



Major Project
In-Situ Combustion

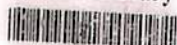
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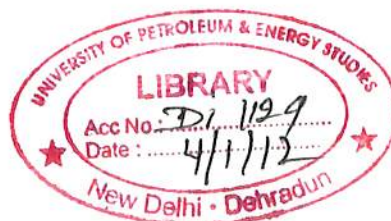
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in Applied Petroleum Engineering

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IN-SITU COMBUSTION

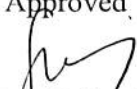
A thesis submitted in partial fulfillment of the requirements for the Degree of
Bachelors of Technology
(Applied Petroleum Engineering)

By
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Under the guidance of
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Dehradun
May, 2010

CERTIFICATE

This is to certify that the work contained in this thesis titled "In-Situ Combustion" has been carried out by Mr. Shashwat Shubham under my/our supervision and has not been submitted elsewhere for a degree.



Mr. Arvind Chittambakkam

12/05/2010

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Abstract

The northern part of the Cambay Basin located in Mehsana, Gujarat (India), is fenced by a number of heavy oil fields reserving about 140 MMT OOIP. Balol and Santhal fields form a part of this heavy oil belt with API gravity 15-18. The viscosity of oil ranging from 50 to 450 cps at reservoir pressure of 100 kg/cm² and temperature of 70°C. High mobility contrast between viscous oil and water has resulted into low primary recovery. Subsequent Artificial lift methods resulted into high water production rather than oil. Thus, it necessitated for in-situ combustion technique.

In-situ combustion is a thermal enhanced oil recovery process. The technique is based on the principle of reducing viscosity by heating of oil in the reservoir itself. It involves ignition in the well and injection of air to sustain flame front. In this process a small quantity of in-place oil burns, producing CO₂, water vapors and heat. It helps in lowering the viscosity of oil, which increases the oil mobility and displace it towards the surrounding producers.

Production engineering for in situ combustion involves careful planning and monitoring for successful implementation.



CHAPTER - 1

INTRODUCTION

CHAPTER 1

INTRODUCTION

The current world oil scenario shows that the conventional oil resources are on decreasing and the hike in oil prices has forced the engineers and the scientists to turn towards the unconventional resources (Heavy Oil, Natural Bitumen and oil shale), which seem promising enough to cater the energy needs of the human race for the upcoming years.

Although the recovery of these resources was earlier not considered economically feasible but the continuously increasing oil prices have now rendered it an economically viable option. The efficient and economic recovery of heavy oil and bitumen from reservoirs is a major technical challenge and task.

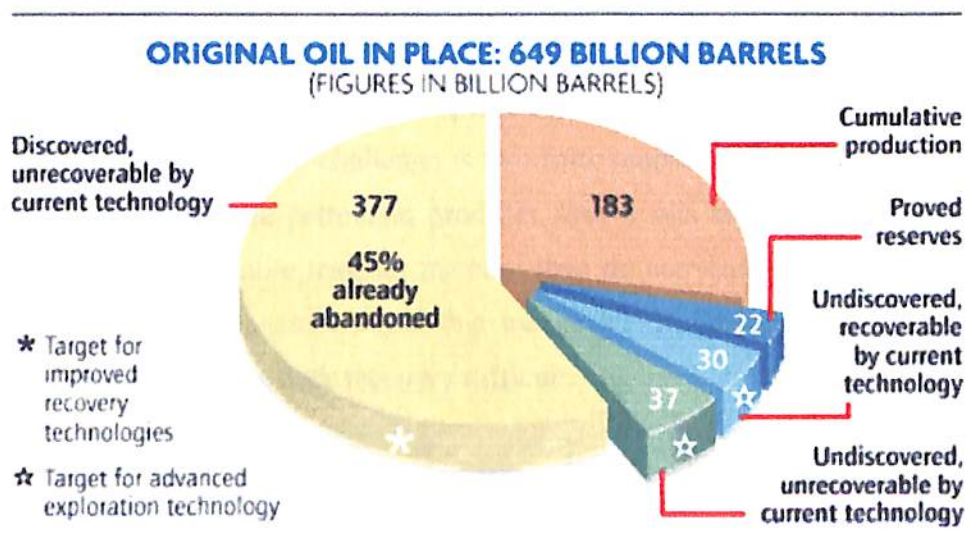


Fig 1.1 Current Oil Scenario

*DISTRIBUTION OF WORLD'S KNOWN RECOVERABLE OIL
RESOURCES AND RESERVES*

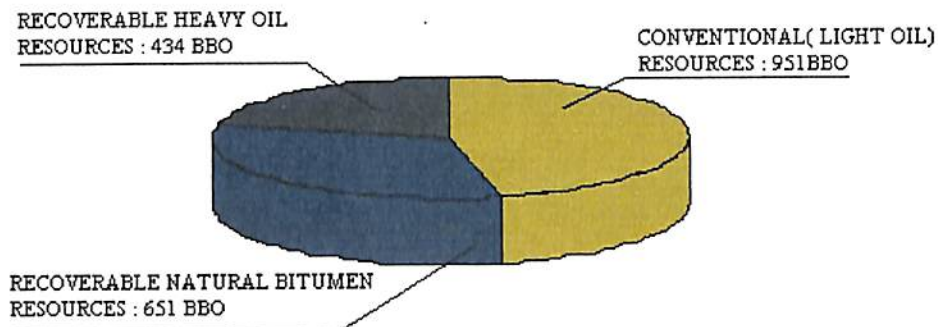


Figure 1.2: Distribution of Oil Resources and Reserves

The quantity of heavy oil and bitumen in place are as large as and probably far larger than those of conventional crude oil. The challenge is two fold: recovering the oil from the reservoirs and converting them into useful petroleum products. Heavy oils and bitumen contains much larger proportions of non distillable residual material than do conventional oils. The residues contain larger proportions of Asphaltenes and this makes them particularly viscous. It is their high natural viscosity that makes their recovery difficult.

