% floods is shown in Figure 4.16. Recorded salinity values are not available for several points during SAG flooding due to variability in produced aqueous phase due to gas:liquid cycling which resulted in several collection samples with volumes too low to measure salinity. This is especially significant for a data point at $1.15\,\text{PV}_{\text{Total fluid}}$ where a progression towards drive salinity may or may not have developed.

One notable aspect of the figure is the earlier progression of salinity from reservoir towards slug or drive salinity. This is indicative of reduced aqueous phase saturation at breakthrough and is shown (below) to represent increased gas saturation. In addition, overall salinity profile appears to show a slightly sharper progression from reservoir to slug salinity and from slug to drive salinity for SAG injection. Missing data
points make this difficult to verify; however, it may indicate increased displacement efficiency due to reductions in mobility of injected fluids. Independent of these slight deviations, overall behavior across the two floods is very similar. This indicates that Co-injection dispersion is a good approximation for SAG dispersion, and vice versa.

Gas saturation at salinity breakthrough is calculated according to the method described in chapter 3. Salinity breakthrough was observed at $1.30PV_{\text{total fluid}}$ ($\sim 0.65PV_{\text{Liquid}}$) where oil saturation is calculated to be 7%. This indicates that gas saturation is 28%. By using pore volume available to mobile oil to quantify the sections of the core with large pore distributions ($PV_{MO}=23\%$), gas saturation is shown to be exceptionally high ($S_G/PV_{MO}=120\%$). These results contrast with the 18-22% gas saturation observed by other floods (tables 3.4 and 4.4) and indicate that SAG cycling can achieve gas saturation approximately 8% higher than that of co-injection floods. Cycle specific variability in gas saturation will result in maximum gas saturations which are likely higher than this value and minimum gas saturations which are less than this saturation, with a cycle saturation change described in *Cycle Change in Gas Saturation* (described previously).
Figure 4.16: Comparison of effluent salinity for LTG_SAG_2G:2L and LTG_Coinj_50%.

4.4.2 Alternative SAG Cycle Strategies

In addition to comparison of SAG injection to reference co-injection flooding, several different SAG cycle strategies were also tested and compared. LTG_SAG_1L:3G and LTG_SAG_3L:1G are described below and used to assist in further understanding of factors affecting gas-liquid mixing, and foam strength.

Reference LTG_SAG_1L:3G Flood

The raw pressure data for LTG_SAG_1L:3G is shown in Figure 4.17. As with the previous SAG flood, a large degree of cycle dependent pressure variability was observed. To allow for direct comparison, the same cycle specific normalized pressure gradient was constructed.
The sectional normalized pressure gradient for LTG_SAG_1L:3G is presented in Figure 4.18. The average normalized pressure gradient is also included later (figure 4.20) where it is compared directly to that of other SAG cycles. The sectional data shows the same overall progression during liquid and then gas cycling.

Interestingly, a very large delay in pressure rise is observed between $X_D=0-0.25$ when compared to the delay in pressure rise from $X_D=0.25-0.75$, a length which is twice as long. This may indicate that imbibition (increasing liquid saturation) initially generates lamellae in the first section but unable to do so in the later sections. Such behavior could be due to diminished displacement efficiency for later sections with possible formation of liquid fingers accelerating the displacement profile. Similar behavior was observed through use of CT images during displacement of foam by water, with notable liquid fingers propagating downstream from a better mixed inlet section (Nguyen 2009). It is, however, important to note the very different permeability (>Darcy vs. 5-10mD) and inlet → outlet gas expansion (500% vs. <15%) which may diminish foam propagation mechanisms tied to high permeability or gas expansion.

Another notable change is the $X_D$ dependent decrease in a) the maximum foam strength (amplitude), b) period over which substantial foaming is observed, and c) average overall foam strength (discussed in detail later). These are all characteristics which were not observed for the previous flood at higher liquid cycling (2L:2G) and indicate a breakdown in foam generation as the mixing front progresses through the core. Such attributes are considered undesirable and should negatively impact displacement efficiency.
Figure 4.17: Raw pressure data for LTG_SAG_1L_3G.

Figure 4.18: Normalized pressure gradient profile for LTG_SAG_1L_3G.
Reference LTG_SAG_3L:1G Flood

The raw pressure data for LTG_SAG_3L:1G is shown in Figure 4.19. As with the previous SAG floods, a large degree of cycle dependent pressure variability was observed. To allow for direct comparison, the same cycle specific normalized pressure gradient was again constructed.

A notable reduction in variability of foam strength was observed for this flood, with consistent foam strength of $5-10 \times$ brine flooding observed for greater than $\frac{3}{4}$ of cycle period over each section. Reductions in foam strength below this threshold first occur during late stage gas injection, which then progress through the core during early stage liquid injection. This behavior is likely due to diminished foam strength (or no foam) at higher gas fractional flow. Gas fractional flow will be the highest at the end of gas injection for section 1 and will then propagate forward through the core.

Another significant observation is that foam strength builds at a slower pace for sections further downstream of the inlet. This is again consistent with a spreading wave where an enlarging downstream mixing zone will create a slower progression from high gas quality to low gas quality. The long and mostly stable foam plateau reflects that the trailing edge of the phase mixing wave demonstrates good foaming attributes. This would indicate that optimal foam strength occurs under conditions of high liquid fractional flow for this experiment.
Figure 4.19: Raw pressure data for LTG_SAG_3L_31.

Figure 4.20: Normalized pressure gradient profile for LTG_SAG_3L_1G.
4.4.3 Overall Comparison of SAG Cycle Strategies

4.4.3.1 Comparison of Average Normalized Pressure Gradient

Figure 4.21 shows the overall $(X_D=0.1)$ normalized pressure gradient data for the three SAG floods with an additional reference brine flood pressure gradient. Progression of specific shock or mixing fronts through the core is more difficult to follow due to the use of overall normalized pressure gradient data (see above for sectional data). Nonetheless, overall data does show overall trends and behavior (discussion below).

