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Dembla Dhiraj

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Simulating Enhanced Oil Recovery (EOR) by High Pressure Air Injection (HPAI) in West Texas Light Oil Reservoir

by

Dembla Dhiraj, B.E.

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Simulating Enhanced Oil Recovery (EOR) by High Pressure Air Injection (HPAI) in West Texas Light Oil Reservoir

Approved by
Supervising Committee:

________________________________________
Jon E. Olson

________________________________________
Sanjay Srinivasan
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Abstract

Simulating Enhanced Oil Recovery (EOR) by High Pressure Air Injection (HPAI) in West Texas Light Oil Reservoir

Dhiraj Dembla, M.S.E.
The University of Texas at Austin, 2004

Supervisor: Jon E. Olson

The underlying objective of any enhanced oil recovery technique is to increase the mobility of reservoir fluids. In case of High Pressure Air Injection (HPAI), this is done by injecting pressurized air in the reservoir. This air, along with the reservoir fluids, undergoes a complex oxidation-combustion scheme and develops a fire front, which serves to heat the reservoir fluids, and thereby aids in enhanced oil recovery. This study was undertaken to investigate the potential of HPAI in a naturally fractured, light-oil reservoir. A simulation model was developed based on available laboratory and field data. The model was utilized to perform waterflood and air injection simulation runs in stratified and fractured reservoir environments. Application of horizontal wells was also investigated. The results obtained after an extensive history matching exercise using combustion tube data indicate that the reservoir under study is a very good candidate for High Pressure Air Injection.
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CHAPTER 1

1.1 Introduction

Approximately 80% of all tertiary oil that is produced worldwide is recovered by thermal recovery methods (Ahner and Sufi, 1990). The thermal recovery processes used today fall into two classes: those in which a hot fluid is injected into the reservoir and those in which heat is generated within the reservoir itself. The latter are known as fire-flooding or in-situ combustion (Prats, 1982; Boberg, 1988).

Many decades of work already exists on aspects of in-situ combustion in heavy oil reservoirs. The approach towards enhanced oil recovery from light oil reservoirs by application of air injection is relatively recent. The objective of this work is to understand and simulate the process of in-situ combustion by High Pressure Air Injection (HPAI) in a naturally fractured and karsted West Texas light oil reservoir. This work is part of a larger program designed to help small independent oil and gas operators to effectively apply this promising technology of HPAI in underexploited, mature carbonate reservoirs.

This Enhanced Oil Recovery (EOR) technique by air injection has been called out by varied names (Moore et al., 2002) such as In-situ Combustion (ISC), Toe-To-Heel Air Injection (THAI) and, in its most successful form, it is currently know as High Pressure Air Injection (HPAI). The difference between these methods is
mostly in the crude oil oxidation characteristics or the injector/producer well configurations, but all essentially involve downhole combustion. In principle the HPAI process consists of injecting an oxygen-containing gas (usually air) into the reservoir where it reacts with the crude oil to create a high-temperature combustion front. This front propagates through the reservoir by burning part of the oil in place in order to sustain the combustion and cause temperature increase that improves the flow of the unburned part. Because of the downhole combustion of oxygen and oil, steam and flue gas (nitrogen and carbon dioxide) are produced that serve to repressurize and flood the reservoir, thereby providing the mobilizing force to the oil downstream of the reaction region, sweeping it to the production wells. Figure 1.1 is a schematic representation of the temperature and saturation profiles and the various zones that are formed during the HPAI process (Wu and Fulton, 1971). It shows how the temperature front propagates through the reservoir starting at the injector, achieving a peak in the combustion zone and slowly reducing as the front moves further and further away from the injection well. The combustion front temperatures that have been reported in the literature vary from 400 to 600 °C (Burger et al., 1985). The volumetric sweep affects the ultimate oil recovery by large-scale permeability variations due to fractures, layering, and faults.

Ito and Chow (1984) have pointed out that one of the main causes of unsuccessful in-situ combustion operations in many heavy oil reservoirs is an unfavorable mobility ratio. The mobility ratio is simply the mobility of the displacing phase
over that of the displaced or the resident phase as described by the equation 1.1 (Craft and Hawkins, 1959).

\[ M = \frac{k_{rw} \mu_o}{k_{ro} \mu_w} \]  \hspace{1cm} (1.1)

where

- \( M \) = mobility ratio
- \( k_{rw} \) = water relative permeability
- \( k_{ro} \) = oil relative permeability
- \( \mu_w \) = water viscosity
- \( \mu_o \) = oil viscosity

Reservoirs with high heterogeneity tend to promote unfavorably high mobility ratios because of severe channeling (Ito et al., 1984). Glandt et al. (1998) indicate that mobility ratios for HPAI process are high, but not as high as those for conventional in-situ combustion in heavy oil reservoirs. However, they say, oil swelling, reservoir repressurization and light ends stripping more than compensates for the poor mobility effects and contribute to improved overall recovery.  Further, many others (Turta and Ayasse, 2000, 2001; Lerner et al., 1985; Greaves et al., 1996, 1999, 2002) have pointed out that along with reservoir heterogeneity, gravity segregation or gas override may cause problems in any air injection process. Reservoir simulation studies conducted by Lerner et al. (1985) and Akkutla and Yortsos (2000, 2002) suggest that variations in vertical
permeability adversely affect the volumetric sweep. They have suggested that injecting water at the top of the oil column can improve oil production by reducing the effect of gas override. Simultaneous water/gas injection or gas injection after in-situ combustion initiation was proposed in their studies. Greaves et al. (1999, 2002) and Xia et al. (2002) have done significant work in the application and testing of horizontal well technology to counter gas override.

1.2 Why HPAI?

HPAI has many advantages over other EOR techniques (Turta and Singhal, 1998; Greaves et al., 2000; Moore et al., 2002). The most obvious advantage is that air is available for injection at any location, and air injection technology is now very reliable. Significant amounts of air can be injected into deep, tight reservoirs and there is very little or no lifting costs associated, which would otherwise make waterflooding unattractive. Another benefit associated with air injection is that of oil swelling and reservoir repressurization, which tends to bring the production wells back to natural flow, thereby eliminating costs due to pumping. Further, air injection has a theoretical advantage over steam drive from the viewpoint of the enhanced thermal efficiency attributed to the in-situ generation of energy, especially in an environment of increasing natural gas prices and increasing competition for water resources. Also, reservoirs act as excellent scrubbers for sulfur compounds and heavy metals that are formed due to the oxidation reactions and that operating temperatures are generally lower than that result in the generation of nitrogen oxides (Greaves et al., Moore et al., 2002, Xia et al., 2002).
Figure 1.1 The High-Pressure Air Injection process (after Wu and Fulton, 1971).

Carbon dioxide sequestration can also be achieved by re-injection of the product gas. Air injection processes are able to maintain stable oxidation zones even at low initial oil saturations, hence it’s possible to employ HPAI in waterflooded reservoirs and improve their vertical sweep by the combined flood (Yannimaras et al., 1991, Fassihi et al., 1996, Moore et al., 1997, 2002).
1.3 History

In situ combustion had its inception in the early 1900s (Schumacher, 1980). It was first discovered accidentally when air was injected to drive the oil towards the producing wells. Sheinman et al. (1969) reported that the process was first intentionally applied to a heavy oil reservoir in the Soviet Union in 1934. They ignited shallow oil with glowing charcoal fed into the well by injected air. Increased production was reported in 1935, with the first English translation of the report appearing in 1938. The first U.S. mention of in situ combustion was a 1923 patent granted to F.A. Howard (Standard Development Company). The first test by Magnolia Petroleum was reported in 1952 in Oklahoma for heavy oil (Grant and Szasz 1954). It produced only 80 barrels but demonstrated the feasibility of this technique. Since then, the process has been applied in over a hundred fields, most of them heavy oil reservoirs (Chu, 1982; Burger et al., 1985). The South Belridge heavy oil project, which began commercial operations in 1954, is of special significance as it yielded a great many new concepts and correlations (Gates and Ramey, 1958). The oldest ongoing in situ combustion project was initiated in March 1958, West Newport Field, Orange County, California (Schumacher, 1980).

1.4 The HPAI Process

When air is injected into a reservoir, two simultaneous phenomena occur: displacement of oil and oxidation of oil. According to the efficiency of displacement and the intensity of oxidation, the downhole process could be one of
immiscible or miscible air flooding with or without intensive oxidation. The miscible air flooding with or without intensive oxidation has been identified as the HPAI process (Turta and Singhal, 1998). The three main reactions that occur during this process have been identified as low temperature oxidation (LTO), cracking, and high temperature oxidation (HTO) (Greaves et al., 1996).

The LTO reactions, also called the ‘oxygen addition’, affect the light components of the crude. The oxygen atoms chemically bind into the molecular structure of the liquid hydrocarbons, producing various oxygenated compounds such as hydroperoxides, aldehydes, ketones and acids. These compounds tend to further react and polymerize and form heavier, less desirable oil fractions. There is little or no carbon dioxide generation, causing the pore pressure to drop below that of the flowing gas and promoting oil trapping. Cracking is defined as the change in composition of oil when it is heated in the absence of oxygen. The cracking reactions are believed to be responsible for what is called “fuel deposition”. This is solid hydrocarbon byproduct from the cracking reactions that is burned in oxygen to produce carbon dioxide, carbon monoxide and water (steam). However, Belgrave et al. (1990) showed that LTO also takes an important part in the fuel deposition process, especially for heavy crudes. The HTO reactions also called ‘bond scission’, are the main source of energy for the combustion process and rely heavily on the fuel deposition reactions. These oxidation reactions are responsible for the temperature peak in the combustion front.
The unfavorable LTO reactions occur at temperatures below 300 °C for heavy crudes while for light oils they dominate below about 150 °C. HTO reactions are specific to temperatures of 300 to 450 °C for heavy crudes and 150 to 300 °C for light crudes (Moore et al., 2002). LTO reactions occur downstream of the front when the oxygen is not consumed completely in the HTO reactions. However, LTO reactions are also responsible for the initiation of combustion process due to spontaneous ignition. Different research groups have suggested different temperature ranges for the LTO and HTO reactions based on oil composition (Moore et al., 1997; Greaves et al., 1999).

The key to a successful HPAI project is to design the process such that it ensures operation in the bond scission mode (HTO). Fortunately, this works quite well for many high gravity, high pressure, light oil reservoirs. In case of heavy oil reservoirs, however, factors such as faulty ignition, insufficient air injection, and permeability restrictions cause the mobilization of the oil into cooler downstream regions where the undesirable LTO reactions are predominant (Moore et al., 1997).

1.5 HPAI Applicability
As with any EOR technology, in order to ascertain the economic and technical feasibility of a potential HPAI application, a rigorous screening process needs to be employed. Many research groups have suggested different screening criteria, but most of them deal with heavy oil “in-situ” combustion projects and therefore
are not directly applicable to HPAI operations. Some of the key parameters that need to be considered for any HPAI project include (Turta and Singhal, 1998; Moore et al., 2002):

- **Amount of oil in place at the start of air injection**: This is the product of porosity and initial oil saturation or $\Phi \cdot S_o$. This helps decide the economic viability and operation time span of the project.

- **Ability to deliver air to the reservoir**: This pertains to the selection of the appropriate equipment for air compression and injection, as they play a pivotal role in the overall process. Too small a discharge from the air compressor could lead to faulty ignition, which will adversely affect the oxidation process and combustion front propagation.

- **Ability of the oil to spontaneously ignite and sustain stable oxygen uptake reactions over the life of injectors**: Laboratory testing of oil provides useful information concerning oil reactivity, oxidation characteristics, kinetic data, pressure effects, air and fuel requirements, product gas compositions, air/oil ratios and other production related data (Fassihi et al., 1990, Pusch et al., 1991). Combustion tube tests provide a direct observation of the ability of the oxidation reactions to maintain stable process (Fassihi et al., 1996). Kazi et al. (1999) discusses the design and application of a high-pressure flow reactor, which can enable physical simulation of the combustion process at high temperature and pressure conditions. Accelerating Rate Calorimeter (ARC) tests (Yannimaras et al., 1995, 1997) and Pressurized Differential Scanning Calorimeter (PDSC)
tests provide information on the energy generation rate of the oxidation reaction as a function of the temperature. Clara et al. (1999) has discussed the newer adiabatic disk reactor experiments and other tests. Ramped Temperature Oxidation (RTO) tests provide direct measure of the oxygen uptake rates as a function of temperature under air flux and core packing. Greaves et al. (2000, 2002) have extensively worked on semi-scaled 3D combustion cell studies that investigate the importance of the application of horizontal wells in line-drive mechanism for air injection, popularly know as Toe-to-Heel Air Injection (THAI). Sarma and Ono (1995) and Petzet (1996) discuss successful application of horizontal well technology in different in-situ combustion projects.