As the world supplies of conventional crude oil continue to dwindle, there has developed an increase incentive for the improvement of the recovery from known reservoirs and methods for “Enhanced Oil Recovery” have been developed, both for conventional and heavy oil reservoirs.

Oil recovery *now* classified as primary, secondary and EOR processes.

Primary recovery: natural energy displacement, solution gas drive, and natural water drive, fluid and rock expansion and gravity drainage.



Secondary recovery:	the augmentation of natural energy through injection of water or gas to displace oil towards producing wells.
EOR:	Injection of gases or liquid chemical and/or the use of thermal energy.
IOR:	which includes EOR but also encompasses a broader range of activities; e.g. reservoir characterization, improved reservoir management, and infill drilling.

1.1 Enhanced Oil Recovery

EOR results principally from the injection of gases or liquid chemicals and/or the use of thermal energy. Hydrocarbon gases, CO₂, nitrogen, and flue gases are among the gases used in EOR processes. A number of liquid chemicals are commonly used, including polymers, surfactants and hydrocarbon solvents. Thermal processes typically consist of the use of steam or hot water, or rely on the in-situ generation of thermal energy through oil combustion in the reservoir rock.

EOR processes involve the injection of fluid or fluids of some type into a reservoir. The injected fluid or injection processes supplement the natural energy present in the reservoir to displace oil to producing wells. Injected fluid interacts with reservoir rock/oil system to create conditions favourable for oil recovery. Examples: result in lower IFT's, oil swelling, oil viscosity reductions, wettability modification or favourable phase behavior. The interactions are attributable to physical and chemical mechanisms and to the injection or production of thermal energy.

General classification and description of EOR processes:

- 1.1.1. Mobility control,
- 1.1.2. Chemical,
- 1.1.3. Miscible,
- 1.1.4. Thermal,
- 1.1.5. Microbial EOR

1.1.1. Mobility Control

This is a generic term describing any process where an attempt is made to alter the relative rates at which injected and displaced fluids are move through reservoir. The objective of mobility control is to improve volumetric sweep efficiency of a displacement process. Mobility control is usually discussed in terms of the mobility ratio, M , and a displacement process is to have mobility control if M less equal to 1.0. Volumetric sweep efficiency generally increases as M is reduced.

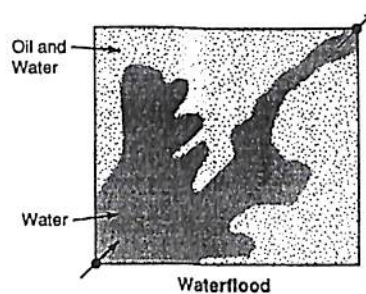


Fig 1.3 Oil and water phase

Because it is often not feasible to change the properties of the displaced fluid when it is oil or the permeabilities of the rock to the displaced fluids, most mobility control processes of current interest involve addition of chemicals to injected fluid. These chemicals increase the apparent viscosity of the injected fluid and/or reduce the effective permeability of rock to the injected fluid. The chemicals are primarily polymers when the injected fluid is water and surfactants that forms foams when injected fluid is a gas. In some cases, mobility control is attained by WAG (water alternate gas) injection.

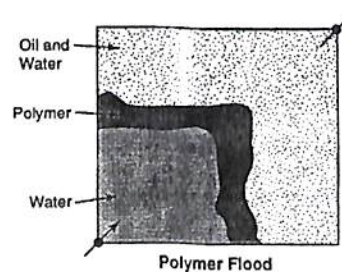


Fig 1.4 Polymer flooding

1.1.2. Miscible Displacement Processes

These are defined as processes where the effectiveness of the displacement results primarily from miscibility between oil in place and the injected fluid. Displacement fluids, such as hydrocarbon solvents, CO₂, flue gas and nitrogen are considered.

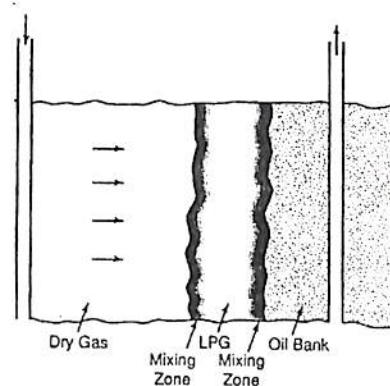


Fig 1.5 Miscible Displacement

The displacement processes treated here are classified as FCM (first contact miscible) and MCM (multiple contact miscible) i.e. on the basis on which miscibility is developed. In a specified fluid and reservoir system, MMP (minimum miscibility pressure) is an important parameter for these processes.

1.1.3. Chemical Flooding

The process treated in depth, called the micellar/polymer process, is based on injection of chemical system that contains surface-active agents i.e., surfactants. The processes to improve recovery efficiency primarily through the use of displacing fluid that has a low interfacial tension (IFT) with the displaced crude oil. In the process, injection of micellar solution usually is followed by injection of an aqueous solution to which polymer has been added to maintain mobility control.

- Alkali Surfactant Flooding
- Polymer Flooding

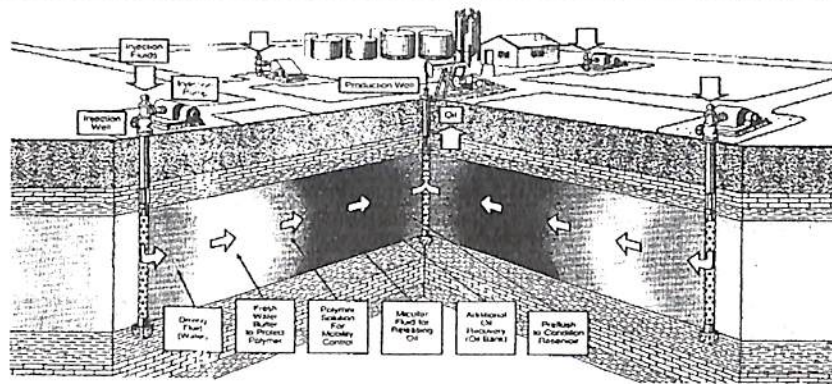


Fig 1.6 Chemical Flooding

1.1.4. Thermal Recovery Processes

It rely on the use of thermal energy in some form both to increase the reservoir temperature, thereby reducing oil viscosity, and to displace oil to producing well. The processes can be sub-divided into cyclic steam stimulation, steam-drive, and in-situ combustion. The motivation for developing thermal recovery processes was the existence of major reservoirs all over the world that were known to obtain billions of barrels of heavy oil and tar sand that could not be produced with conventional methods. In many reservoirs the oil viscosity so high that primary recovery on the order of few percent of original oil in place was common