![Figure 4.21: Overall $(X_D=0.1)$ normalized pressure gradient for LTG_SAG_2L:2G, LTG_SAG_1L:3G, and LTG_SAG_3L:1G.](image)

Increases in the relative length of the gas portion of the overall SAG cycle were correlated with increased variability of foam strength. This indicates that high fractional flow of gas can have a destructive impact upon foam strength and stability (1L:3G
injection) where initial gas saturation has already been established. Poor dispersion of gas into the bulk (entrapment) liquid phase and possible free flow of gas and/or liquid are considered to be the likely causes of this behavior.

Flooding at moderate average gas cycle fraction (2L:2G) exhibited diminished aspects of this destabilization of foam by high gas fractional flow. Flooding at moderate gas cycle fraction (2L:2G) also exhibited the highest maximum foam strength among the floods. This may indicate that 2L:2G injection experiences a foam spreading wave which crosses the optimal foam strength in a controlled manner (before becoming too gas rich and demonstrating a decline in foam strength). Existing free flow of gas for higher gas cycle fraction (1L:3G) may mitigate this spreading wave cross-over (from sub-optimal, to optimal, to over-optimal gas saturation), while lower gas cycle fraction (3L:1G) may always be on the liquid rich side of maximum apparent foam strength. Spreading wave theory and the impacts of mixing are described in detail in section 2.4.

Overall average apparent foam strength increased with liquid cycle fraction. This is consistent with gas cycling only being required to drain a small number of incremental pores after initial gas saturation is established. It also indicates that, once established, this gas saturation is highly stable (is not displaced easily). The stable dispersed gas reduces mobility of injected fluids by reducing liquid saturation and relative permeability.

For each cycle strategy, transitions in foam strength were located at different points with respect to gas:liquid changeover. For 1G:3L injection, increased foam strength immediately followed gas injection, while the start of liquid injection had little impact. For 2L:2G injection, increased foam strength was 1/8 of a cycle after liquid injection began, with gas injection showing no immediate impact (pressure declines ¼ of a cycle later) For 3L:1G injection, pressure rise occurred approximately 1/6 of a cycle after the start of liquid injection with gas injection showing no immediate impact. This
behavior was previously discussed (see *Normalized Sectional Pressure Gradient* data) and is related to the transition in phase fractional flow, propagation of mixing zones, and effectiveness (or lack thereof) of imbibition process in creating foam.

**4.4.3.2 Comparison of SAG Average Apparent Viscosity**

Sectional and overall average normalized pressure gradient over a minimum of three cycles was used for calculations of average apparent viscosity. Because the pressure gradient for brine flooding at 100% was already known—it is depicted in normalized pressure gradient figures and drawn from rate-pressure drop correlations during permeability testing—the following relation was used (Eq. 4.7) for calculations in Table 4.7. These values represent apparent viscosity where injected fluids are considered a single phase.

\[
\mu_{app} = \left(\frac{\Delta \rho}{\Delta X}\right)_{observed} \times \mu_{brine}
\]

**Table 4.7:** Calculated apparent viscosity and contributing model values.

<table>
<thead>
<tr>
<th>Experiment ID:</th>
<th>(\mu_{app}) X=0-0.25</th>
<th>(\mu_{app}) X=0.25-0.75</th>
<th>(\mu_{app}) X=0.75-1.0</th>
<th>(\mu_{app}) X=1-1.0</th>
</tr>
</thead>
<tbody>
<tr>
<td>LTG_SAG_2L:2G</td>
<td>6.0cP</td>
<td>5.1cP</td>
<td>4.6cP</td>
<td>5.1cP</td>
</tr>
<tr>
<td>LTG_SAG_1L:3G</td>
<td>4.0cP</td>
<td>2.8cP</td>
<td>2.8cP</td>
<td>3.2cP</td>
</tr>
<tr>
<td>LTG_SAG_3L:1G</td>
<td>8.6cP</td>
<td>8.0cP</td>
<td>6.9cP</td>
<td>7.7cP</td>
</tr>
</tbody>
</table>

Additionally, these values are re-normalized to reflect only liquid injection rate in the same manner as mobility and apparent viscosity calculations during co-injection flooding (chapter 4.3). This is shown by Eq. 4.8 and Table 4.8. It is important to note that re-normalization is done at a set gas-liquid fractional flow. This is equivalent to injection
quality for steady-state co-injection processes; however, this is not the case for SAG flooding and use of average injection quality will unduly amplify apparent viscosity effects during high liquid flow and reduce apparent viscosity effects during high gas flow. Relating this behavior to the cycle dependent normalized pressure gradient (figure 4.21) indicates that this methodology will result in slight underestimation of average effective apparent viscosity.

\[
(\mu_{app})_{\text{liquid normalized}} = (\mu_{app})_{\text{total fluid injection rate}} \times (1 - \text{Avg. Inj. Gas Quality}) \quad (4.8)
\]

<table>
<thead>
<tr>
<th>Experiment ID:</th>
<th>( \mu_{app} )</th>
<th>( \mu_{app} )</th>
<th>( \mu_{app} )</th>
<th>( \mu_{app} )</th>
</tr>
</thead>
<tbody>
<tr>
<td>@2PV water injected</td>
<td>( X_g=0-0.25 )</td>
<td>( X_g=0.25-0.75 )</td>
<td>( X_g=0.75-1.0 )</td>
<td>( X_g=0-1.0 )</td>
</tr>
<tr>
<td>LTG_SAG_2L:2G</td>
<td>12cP</td>
<td>10.2cP</td>
<td>9.1cP</td>
<td>10.3cP</td>
</tr>
<tr>
<td>LTG_SAG_1L:3G</td>
<td>15.9cP</td>
<td>11.3cP</td>
<td>11.2cP</td>
<td>12.6cP</td>
</tr>
<tr>
<td>LTG_SAG_3L:1G</td>
<td>11.5cP</td>
<td>10.7cP</td>
<td>9.2cP</td>
<td>10.3cP</td>
</tr>
</tbody>
</table>

Table 4.8: Calculated apparent viscosity and contributing model values.