- **Numerical Modeling:** It is seen as a valuable and a cost effective step in the screening processes and optimizing HPAI implementation. It becomes very useful if immiscible or miscible gas flooding is considered to be the dominant recovery mechanism. Compositional simulators can accurately model immiscible/miscible gas flooding processes. However, modeling of the reaction zone(s) becomes much more difficult as the thermal fronts are usually very narrow, with respect to grid block size. Recent advances in front tracking techniques (Davies, 1989), which help minimize numerical dispersion and maintain proper temperature profiles ahead of the combustion front, may improve results. Further, current models are only able to model the simple bond scission reactions while the process itself is much more complex. Therefore, development of pseudo-kinetic models
that can predict changes in reaction mechanisms, which in turn will impact the effectiveness of the overall process, remain a significant challenge.

Apart from the initial process design, certain issues need to be addressed while the HPAI project is in operation (Turta and Singhal, 1998).

- Regular monitoring of the product gas vent rates and composition: This becomes very important as the gas phase composition data provides information about mean temperatures, oxygen and carbon dioxide concentrations, which is useful in determining the efficiency of the overall process.

- Operating Strategies: In the event that the air injection process is not performing according to the expectations, assuming sufficient air is being injected, the best approach is to shut in the injector believed to be serving the producer. This affects the oxygen partial pressure and may change the oxidation mode from one of low temperature to high temperature. This change in the oxidation mode is often reflected in elevated amounts of carbon dioxide in the product gases. If no change in the carbon dioxide/nitrogen occurs following the shut-in, it is safe to assume that the temperatures in the reaction zone are lower than that required for effective operation, which may be due to that the injector in question does not possess good communication with the reservoir.
1.6 HPAI Case Histories

Many HPAI injection projects have been attempted over the years, but some were more successful than others. Turta and Singhal (1998) provide a review of many of the HPAI projects undertaken across the globe. Some of the notable HPAI projects implemented in the USA were the ones started by Koch Exploration Company and Amoco (now BP) in the Buffalo Red River and Medicine Pole Hills Units, Williston Basin, North and South Dakota (Erickson et al., 1994; Kumar et al., 1995). These continue to be operated by Continental Resources, Inc. Watts et al. (1997) describe a newer project started in the nearby Horse Creek Field by Total Minatome Corporation. Fassihi et al. (1993, 1996) describe the air injection project initiated by Amoco with the United States Department of Energy (DOE) in the West Hackberry Field, Louisiana. Fraim et al. (1997) have published a feasibility study for a probable HPAI application in the Maureen Field, North Sea. This mature waterflooded field is nearing the end of its producing life, and HPAI studies indicate a potential of another 5 to 6% OOIP recovery (18 to 26 MM STB). A comprehensive economic and technical feasibility study for a potential HPAI application was undertaken for Shell’s Coral Creek Field in the Williston Basin (Glandt et al., 1998). This reservoir had been under waterflood for several years and the production had been on a decline. The study concluded that the HPAI process could not only arrest the decline but also double the waterflood reserves and current production rates within 5 years. Clara et al. (1999) discuss another study that was undertaken for a potential HPAI application for the Handil

1.7 The Ellenburger Formation

The focus of this study is the Ellenburger formation in the Permian Basin that houses an estimated 900 MMbbl of oil resource. The formation is composed of shallow-water, lower Ordovician carbonates (both dolostone and limestone) and is similar to other reservoirs in which HPAI has been effectively applied (Kumar et al., 1995, Erikson et al., 1994, Holtz and Kerans, 1992). These rocks typically contain low permeabilities and high initial water saturations despite relatively high porosity. Core data obtained from the Ellenburger suggests that the formation is dominated by complex karst geometry and is highly fractured (Figure 1.2) (Loucks and Mescher, 2001). Figure 1.3 shows the Ellenburger Ramp Carbonate subplay and the Ellenburger Karst-Modified Carbonate subplay (Holtz and Kerans, 1992). Since less than one-third of the original oil in place in the Ellenburger has been recovered, implementation of advanced oil recovery options seems reasonable. However, due to the great depths of the Ellenburger reservoirs and the high costs associated with drilling, the economics of advanced recovery operations is more challenging.
Figure 1.2 Karst features of Ellenburger (from Loucks and Mescher, 2001).
Figure 1.3 Ellenburger carbonate subplay (from Holtz and Kerans, 1992).
1.8 The Barnhart Field

The Barnhart field (Figure 1.3) was chosen to demonstrate the effectiveness of the HPAI process. The field was discovered in 1941 on the Ozona Uplift, southeastern Reagan County, Texas. The mineral rights for the southern half of the approximately 10,000 acre field are owned by the University of Texas Lands, while the northern half is privately held (Hunt, 2001). The field was abandoned in 1976 after producing about 16 MMbbl of oil. A detailed field history can be found in Hunt (2001). Galloway et al. (1983) and Tyler et al. (1991) have estimated 115 MMbbl OOIP for the field. The poor recovery is attributed to the rapid loss of reservoir energy caused by pressure decline in the solution-gas-drive reservoir. Figure 1.4 shows the oil production and pressure decline profile for the Barnhart field. The reservoir pressure has reduced to 1600 psi from its original 3920 psi. In the 1950’s, 45 producers were active with a daily output of about 3,000 barrels of oil per day (bopd) from an area of 5000 acres. Only a four producing wells remained in 2000, producing about 10 bopd. Two pilot waterfloods were attempted from 1960 through 1971, but neither was successful. Resource characterization studies conducted by Galloway et al. (1983) and Tyler et al. (1991) suggested that about 50 MMbbl of oil is mobile and therefore recoverable. The Barnhart field meets the criteria for successful application of HPAI technology as defined by Erickson et al. (1992): depth greater than 5,500 ft, API gravity greater than 25, and temperature greater than 170 °F. Further, laboratory tests conducted on the Barnhart oil and core strongly support the feasibility HPAI in the field. These tests will be reviewed in detail in Chapter 2.
Figure 1.4 Oil production and pressure decline trend for the Barnhart field (from Gomez et al., 2002).

To ascertain the applicability of the HPAI process in the Barnhart field, a HPAI pilot program was established in 2000 with a single vertical injection well and a horizontal producing well. In the first year, approximately 500,000 thousand cubic feet (Mcf) of air was injected with air-injection rates of 1,500 Mcf per day (Mcfd). A positive production response in terms of higher oil, natural gas and CO₂ rates was monitored in the horizontal producing well, indicating that a stable combustion front was initiated in the reservoir (John Lomax, personal communication). Combustion has been confirmed by increased injection pressures in the injection well, indicating the development of combustion and increase in flue gas volumes in the produced gas stream.
2.1 Laboratory Tests

Accelerated Rate Calorimetry (ARC) tests and Combustion Tube Experiments form the backbone for any reservoir evaluation study concerning air injection or insitu combustion. These tests are very important from the viewpoint of ascertaining the feasibility of the whole HPAI process. This section outlines the basic setup for these tests and summarizes the results obtained from the tests performed on the Barnhart light oil and reservoir matrix by Yannimaras and Spencer (1999) and Christopher et al. (1999).

2.2 Accelerated Rate Calorimetry (ARC)

The Accelerated Rate Calorimetry (ARC) test was developed to quickly assess the suitability of an oil for in-situ combustion and obtain basic kinetic parameters (Yannimaras and Tiffin, 1995). These tests are conducted under quasi-adiabatic conditions and provide with following information:

- oil reactivity and oxidation characteristics,
- auto ignition and sustainable operability characteristics, and
- arrhenius kinetics parameters (activation energy, reaction order, pre-exponential factor).

The information collected above can be used for numerical simulation of combustion tube experiments and field projects.
2.2.1 Experimental Design

The oxidation character of an oil is to be studied at the reservoir conditions, and therefore proper laboratory equipment that can handle oxidation reactions at high temperature and pressure conditions is required. The ARC design can handle pressures up to 6000 psi and study exothermic reactions in the temperature range of 30 to 500° C (Yannimaras and Tiffin, 1995). Other commercially available instruments such as Differential Scanning Calorimeter (DSC), Differential Temperature Analyzer (DTA), and Thermogravimetric Analyzer (TGA), are limited to low and medium pressures (Yannimaras and Spencer, 1999). The ARC setup consists of a calorimeter unit with a small, spherical sample holder (Figure 2.1) (Sarma et al., 2001), a power unit, a temperature control unit, and a main processor unit. The main processor is used to enter the parameter values and control the experiment. It also processes the results and provides the kinetics and thermal values. Further information on the ARC theory, operation and performance is provided by Zelenko and Solignac (1997) and Sarma et al.(2001).

2.2.2 Operation

The ARC tests can be performed in two operating modes (Yannimaras and Tiffin, 1995; Sarma et al., 2001):

- Closed System: A fixed amount of air is included with the sample at reservoir conditions. This mode provides most of the kinetic parameters from oil oxidation.
• Flowing System: The oil sample placed under continuous supply of air at reservoir conditions. This mode provides effluent gas analysis, which furthers the process understanding.

Only the closed system tests were performed for the Barnhart case study. Two types of ARC runs can be conducted (Yannimaras and Tiffin, 1995; Yannimaras and Spencer, 1999; Sarma et al., 2001):

• Scanning Run: A scanning run results when the ARC system is programmed to raise the temperature in pre-determined steps (generally 5 °C) after a certain waiting and searching period (typically 20 minutes to an hour). Whenever an exothermic reaction is encountered, the system temperature starts increasing. The rise in temperature is recorded while the oil is allowed to burn adiabatically at its inherent reaction rate without any further forced heating. The system boundaries are kept at a temperature equal to the sample holder at all times to maintain adiabatic conditions. Such a run is useful to quickly identify the temperature intervals in which the oil reacts with the air.

• Isoaging Run: Isothermal aging involves holding the oil, core and air in the sample holder at reservoir conditions for up to 5 days. As a reaction takes place, the system temperature may slowly increase until self-ignition results in a sustained exothermic reaction. Self-ignition is defined when the self-heating rate (SHR) exceeds 0.025 °C/min and produces a
self-sustaining exothermic reaction. Such a run is useful in determining if an oil is likely to auto-ignite upon air injection in the reservoir.

### 2.2.3 Interpretation

The ARC results are presented as the log of the self-heating rate (rate of exothermic heat release - °C/min) vs. temperature. As the system is sealed adiabatically, presence of a self-heating rate trace (experimentally recorded points) over a temperature interval indicates a region of exothermic reaction. The first peak observed in an ARC plot is the LTO (Low Temperature Oxidation) peak, which is followed by a HTO (High Temperature Oxidation) peak.
Occurrence of a LTO peak is considered sufficient for light and medium gravity oils, while occurrence of a HTO peak is thought to be necessary for heavy oil oxidation. Generally, a large temperature range for an LTO reaction with an endpoint above 300 °C or a smooth LTO to HTO transition qualifies the oil for successful in-situ combustion operation.

The following chemical reaction can be used to represent the oxidation of a typical hydrocarbon fuel (Yannimaras and Spencer, 1999):

\[ \text{Fuel} + n_1 \text{O}_2 \rightarrow n_2 \text{CO} + n_3 \text{CO}_2 + n_4 \text{H}_2\text{O} + \text{Energy.} \quad (2.1) \]

Here the stoichiometric coefficients \( n_i \) depend on the choice of fuel. This global reaction can conveniently represent the overall effect of many elementary reactions that actually occur in the combustion process. Therefore writing a single Arrhenius rate equation for the above reaction we get:

\[
k = A e^{-E_a/RT} \left[ \text{Fuel Conc.} \right]^n \left[ \text{Oxidizer Conc.} \right]^m, \quad (2.2)
\]

where

- \( k \) = reaction rate coefficient,
- \( A \) = pre-exponential factor (frequency factor),
- \( E_a \) = activation energy,
- \( R \) = gas constant \( (8.314 \times 10^{-3} \text{kJ mol}^{-1}\text{K}^{-1}) \),
\[ T = \text{temperature (K)}, \]
\[ N = \text{order of reaction, and} \]
\[ M = \text{constant.} \]

A further simplification to the above equation is that the constant \( M \) is assumed to be zero, which implies that the reaction rate is independent of the overall oxygen concentration, i.e., there is excess oxygen available at all times. Hence,

\[ k = A \exp\left(-\frac{E_a}{RT}\right) [\text{Fuel}]^N. \]  

(2.3)

The above equation along with the mass and energy conservation equations and some algebraic manipulation yields the following equation:

\[ \frac{dT}{dt} = A_0 \exp\left(-\frac{E_a}{RT}\right) C_o^{N-1} (T_F - T_o) \left(\frac{T_F - T}{T_F - T_o}\right)^N, \]

(2.4)

where
\[ T = \text{sample (bomb) temperature}, \]
\[ t = \text{time}, \]
\[ C_o = \text{initial sample concentration, constant}, \]
\[ T_F = \text{final exotherm temperature, and} \]
\[ T_o = \text{initial exotherm temperature}. \]

Defining
\[ k^* = A e^{-\frac{E_a}{RT}} C_o^{N-1} \] and \[ mT = \frac{dT}{dt}, \] (2.5)

we get,

\[ k^* = \frac{mT}{(T_F - T_o)} \left[ \frac{T_F - T_o}{T_F - T} \right]^N. \] (2.6)

The activation energy \( E_a \), order of reaction \( N \), and the pre-exponential factor \( A \) are obtained experimentally from the above equations (2.5 and 2.6) by plotting \( k^* \) vs. \( \left[ \frac{T_F - T_o}{T_F - T} \right] \) on log scales. This determines \( N \) as the slope of the straight line.