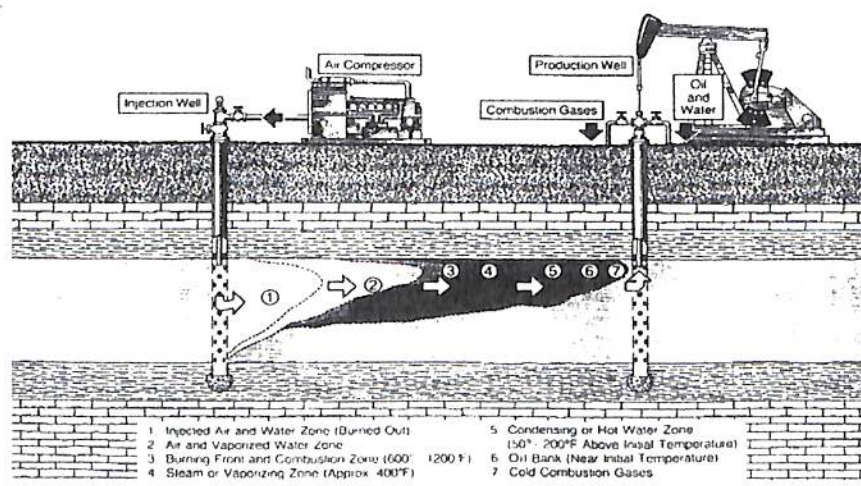


Fig 1.8 In situ combustion



CHAPTER - 2

THERMAL RECOVERY PROCESSES



CHAPTER 2

Thermal Recovery Processes

For very viscous crudes the ratio of μ_o / μ_d can be of the order of thousands (which means that M has the same order of magnitude) and therefore, water drive cannot be considered as a feasible project). In such cases the viscosity ratio can be drastically reduced by increasing the temperature.

This is achieved by one of the method of thermal recovery:

- Steam Flooding
- In Situ Combustion (Fire Flooding)
- Hot Water Injection

2.1 Steam flooding

- Steam flooding is a process in which steam is forced continuously into specific injection wells and oil is driven to separate production wells.
- The zones around the injection wells become heated to the saturation temperature of the steam and these zones expand towards the production wells, hence sweeping the oil towards the production well.
- The method is very efficient for the shallow wells as the scope for heat loss is less.

2.2 In-Situ Combustion

- In situ combustion involves the injection of air, enriched-air, or oxygen to enable combustion of oil within the reservoir formation, creating chemical reactions and the release of CO_2 .
- Heat ahead of the combustion front reduces viscosity and some in situ distillation (upgrading) occurs. CO_2 created during combustion can also assist by increasing pressure and mixing with the oil, further reducing viscosity and aiding flow.



-
- Unlike steam injection processes, the technique has not found wide spread acceptance among operators, despite many economically successful field projects.
 - Steam injection requires treatment of water and energy (usually gas) to heat the water, both of which incur significant cost. ISC avoids these heat-related costs, requiring only compressors for the injected air. It should, however, be noted that ISC is not free—the compressors are very powerful and quite expensive. ISC requires very large volumes of air, although not very high pressures, as these might damage the formation.
 - Analysis of the successful projects, however, indicates that the process is applicable to a wide range of reservoirs, and the chances of failure can be minimized by careful selection of the reservoir and adopting prudent engineering practices.

2.3 Hot Water flooding

- The process is very much similar to Steam flooding, just that instead of steam hot water is injected into the reservoir. Because of the lower heat content of water compared to steam it is more efficient process.
- It is thought that steam is more effective in displacing oil than hot water because of the extra pressure differential resulting from higher kinematic viscosity of steam, relatively low tendency for steam to finger compared with water and steam distillation effects (which allow volatile fractions of the crude oil to evaporate into steam and be carried by it).
- This method also has heat loss problems. However cool and high wax content reservoirs are most suitable candidates for this application.



CHAPTER - 3

IN-SITU COMBUSTION METHOD



CHAPTER 3

IN SITU COMBUSTION METHOD

3.1 Introduction

This method is sometimes applied to reservoirs containing oil too viscous or "heavy" to be produced by conventional means. Burning some of the oil in situ (in place), creates a combustion zone that moves through the formation toward production wells, providing a steam drive and an intense gas drive for the recovery of oil.

This process is sometimes started by lowering a heater or ignitor into an injection well. Air is then injected down the well, and the heater is operated until ignition is accomplished. After heating the surrounding rock, the heater is withdrawn, but air injection is continued to maintain the advancing combustion front. Water is sometimes injected simultaneously or alternately with air, creating steam which contributes to better heat utilization and reduced air requirements.

Many interactions occur in this process, but the accompanying drawing shows the essential elements. The numbered statements below correspond to numbers on the drawing.

1. This zone is burned out as the combustion front advances.
2. Any water formed or injected will turn to steam in this zone because of residual heat. This steam flows on into the unburned area of the formation, helping to heat it.
3. This shows the combustion zone which advances through the formation. High temperature just ahead of the combustion zone causes lighter fractions of the oil to vaporize, leaving a heavy deposit of residual coke or carbon as fuel for the advancing combustion front.
4. A vaporizing zone that contains combustion products, vaporized light hydrocarbons, and steam.