Analysis of bulk flow \( \mu_{app} \) and re-normalized liquid flowing \( \mu_{app} \) indicate substantial improvement in observed SAG apparent viscosity over that of co-injection floods with comparable quality (see Table 4.6 for co-injection data). Slight length (\( X_D \)) dependent degradation in average apparent viscosity was observed for all floods and was positively correlated with injected gas cycle size—more degradation for larger gas cycles. Nonetheless, overall average apparent viscosity was mostly uniform.

It is not currently possible to validate the respective calculated \( \mu_{app} \) values, as it was for co-injection flooding. However, it is believed that the re-normalized liquid flowing \( \mu_{app} \) is likely more reflective of actual displacement processes. This is based
upon the fact that: a) re-normalized liquid flowing $\mu_{app}$ was shown to reflect displacement during analogous co-injection processes, and b) liquid normalized apparent viscosity values for SAG injection are more uniform across SAG floods, which is consistent with the previously stated theory of liquid as the displacing agent and mostly uniform gas saturation. If this belief is valid, observed apparent viscosity values of 10.3cP to 12.6cP would indicate favorably for the potential application of SAG flooding for light oil recovery in tight formations. It is, nonetheless, important to again note that this behavior only reflects macroscopic conditions and may not accurately present megascopic (inter-well) displacement processes due to gravity segregation or other factors.

4.5 KEY FINDINGS AND THEORETICAL SIGNIFICANCE

4.5.1 LTG Co-injection Study

4.5.1.1 Key Findings

- Overall recovery relationships were developed based upon the four selected gas fractional flow ($f_g$) values during LTG co-injection flooding. Optimal recovery profiles were observed at 50% injected gas fraction with diminished recovery observed at higher and lower gas fractional flow values. This is consistent increased mobility reduction and foam theory as described in section 2.4.

- Effluent salinity dispersion measurements showed strong consistency with observed recovery profiles, with less favorable recovery profiles being associated with increased dispersion during both a) reservoir $\rightarrow$ slug and b) slug $\rightarrow$ drive fluid transitions. Overall observation validates salinity as an important empirical marker for anticipating flood success.
• Steady-state gas saturation was relatively consistent across LTG co-injection floods. This indicates that increased gas fractional flow does not result in increased dispersed gas saturation for the range of steady-state gas fractional flow values tested ($f_g > 30\%$). Such behavior would indicate similar reductions in relative permeability to water at all tested gas fractional flow values.

• Overall calculated bulk (injected fluids considered as single phase) mobility ratios and apparent viscosity values exhibited trending consistent with foam literature, with mobility minimums or viscosity maximums observed at $f_g = 30\%-50\%$ (depending on the metric or reference values used).

• Relationship between observed recovery profiles and apparent viscosity ($\mu_{app}$) values was shown to deviate at high and low gas fractional flow ($f_g$), with high $f_g$ flooding exhibiting unexpectedly good displacement properties and low $f_g$ flooding exhibiting unexpectedly poor displacement properties. Re-normalization of $\mu_{app}$ to account for only liquid injection rate ($q_{\text{Liquid}}$) demonstrated a very strong correlation between observed displacement properties and macroscopic stability parameters (R and $\mu_{app}$). Figure 4.10 provides an important visualization of this relationship.

Such described correlation between liquid rate normalized stability parameters and observed displacement conditions is highly significant. It validates previous empirical flooding results where displacement period was shown to be a function of total fluid injected ($PV_{Total \ fluid}$). Further, it establishes the mechanism for oil displacement
during LTG flooding (below) which is of great assistance in understanding process stability.

4.5.1.2 Theoretical Significance: Displacement Mechanisms

Based upon the above described results, it is believed that the mechanism for oil displacement during tertiary LTG recovery is entirely due to liquid displacement of oil filled pores. For observed gas injection fraction ($f_g > 30\%$), gas achieves a steady-state saturation which is mostly independent of injected fraction. This saturation occupies the higher permeability pore networks (due to gas-water interfacial tension) and forces injected liquid to displace through the low and medium permeability networks where oil contact is observed. On a macroscopic level, this relationship is observed through substantial reduction in relative permeability to the liquid phase and associated macroscopic mobility reduction. This relationship also has the effect of reducing aqueous phase dispersion (observed) by tightening the permeability distribution over which the aqueous phase flows (high k channels are removed from the distribution).

The result of diversion of the aqueous phase into low and moderate permeability channels is improved displacement efficiency and mobility control, which is not captured by bulk mobility measurements which consider both injected phases. Re-normalization of stability parameters to reflect only the liquid phase ($q_{\text{Liquid injected}}$) was shown to strongly correlate said parameters with observed displacement and recovery.

The primary complicating factor for this interpretation is the diminished re-normalized stability parameters and overall recovery for low gas fraction (LTG_Coinj_30%) flooding given the similar calculated steady-state gas saturation. According to the mechanism presented above, floods at similar gas saturation should exhibit similar relative permeability to water (ignoring oil saturation effects) and
therefore similar re-normalized (to liquid rate) apparent viscosity. Re-normalized apparent viscosity is, however, substantially lower for low gas injection fraction flooding.

There are several possible reasons for this relation, including: a) possible overestimation of LTG_Coinj_30% gas saturation due to the large error associated with the calculation method (previously noted), b) possible destabilization of liquid lamellae, and thus weaker foam in LTG_Coinj_30% due to the due to the presence of higher remaining oil saturation (after LTG displacement), or c) for a constant gas saturation, possible contributions to overall pressure gradient from increased relative flow rate of gas—at the same overall gas saturation and thus capillary pressure. This would cause an increase in gas pressure gradient and accordingly liquid pressure gradient (simple capillary pressure relation) and thus improved displacement efficiency..

4.5.2 Surfactant-Alternating-Gas (SAG) Investigation

4.5.2.1 Key Findings

0.10PV_L:0.10PV_G SAG Flooding

- Surfactant-Alternating-Gas (SAG) injection at 0.10PV_L:0.10PV_G was shown to exhibit improved recovery characteristics versus reference co-injection flooding (LTG_Coinj_50%). In addition to final tertiary recovery of over 90% ROIP (S_o<3%), the flood exhibited earlier production of an oil bank at higher oil cut. This resulted in substantially accelerated oil production (76% ROIP by 1.25PV_Total fluid injected) and is indicative of more favorable displacement of crude oil.