Plotting \( k^* \) vs. \( T \) on log scales gives \( E_a \) as the slope of the straight line and \( A \) as the intercept.

### 2.2.4 Results

Table 2.1 summarizes the results obtained from the ARC tests undertaken for the Barnhart light oil (Yannimaras and Spencer, 1999). Only the Isoage runs in the closed mode were carried out. Two tests were conducted, with and without the reservoir core material. In the first test, the oil was tested by itself in a closed ARC configuration at an initial pressure of 3925 psi and temperature of 79 °C. The oil-air system was kept at reservoir conditions for five days. There was notable exothermic activity even though the sample did not auto-ignite. A large LTO reaction temperature range with a \( \Delta T=245 \) °C and an endpoint of 410 °C was noted (Figure 2.2). This suggests that this oil is a very good candidate for air
Figure 2.2 ARC test 1 (from Yannimaras and Spencer, 1999).

Figure 2.3: ARC test 1, two-reaction scheme-1
(from Yannimaras and Spencer, 1999).
Figure 2.4: ARC test 1, two-reaction scheme-2
(from Yannimaras and Spencer, 1999).

injection and a combustion front is expected to propagate in a stable and continuous manner. The LTO reaction mechanism exhibits a non-linear character and cannot be fitted with a one-reaction model. Figures 2.3 and 2.4 show the two-reaction character for this oil. The activation energy of the initiating reaction is 18.4 kcal/gmole, while that for the steeply ascending second one is 109 kcal/gmole.

In the second test, the oil was tested along with the reservoir core material at reservoir conditions of 3925 psi and 79 °C for 5 days. A more pronounced exothermic activity was noted here which could be attributed to the catalytic
effects of the reservoir matrix. The LTO reaction end point was recorded at 322 °C, much lower than the first test (410 °C), due to the thermal inertia of the rock matrix. The matrix was primarily dolomite and was disaggregated to a certain random pore size distribution. Of course, the in-situ pore size distribution would be different then used for the experiment, but the effect cannot be quantified except in a general sense that larger surface area per unit rock volume would promote better combustion. The shape of the LTO exotherm has notably changed, and also the HTO exotherm is now visible in the 450-480 °C region (Figure 2.5). Under normal air fluxes, this oil would burn in the LTO reaction mode with a peak temperature close to 320 °C. If high air fluxes are used, the HTO reaction would result in a temperature peak around 500 °C. The activation energy for the LTO reaction was derived to be 25 kcal/gmole and the order of reaction was 0.5.

Figure 2.5 ARC test 2 (from Yannimaras and Spencer, 1999).
<table>
<thead>
<tr>
<th>Run No., Temp. Step, Total t</th>
<th>Run Type</th>
<th>Exotherms dT, °C</th>
<th>dT, °C</th>
<th>Pmax, psig</th>
<th>Ea, kcal/gmole N, lnA, ln(1/sec)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Closed Isoage</td>
<td>165-410</td>
<td>269-276</td>
<td>245</td>
<td>1363@257°C</td>
</tr>
<tr>
<td>2</td>
<td>Closed Isoage</td>
<td>125-322</td>
<td>275-276</td>
<td>197</td>
<td>604@261°C</td>
</tr>
</tbody>
</table>

Nomenclature

- **Oil**: Oil API gravity, temperature and pressure, volume of oil used in the test
- **Temp. Step**: Temperature step applied in search for exothermic activity
- **Total t**: Total time taken for run completion
- **Run Type**: Type of run implemented; increasing temperature in steps, or holding temperature constant
- **Exotherms**: Temperature range of continuous exothermicity, as determined by the ARC control program
- **dT, °C**: Maximum adiabatic temperature rise for the major exotherm
- **Pmax, psig**: Maximum recorded pressure for the major exotherm
- **Ea, kcal/gmole N, lnA, ln(1/sec)**: Arrhenius activation energy, order of reaction, and pre-exponential factor

**Table 2.1 ARC Test Results**

Based on the above tests, the Barnhart light oil was concluded to be a very good air injection candidate, and further laboratory work such as combustion tube experiments were recommended.

**2.3 Combustion Tube Test**

The Combustion Tube tests are designed to simulate and evaluate the dynamics of the combustion front that is created due to air injection and subsequent in-situ...
combustion. These tests are conducted under conditions closely approximating those in a reservoir and provide the following information (Hansel et al., 1982; Shahani and Hansel, 1984; Christopher et al. 1999; Greaves et al., 2000):

- auto-ignition and stable front propagation characteristics,
- oil displacement (reservoir sweep),
- produced oil, water and gas compositions,
- fuel deposition, and
- air/Fuel ratio and air requirement.

The above results along those from the ARC tests provide an improved understanding of the combustion process and aid in the design and interpretation of a pilot project.

2.3.1 Experimental Design

The flow system setup typically consists of a combustion tube, high-pressure cylinders to deliver gas or liquid to the combustion tube, a high-pressure separator where the produced fluids are flashed to atmospheric conditions and collected for later analysis, gas chromatograph for produced gas analysis, and high-pressure tubing/fittings (Figure 2.6) (Voussoughi et al., 1981; Ambastha and Kumar, 1999; Christopher et al., 1999; Greaves et al., 2000). A series of independently controlled heaters heat the tube wall to maintain adiabatic conditions in the tube. A number of thermocouples are installed on the wall as well as the center to accurately report temperatures along the length of the tube (Figure 2.7). The tube itself is operated in a large containment vessel rated for over 6000 psi. The
The combustion tube used in this study was 6 ft long by 4 in. in diameter. Due to unavailability of 6 ft long reservoir cores, the test used crushed core material and therefore honors only the mineralogy and the reservoir temperature and pressure conditions and not rock properties (porosity and permeability).

### 2.3.2 Operation

The combustion tube undergoes a lengthy preparation for each test to be conducted. First the tube is filled with crushed core material in increments of 500

![Figure 2.6 Combustion tube flow system schematic (Christopher et al., 1999).](image)

Figure 2.6 Combustion tube flow system schematic (Christopher et al., 1999).

![Figure 2.7 Combustion tube schematic (Christopher et al., 1999).](image)

Figure 2.7 Combustion tube schematic (Christopher et al., 1999).
grams. Following packing, the tube is saturated with methanol and thermocouples are inserted in place. Next the heaters are installed and insulation applied. Lastly the tube is mounted in the high-pressure annulus vessel. Further, the tube is successively flushed with benzene, pentane and nitrogen to clean and dry. Once clean and dry, the sandpack is saturated with synthetic reservoir brine. This is then driven out to the immobile saturation limit by injecting a series of refined oils of varying viscosities to reduce the brine to irreducible water saturation. Now the reservoir crude is injected until all of the lightest oil is displaced. Once an immobile water saturation is achieved, the pressure in the annulus and the tube is raised to the reservoir pressure. In order to get a more orderly sweep the combustion tube is turned vertical, heated to reservoir temperature and flooded with nitrogen. The nitrogen injection simulates the flue gas front formed before the steam and combustion front in an in-situ combustion. Following gas breakthrough, the produced fluids are switched to flow through the separator. The initial three zones of the tube are heated to about the auto ignition temperature (as determined by the ARC test) and then injection gas is switched to air. The heaters are then switched to adiabatic mode. Table 2.2 summarizes the test conditions.

<table>
<thead>
<tr>
<th>Injection Rate (SLH)</th>
<th>Pressure (psig)</th>
<th>Reservoir Temperature (°C)</th>
<th>Permeability (md)</th>
<th>Porosity (%)</th>
<th>Oil</th>
<th>Water</th>
<th>Gas</th>
</tr>
</thead>
<tbody>
<tr>
<td>444</td>
<td>3920</td>
<td>79.4</td>
<td>1200</td>
<td>42.1</td>
<td>31.3</td>
<td>24.2</td>
<td>44.5</td>
</tr>
</tbody>
</table>

Table 2.2 Combustion Test Conditions
2.3.3 Results and Discussion

Christopher et al. (1999) discuss the combustion tube testing and results. One of the most important results obtained from the combustion tube test are the temperatures measured by each center thermocouple as a function of time. A set of such curves from the Barnhart test is shown in Figure 2.8. The rapidly rising leading edge of these curves is used to calculate the combustion front velocity. The front velocity for this test was determined to be about 1ft/hr. This indicates that combustion was stable. Table 2.3 summarizes this and other results obtained.

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>(ft/hr)</td>
<td>(SCF/ft^2-hr)</td>
<td>(ft/d)</td>
<td>(°C)</td>
<td>(%)</td>
<td>(H/C)</td>
<td>(SCF/lb)</td>
<td>(lb/ft^3)</td>
<td>(SCF/ft^3)</td>
<td></td>
</tr>
<tr>
<td>0.92</td>
<td>195.5</td>
<td>38.6</td>
<td>370</td>
<td>0.572</td>
<td>5.6</td>
<td>86</td>
<td>2.17</td>
<td>185.1</td>
<td>0.71</td>
</tr>
</tbody>
</table>

Table 2.3 Combustion Tube Test Results

The produced oil was collected and analyzed for composition. Figure 2.9 shows the analysis of the samples collected along with the original oil sample. As can be seen, the composition of the produced oil has changed slightly, with a concentrating effect around C_7 as the lighter and some of the heavier components get reduced. This phenomenon may occur at the field scale and yield lower API gravity oil than the original. The final oil recovery was calculated to be about 80%. This recovery may be optimistic, however, because the core material was
Figure 2.8 Combustion tube zone temperatures (from Christopher et al., 1999).

Air flux changed from 444 to 666 SLH at 12:00.
Figure 2.9 Combustion tube produced oil analysis
(from Christopher et al., 1999).
Figure 2.10 Combustion tube produced gas analysis (from Christopher et al., 1999).
crushed and packed into the tube and thus did not represent in-situ porosity and permeability.

The produced gas was analyzed for CO$_2$, CO, N$_2$, and O$_2$ by using specific gas analyzers and gas chromatography. The steady state gas composition was reported to be - O$_2$: 3.0%, CO$_2$: 11.5%, CO: 2.5%, and N$_2$: 83% (Figure 2.10). These numbers were used to calculate parameters such as oxygen utilization, CO/CO$_2$ ratio, fuel deposition, air/fuel ratio, air requirement (Table 2.3), which will be useful in designing a pilot air injection program.

The overall conclusion attained from the above test was that the Barnhart light oil is an excellent candidate for air injection. The combustion process progressed in the HTO reaction regime and resulted in a stable burn. The produced oil had a lower API gravity due to stripping of the light ends.

2.3.4 Combustion Tube History Match

This section presents the combustion tube simulations that were reasonably history matched to the laboratory data.

A 1D simulation grid (1x1x33) with 33 active cells in the vertical direction was employed. The test conditions for the simulation were the same as those used in the laboratory test. These are summarized below.
Table 2.4 Combustion Tube Simulation Conditions

<table>
<thead>
<tr>
<th>Injection Rate (SLH)</th>
<th>Pressure (psig)</th>
<th>Reservoir Temperature (°C)</th>
<th>Permeability (md)</th>
<th>Porosity (%)</th>
<th>Saturation at Start of Air Injection</th>
</tr>
</thead>
<tbody>
<tr>
<td>444</td>
<td>3920</td>
<td>79.4</td>
<td>1200</td>
<td>42.1</td>
<td>Oil 31.3</td>
</tr>
</tbody>
</table>

Reservoir matrix, reservoir fluids, reaction chemistry and kinetics are the same as those for the field scale simulation model described in the Chapter 3. External heating was provided for the first few grid blocks. Adiabatic (no heat loss to the surroundings) conditions were employed. The simulation time was 7 hours. The following model parameters were adjusted in order to achieve a reasonable history match:

- reaction activation energy,
- enthalpy of reaction,
- frequency factor,
- relative permeability curves, and
- chemical reaction stoichiometric coefficients.

The adjusted parameters have been described in greater detail in Chapter 3.