5. In this zone, owing to its distance from the combustion front, cooling causes light hydrocarbons to condense and steam to revert back to hot water. This action displaces oil, condensed steam thins the oil, and combustion gases aid in driving the oil to production wells.
6. In this zone, an oil bank (an accumulation of displaced oil) is formed. It contains oil, water, and combustion gases.
7. The oil bank will grow cooler as it moves toward production wells, and temperatures will drop to that near initial reservoir temperature.

When the oil bank reaches the production wells, the oil, water, and gases will be brought to the surface and separated – the oil to be sold and the water and gases sometimes reinjected. The process will be terminated by stopping air injection when pre-designated areas are burned out or the burning front reaches production wells.

Notice in the accompanying illustration that the lighter steam vapors and combustion gases tend to rise into the upper portion of the producing zone, lessening the effectiveness of this method. Injection of water alternately or simultaneously with air can lessen the detrimental overriding effect.

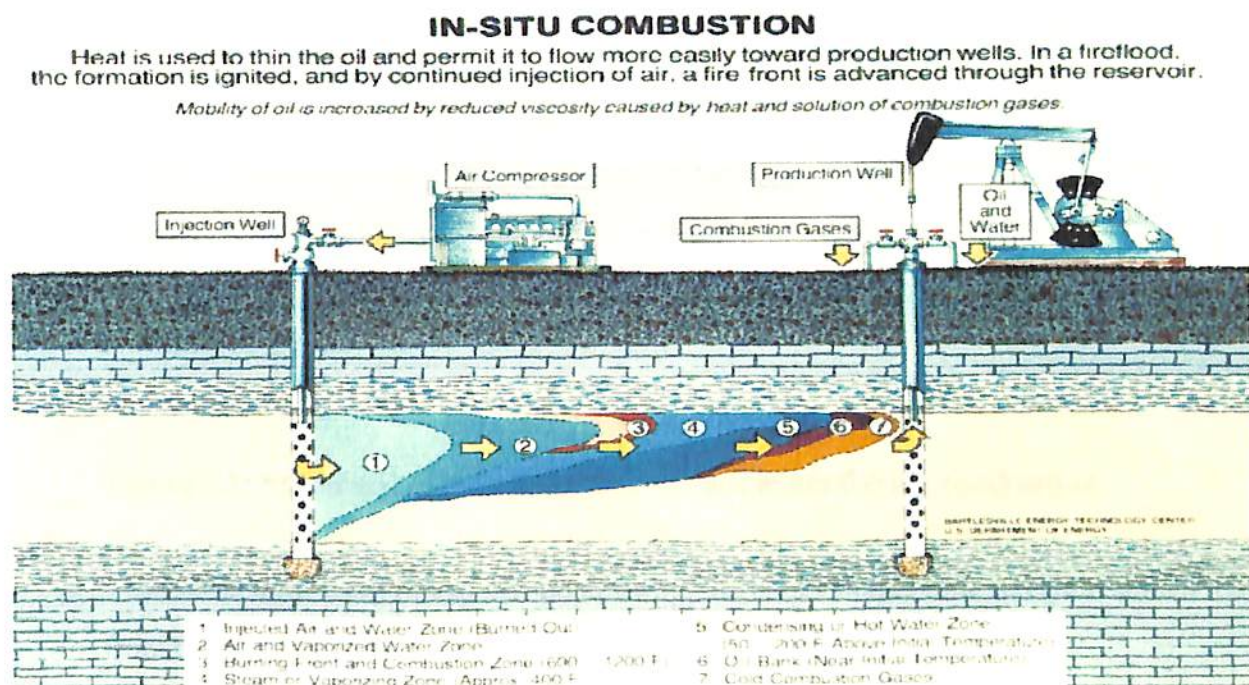


Fig 3.1 In Situ combustion

3.2 Mechanism of In-Situ Combustion

The events which occur as high temperature combustion front approaches at a point in a porous media containing oil and gas as follows .

- ✚ Initially the temperature in the porous media is at reservoir temperature, once combustion front created and is propagating at stable velocity increases the temperature gradually until the condensation and vaporization point of water is reached .
- ✚ The water vapor in the sweep gas condenses and residual water saturation is maintained by liquid flow.
- ✚ The residual water then begins to vaporize and moved away when more heat is transferred.