- Observed averaged pressure profile during SAG injection displayed similar properties to that of comparable co-injection flooding (with respect to average gas fraction). This indicates that co-injection floods and SAG floods experience generally similar
mobilization and displacement properties. Notable increases in SAG pressure gradient at 0.6PV_{Total fluid} (vs. co-injection) are indicative of a larger displacing oil bank.

- Investigation of cycle-specific pressure behavior shows substantial variability in fluid mobility reduction during flooding. Normalization of observed sectional pressure drop to correct for differences in sectional permeability and length resulted in a normalized pressure gradient. Through use of a normalized pressure gradient, progression of a spreading (foam) wave was demonstrated. It is characterized by progressive increases and then decreases in sectional pressure gradient as the front progresses through the core. The inverse relation between pressure gradient and fluid mobility indicates that an ultra-low mobility regime is achieved during for select periods of each cycle which are not captured by averaged pressure characteristics. This may allow for improved displacement to be achieved during SAG cycling for floods which may otherwise exhibit similar averaged mobility and pressure behavior to that of co-injection floods.

- Progressive expansion of the spreading (foam) wave was shown to increase maximum normalized pressure gradient for downstream sections due to an expanded foam region. This has the potential to substantially improve displacement efficiency for downstream sections when compared with the large degradation in mobility reduction and displacement efficiency that is usually observed by foam (and other) processes.

- Decreased dispersion (qualitative) and increased calculated gas saturation at salinity breakthrough (28% vs. 18-22% for co-injection) indicate that increased mobility
control was present during SAG flooding which is likely related to increased average gas saturation (and thus decreased liquid relative permeability).

- Cyclical variability in gas saturation was calculated to be \(~5\%\) for steady-state SAG flooding by observing progression of pressure shocks during flooding. This indicates that a) mixing waves propagate at \(20x\) injection rate during steady-state conditions, and b) SAG imbibition processes only displace a small portion of in-situ gas.

**SAG Strategy Comparison**

- Increase in gas cycle size (1G:3L) was shown to result in sub-optimal foam mobility reduction properties (versus 2L:2G cycling strategy). This can be attributed to diminished foam strength due to “drying” of the foam and increased gas fingering during the last \(0.10PV_G\) of the \(0.15PV_G\) cycle. Increases in gas injection during extended gas injection also appear to reduce the ability for foam to form during the liquid imbibition portion of the cycle. This may be due to larger changes in gas saturation which must be overcome (increased “lag”) or it may be due to greater segregation of the phases due to breakdown of the foam during gas injection.

- Increase in liquid cycle size (3L:1G) was shown to result improved foam mobility reduction versus both 2L:2G and 1L:3G cycling strategies. Unlike the two floods which exhibited a characteristic rise and fall in mobility reduction as a mixing wave progressed through the core, high liquid cycle size resulted in high degree of plateau like behavior. The believed mechanism for this relationship is presented below (see *Theoretical Significance*); however, it is important to note that the overall result of
said behavior was greater consistency in mobility reduction and an overall increase in average mobility reduction during the flood.

- Notable decreases in the effectiveness of overall flood mobility reduction were observed after approximately ~0.05PV gas injected for all three SAG cycle strategies, with even earlier decreases observed for section 1 (~0.03PV gas injected). This is contrasted with liquid injection cycles where no notable decreases in effectiveness of mobility reduction were observed during any of the SAG strategies—the exception being early stage decreases due to displacement of previously injected gas. The fact no notable degradation in mobility reduction was observed after 0.15PV_L injected (3L:1G flood) indicates that (pseudo) steady-state mobility reduction phenomenon may be present during high liquid fractional flow or single phase (liquid) flow. This has important consequences for displacement phenomenon as described below.

4.5.2.2 Theoretical Significance: SAG Spreading Wave and Displacement Phenomenon

The presence of a spreading (foam) wave during SAG injection is consistent with overall foam theory as described by foam theory. Through displacement and steady-state study of this phenomenon, this paper provides an improved understanding of how the presence of a spreading wave: a) creates period dependent localized mobility minimums which may improve displacement, b) exhibits a cycle dependent gas saturation change of 5% for displacement in tight reservoirs, c) exhibits a relative rate of advance of ~20x injection rate due to such small saturation change, and d) exhibits highly destructive foam behavior at high gas cycling but only minimally destructive behavior at high liquid cycling. These observations are described in their relation to the proposed displacement mechanism below.
Indications of plateau-like foam strength behavior during liquid portions of SAG injection potentially validate the previously proposed displacement mechanism (see *Displacement Mechanisms*). Such observation supports the proposal that liquid rate determines actual displacement and effective pressure gradient during foam injection in tight formations. During gas injection, a mobility reduction maximum is quickly achieved and will be associated with increased gas saturation (reduced relative permeability to liquid) and continued high/moderate fractional flow of liquid. As liquid fractional flow drops during further gas injection, the observed pressure gradient also drops due to the flow of low viscosity gas. On the other hand, during liquid injection, mobility reduction continues to build or plateau for the entire liquid cycle (cycles were as long as 0.15PV_L). This indicates that high strength foam can be achieved at very high liquid fractional flow.

Plateau-like foam strength during late stage SAG liquid cycling also has important relevance in the context of gas fractional flow and its contribution to observed foam pressure gradients. During late stage liquid injection, observed pressure gradient is mostly constant—with earlier sections exhibiting plateau like behavior at earlier points during liquid injection. This indicates that gas saturation is mostly immobile under these conditions, causing it to exert a steady and effective reduction in liquid relative permeability. Any changes in gas saturation would be accompanied by an increase in liquid relative permeability and an accompanying decrease in pressure gradient, which was not observed. The presence of a mostly immobile gas saturation which provides effective mobility reduction has important implications for both foam generation mechanisms in tight formations and overall flood design.