Figure 2.11 shows the temperature profiles obtained for each of the grid blocks, while Figure 2.12 shows the temperature profiles obtained from the laboratory run. The two temperature profiles have comparable front temperature ranges. Although the simulated thermal front temperatures are a little higher than those obtained from the laboratory run, this difference could be ascribed to some minor
heat loss taking place from the laboratory apparatus resulting in lower front temperatures. Figure 2.13 shows the produced gas composition obtained from the simulation run, while Figure 2.14 shows that obtained from the laboratory run. The produced gas composition profiles obtained from the laboratory run are in good agreement with those obtained from the simulation run. Observed mole fraction figures for the produced gas from the simulation match well to the steady state compositions recorded in the laboratory run. Fuel deposition could not be matched as the STARS simulator does not provide output for bulk volume of fuel burnt but gives out the fuel concentration.
Figure 2.11 Temperature profiles from simulation run.

Figure 2.12 Temperature profiles from laboratory run
(from Christopher et al., 1999).
Figure 2.13 Produced gas composition from simulation run.

Figure 2.14 Produced gas composition from laboratory run
(from Christopher et al., 1999).
CHAPTER 3

3.1 Reservoir Simulation
This chapter lays out the framework for the reservoir simulation model that was used for this study. The software used for the HPAI simulations is STARS (Steam, Thermal, and Advanced Processes Reservoir Simulator) from the Computer Modeling Group (CMG™), Calgary, Canada.

3.2 Scope of Work
The objectives of the present work were to investigate numerically the potential of HPAI to displace oil versus a typical waterflood program in a naturally fractured light oil reservoir. The model tries to emulate the Ellenburger reservoir (Barnhart field) in West Texas. To achieve proper representation, every attempt was made to incorporate the available field data in the simulation model. Further, to demonstrate the credibility of the simulation model, combustion tube test data was history matched as reported in the previous chapter. Although safety and economics aspects will ultimately determine the viability of a project, these aspects were not considered here.

3.3 Model Set-up
The model represents an injection-production well pair in a quarter of a 5 spot for a 40-acre field, using a vertical injector and either vertical or horizontal producers
(Figure 3.1 and 3.2). Since secondary recovery in the form of a waterflood program was not implemented successfully for the reservoir in question, the initial

Figure 3.1 5-Spot well configuration with vertical wells.

Figure 3.2 5-Spot well configuration with horizontal producer.
conditions used in the simulation model represent depleted conditions for the Ellenburger reservoir. The reservoir pressure is 1600 psi and the reservoir temperature is 200 °F (Gomez et al., 2002). The depth to the top of the interval of interest is 9000 ft. The thickness of this interval was evaluated to be 92 ft based on the well log data from an existing well (Figures 3.3 to 3.5). The log data which was measured every feet, is plotted as a moving average over a 5 ft interval to smooth out the spikes in the log. Further, this interval was zoned into 6 distinct layers of varied thickness and each layer was assigned different porosity, permeability and water saturation numbers (Table 3.1).

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>9028 – 9044ft, 16ft</td>
<td>0.04</td>
<td>0.9</td>
<td>0.62</td>
</tr>
<tr>
<td>2</td>
<td>9044 - 9063ft, 19ft</td>
<td>0.04</td>
<td>1.0</td>
<td>0.56</td>
</tr>
<tr>
<td>3</td>
<td>9063 - 9074ft, 11ft</td>
<td>0.08</td>
<td>8.11</td>
<td>0.46</td>
</tr>
<tr>
<td>4</td>
<td>9074 - 9091ft, 17ft</td>
<td>0.05</td>
<td>1.67</td>
<td>0.35</td>
</tr>
<tr>
<td>5</td>
<td>9091 - 9107ft, 16ft</td>
<td>0.07</td>
<td>5.42</td>
<td>0.42</td>
</tr>
<tr>
<td>6</td>
<td>9107 - 9120ft, 13ft</td>
<td>0.05</td>
<td>1.22</td>
<td>0.31</td>
</tr>
</tbody>
</table>

Table 3.1 Grid Matrix Properties
Figure 3.3 Matrix porosity from well log data.
Figure 3.4 Matrix water saturation from well log data.
Figure 3.5 Matrix permeability evaluated from transform.
3.3.1 Simulation Grid

The objective was to simulate a reservoir pattern using sufficient number of grid blocks that will provide results with adequate accuracy without unduly large simulation times. A sensitivity analysis was done to investigate the effect of using different grid sizes. Three different grid sizes (10x10x6, 30x30x6 and 60x60x6) were each used to simulate in-situ combustion. The results obtained in all three cases were pretty close indicating that numerical dispersion was not a problem. To represent a quarter of a 5-spot pattern on a 40-acre area, a 3D Cartesian grid (30x30x6) with 5400 active cells having six layers was chosen. Figure 3.6 shows the simulation grid. A dual permeability model was employed to simulate natural fractures and karst features in the reservoir. Each matrix layer in the model was assigned a unique permeability, porosity and water saturation character (Table
3.1). Permeability data for the matrix was evaluated from the porosity log by using a transform that was based on permeability-porosity cross plots generated from the core data obtained from the logged well (Jeff Kane, personal communication).

\[ k = 10^{(4.826+3.687\log(\Phi))} \]  

(3.1)

Figure 3.5 shows the matrix permeability values obtained by using the above relationship. A vertical permeability value of 2 md was assumed for the matrix component throughout the reservoir based on the core analysis data obtained for the producing well. However, as the reservoir is interpreted to be naturally fractured and karsted, permeability may be more heterogeneous (Hunt, 2001; Gomez et al., 2002; Combs et al., 2003).

Figure 3.7 shows the simulation grid with the matrix properties. A porosity of 10% and permeability value of 100 md was assumed for the fracture component of the reservoir since no fracture measurements were available. Further, since no relative permeability data was available for the Barnhart field, the data used in this study was obtained by history matching the combustion tube data available for the Barnhart oil and core. Figure 3.8 and 3.9 give the matrix relative permeability distribution for oil-water and gas-oil systems. Relative permeabilities for the fracture network were assumed to be linear (Gilman and Kazemi, 1983).
3.3.2 Rock Properties

The rock properties used in this study are based on default in-situ combustion example available in STARS simulator (CMG 2003.10). These are presented in Table 3.2.

<table>
<thead>
<tr>
<th>Property</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Rock Compressibility</td>
<td>$3.4 \times 10^{-6}$ psi$^{-1}$</td>
</tr>
<tr>
<td>Rock Heat Capacity</td>
<td>35 Btu/ft$^3$-F</td>
</tr>
<tr>
<td>Rock Thermal Conductivity</td>
<td>24 Btu/ft-day-R</td>
</tr>
<tr>
<td>Water Phase Thermal Conductivity</td>
<td>8.6 Btu/ft-day-R</td>
</tr>
<tr>
<td>Oil Phase Thermal Conductivity</td>
<td>1.8 Btu/ft-day-R</td>
</tr>
<tr>
<td>Gas Phase Thermal Conductivity</td>
<td>1.2 Btu/ft-day-R</td>
</tr>
<tr>
<td>Heat Loss to Over and Underburden</td>
<td>35 BTU/ft$^3$-F</td>
</tr>
</tbody>
</table>

Table 3.2 Rock Properties
Matrix Porosity (fraction)

Matrix Permeability (md)

Matrix Water Saturation (fraction)

Figure 3.7 Grid matrix properties.
Figure 3.8 Oil-water relative permeability based on combustion tube data.

Figure 3.9 Gas-oil relative permeability based on combustion tube data.
3.3.3 Reservoir Fluid Properties

A total of 8 components were used in the compositional simulator:

- Water
- Light Oil, C_{2+}
- Methane gas, CH\textsubscript{4}
- Carbon Dioxide, CO\textsubscript{2}
- Carbon Monoxide, CO
- Oxygen, O\textsubscript{2}
- Nitrogen, N\textsubscript{2}
- Coke

A two-hydrocarbon pseudo-components scheme was chosen for our study. These are CH\textsubscript{4} for the gas component and C\textsubscript{2+} for the remaining light oil. The specific gravity of the light oil is 0.822 gm/cc, corresponding to 40.7 °API gravity and a molecular weight of 179 lb/lbmole. Original oil composition is shown in Table 3.3 (Yannimaras and Spencer, 1999. Critical properties, thermal expansion, liquid compressibility, heat capacities and heats of vaporization were obtained from literature (Reid, Prausnitz, and Sherwood, 1977).

In compositional models, the phase equilibrium is specified via ratios (K-values). For the pseudo component C\textsubscript{2+}, STARS requires direct input of these as functions of pressure, temperature and composition. The gas-liquid K-values for the pseudo-component C\textsubscript{2+} were calculated by flashing one mole of C\textsubscript{2+} with 4 moles
<table>
<thead>
<tr>
<th>C#</th>
<th>Wt%</th>
<th>Mole%</th>
<th>C#</th>
<th>Wt%</th>
<th>Mole%</th>
<th>C#</th>
<th>Wt%</th>
<th>Mole%</th>
</tr>
</thead>
<tbody>
<tr>
<td>C1</td>
<td>0.00</td>
<td>0.00</td>
<td>C21</td>
<td>2.83</td>
<td>1.80</td>
<td>C41</td>
<td>0.35</td>
<td>0.11</td>
</tr>
<tr>
<td>C2</td>
<td>0.00</td>
<td>0.00</td>
<td>C22</td>
<td>2.68</td>
<td>1.63</td>
<td>C42</td>
<td>0.11</td>
<td>0.03</td>
</tr>
<tr>
<td>C3</td>
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<td>0.02</td>
<td>C23</td>
<td>2.51</td>
<td>1.46</td>
<td>C43</td>
<td>0.09</td>
<td>0.03</td>
</tr>
<tr>
<td>C4</td>
<td>0.09</td>
<td>0.31</td>
<td>C24</td>
<td>2.45</td>
<td>1.37</td>
<td>C44</td>
<td>0.07</td>
<td>0.02</td>
</tr>
<tr>
<td>C5</td>
<td>1.65</td>
<td>4.32</td>
<td>C25</td>
<td>2.24</td>
<td>1.20</td>
<td>C45</td>
<td>0.05</td>
<td>0.01</td>
</tr>
<tr>
<td>C6</td>
<td>3.84</td>
<td>8.42</td>
<td>C26</td>
<td>2.17</td>
<td>1.12</td>
<td>C46</td>
<td>0.03</td>
<td>0.01</td>
</tr>
<tr>
<td>C7</td>
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<td>11.00</td>
<td>C27</td>
<td>2.12</td>
<td>1.05</td>
<td>C47</td>
<td>0.01</td>
<td>0.00</td>
</tr>
<tr>
<td>C8</td>
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<td>9.04</td>
<td>C28</td>
<td>1.94</td>
<td>0.93</td>
<td>C48</td>
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<td>0.00</td>
</tr>
<tr>
<td>C9</td>
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<td>7.75</td>
<td>C29</td>
<td>1.80</td>
<td>0.83</td>
<td>C49</td>
<td>0.01</td>
<td>0.00</td>
</tr>
<tr>
<td>C10</td>
<td>4.95</td>
<td>6.57</td>
<td>C30</td>
<td>1.67</td>
<td>0.75</td>
<td>C50</td>
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<td>0.00</td>
</tr>
<tr>
<td>C11</td>
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<td>5.91</td>
<td>C31</td>
<td>1.57</td>
<td>0.68</td>
<td>C51</td>
<td>0.00</td>
<td>0.00</td>
</tr>
<tr>
<td>C12</td>
<td>4.77</td>
<td>5.29</td>
<td>C32</td>
<td>1.51</td>
<td>0.63</td>
<td>C52</td>
<td>0.00</td>
<td>0.00</td>
</tr>
<tr>
<td>C13</td>
<td>4.48</td>
<td>4.59</td>
<td>C33</td>
<td>1.64</td>
<td>0.55</td>
<td>C53</td>
<td>0.00</td>
<td>0.00</td>
</tr>
<tr>
<td>C14</td>
<td>4.23</td>
<td>4.03</td>
<td>C34</td>
<td>1.23</td>
<td>0.49</td>
<td>C54</td>
<td>0.00</td>
<td>0.00</td>
</tr>
<tr>
<td>C15</td>
<td>4.09</td>
<td>3.64</td>
<td>C35</td>
<td>1.14</td>
<td>0.44</td>
<td>C55</td>
<td>0.00</td>
<td>0.00</td>
</tr>
<tr>
<td>C16</td>
<td>3.81</td>
<td>3.18</td>
<td>C36</td>
<td>1.00</td>
<td>0.37</td>
<td>C56</td>
<td>0.00</td>
<td>0.00</td>
</tr>
<tr>
<td>C17</td>
<td>3.54</td>
<td>2.79</td>
<td>C37</td>
<td>0.86</td>
<td>0.31</td>
<td>C57</td>
<td>0.00</td>
<td>0.00</td>
</tr>
<tr>
<td>C18</td>
<td>3.33</td>
<td>2.48</td>
<td>C38</td>
<td>0.80</td>
<td>0.28</td>
<td>C58</td>
<td>0.00</td>
<td>0.00</td>
</tr>
<tr>
<td>C19</td>
<td>3.08</td>
<td>2.17</td>
<td>C39</td>
<td>0.56</td>
<td>0.19</td>
<td>C59</td>
<td>0.00</td>
<td>0.00</td>
</tr>
<tr>
<td>C20</td>
<td>3.01</td>
<td>2.01</td>
<td>C40</td>
<td>0.52</td>
<td>0.17</td>
<td>C60</td>
<td>0.00</td>
<td>0.00</td>
</tr>
</tbody>
</table>

| Total | 100 | 100 |

Table 3.3 Original oil composition (from Yannimaras and Spencer, 1999).
of air (20% O₂, 80% N₂) using CMG’s equation of state multiphase equilibrium property package WinProp (Ren et al., 2001). These K-values have been tabulated in Table 3.4. The gas-liquid K-values for the remaining components were calculated internally in the simulator according to the following correlation:

\[ K = \left( k_{v1} / p + k_{v2} / p + k_{v3} \right) e^{(k_{v4}(T-k_v))} \]  \hspace{1cm} (3.2)

In the above equation, the K-value correlation coefficients, \( k_{v1} \) to \( k_{v5} \) were obtained from literature (Reid, Prausnitz, and Sherwood, 1977).