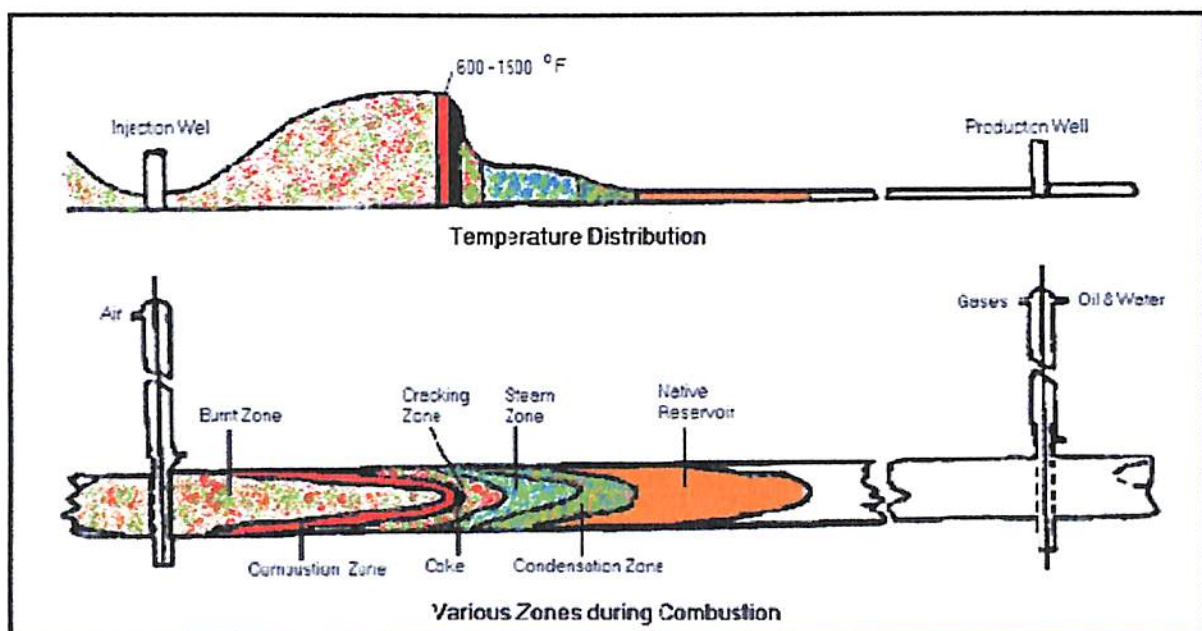


Figure 3.2: Schematic of occurrences of various zones during combustion

- ✚ The rate of movement of vaporization of water corresponding to rate of heat is transferred from combustion zone.
- ✚ Some of the lighter fraction in oil moved out by distillation affect and increase gas flow resulting from vaporization of water.

- ✚ When all the water has been vaporized, the temperature increases. Due to increase in temperature there is reduction in viscosity of oil and increase in volume of oil and gas by thermal expansion.
- ✚ Vaporization of oil will occur as component vapor pressure exceeds the prevailing pressure.
- ✚ When temperature reaches 325°C most of the original oil saturation will have been moved away from this point. The left over residual oil component of oil begins to crack forming lighter hydrocarbons and coke. Combustion will be occurring at rates controlled by process variable.
- ✚ If combustion zone temperature is less than 325°C , considerable hydrogen will be burned. The resulting water vapor is carried by sweep gas until it condenses ahead of the zone. The temperature increases beyond 325°C , residue starts cracking before burned.

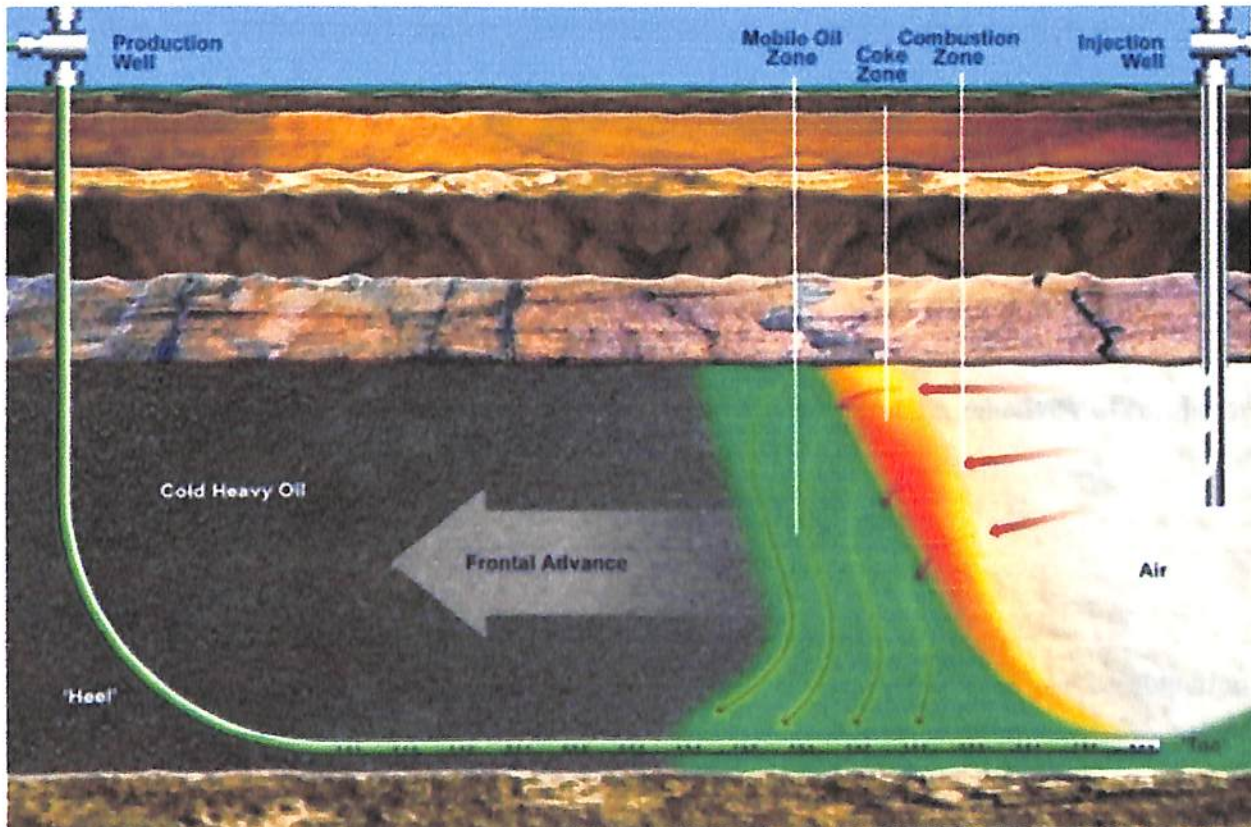


Fig 3.3 Mechanism Of in situ combustion



Liquids are moved away from an advancing combustion front in part by vaporization and in part by flow vaporization occurs at a rate corresponding to the rate of heat flow from high heat zones to liquids.

At low rates of advance, the amount of pre heat received by the porous matrix prior to the combustion zone should increase with the distance traversed by the front. This will result in a decrease in residual material and air flux for sustained combustion.

3.3 Critical Features

- Advancement of combustion zone in porous media is most rapid method in thermal recovery.
- Experimental and analytical data indicate that the combustion zone moves more rapidly than heat can be transmitted by combined processes of conduction and convection.
- For given crude, the rate of advance of combustion is directly proportional to the rate of formation of carbon oxides and the rate of total oxygen conversion.
- But the relationship between the rate of advance and air flux is influenced by many inter related variables like the amount of residual material burnt per unit volume of sand cleaned ,the length of combustion zone, pressure and temperature, reactivity of residuum and the air flux.