In the context of foam generation mechanisms, it was proposed that a ‘weak foam’ state with production of mostly immobile lamellae via ‘snap off’ and ‘leave behind’ could provide the desired mobility reduction. The presence of a mostly immobile
gas phase seems to indicate that the liquid lamellae are both mostly stationary and able to maintain a large dispersed gas phase. Additionally, observed normalized pressure gradients indicates that this stationary dispersed gas phase can provide substantial reductions in liquid relative permeability and thus desired mobility reduction during steady-state liquid injection ($\mu_{\text{app}} \sim 10\text{cP}$).

In the context of overall flood design in tight formations, the observed results indicate that after initial gas saturation has been established, gas portions of gas-liquid cycling could be minimized to that required to re-establish gas saturation after large quantities of liquid have been displaced. Because displacement during LTG flooding is a function of PV liquid injected, this observation has the potential to accelerate payback with respect to total fluid injected. Additionally, for regions with high injected gas cost, this observation has the potential to decrease the required volumes of injected gas. It is important to note that higher fractions of gas may be required during initial displacement processes where initial gas saturation is established. Likewise, conformance control for fractures and higher permeability zones, gravity segregation, reservoir geometry, and/or other factors may require increased injected gas cycle size.
Chapter 5: Summary and Recommendations

Note—More detailed summaries and theoretical or economic analyses of experimental work and findings are included at the end of chapters 3 and 4. Because these two chapters exist mostly independent of one another, with each citing relevant material from preceding work, grouping of results into a singular chapter (as shown here) is considered non-ideal. As such, it is suggested for the reader to refer to these summary sections in conjunction with or in place of their reading of this chapter. The findings expressed below are aimed towards “high level” discussion with substantially improved understanding provided in the respective chapter summaries.

5.1 Summary

This paper establishes Low-Tension-Gas (LTG) as a method for sub-miscible tertiary recovery in tight sandstone and carbonate reservoirs. The LTG process involves the use of a low foam quality surfactant-gas solution to mobilize and then displace residual crude after waterflood. It replicates the existing Alkali-Surfactant-Polymer (ASP) process in its creation of an ultra-low oil-water interfacial tension (IFT) environment for oil mobilization, but instead supplements the use of foam over polymer for mobility control. By replacing polymer with foam, chemical Enhanced Oil Recovery (EOR) methods can be expanded into sub-30 mD formations where polymer is impractical due to plugging, shear, or the requirement to use a low molecular weight polymer.

Within the literature review, it was proposed that a different interpretation of relative importance of specific foam mechanisms was required to scale foam flooding to tight reservoirs. It was noted that existing foam literature, both experimental and theoretical, was restricted to substantially higher permeability values of at least 1-2 orders
of magnitude greater than that tested in this thesis. Use of high permeability media in prevailing literature was shown to be associated with an interest in achieving a ‘high strength’ foam state associated with liquid lamellae mobilization, a state which may otherwise not exist in tight formations due to high capillary pressures.

However, it was shown that conventional ‘high strength’ foams, if they existed in tight formations, could be considered undesirable due to the ultra-high pressure drops associated with their propagation. A new understanding based upon diminished effects from ‘snap off’ and ‘leave behind’ was proposed. It was believed that mostly immobile liquid lamellae and a select number of mobile lamellae networks in high permeability channels (low capillary pressure) could exhibit the desired rheological properties for displacement of light crudes in tight formations. This interpretation is tested and further built upon through experimental work as described below.

5.1.1 Initial Investigation: Proof of Concept, Development of Evaluation Tools—Chapter 3

The proposed strategy was tested through low-quality, low rate co-injection of nitrogen and a slug/drive surfactant solution. Results indicate favorable mobilization and displacement of residual crude oil in both tight carbonate and tight sandstone reservoirs. Tertiary recovery of 75-90% ROIP was achieved for cores with 2-15 mD permeability. Consistent with successful ASP floods typically observed in high permeability rocks, a large oil bank was observed at the effluent before the production of Windsor Type III and Type II(-) microemulsion. High LTG tertiary recovery is contrasted with results from reference surfactant (no gas) flooding (28% ROIP tertiary recovery) and immiscible gas co-injection (no surfactant) flooding (14% ROIP tertiary recovery).

Additionally, high initial oil saturation was tested to determine process tolerance to oil and evaluate potential for application during secondary recovery. During flooding
at initial oil saturation ($1-S_w$), LTG injection achieved recovery of 84% of OOIP with similar fractional flow, mobility, and other process attributes to those exhibited during LTG tertiary flooding. This reduces the risk that in-situ oil may cause unfavorable displacement due to destabilization of liquid lamellae which provide mobility control by creation of a dispersed gas phase (foam). Potential application at secondary recovery is suggested which would improve reserve capture and reduce high pressure gradients typically associated with flooding tight reservoirs.

To better understand the physical mechanisms which impact mobilization and displacement, early production of an elongate oil bank at reduced fractional flow of oil was shown to be an attribute of high crude oil relative mobility and low pore volume available to mobile oil. This should favorably impact economics during chemical flooding by accelerating production of an oil bank. Next, by application of salinity as a conservative tracer and oil material balance, gas saturation during LTG floods was calculated to be 18-22%. This is contrasted with gas saturation during co-injection of 5% and indicates that a large dispersed gas phase was present during LTG flooding and is consistent with stable lamellae production during flooding. Finally, by comparing effluent salinity profiles across floods, qualitative understanding of dispersion and macroscopic stability is developed. Plots show a reduction in dispersion for LTG flooding versus surfactant flooding, which indicates improvement in mobility ratios across the displacement fronts.

Macroscopic stability of displacement fronts was studied via pressure derived mobility ratios and apparent viscosity. Approximate parity of relative mobility of injected fluids was observed with respect to relative mobility of displaced water at true residual oil saturation and interpreted relative mobility of a formed oil bank. Additionally, by removing relative permeability effects from remaining oil, it was shown that LTG drive
injection exhibited highly stable apparent viscosity of ~4cP. Overall, these results indicate that in-situ foaming was present which enabled mobility control, and that stable displacement of in-situ fluids was achieved during flooding.