The viscosity of the chemical components is given as a function of temperature according to the following expression:

\[ \mu = a_i e^{b_i/T} \]  \hspace{1cm} (3.3)

In the above equation, the values of the coefficients, \( a_i \) and \( b_i \), correspond to the units of viscosity \( \mu \) and absolute temperature \( T \). Table 3.5 gives the values of these coefficients adapted from Tingas et al., (1996). Tingas et al. have conducted simulation studies in high-pressured, North Sea light oil. The crude oil characteristics used in that study are very similar to the present case.
<table>
<thead>
<tr>
<th>Pressure, Kpa</th>
<th>1.02E+04</th>
<th>1.09E+04</th>
<th>1.16E+04</th>
</tr>
</thead>
<tbody>
<tr>
<td>Temperature, °C</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>90</td>
<td>5.17E-04</td>
<td>5.35E-04</td>
<td>5.54E-04</td>
</tr>
<tr>
<td>110</td>
<td>1.09E-03</td>
<td>1.11E-03</td>
<td>1.14E-03</td>
</tr>
<tr>
<td>130</td>
<td>2.12E-03</td>
<td>2.15E-03</td>
<td>2.18E-03</td>
</tr>
<tr>
<td>150</td>
<td>3.89E-03</td>
<td>3.91E-03</td>
<td>3.93E-03</td>
</tr>
<tr>
<td>170</td>
<td>6.76E-03</td>
<td>6.75E-03</td>
<td>6.76E-03</td>
</tr>
<tr>
<td>190</td>
<td>1.12E-02</td>
<td>1.12E-02</td>
<td>1.11E-02</td>
</tr>
<tr>
<td>210</td>
<td>1.80E-02</td>
<td>1.78E-02</td>
<td>1.77E-02</td>
</tr>
<tr>
<td>230</td>
<td>2.80E-02</td>
<td>2.76E-02</td>
<td>2.74E-02</td>
</tr>
<tr>
<td>250</td>
<td>4.24E-02</td>
<td>4.18E-02</td>
<td>4.13E-02</td>
</tr>
<tr>
<td>270</td>
<td>6.31E-02</td>
<td>6.20E-02</td>
<td>6.13E-02</td>
</tr>
<tr>
<td>290</td>
<td>9.25E-02</td>
<td>9.09E-02</td>
<td>8.98E-02</td>
</tr>
<tr>
<td>310</td>
<td>1.34E-01</td>
<td>1.32E-01</td>
<td>1.31E-01</td>
</tr>
<tr>
<td>330</td>
<td>1.95E-01</td>
<td>1.93E-01</td>
<td>1.91E-01</td>
</tr>
<tr>
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<td>2.85E-01</td>
<td>2.84E-01</td>
</tr>
<tr>
<td>370</td>
<td>4.39E-01</td>
<td>4.41E-01</td>
<td>4.46E-01</td>
</tr>
<tr>
<td>390</td>
<td>8.86E-01</td>
<td>9.99E-01</td>
<td>1.00E+00</td>
</tr>
<tr>
<td>410</td>
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<td>510</td>
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<td>4.35E+00</td>
<td>4.33E+00</td>
</tr>
<tr>
<td>530</td>
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<td>4.90E+00</td>
<td>4.88E+00</td>
</tr>
<tr>
<td>550</td>
<td>4.46E+00</td>
<td>5.46E+00</td>
<td>5.43E+00</td>
</tr>
<tr>
<td>570</td>
<td>4.91E+00</td>
<td>6.02E+00</td>
<td>5.99E+00</td>
</tr>
</tbody>
</table>

Table 3.4 Gas-Liquid K values for C\textsubscript{2+}
Table 3.5 Liquid Viscosity Coefficients (from Tingas et al., 1996)

<table>
<thead>
<tr>
<th>Pseudo Component</th>
<th>(a_i)</th>
<th>(b_i)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>H(_2)O</td>
<td>7.52E-03</td>
</tr>
<tr>
<td>2</td>
<td>CH(_4)</td>
<td>1.38E-01</td>
</tr>
<tr>
<td>3</td>
<td>C(_7)</td>
<td>1.303E-01</td>
</tr>
<tr>
<td>4</td>
<td>CO(_2)</td>
<td>4.41E-02</td>
</tr>
<tr>
<td>5</td>
<td>N(_2)</td>
<td>1.41E-01</td>
</tr>
<tr>
<td>6</td>
<td>O(_2)</td>
<td>1.89E-01</td>
</tr>
</tbody>
</table>

Gas phase heat capacities were be estimated as a function of temperature according to the following correlation (Reid, Prausnitz, and Sherwood, 1977):

\[ C_{pg} = C_{pg1} + C_{pg2} \cdot T + C_{pg3} \cdot T^2 + C_{pg4} \cdot T^3 \quad (3.4) \]

where \(C_{pg1}\) to \(C_{pg4}\) are the heat capacity coefficients. Vaporization enthalpies were obtained as a function of temperature according to the following correlation:

\[ H_{vap}(T) = HVR \cdot (T_c - T)^{EV}, \quad (3.5) \]

where \(T\) is the temperature, \(T_c\) is the critical temperature for the component, \(EV\) is an exponent (=0.38) and \(HVR\) is the vaporization enthalpy coefficient. Heat capacities and vaporization enthalpies were calculated using the coefficients presented in Table 3.6 (Tingas et al., 1996).
Table 3.6 Heat Capacity and Vaporization Enthalpy Coefficients
(from Tingas et al., 1996)

<table>
<thead>
<tr>
<th>Pseudo Component</th>
<th>CPG1</th>
<th>CPG2</th>
<th>CPG3</th>
<th>CPG4</th>
<th>HVR</th>
</tr>
</thead>
<tbody>
<tr>
<td>1 H₂O</td>
<td>7.7</td>
<td>2.55E-04</td>
<td>7.78E-07</td>
<td>-1.47E-10</td>
<td>1657</td>
</tr>
<tr>
<td>2 CH₄</td>
<td>4.6</td>
<td>6.92E-03</td>
<td>6.83E-07</td>
<td>-4.64E-10</td>
<td>535</td>
</tr>
<tr>
<td>3 C₂+</td>
<td>0.04</td>
<td>-3.14E-03</td>
<td>9.12E-10</td>
<td>1.37E-10</td>
<td>1009</td>
</tr>
<tr>
<td>4 CO₂</td>
<td>4.73</td>
<td>9.74E-03</td>
<td>4.13E-06</td>
<td>7.03E-10</td>
<td>991</td>
</tr>
<tr>
<td>5 N₂</td>
<td>7.44</td>
<td>-1.80E-03</td>
<td>1.98E-06</td>
<td>-4.78E-10</td>
<td>438</td>
</tr>
<tr>
<td>6 O₂</td>
<td>6.71</td>
<td>-4.88E-07</td>
<td>1.29E-06</td>
<td>-4.36E-10</td>
<td>482</td>
</tr>
</tbody>
</table>

3.3.4 Chemical Reactions

The oxidation process during HPAI combustion involves many chemical reactions occurring over different temperature ranges. Unfortunately, there is little kinetic data for West Texas light oil. Zelenko and Solignac (1997) suggest that a single-reaction combustion model will not represent the complex in-situ combustion process adequately and Ambastha and Kumar (1999) found that a four-reaction model gave much higher cumulative oil production than that for a single-reaction model. However, the Ambastha and Kumar (1999) results showed that the difference in the results was not significant in the case of combustion tube simulations. All the research groups above stress that choosing an appropriate
combustion scheme will largely depend on proper fluid characterization and laboratory reaction kinetics studies.

In this study a direct oxidation scheme with 3 chemical reactions was needed to match combustion tube data. The reactions include:

- Light oil burning
- Gas burning
- Coke burning

This approach allows heat production to be represented by burning X amounts of oil and consuming Y amounts of oxygen consistent with combustion tube experiments. The following chemical reactions have been used in our study assuming a High and Medium Temperature Oxidation scheme. The stoichiometric coefficients were evaluated and adjusted based on component molecular weights and matching combustion tube data.

*Chemical Reaction 1:*

Light fraction cracking:

\[ \text{C}_2^+ \rightarrow 2.46 \text{CH}_4 + 4.92 \text{Coke} + \text{Energy} \]
Chemical Reaction 2:
Light fraction burning:
\[ C_{2+} + 4.11 \text{O}_2 \rightarrow 3.21 \text{H}_2\text{O} + 2.44 \text{CO}_2 + 0.13 \text{CO} + 3.86 \text{Coke} + \text{Energy} \]

Chemical Reaction 3:
Coke burning:
\[ \text{Coke} + 1.23 \text{O}_2 \rightarrow 0.5 \text{H}_2\text{O} + 1.1 \text{CO}_2 + 0.05 \text{CO} + \text{Energy} \]

Reaction kinetics provides information on the speed with which the reaction is proceeding. The general expression for the rate of reaction, \( r_k \), is:

\[
r_k = r_{r k} \cdot e^{-\frac{E_{ak}}{RT}} \cdot \Pi C_i^{e_k}, \tag{3.6}
\]

where
\( r_{r k} \) = reaction frequency factor, constant,
\( E_{ak} \) = activation energy,
\( R \) = universal gas constant,
\( T \) = temperature in the reaction region,
\( C_i \) = concentration factor contributed by the reacting component i, function of porosity, density, saturation and mole fraction of the component i, and
\( e_k \) = order of reaction with respect to component i.
The temperature term in the above equation is taken to be the averaged grid block temperature. However, for field-scale simulations with large grid block sizes, this will give a lower average temperature in the combustion zone and therefore will lead to faulty front temperatures. In Tingas et., al (1996), the activation energies are reduced to zero to make the reaction rate independent of the grid block temperature. However, Ren et al. (2001) indicate that the lower front temperatures generated due to coarse grid effects do not significantly affect the overall process for light oil combustion since repressurization of the reservoir is a dominant recovery mechanism. Consequently, the reaction kinetic data used for this study was based on history matching the combustion tube data without adjustment. These values are listed in Table 3.7.

<table>
<thead>
<tr>
<th>Reaction</th>
<th>Enthalpy Btu/lbmole</th>
<th>Reaction Frequency</th>
<th>Activation Energy for Kinetic Models Btu/lbmole</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>9.99E6</td>
<td>1.296E8</td>
<td>2.86E5</td>
</tr>
<tr>
<td>2</td>
<td>1.10E7</td>
<td>1.56E9</td>
<td>8.96E4</td>
</tr>
<tr>
<td>3</td>
<td>2.35E6</td>
<td>2.28E5</td>
<td>6.98E4</td>
</tr>
</tbody>
</table>

Table 3.7 Kinetic Parameters for 3-Reaction Combustion Scheme
3.3.5 Reservoir Initial Conditions

The simulation was initiated with the conditions outlined in Table 3.8. Reservoir properties are based on present day measurements as discussed in section 3.3, which represent depleted conditions.