3.4 Advantages of In-Situ Combustion Method

In-Situ Combustion Process is a unique oil recovery process. It can be viewed as a combination process. Next to water flooding, ISC is perhaps the most widely applicable improved oil recovery technique.



The major assets and benefits over steam injection process e.g., steam assisted gravity drainage (SAGD) and cyclic steam stimulation (CSS).

- It is the most efficient oil recovery process in thermal section.
- ISC can recover oil economically from a variety of reservoir settings. The process has proven to be economically in recovering heavy oil (10-20°API) from shallow reservoirs (less than 1,500 ft.), and light oil (>30°API) from deep reservoirs (1 1,000 ft.).
- It is increasingly being used to recover light oil from deep reservoirs, although most combustion projects are implemented in heavy oil reservoirs. As for instance there are more light oil reserves in U.S. than heavy oil reserves.
- An ideal process for producing oil from thin formation. The process, however, proved to be most effective in 10-50 ft. sand bodies.
- The process has been successfully implemented in reservoirs ranging in pressure from vacuum to 4,500 psig. So, no impact of pressure technical success.
- Minimal effect of formation permeability on the process. 5 md to 10,000 md are viable range.
- Can also follow-up to waterflood and steamflood processes and can be applied in reservoirs where waterflood and/or steamflood are not effective.
- Steam injection requires treatment of water and energy (usually gas) to heat the water, both of which incur significant cost. ISC avoids these heat-related costs, requiring only



compressors for the injected air. It should, however, be noted that ISC is not free—the compressors are very powerful and quite expensive..

- ISC requires very large volumes of air, although not very high pressures, as these might damage the formation.
- Steam generation produces CO₂ at the surface, representing a significant environmental impact, and heat is lost during transport to the formation. ISC produces CO₂ downhole, some of which may subsequently be produced to surface, but probably less than would be created during steam generation.

ISC success stories are limited but quiet effective. It used in the US during the 1950s and 1960s and in Venezuela during the 1970s, ISC has often not been economical due to low oil prices, so there is little worldwide experience. Notable exceptions include Romania and India.

ISC in the Romanian Supalcu de Barcau reservoir began in 1964. Since then it has maintained production and a recovery factor of 56% in the area swept by the front. This and several other successful thermal recovery projects were celebrated at the SPE conference in Bucharest, “150 years of the Romanian Petroleum Industry”, in October 2007.

In India, ONGC implemented ISC in its Balol and Santhal heavy oil fields in 1997, where recovery factors using conventional methods had fallen to 6–15%. ISC increased recovery to 39–45%, producing an additional 8400 bbl/d. ONGC has developed a special ignition technique for the project to overcome the challenges of high pressures in wells over 3,300 ft (1,000 m).

Several new ISC pilot tests are being performed in Canada and elsewhere and O’Callaghan is confident that, if successful, these could be the catalyst for a rapid expansion in the use of ISC worldwide. The technique may not only be applicable for heavy oil. It has also been considered for depleted conventional oil reservoirs.



3.5 Limitations of In-Situ combustion method

As all other oil recovery methods, combustion process has its share of shortcomings. Most of these limitations can be overcome at considerable expense. This has reduced its overall attractiveness.

- Steam injection systems can produce oil economically and operators understand the dynamics of these systems. By contrast, there is a lack of confidence in ISC systems, despite the fact that they have the potential to deliver significantly higher recovery rates. In addition, until recently, software tools and computer power were inadequate to handle the complexities of modeling ISC.
- Although air is free, it must be compressed and delivered to the formation. The power required for compressing air together with maintenance costs of the compressor are high enough that overall costs for delivering air to the reservoir can be substantial.
- Expensive laboratory investigations are needed to ascertain the burning characteristics of the crude, fuel availability and air requirements. Thus, planning and design of a combustion project is more expensive.
- The complexity of the in-situ combustion process hinders the development of more sophisticated numerical simulators for complete performance prediction.

It is likely that the coming decade may see important advances in the application of this process in reservoirs found in hostile environments.

It is also likely that the process will increasingly be applied to recover light oil. Thus future potential for oil recovery by ISC is very promising.



3.6 In situ combustion essential requirement

ISC requirements include high permeability (e.g., 3–5 Darcies), which is common in the shallow depths in which heavy oil bearing formations are usually found. It is most suitable for homogeneous sandstones.

Formation thickness is a key factor determining well geometry and production strategy, which must consider gravity effects. The high well density required for ISC and other thermal processes means that it is usually only economical for shallow onshore reservoirs.

Effective control of air injection rates requires good up-front experiments plus modeling and simulation based on actual production rates. It is also important to avoid breakthrough of air/oxygen from behind the combustion front.

3.7 Combustion Efficiency

Oxygen in injected air is consumed in passing through the front is measure of efficiency of combustion process. The percentage is calculated by dividing the rate at which oxygen is consumed by the rate of oxygen injection.

To maintain isothermal combustion in any condition, heat must be liberated by combustion at a rate equal to the net rate of heat loss to the surroundings.

As per the experimental observations the minimum rate of self sustained combustion for unconsolidated sand pack is required to be 600 °F to replace the heat losses. The effect of pressure on the rate of advance appears to be small. It is also noticed that increasing water saturation in lower levels also help in increases rate of advance.

Oxygen consumed was calculated based on the difference between injected and unreacted oxygen in produced gas.

It is assumed that the oxygen not appearing in any form of in the produced gases was reacted with Hydrogen to form water or oxygenated products, such as organic acids and alcohols. The presence of oxygenated compounds in the produced water was indicated by its color, odor and low pH.

3.8 In-Situ Combustion Processes

Direction of the combustion front propagation in relation to the air flow decides the process that can be classified as forward combustion and reverse combustion. Forward process, the combustion front advances in the general direction of air flow.