5.1.2 Further Investigation: Foam Mixing & Fractional Flow Behavior, Displacement Mechanisms—Chapter 4

Because true application of foam flooding within an oil reservoir is not captured by a single steady-state displacement condition, a series of four corefloods were performed at differing gas fractional flow ($f_g=0, 0.3, 0.5, 0.85$). Overall recovery relationships were developed and characterized by optimal recovery at 50% injected gas fraction, with diminishing recovery at higher or lower gas fractional flow. Salinity dispersion relationships showed strong observable correlation to recovery profiles, where favorable recovery was associated with reduced dispersion. Such recovery and dispersion relationships were consistent with existing foam theory at high permeability which indicates maximum foam strength, and therefore displacement and recovery, at moderate gas-liquid fractional flow.

Notable differences between apparent bulk mobility reduction calculated from pressure and actual oil displacement and recovery were observed. This is reflected in floods at high gas fraction exhibiting more favorable oil displacement and recovery results than calculated bulk mobility would indicate, with floods at low gas fraction exhibiting the inverse (unusually poor actual results). By re-normalizing calculated bulk mobility reduction to account for only injected liquid rate, a much stronger relationship between recovery phenomenon and mobility reduction was demonstrated. Using the related apparent viscosity ($\mu_{app}$) to visualize this relationship, it was shown that increases in re-normalized $\mu_{app}$ are strongly correlated with increased late stage flood displacement and overall recovery across all four floods.
Based upon the strong observed correlation between re-normalized (to liquid rate) mobility reduction metrics and overall observed displacement phenomenon, a displacement mechanism is proposed. It states that displacement through injected liquid flow is the dominant displacement regime for in-situ oil and water. Injected gas fulfills the primary purpose of occupying the larger pore distributions (due to capillarity) and diverting liquid into the moderate and small pore distributions. It is the moderate and small pore distributions which contain residual oil after waterflood, and by diverting injected liquid into the sections, displacement efficiency is substantially improved. On a macroscopic level, this diversion phenomenon is directly related through foam mobility reduction which is primarily a function of relative permeability to water. As such, increases in gas fractional flow beyond a proposed threshold (40%) which do not increase gas saturation (observed) will not result in a measureable increase in mobility reduction.

Additional flooding was also completed to understand the effects that Surfactant-Alternating-Gas (SAG) cycling injection strategies have upon mobility reduction and displacement. Such strategies are commonly implemented as part of existing foam flooding in more permeable reservoirs to improve injectivity and concentrate pressure gradients in the far-well region.

It was shown that Surfactant-Alternating-Gas (SAG) injection at 0.10PV_L:0.10PV_G exhibited improved recovery characteristics versus reference co-injection flooding (50% quality). This was expressed through earlier production of an oil bank at higher oil cut and resulted in substantially accelerated oil production (76% ROIP by 1.25PV_{Total fluid} injected). Overall averaged pressure profile was similar to that of co-injection flooding, with notably increased medium and late stage displacement pressure gradient (~0.5-0.6 PV_{Total fluid}) which is consistent with increased oil and microemulsion mobilization. Moreover, diminished salinity dispersion and increased gas saturation (28%
vs 18-22% for co-injection) were observed, further validating the interpretation of increased mobility control.

Cycle-specific behavior for SAG injection was investigated to understand the unusually good displacement attributes when compared to averaged pressure data. It was shown that substantial variability in observed in-situ mobility resulted in an ultra-low mobility state for specific sections during certain periods of flooding. Such behavior was shown to progress from core inlet to outlet near the start of gas or liquid injection and was consistent with behavior expected from a low mobility spreading (foam wave). Due to the low calculated saturation change during gas-liquid cycling of 5%, the spreading wave advanced at a rate of approximately 20x that of the injected fluid. The ultra-low mobility shock has the effect of concentrating pressure drop and improving spatial diversion into ultra-tight portions of the core which is believed to result in the observed improved displacement efficiency.

Additional SAG reference cycles were tested to determine the impact of high gas or liquid fraction. These floods indicated that increased gas cycle size beyond 0.05PV was highly destructive to foam strength. This is due to greatly reduced fractional flow of liquid and increasing flow of what is likely free gas. Interestingly, increases in liquid cycle size did not show the same destructive effects. In testing of liquid cycle size up to 0.15PV, a continued progression in foam strength was observed for all sections of the core. This is especially notable for the inlet section \( (X_D=0.25) \) where moderate or even low fractional flow of gas would result in large decreases in gas saturation over a 0.15PV liquid injection interval. The fact that this does not take place indicates that the dispersed gas phase is mostly immobile. This further implies that: a) liquid lamellae are mostly immobile in this regime, an observation that is consistent with the proposed foam mechanisms (see section 2.5), b) liquid injection is the primary mechanism for
displacement in tight formations, further validating what was discussed above, and c) for
gas-liquid cycling in tight reservoirs where initial gas saturation is already established,
successful injection strategy may only require short and intermittent gas cycles.

5.2 Recommendations and Future Work

The presented displacement mechanisms and relations are based upon a restricted
number of discrete fractional flow values. Additional flooding at varied fractional flow
could be useful in further quantifying this relationship and validating the proposed
displacement mechanisms. Furthermore, flooding involving differing rock mineralogy,
surfactant type and concentration, and/or reservoir crudes of different source and
composition could better establish repeatability.

For consideration during possible flood upscaling, better understanding of time
dependent surfactant absorption and decomposition is required. Flooding in tight
reservoirs will require larger flood lengths, and the ability for injected chemicals to both
survive and exhibit similar interfacial relationships is critical. Long term retention tests
and intra-well testing for absorption may be required to provide additional understanding.