<table>
<thead>
<tr>
<th>Initial Reservoir Pressure</th>
<th>1600 psi</th>
</tr>
</thead>
<tbody>
<tr>
<td>Initial Reservoir Temperature</td>
<td>200 °F</td>
</tr>
</tbody>
</table>
| Initial Water Saturation | Layer 1: 0.62  
Layer 2: 0.56  
Layer 3: 0.46  
Layer 4: 0.35  
Layer 5: 0.42  
Layer 6: 0.31 |

Table 3.8 Reservoir Initial Conditions

3.3.6 Numerical Control

The defaults used in the simulator provide a robust and efficient way to simulate most simulation problems (STARS Manual, 2003.10). The default convergence criterion uses the residual averaged over all the grid blocks to control the final material balance error. Typical changes in temperature, pressure, and saturation during a time step are identified. These are used for automatic time step selection. The simulator chooses automatic time step cutting, if the convergence criteria are not met. The method of repeated time step cutting is used to achieve convergence.
in grid blocks covering the combustion front. All the grid blocks were treated in a fully implicit manner for both mass and energy balances.

3.3.7 Well Data

Both vertical and horizontal well arrangements were studied. The injector as described in section 3.1 was operated with pressure control at 5000 psi for both waterflood and HPAI simulations. For waterflood cases this usually resulted in an injection rate of 100 to 150 bbls/day (see Appendix 2). For the HPAI cases, the air injection rate was around 250 to 500 Mcfd. For the fractured well cases, the 5000 psi pressure control resulted in 400 bbl/day of water injection, while for the HPAI the air injection rate was 1500 Mcfd. The producer was operated under pressure control at 50 psi. Backflow was not a problem, since the injection pressure (5000 psi) was well above the reservoir pressure (1600 psi) and the production well pressure (50 psi) was well below the same. The well indices were calculated internally based on a radial inflow well model (STARS Manual, 2003.10). The radial inflow well model couples the pressure in the wellbore to the average grid block pressure. The grid block is deemed to have an effective radius, and the radial flow equation is solved between the effective block radius and the wellbore radius for an equivalent proportionality factor called the well index. The effective wellbore radius is defined as:

\[
r_c = CC \sqrt{\frac{\Delta x^2 + \Delta y^2}{f\pi}},
\]

(3.7)
where $\Delta x$ and $\Delta y$ are block dimensions in the plane perpendicular to the well. CC is a factor depending upon the geometry of the situation, which for our study was 0.249. $f$ is the well fraction, which is 1 for wells going approximately through the center of the grid block.

### 3.3.8 Simulation Times

All the simulations were run for 3650 (10 years). The well and field data was reported at 50 day intervals for the first 100 days. Thereafter the data was reported every 200 to 300 days. Results for the field simulation runs follow in the next chapter.
CHAPTER 4

4.1 Simulation Results

Simulation studies were conducted with two types of injection fluids, water and air. The objective of these studies was to investigate numerically the potential of HPAI to displace oil versus a typical waterflood program. Steam injection for reservoir depths of 9000 ft is considered impractical. These simulations were performed for a variety of reservoir conditions: a homogeneous reservoir, a layered reservoir, and a layered reservoir with fractures. Both vertical and horizontal well arrangements were used. A summary of results for each case with relevant plots is presented below.

4.2 Homogeneous Reservoir

To investigate the effects of gravity segregation and gas override for waterflood and air injection respectively, a homogeneous reservoir with single porosity and permeability values was simulated. The 30x30x6 simulation grid with vertical wells discussed in section 3.3.1 in Chapter 3 was employed. Only the following properties were changed in the simulation model discussed earlier.

- Porosity: 5%
- Horizontal Permeability: 3 md
- Vertical Permeability: 1 md
- Water Saturation: 45%
Table 4.1 summarizes the results obtained for waterflood and air injection in a homogeneous reservoir.

<table>
<thead>
<tr>
<th>Prediction Run</th>
<th>Cumulative Production</th>
<th>Final Oil Recovery</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Oil, MBBL</td>
<td>Gas (CH₄), MMSCF</td>
</tr>
<tr>
<td>Water Flood</td>
<td>112</td>
<td>0</td>
</tr>
<tr>
<td>Air Flood (No Combustion)</td>
<td>134</td>
<td>0</td>
</tr>
<tr>
<td>Air Flood</td>
<td>146</td>
<td>26</td>
</tr>
</tbody>
</table>

Table 4.1 HPAI Vs Waterflood in a Homogeneous Reservoir

4.2.1 Water Flood

Waterflood operation was run for a total of 3650 days. Total oil recovered at the end of the program was 112 Mbbl. Water breakthrough happened at around 1000 days. Figure 4.1 is a plot with all the relevant waterflood parameters obtained during the simulation. Figures for injection and production rate profiles are available in the appendix. Figure 4.2 is a water saturation snapshot for the reservoir at the end of run (3650 days). The water saturation in the lower part of the grid appears to be a little higher depicting a certain water gravity underride. Ultimate oil recovery was 59%.
Figure 4.1 Homogeneous waterflood.

Figure 4.2 Water saturation at 3600 days (Gravity Segregation).
4.2.2 HPAI

Air Injection is found to be much better than the waterflood program. Total oil recovered at the end of run was 146 Mbbl. Methane gas recovered is 26 MMSCF. Approximately 6000 cu ft of natural gas equals 1 bbl of oil equivalent (www.usgs.gov). Therefore, the ultimate recovery was calculated to be around 80% (with the gas). Figure 4.3 shows the relevant air injection parameters recorded during the run. Figure 4.4 shows the gas saturation at the end of run depicting some gas gravity override near the producer. To prevent this phenomenon, water injection immediately after air injection (wet combustion) is usually employed. To investigate the effectiveness of the combustion operation, air injection without combustion was performed and a total oil recovery of 134 Mbbl was registered. No gas was produced during this run (Figure 4.5). Ultimate recovery was 70%. This was about 10% less than the case with combustion confirming the advantage of in-situ combustion over gas injection without combustion.
Figure 4.3 Homogeneous HPAI (with combustion).

Figure 4.4 Gas saturation at 3600 days (Gas Override).
4.3 Layered Reservoir: Vertical Wells

The 6-layered reservoir model (30x30x6) discussed in sections 3.3.1 through 3.3.8 with different permeability-porosity characteristics for each layer was employed here. Comparisons between waterflood and air injection processes were drawn with combustion and these will be compared further with the results obtained from a naturally fractured reservoir model study. Table 4.2 below presents the results for the water flood and air flood simulation runs carried out in this reservoir with vertical wells. Recovered CH$_4$ gas was not accounted for in the oil recovery calculations.
<table>
<thead>
<tr>
<th>Prediction</th>
<th>Cumulative Production</th>
<th>Final Oil Recovery</th>
</tr>
</thead>
<tbody>
<tr>
<td>Run</td>
<td>Oil, MBBL</td>
<td>Gas, (CH₄), MMSCF</td>
</tr>
<tr>
<td>Water Flood</td>
<td>112</td>
<td>0</td>
</tr>
<tr>
<td>Air Flood</td>
<td>144</td>
<td>24</td>
</tr>
</tbody>
</table>

Table 4.2 HPAI Vs Waterflood in a Layered Reservoir

4.3.1 Water Flood

Water injection rate of 200 bbl/day was specified for the vertical injector along with a pressure constraint of 5000 psi. The simulation was run for 3650 days. Figure 4.6 shows the relevant waterflood results. Water breakthrough was achieved at the producer at about 1000 days with the water cut increasing to 92% at the end of run. Cumulative oil recovered at the end of the simulation was 112 Mbbl. Figures 4.7 and 4.8 are water saturation snapshot for the reservoir at the end of run (3650 days). The high permeability zones (layers 3 and 5) appear to have been swept better ($S_w=0.82$) than the other zones.
Figure 4.6 Layered Reservoir Waterflood

Figure 4.7 Water Saturation at 3600 days -1 (fraction)
4.3.2 HPAI

An injection rate of 1.5 MMSCF/day was specified for the injector along with pressure constraint of 5000 psi. The simulation was run for 3650 days. Figure 4.9 is a plot for various air injection parameters recorded during the combustion run. Gas breakthrough was achieved at the producer in the third layer at around 2600 days of the combustion run, much later than water breakthrough for the waterflood case. Figures for injection and production rate profiles are available in the appendix. The cumulative oil production begins to plateau at the end of run at 144 Mbbl. However, the gas production rate continues to increase with time. Cumulative methane gas production after 3650 days was 24 MMSCF. Ultimate recovery was about 79% (including gas). This is about 20% better than the
waterflood program (59%). Figures 4.10 through 4.12 show the gas saturation maps at 200, 1500 and 3650 days. No gas override effects are noted for this case. Sweep in the high permeability zones appears to be considerably better than the low permeability zones. Figure 4.13 presents the 2D temperature maps for the reservoir at 50, 100, 400 and 1000 days. Temperature change also follows the high permeability regions. A peak temperature of 1067 °F was registered during combustion. Figures 4.14 and 4.15 depict the reservoir temperature and pressure at the end of run.
Figure 4.9 Layered Reservoir HPAI

Figure 4.10 Gas Saturation at 200 days (fraction)
Figure 4.11 Gas Saturation at 1500 days (fraction)

Figure 4.12 Gas Saturation at 3650 days (fraction)
Figure 4.13 Temperature maps at 50, 100, 400 and 1000 days (°F)
(from the X-Z plane)
Figure 4.14 Reservoir Temperature map at 3650 days (°F)

Figure 4.15 Reservoir Pressure map at 3650 days (psi)
4.4 Layered Reservoir: Vertical Injector – Horizontal Producer

A vertical injector-horizontal producer pair was next utilized to investigate the advantage derived by using a 330 ft horizontal producer. The horizontal well was established in the fifth layer, which had high porosity and permeability characteristics (Figure 4.16). Table 4.3 presents the results obtained for the water flood and air flood simulation runs carried out in this reservoir. Again, recovered CH₄ gas was not accounted for in the final oil recovery calculations. However, recovered gas adds to a higher oil recovery from air injection. Approximately 6000 cu ft of natural gas equals 1 bbl of oil equivalent (www.usgs.gov).

![Figure 4.16 Horizontal Producer Arrangement](image)

<table>
<thead>
<tr>
<th>Prediction</th>
<th>Cumulative Production</th>
<th>Final Oil Recovery</th>
</tr>
</thead>
<tbody>
<tr>
<td>Run</td>
<td>Oil, MBBL</td>
<td>Gas (CH₄), MMSCF</td>
</tr>
<tr>
<td>Water Flood</td>
<td>120</td>
<td>0</td>
</tr>
</tbody>
</table>
| Air Flood  | 151                   | 34.6               | 42.4        | 79.5%

Table 4.3 HPAI Vs Waterflood with a Horizontal Producer
4.4.1 Water Flood – Horizontal Producer

When a horizontal well was employed, water breakthrough occurred at the producer more quickly (at about 600 days) with the water cut increasing to 96% at the end of run. Cumulative oil recovered at the end of the simulation was 120 Mbbl, a little more than in the case of vertical producer. A final oil recovery of 63% was achieved (4% more than the vertical producer case). Figure 4.17 below is a plot with all the relevant waterflood parameters obtained during the simulation. Figure 4.18 shows the reservoir water saturation map at the end of run. The sweep in the high permeability layers (3 and 5) is higher than other layers. High permeability streaks tend to deteriorate the waterflood performance. However, this could be improved by putting the producer in a lower permeability zone.

4.4.2 HPAI – Horizontal Producer

Gas production steadily rose at the horizontal producer from around 1000 days. Total oil recovered at the end of run stood at 151 Mbbl. CH₄ gas production rate continued to increase with time. Cumulative methane gas production at end of run stood at 34.6 MMSCF. Ultimate recovery achieved was about 82.5% (with gas). This is about 5% more than the vertical producer case previously reported. Application of horizontal wells indeed improves the ultimate resource recovery. Figure 4.19 is a plot for various air injection parameters recorded during the combustion run. Figures 4.20 through 4.22 show the gas saturations at various times during the run. As noted earlier, high permeability zones exhibit better
Figure 4.17 Waterflood with Horizontal Producer

Figure 4.18 Reservoir Water Saturation at 3650 days
Figure 4.19 HPAI with Horizontal Producer

Figure 4.20 Reservoir Gas Saturation at 200 days
Figure 4.21 Reservoir Gas Saturation at 2000 days

Figure 4.22 Reservoir Gas Saturation at 3650 days
50 days (Injector)  
2000 days (Horizontal Producer) 

200 days (Injector)  
2500 days (Horizontal Producer) 

1000 days (Injector)  
3650 days (Horizontal Producer) 

Figure 4.23 Reservoir Temperature at various times (F)
sweep efficiency. There was no sign of gas override. Figure 4.23 shows the temperature in the reservoir at various times into the simulation. The temperature advance is concentrated in the high permeability zone compared to the vertical well case from section 4.3. Figure 4.24 shows the pressure in the reservoir at the end of run.