Reverse combustion, the combustion front moves in a direction opposite to that of the air flow. The forward combustion is further categorized into 'dry forward combustion' and 'wet forward combustion'. In the dry process, only air or oxygen enriched air is injected into the reservoir to sustain combustion. In the wet process, air and water are co injected into the formation through the injection well.

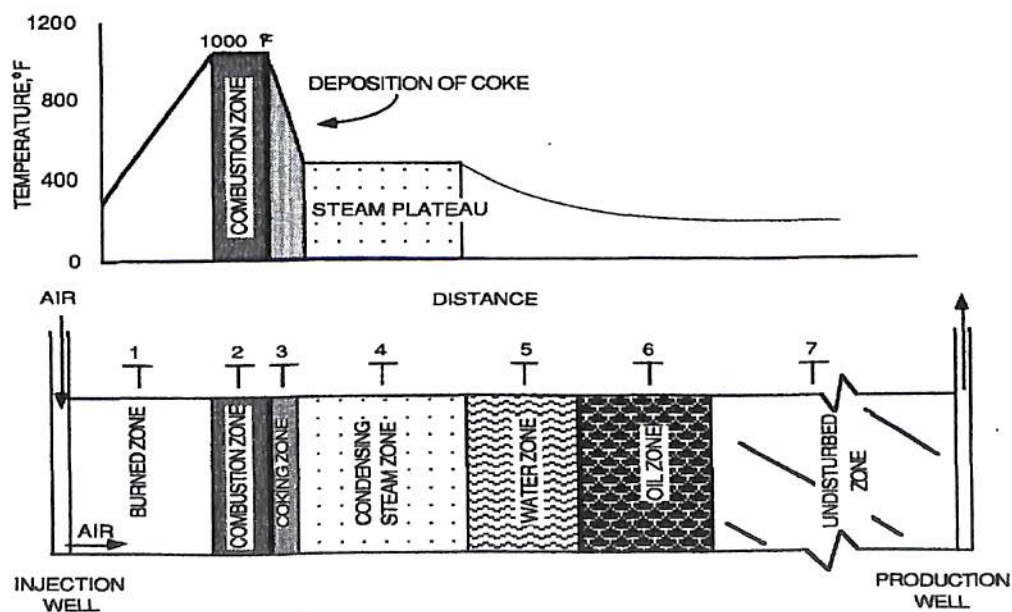


Figure 3.4: In-Situ Combustion Schematic Temperature Profile



[Figure is an idealized representation of a forward combustion process and developed based on liner combustion tube experiments. In the field there are transitions between all the zones. The concept depicted in figure is easier to visualize and provide much insight on combustion process.]

3.8.1 Dry Combustion

It is dry because no water is injected along with air. It is forward because combustion starts at the injector and the combustion front moves in the direction of the air flow.

In ordinary cigarette smoking, one ignites the tip of the cigarette and inhales. The burning front will travel from the tip of the cigarette toward one's mouth, along with the air. This is forward combustion.

The process is initiated by injecting air into a centrally located injection well and as the permeability to gas develops, the burning front moves radially towards producers.

Combustion is started in the formation by injecting air that is heated to 400-1200°F, depending on the low temperature oxidation characteristics of crude oil being ignited. Usually the air is preheated at the sand face of the injection well, by a gas burner or electrical heater. However, in some reservoirs like of Balol field, oil can ignite spontaneously after air is injected for some time. Ignition can occur in few hours in high bottom hole temperature reservoirs, while shallow formations require several weeks for ignition. After ignition operation is completed air, without any preheating, is continuously injected into the formation.

As the burning front moves away from the injection well, several distinct zones develop and a number of different but intimately related mechanisms are operative. These zones are illustrated in figure which depicts a cross section of the burning front between an injection well and one production well. The upper portion of the figure illustrates the corresponding formation temperatures.

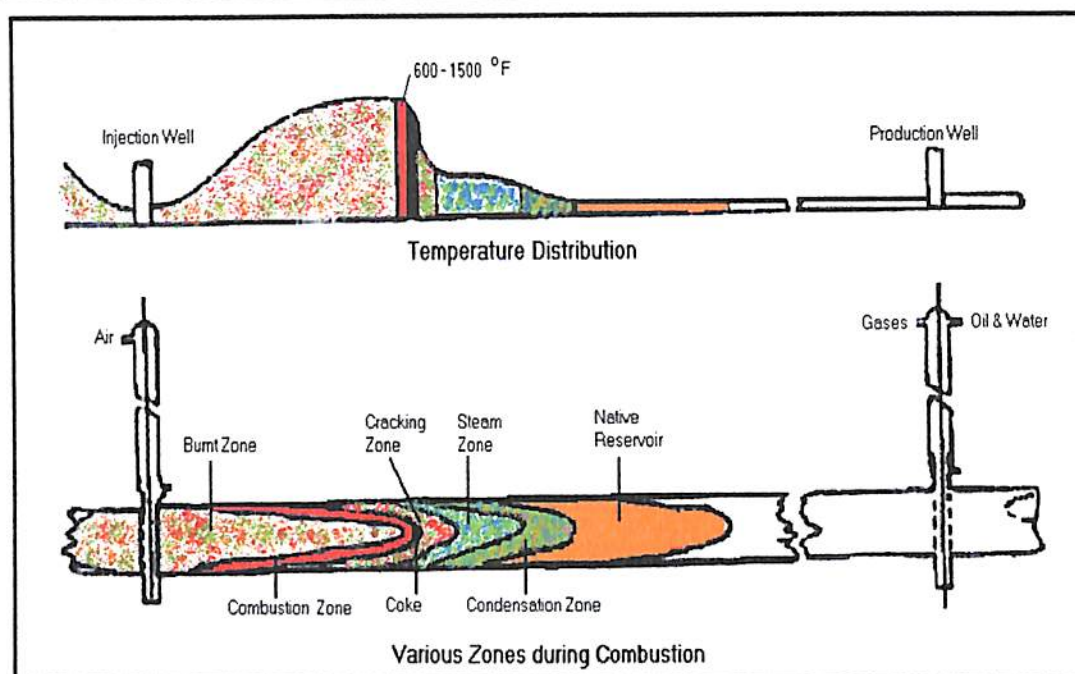


Figure 3.5: Schematic of occurrences of various zones during combustion

i. Burning Front

The crude oil ahead of the high temperature burning front is carbonized to produce coke like deposit on the sand grain. This deposit constitutes the principal fuel for the process. The burning front leaves behind hot, clean sand that can be used effectively to heat the injected air before the gas reaches the burning zone. Maximum temperature of 600-1500°F have been observed at the burning front in normal in situ projects.