Finally, an understanding of the interrelationship between field-scale
complicating factors is required. Such factors include contributions from fracture
networks, gravity drainage, high permeability variation or thief zones, and changes in
mineralogy. These topics are individually well understood in the context existing
applications of foam; however, additional thought towards their relationship with
displacement in tight reservoirs may be required. For example, the injection strategies
required for conformance control of fracture networks or high permeability thief zones
may be non-optimal for displacement of larger, tighter portions of the reservoir. On the
other hand, these strategies may align in a constructive manner.
Appendices

Note—Files containing additional figures from the experiments in this paper may be made available upon request. For access to these files, please contact Dr. Quoc Nguyen who is part of the UT chemical EOR research consortium. They are currently excluded from this paper and appendices for reasons of brevity, with notable observations from such floods either depicted or otherwise indicated in these chapters.

APPENDIX A: EXPERIMENTAL SETUP AND ADDITIONAL SURFACTANT PHASE BEHAVIOR FIGURES

Figures A1 and A2 are presented in addition to described equipment and surfactant phase behavior in section 3.2.
Figure A1: Schematic of experimental setup used in coreflood experiments

Figure A2: Photo of surfactant phase behavior for the selected formulation used in corefloods. 1.25% surfactant at 3:1 propoxylated sulfate to IOS with an additional 1.0% TEGBE ($t=7$ days, $T=45^\circ C$).
APPENDIX B—FIGURES FROM PREPARATORY FLOODING PROCESS

For the experimental procedure described in section 3.2.2.3, the following figures represent observed pressure or material balance data during preparation for tertiary LTG flooding for of a single flood (Gas_Tert_#4 from chapter 3).

**Brine Flood Permeability Measurement and Transducer Calibration**

Steady-state measurement of pressure drop at a number of discrete flow rates was used to determine brine permeability and improved transducer calibration. Figure B1 shows the observable pressure drop during the brine calibration for Gas-Tert_#4. Flow rates at 60 cc/hr, 120 cc/hr, 180 cc/h, 6cc/hr and 12 cc/hr were used to calculate permeability. Shear thinning behavior was not observed.

![Figure B1: Steady-state pressure drop values used in brine permeability measurements.](image)
For improved transducer calibration, a sectional regression was developed to re-normalize the pressure transducers and exhibit an improved Darcy’s law relationship. By doing so, inter-experimental drift in individual transducer calibration is greatly reduced and capillary endpoint affects are accounted for. The described method measures the pressure gradient-flow rate relationship at the discrete flow rates tested during permeability measurement. Using a linear regression (which is consistent with Darcy’s law for Newtonian fluids), pressure gradient is adjusted upwards or downwards through use of an additive correction factor (B in the Y=Mx+B relation) to achieve a y-axis intersection at 0 psi. Figure B2, depicts the final result of this regression. Pressure-rate relationship is shown to be highly linear and effects of capillary end effect are not apparent. Identical behavior is also expressed for the other sectional pressure drops (not shown) with their correction factors for Gas_Tert_#4 equal to $X_{D=0-0.25}=0.1590$, $X_{D=0.25-0.75}=0.8451$, $X_{D=0.75-1}=-1.7147$, $X_{D=1}=-1.0286$. The sum of the sectional correction factors is shown to be the same as the overall correction factor.

Figure B2: Plot of the corrected pressure drop-flow rate relationship for section $X_{D=0-0.25}$ during Gas_Tert_#4 after transducer calibration.
**Oilflood Displacement**

Initial oil saturation was established through constant rate injection of 20cc/hr. Figure B3 shows the fractional flow and oil saturation profile which was observed from material balance. Due to the favorable mobility ratio between displaced brine at 100% saturation and injected crude oil (with a higher viscosity of 1.9cP), favorable displacement was observed. This results in a large (0.40PV) period before oil breakthrough where only water production is observed. After oil breakthrough, continued decreases in water fractional flow is observed until displacement is completed at 2.0PV (the final data point is not depicted). Additional increases in oil saturation (decreases in water saturation) could be observed through more extended injection of crude oil.

![Saturation Profile During Gas_Tert_#4 Oilflood](image)

**Figure B3:** Saturation profile during Gas_Tert_#4 oilflood.
The observed pressure profile for this displacement is shown in figure B4. Initial increases in pressure drop are associated with displacement of high mobility water (at 100% saturation) by lower mobility crude oil. A notable progression in this pressure drop is apparent as the oil displacing water shock progresses through the core. As injection continues, further increases in oil saturation cause increases in relative permeability of oil and increases in total oil mobility.

Because permeability for each section of the core is variable, normalization of each section is required for direct comparison of observed mobility properties. Figure B5 normalizes the observed oilflood mobility to the reference brine flood mobility (at $S_w=100\%$) in order to remove effects of permeability variation. The figure shows that initial mobility ratio of approximately 1 makes a progression to below 0.2 with arrival of the displacement front. Slight increases in mobility ratio are observed until a final value

![Pressure Profile During Gas_Tert_#4 Oilflood](image)
of ~.20 is achieved. Similar steady-state mobility values for each section can be related to similar endpoint relative permeability values. This is closely associated with displacement efficiency and is consistent with favorable displacement efficiency which would be expected based upon the macroscopic mobility ratio for displacement.

Figure B5: Observed oilflood mobility vs. reference brine mobility (mobility ratio) for Gas-Tert_#4.
**Waterflood Displacement**

Residual oil saturation (after 2PV waterflood) was established through constant rate injection equivalent to $2PV_{\text{Fluid injected/day}}$ (~6cc/hr). Figure B6 shows the fractional flow and oil saturation profile which was observed from material balance. Less favorable mobility ratios (below parity and far below oilflood displacement) result in earlier breakthrough of water and diminished oil cut. Near final water saturation is achieved rapidly with final water saturation of 28% observed before water cutoff at 2.0PV injected. Final fractional flow data points are not pictured due to ~0% oil cut.

Figure B6: Calculated fractional flow and water saturation data for Gas_Tert_#4 waterflood displacement.
The pressure profile for this flood is shown below (Figure B7). A notable increase in pressure gradient is attributed to diminished relative permeability to water and poor displacement efficiency (discussed below). This behavior results in the interesting phenomenon where pressure gradient is actually higher (and mobility lower) after waterflooding than before. Steady-state pressure drop is achieved relatively rapidly (minimal additional oil displacement) and the flood is completed at 2PV.