4.5 Fractured (Dual Permeability) Reservoir: Vertical Wells

The Barnhart field is postulated to be naturally fractured and karsted. To study the impact of natural fractures, dual permeability characteristics were introduced into the layered reservoir model used before. Table 4.4 summarizes the oil recovery figures for a waterflood and air injection in a fractured reservoir.
Table 4.4 HPAI Vs Waterflood in Fractured Reservoir

<table>
<thead>
<tr>
<th>Prediction</th>
<th>Cumulative Production</th>
<th>Final Oil Recovery</th>
</tr>
</thead>
<tbody>
<tr>
<td>Run</td>
<td>Oil, MBBL</td>
<td>Gas (CH₄), MMSCF</td>
</tr>
<tr>
<td>Water Flood</td>
<td>68</td>
<td>0</td>
</tr>
<tr>
<td>Air Flood</td>
<td>149</td>
<td>54.6</td>
</tr>
</tbody>
</table>

### 4.5.1 Water Flood

For fractured reservoir, a waterflood program gave poor results. Water breakthrough was achieved at the producer in the first 100 days with the water cut increasing to 96% half way through the simulation run. Cumulative oil recovered at the end of the simulation was 68 Mbbl. A final oil recovery of 30.6% was recorded. This is the direct result of the severe channeling that occurs during the waterflood process. Figure 4.25 shows the oil recovery profile for this case. Figure 4.26 shows the reservoir water saturation in the matrix and fracture at the end of run. Severe gravity segregation occurs in the matrix due to the presence of the fractures. Very poor reservoir sweep is noted in this case.

### 4.5.2 HPAI

Figure 4.27 shows the oil and gas recovery profiles for a fractured reservoir. Total oil recovered at the end of the run stood at 149 Mbbl. CH₄ gas production rate continued to increase with time. Cumulative methane gas production recorded at end of run was 54.6 MMSCF. Ultimate resource recovery of 71.2% (with gas)
Figure 4.25 Waterflood in Fractured Reservoir

Figure 4.26 Reservoir Water Saturation at 3650 days
Figure 4.27 HPAI in Fractured Reservoir

Figure 4.28 Reservoir Gas Saturation at 600 days
Matrix                                                   Fractures

Figure 4.29 Reservoir Gas Saturation at 1800 days

Matrix                                                   Fractures

Figure 4.30 Reservoir Gas Saturation at 3650 days

Matrix                                                   Fractures

Figure 4.31 Reservoir Temperature at 3650 days

88
was reported at the end of run. This is lower than reported for the unfractured case (78%) and can be attributed to the gas channeling effects occurring in the reservoir. Figures 4.28 through 4.30 show the gas saturations at various times during the run. A certain element of gas underride can be observed. This is most probably due to the presence of the fracture network throughout the reservoir. Temperature maps for the reservoir are shown in figure 4.31. Temperature profiles in the matrix and fracture remain more or less the same depicting a stable combustion front propagation through the reservoir.

### 4.6 Fractured Reservoir: Vertical Injector – Horizontal Producer

The fractured reservoir case was now run with a 330 ft horizontal producer as discussed in section 4.5 above. Table 4.5 summarizes the results obtained in this case.

<table>
<thead>
<tr>
<th>Prediction</th>
<th>Cumulative Production</th>
<th>Final Oil Recovery</th>
</tr>
</thead>
<tbody>
<tr>
<td>Run</td>
<td>Oil, MBBL</td>
<td>Gas (CH₄), MMSCF</td>
</tr>
<tr>
<td>Water Flood</td>
<td>23.8</td>
<td>0</td>
</tr>
<tr>
<td>Air Flood</td>
<td>168.5</td>
<td>46.8</td>
</tr>
</tbody>
</table>

Table 4.5 HPAI Vs Waterflood in Fractured Reservoir with a Horizontal Producer
4.6.1 Water Flood

For fractured reservoir with a horizontal well, a waterflood program gave even more disappointing results than the vertical producer case discussed earlier. Water breakthrough was achieved at the horizontal producer in the first 10 days with the water cut increasing to 96%. Cumulative oil recovered at the end of the simulation was a mere 23.8 Mbbl. A final oil recovery of 10.7% was recorded. This clearly demonstrates that waterflooding does not work well as implemented in these simulation configurations. Figure 4.32 shows the oil recovery profile for this case. Figure 4.33 shows the reservoir water saturation in the matrix and fracture at the end of run. As in the previous case, severe gravity segregation takes place in the matrix and very poor reservoir sweep is observed.

4.6.2 HPAI

Figure 4.34 shows the oil and gas recovery profiles for a fractured reservoir under HPAI. Total oil recovered at the end of run stood at 168.5 Mbbl. Cumulative methane gas production recorded at end of run was 46.8 MMSCF. Combustion seems to work quite well in fractured reservoirs with horizontal producer. An ultimate recovery of about 80% was reported for this case. Figures 4.35 through 4.37 show the gas saturations at various times during run. Temperature maps for the reservoir at the end of run are shown in figure 4.38. These indicate a stable front propagation through the reservoir. Issues like gas override and channeling are virtually nonexistent in this case.
Figure 4.32 Waterflood in Fractured Reservoir with Horizontal Producer

Figure 4.33 Reservoir Water Saturation at 3650 days
Figure 4.34 HPAI in Fractured Reservoir with Horizontal Producer

Figure 4.35 Reservoir Gas Saturation at 600 days
Matrix Fractures

Figure 4.36 Reservoir Gas Saturation at 2000 days

Matrix Fractures

Figure 4.37 Reservoir Gas Saturation at 3650 days

Matrix Fractures

Figure 4.38 Reservoir Temperature at 3650 days

93
4.7 Summary

Table 4.6 summarizes the results obtained from all the cases studied above. In general, HPAI performs better than waterflood for the well arrangements used. However, implementation of well optimization studies may further change the recovery profiles for both waterflood and HPAI.

<table>
<thead>
<tr>
<th>Type of Run</th>
<th>Prediction Run</th>
<th>OOIP MBBL</th>
<th>Cumulative Production</th>
<th>Final Oil Recovery</th>
<th>Ultimate Recovery (With Gas)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Homo.</td>
<td>Water Flood</td>
<td>177</td>
<td>112, 0, 156</td>
<td>63 %</td>
<td>63 %</td>
</tr>
<tr>
<td>Vertical</td>
<td>Air Flood</td>
<td></td>
<td>146, 26, 16</td>
<td>82.5 %</td>
<td>85 %</td>
</tr>
<tr>
<td>Layered</td>
<td>Water Flood</td>
<td>190</td>
<td>112, 0, 139</td>
<td>59 %</td>
<td>59 %</td>
</tr>
<tr>
<td>Vertical</td>
<td>Air Flood</td>
<td></td>
<td>144, 24, 14</td>
<td>76 %</td>
<td>78 %</td>
</tr>
<tr>
<td>Layered</td>
<td>Water Flood</td>
<td></td>
<td>120, 0, 287</td>
<td>63 %</td>
<td>63 %</td>
</tr>
<tr>
<td>Horizontal</td>
<td>Air Flood</td>
<td></td>
<td>151, 34.6, 42.4</td>
<td>79.5 %</td>
<td>82.5%</td>
</tr>
<tr>
<td>Fractured</td>
<td>Water Flood</td>
<td>222</td>
<td>68, 0, 1407</td>
<td>30.6 %</td>
<td>30.6 %</td>
</tr>
<tr>
<td>Vertical</td>
<td>Air Flood</td>
<td></td>
<td>149, 54.6, 111</td>
<td>67 %</td>
<td>71.2%</td>
</tr>
<tr>
<td>Fractured</td>
<td>Water Flood</td>
<td></td>
<td>23.8, 0, 1454</td>
<td>10.7 %</td>
<td>10.7 %</td>
</tr>
<tr>
<td>Horizontal</td>
<td>Air Flood</td>
<td></td>
<td>168.5, 46.8, 95</td>
<td>76 %</td>
<td>79.4%</td>
</tr>
</tbody>
</table>

Table 4.6 Summary of all simulation runs
CHAPTER 5

Conclusion
A reservoir simulation study for High Pressure Air injection (HPAI) in a naturally fractured light-oil reservoir has been completed. The results obtained from this investigation give a better understanding for the implementation air injection process in the Barnhart stratified reservoir. The model consisted of a injector-producer pair of a quarter of a 5-spot pattern about 930ft apart. Three reservoir descriptions were studied: a homogeneous reservoir, a layered reservoir and a naturally fractured reservoir. Two well arrangements were employed: vertical injector-producer and vertical injector-horizontal producer. Two types of injection fluids were used: water and air. A Total of seven fluid components and one solid component were utilized in the combustion model. Oil and rock properties were obtained from laboratory tests and well logs made available previously for the reservoir under study. Relative permeability data was obtained by matching the available laboratory combustion tube data. Chemical reaction kinetics data was obtained from available accelerated rate calorimetry (ARC) test and adjusted by matching laboratory combustion tube data.

For the homogeneous reservoir case, a small amount of water gravity segregation was observed, while for the air injection case gas override was very evident. However, gas override was not observed in the layered reservoir and fractured reservoir models. This may be due to the fact that the reservoir had high
permeability streaks sandwiched between low permeability ones. For all the cases, good reservoir sweep for water flood and air injection was observed in the high permeability zones. However, waterflood studies in the fractured reservoir with these high permeability zones resulted in very low oil recoveries (as low as 11%) due to severe channeling in the fractures, rendering the waterfloods ineffective. On the other hand, air injection in fractured reservoirs resulted in stable combustion front propagation through the reservoir and yielding high ultimate oil recoveries (as high as 80%).

To further improve the understanding of the air injection process in the field, various sensitivity analyses such as use of different vertical to horizontal permeability ratios, use of different types of well arrangements, injection of enriched oxygen air, cyclic water and air injection (wet combustion) is suggested. This simulation study shows that the reservoir under study is a very good candidate for High Pressure Air Injection. Application of horizontal well technology will further the ultimate resource recovery from the reservoir. However, incorporating accurate reservoir characterization studies and detailed combustion kinetics into the simulation model will ultimately decide the applicability and profitability of the HPAI process on a large scale.
APPENDIX 1

CMG STARS Keyword Input File
Fractured Reservoir with Horizontal Producer

** ==== INPUT/OUTPUT CONTROL =========================

*TITLE1 'STARS HPAI MODEL'
*TITLE2 'BARNHART ELLENBURGER RESERVOIR'
*TITLE3 'COMBUSTION'
*INUNIT *SI
*OUTUNIT *FIELD
**CHECKONLY
*INTERRUPT *STOP
*WRST 300
*WPRN *GRID 300
*WPRN *ITER 300
*OUTPRN *WELL *ALL
*OUTPRN *GRID *PRES *SW *SO *SG *TEMP *Y *X *SOLCONC *OBHLOSS *VISO
*CCHLOSS
*OUTSRF *WELL *MASS *MOLE *COMPONENT *ALL *DOWNHOLE
*OUTSRF *GRID *PRES *SW *SO *SG *TEMP *Y *X *W *SOLCONC *OBHLOSS
*MASDENW *MASDENO *MASDENG *PCOW *PCOG *VISW *VISO *VISG *KRW
*KRO *KRG *KVALYW *KVALYX *CMPDENW *CMPDENO *CMPVISW *CMPVISO
*CMPVISG *CCHLOSS

*OUTSRF *SPECIAL

*MATBAL REACTION 'WATER'
*MATBAL REACTION 'LITE'
*MATBAL REACTION ENERGY
*VOLFRAC 'PRODUCER' 'LITE'
*VOLFRAC 'PRODUCER' 'WATER'
*VOLFRAC 'PRODUCER' 'CO2'
*VOLFRAC 'PRODUCER' 'OXYGEN'
*MASSFRAC 'PRODUCER' 'LITE'
*MASSFRAC 'PRODUCER' 'WATER'
*MASSFRAC 'PRODUCER' 'CO2'
*MASSFRAC 'PRODUCER' 'OXYGEN'
*MOLEFRAC 'PRODUCER' 'LITE'
*MOLEFRAC 'PRODUCER' 'WATER'
*MOLEFRAC 'PRODUCER' 'CO2'
*MOLEFRAC 'PRODUCER' 'OXYGEN'
**==== GRID AND RESERVOIR DEFINITION =======================**

GRID CART 30 30 6
KDIR DOWN
DI CON 6.7056 **22FT **3.3528
DJ CON 6.7056 **3.3528
DK KVAR 4.88 5.79 3.35 5.18 4.88 3.96 ** 16 19 11 17 16 13 FT TOTAL 92 FT
DUALPERM
DIFRAC CON 10
DJFRAC CON 10
DJFRAC CON 0
**MATRIX
POR  MATRIX KVAR 0.04 0.04 0.08 0.05 0.07 0.05
PERMI  MATRIX KVAR 0.9 1.0 8.11 1.67 5.42 1.22
PERMJ  MATRIX KVAR 0.9 1.0 8.11 1.67 5.42 1.22
PERMK  MATRIX CON 1