![Pressure Profile During Gas_Tert_#4 Waterflood](image)

Figure B7: Observed pressure profile for Gas_Tert_#4 waterflood displacement.
To better understand mobility during the displacement process the observed sectional waterflood mobility is normalized to the reference sectional brine mobility. Figure B8 shows this normalized mobility ratio. As shown, section 1 exhibits substantially higher mobility during waterflood. This is consistent with diminishing displacement efficiency as flooding progresses from section 1 to downstream sections. The higher displacement efficiency for section 1 results in a higher endpoint relative permeability value, a phenomenon that is discussed in detail in sections 3.3 and 3.6.

Figure B8: Observed waterflood mobility vs. reference brine mobility (mobility ratio) for Gas-Tert #4.
Glossary

Nomenclature

\[ f_o = \text{fractional flow of oil (cc/cc)} \]
\[ f_w = \text{fractional flow of water (cc/cc)} \]
\[ k = \text{permeability (mD)} \]
\[ k_r = \text{relative permeability} \]
\[ k_{ro} = \text{relative permeability to oil} \]
\[ k_{ro}^{\infty} = \text{endpoint relative permeability to oil. Relative permeability of oil at residual water saturation} \]
\[ k_{rw} = \text{relative permeability to water} \]
\[ k_{rw@2PV \text{ waterflood}} = \text{relative permeability to brine at 2 PV water injected} \]
\[ k_{rw}^{\infty} = \text{endpoint relative permeability to water. Relative permeability of oil at residual oil saturation} \]
\[ L = \text{length (in)} \]
\[ PV = \text{pore volume (cc); also used as nondimensional pore volume (volume injected/pore volume)} \]
\[ PV_{\text{Liquid}} = \text{volume liquid injected with respect to pore volume} \]
\[ PV_{MO} = \text{pore volume available to mobile oil. Defined as } S_{oi} - S_{orw} \]
\[ PV_{\text{Total fluid}} = \text{volume total fluid injected with respect to pore volume} \]
\[ q_L = \text{liquid rate (cc/hr)} \]
\[ q_{\text{Total}} = \text{total fluid rate (cc/hr)} \]
\[ R = \text{mobility ratio} \]
\[ S_o = \text{oil saturation (%)} \]
\[ S_{oi} = \text{initial oil saturation (%)} \]
$S_{\text{oil bank}} = \text{oil saturation of the oil bank} \%$

$S_{\text{or@2PV waterflood}} = \text{residual oil saturation after 2PV water injected} \%$

$S_{\text{orw}} = \text{residual oil saturation after water flooding} \%$

$S_w = \text{water saturation} \%$

$S_{w@2PV waterflood} = \text{water saturation after 2 PV water injected.}$

$S_{\text{wi}} = \text{irreducible water saturation} \%$

$S_{w^o} = \text{dimensionless water saturation} \%$

$t_{D \text{ liquid}} = \text{dimensionless liquid injected} (\text{PV}_{\text{Liquid injected/PV}})$

$t_{D \text{ total fluid}} = (\text{PV}_{\text{total fluid injected/PV}})$

$t_{D1} = \text{dimensionless time of tracer transition}$

$X_D = \text{dimensionless distance}$

$X_{\text{oil bank}} = \text{oil bank length}$

$X_{\text{oil bank}}^o = \text{oil bank dimensionless length}$

$\Delta P = \text{Pressure drop} (\text{psi})$

$\Delta S_{\text{oil bank}} = \text{oil bank saturation change} \%$. Defined as $S_{\text{oil bank}} - S_{\text{orw}}$

$\nu_{r \text{ oil bank}} = \text{relative velocity of the oil bank} (V_{\text{oil bank}}/V_{\text{inj}})$

**Greek Symbols**

$\mu_o = \text{oil viscosity} \text{(cP)}$

$\mu_w = \text{water viscosity} \text{(cP)}$

$\phi = \text{Porosity}$

$\lambda = \text{relative mobility} (1/\text{cP})$

$\lambda_{wro} = \text{water relative mobility at residual oil} (1/\text{cP})$. Not equal to $\lambda_{w@2PV waterflood}$ due to diminished displacement.

$\lambda_{\text{injected}} = \text{injected fluid relative mobility} (1/\text{cP})$
$\lambda_o$ = oil relative mobility (1/cP)

$\lambda_{\text{oil bank}}$ = oil bank relative mobility (1/cP)

$\lambda_{o^o}$ = endpoint oil relative mobility (1/cP)

$\lambda_{w@2PV \text{ waterflood}}$ = water relative mobility after 2PV water injected (1/cP)

$\lambda_w$ = water relative mobility (1/cP).

$\lambda_{w^o}$ = endpoint water relative mobility (1/cP)

$\sigma^* =$ solubization ratio (cc/cc)
References


Hirasaki, G.J., Miller, C.A., and Pope, G.A. Second Annual Technical Report on Surfactant Based Enhanced Oil Recovery and Foam Mobility Control; prepared for U.S. DOE (DE-FC26-03NT15406), Rice University, Houston, TX (June 2004-b)


Huh, C. “Interfacial Tensions and Solubilizing Ability of a Microemulsion Phase That Coexists with Oil and Brine,” Journal of Colloid and Interface Science (1979), 71 (2): 408-426


Levitt, D.B. “Experimental Evaluation of High Performance EOR Surfactants for a Dolomite Oil Reservoir,” MS Thesis 2006-a, The University of Texas at Austin, Austin, Texas.


196


Nguyen, N.M. “Systematic Study of Foam for Improving Sweep Efficiency in Chemical Enhanced Oil Recovery,” MS thesis 2010, The University of Texas at Austin, Austin, TX.


Shi, J.-X. *Simulation and Experimental Studies of Foam for Enhanced Oil Recovery*. Ph.D. Dissertation (1996), The University of Texas at Austin, Austin, Texas.