**FRACTURE
POR FRACTURE CON 0.01
PERMI FRACTURE CON 100
PERMJ FRACTURE CON 100
PERMK FRACTURE CON 0
END-GRID
*PRPOR 26656
*CPOR 3.0E-06

** ============= THERMAL AND HEATLOSS PROPERTIES OF THE ROCK
ROCKTYPE 1 ** MATRIX

*ROCKCP 2.35E+06 0.
*THCONR 1.5E+05 *THCONW 5.35E+04 *THCONO 1.2E+04 *THCONG 3.2E+03
*HLOSST 16.
*HLOSSPROP *OVERBUR  2.350E6 1.496E5
*HLOSSPROP *UNDERBUR  2.350E6 1.496E5

ROCKTYPE 2 ** FRACTURE

*ROCKCP 0 ** FRACTURE DOES NOT CONTAIN ROCK
*THCONR 0 *THCONW 5.35E+04 *THCONO 1.2E+04 *THCONG 3.2E+03
*HLOSST 16.
*HLOSSPROP *OVERBUR  2.350E6 1.496E5
*HLOSSPROP *UNDERBUR  2.350E6 1.496E5

**============COMPONENT PROPERTIES
=================================================================
*MODEL 8 7 5 1
*COMPNAME 'WATER' 'LITE' 'CH4' 'CO2' 'CO' 'N2' 'OXYGEN' 'COKE'
*KV1  0.E+00  0.E+00  5.454683E+05  1.19950E+05  0
*KV3  0.E+00  0.E+00  0.E+00  4.55E+00  0
*KV4  0.E+00  0.E+00  -8.7984E+02  -2.368E+02  0
*KV5  0.E+00  0.E+00  -2.65E+02  -7.91E+01  0
*CMM   0.01802  0.125  0.016  0.044  0.028  0.028  0.032  0.0174
*TCRIT  3.743E+2  6.59E+2  -8.2E+1  3.0E+1  -1.40E+2  -1.47E+2  -1.20E+2
*SOLID_DEN 'COKE' 1.740E+3  0.0E+0  0.0E+0

*SOLID_CP 'COKE' 1.7E+1  0.0E+0

*CPL1  0.0E+0  1.060E+3  1.925E+1  1.979E+1  3.114E+1  3.114E+1  2.81E+1
*CPL2  0.0E+0  0.0E+0  5.211E-2  7.34E-2  -1.356E-2  -1.356E-2  -3.7E-6
*CPL3  0.0E+0  0.0E+0  1.197E-4  5.6E-5  2.678E-5  2.678E-5  4.745E-5
*CPL4  0.0E+0  0.0E+0  -1.131E-8  1.715E-8  -1.167E-8  -1.167E-8  -1.065E-8
*HVR    1657  1009  535  991  438
*EV     0  1  0.38  0.38  0.38
*AVG    1.7E-5  1.0573E-4  1.0573E-4  1.07E-4  3.213E-4  3.213E-4  3.355E-4
*BVG    1.116E+0  8.2E-1  8.126E-1  8.655E-1  7.02E-1  7.02E-1  7.21E-1

*AVISC  0  .1303  1.38E-1  4.41E-2  1.41E-1  ** 1.89E-1  .1303  0.0599
*BVISC  0  800  114.14  578.08  90.30  **85.68  800  194.2

*PRSR   2750

101
*TEMR  16
*PSURF  1.01E+2
*TSURF  1.6E+1
*XNACL  0

*MOLDEN  0.0E+0 6.400E+3 5.91997E+4 1.81036E+4 1E4
*CP  0.0E+0 1.0E-6 1.0E-6 1.0E-6 1E-6
*CT1  0.0E+0 8.48E-4 8.48E-4 8.48E-4 8.48E-4
*CT2  0.0E+0 0.0E+0 0.0E+0 0.0E+0 0

** CHEMICAL REACTIONS

** ===== REACTION 1  LITE --> CH4 + COKE
*STOREAC  0.0  4.064  0.0  0.0  0.0  0.0  0.0  0.0
*STOPROD  0.0  0.0  10.0  0.0  0.0  0.0  0.0  20.0
*FREQFAC  1.296E+8
**FREQFAC  1.296E+19
*EACT  2.86E5 **2.36E+05
*RENTH  9.99E+06 **RENTH  6.86E+06
*RPHASE  0 2 0 0 0 0 0 0
*RORDER  0 1 0 0 0 0 0 0
*O2PP
*RT EMLOWER  6.86 *RT EMUPR  1500.
** ===== REACTION 2  LITE + O2 --> H2O + CH4 + CO2 + CO + COKE
*STOREAC  0.0  3.89  0.0  0.0  0.0  0.0  16.0  0.0
*STOPROD  12.5  0.0  5.0  9.5  0.5  0.0  0.0  15.0
*FREQFAC  1.56E+9 **4.56E+9
*EACT    8.96E4 **8.41E4
**RENTH  6.29E+06
*RENTH  9.99E+06
*RPHASE  0 2 0 0 0 0 3 0
*RORDER  0 1 0 0 0 0 1 0
*O2PP
*RTEMLOWR  6.86 *RTEMUPR  250.
*RXCRITCON 'OXYGEN' 1

** ===== REACTION 3  COKE + O2 --> H2O + CO2 + CO
*STOREAC  0.0  0.0  0.0  0.0  0.0  0.0  1.225  1.0
*STOPROD  0.5  0.0  0.0  1.08  0.05  0.0  0.0  0.0
*FREQFAC  2.28E+05 **2.28E+05
*EACT    6.98E4 **9.55E4 **5.13E5 **5.13E+04
**RENTH  5.58E+05
*RENTH  2.35E6 **2.25E5 **9.75E6 **5.58E+05
*RPHASE  0 0 0 0 0 0 3 4
*RORDER  0 0 0 0 0 1.0 1.0
*O2PP
**K VALUES FOR LITE OIL**

*KVTABLE 'LITE'*

| 5.17E-04 | 5.35E-04 | 5.54E-04 |
| 1.09E-03 | 1.11E-03 | 1.14E-03 |
| 2.12E-03 | 2.15E-03 | 2.18E-03 |
| 3.89E-03 | 3.91E-03 | 3.93E-03 |
| 6.76E-03 | 6.75E-03 | 6.76E-03 |
| 1.12E-02 | 1.12E-02 | 1.11E-02 |
| 1.80E-02 | 1.78E-02 | 1.77E-02 |
| 2.80E-02 | 2.76E-02 | 2.74E-02 |
| 4.24E-02 | 4.18E-02 | 4.13E-02 |
| 6.31E-02 | 6.20E-02 | 6.13E-02 |
| 9.25E-02 | 9.09E-02 | 8.98E-02 |
| 1.34E-01 | 1.32E-01 | 1.31E-01 |
| 1.95E-01 | 1.93E-01 | 1.91E-01 |
| 2.87E-01 | 2.85E-01 | 2.84E-01 |
| 4.39E-01 | 4.41E-01 | 4.46E-01 |
| 8.86E-01 | 9.99E-01 | 1.00E+00 |
| 1.33E+00 | 1.56E+00 | 1.55E+00 |
| 1.78E+00 | 2.11E+00 | 2.11E+00 |
| 2.23E+00 | 2.67E+00 | 2.66E+00 |
| 2.67E+00 | 3.23E+00 | 3.22E+00 |
| 3.12E+00 | 3.79E+00 | 3.77E+00 |
| 3.57E+00 | 4.35E+00 | 4.33E+00 |
| 4.01E+00 | 4.90E+00 | 4.88E+00 |
| 4.46E+00 | 5.46E+00 | 5.43E+00 |
| 4.91E+00 | 6.02E+00 | 5.99E+00 |
** ====== ROCK-FLUID PROPERTIES ==============

*ROCKFLUID

*RPT 1 ** MATRIX

*SWT

**WATER-OIL SYSTEM

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<tr>
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<th>KROW</th>
<th>PC</th>
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*SLT

**GAS-LIQUID SYSTEM

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<th>KROG</th>
<th>PC</th>
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0.7415 0.0070 0.2200 0.0000
0.7934 0.0045 0.3000 0.0000
0.8452 0.0026 0.4400 0.0000
0.8970 0.0016 0.6000 0.0000
0.9280 0.0006 0.8400 0.0000
0.9389 0.0003 0.9300 0.0000
0.9500 0.0000 1.0000 0.0000

*RPT 2  ** FRACTURE

*SWT

**WATER-OIL SYSTEM

**  SW    KRW    KROW    PC
0.0    0.0000    1.0000    0.0000
1.0    1.0000    0.0000    0.0000

*SLT

**GAS-LIQUID SYSTEM

**  SL    KRG    KROG    PC
0.0000    1.0000    0.0000    0.0000
1.0000    0.0000    1.0000    0.0000
** ASSIGN REL PERM SETS

KRTYPE MATRIX CON 1
KRTYPE FRACTURE CON 2

** ============== INITIALIZATION ================

*INITIAL
*PRES MATRIX *CON 10880  ** KPA
*PRES FRACTURE *CON 10880
*TEMP MATRIX *CON 93.0  ** C
*TEMP FRACTURE *CON 93.0
*SW MATRIX  KVAR 0.62 0.56 0.46 0.35 0.42 0.31
*SW FRACTURE  KVAR 0.62 0.56 0.46 0.35 0.42 0.31  **CON 0.25
*SO MATRIX  KVAR 0.38 0.44 0.54 0.65 0.58 0.69
*SO FRACTURE  KVAR 0.38 0.44 0.54 0.65 0.58 0.69  **CON 0.75

** ============== NUMERICAL CONTROL ================

*NUMERICAL
RUN

** ============== RECURRENT DATA ================

TIME 0

DTWELL 0.01
WELL  1 'PRODUCER'
PRODUCER 'PRODUCER'
OPERATE MIN BHP  340. CONT REPEAT

**MONITOR TEMP 600 STOP
**       RAD  GEOFAC  WFRAC  SKIN
GEOMETRY K 0.1524 0.249 1. 0.
PERF GEO  'PRODUCER'
         1 1 1:5 1. 
         1:15 1 6 1. 

WELL  2 'INJECTOR'
INJECTOR UNWEIGHT 'INJECTOR'
TIN JW 50.
INCOMP GAS  0.0 0.0 0.0 0.0 0.0 0.0 0.79 0.21
OPERATE BHP  34000
OPERATE STG  4.248E4 **2.124E+04 CONT REPEAT  1.5E6 FT3/DAY

**       RAD  GEOFAC  WFRAC  SKIN
GEOMETRY K 0.1524 0.249 1. 0.
PERF GEO  'INJECTOR'
** PARTIAL COMPLETIONS THROUGH A GRID BLOCK. YOU MAY USE FF = 0 TO
INDICATE A SHUT-IN LAYER.
30 30 1.6 1.

TIME 50  ** DAYS
TIME 100
TIME 200
TIME 400
TIME 600
TIME 800
TIME 1000
TIME 1200
TIME 1500
TIME 1800
TIME 2000
TIME 2500
TIME 2800
TIME 3000
TIME 3200
TIME 3650

STOP
APPENDIX 2

The following figures represent the injection and production rate patterns for the simulation runs described in Chapter 4.

Figure 1 Homogeneous Waterflood

Figure 2 Homogeneous HPAI
Figure 3 Layered Waterflood

Figure 4 Layered HPAI
Figure 5 Layered Waterflood with Horizontal Producer

Figure 6 Layered HPAI with Horizontal Producer
Figure 7 Fractured Waterflood

Figure 8 Fractured HPAI
Figure 9 Fractured Waterflood with Horizontal Producer

Figure 10 Fractured HPAI with Horizontal Producer
REFERENCES


Clara, C., Durandeau, M., Quenault, G., Nguyen, T., “Laboratory Studies for Light Oil Air Injection Projects : Potential Application in Handil Field”, SPE


VITA

Dhiraj Dembla was born in Surat, Gujarat, India, on March 14, 1977, the son of Mr. M. Dembla and Mrs. U. Dembla. He completed his primary and high school studies at the St Xaviers’ High School, Surat. He received the degree of Bachelor of Engineering in Chemical Engineering from Sarvajanik College of Engineering & Technology (SCET), South Gujarat University, Surat, India in May 1999. He worked as a junior lecturer at SCET, Surat, India between 1999 and 2000. He studied at the University of Texas at Austin and completed his Master of Science in Petroleum Engineering degree in spring of 2004.

Permanent address: 301 Satyaguru Apt., Majura Gate, Surat, 395002, Gujarat, India.

This thesis was typed by the author.