ii. Thermal Cracking

Further downstream of the burning zone, the temperature is high enough to vaporize the lighter hydrocarbons which move away and condensate in the cooler reservoir. Nearer the burning front, the high temperature converts the interstitial water into steam which also moves and condenses into the cooler part of the reservoir. Immediately ahead of the burning oil, high temperatures thermally crack the heavy hydrocarbons left on the sand. Products from this cracking are petroleum coke and gaseous hydrocarbons. The hydrocarbon gases also moves ahead of the front and partially condense in the cooler sand. The petroleum coke is deposited on the sand grains and becomes fuel for the process.



iii. Condensing Steam Drive

As the injected air reacts with the injected fuel at the burning front, steam is one of the products formed. This steam along with that produced by vaporizing the interstitial water of the formation, moves forward and contacts the cooler sand ahead. The steam loses heat rapidly to the formation, and a condensing steam type drive results. The large amount of latent heat of steam reduces the viscosity of oil greatly and mobility increases, which in turn enhances oil displacement.

iv. Miscible Drive

The hydrocarbon gases formed during normal distillation or thermal cracking, condense ahead and mix with the oil making the oil more mobile and improve oil displacement.

v. Gas Drive

Combustion gases generated at the burning front transfer heat to the oil. Carbon dioxide partially dissolves in oil and reduces the viscosity further. The oil bank that forms ahead of the steam zone is displaced physically by the combustion gases.

vi. Thermal Drive

Thermal energy transfers to the formation above, below and ahead of the burning front by convection in the reservoir fluids and by conduction through the formation rocks. No other oil recovery process can displace fluids across an impermeable zone in this manner.

3.8.2 Wet Combustion

Although dry combustion phase is successful, the process retains most of the heat generated behind the front in the burned out zone and does not affect oil production. In wet combustion process, air and water are injected simultaneously or alternatively to create a motive force. As shown in figure the burning front velocity, VBF and peak temperatures are identical to normal dry combustion. The water however, is flashed into steam, so the steam front velocity, VS, approaches VBF. Heat scavenged from the burned sand is transferred by air and superheated

steam to the condensation zone ahead of the combustion front. This increases V_H , the heat front velocity.

The ratio of water to air (WAR) at the burning front is regulated to transfer 70-90% of the effective heat generated after heat losses and design factors are considered. This WAR generally varies between 0.00045 to 0.0015 m^3/Nm^3 .

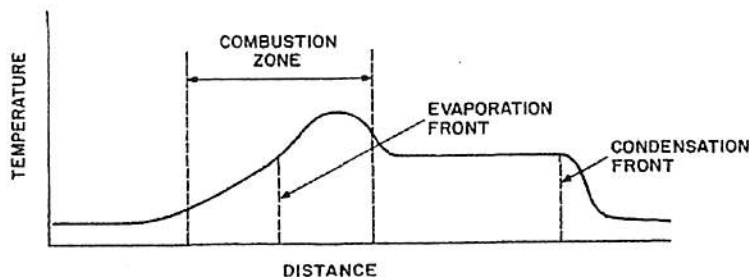


Figure 3.6: Schematic of Temperature Profile for an Incomplete (partially quenched) Wet Combustion Process

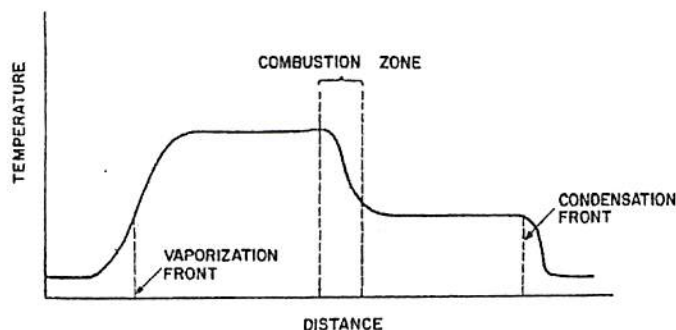


Figure 3.7: Schematic of Temperature Profile for a Normal Wet Combustion Process

i. Water Drive

Breakthrough of combustion front in the producers can result in many operational problems. Hence the combustion front is permitted to move to the desired portion of the reservoir, air injection is stopped and continuous water injection at accelerated rate is adopted. This increases the heat transfer rate to the unburned region and the heated oil readily moves to the producers too achieve higher ultimate recovery. This may prove to be economically beneficial also.



ii. Design of the Process

Actual design to the process, which includes the amount of heat to be generated in each phase, the air/water injection rates etc. depends on the detailed laboratory investigations, engineering calculations and the actual performance during the implementation of the process in the field.

3.8.3 Reverse Combustion

The burning front moves in an opposite direction to the injected air. Initially, air is injected into a production well and the fire is ignited. After the burning front has advanced some distance from the production well, air is supplied only near the injection well. The burning front advances toward the injection well while the oil moves toward the production well.

In heavy oil, reservoir forward combustion is often plagued with infectivity problems because the oil has to flow from the heated, stimulated region to cooler portions of the reservoir. Viscous oil becomes less mobile and tends to create barriers to flow. This phenomenon is especially prevalent in very viscous oils and tar sands. A process called reverse combustion has been proposed and found technically feasible in laboratory tests.

The operating principles of reverse combustion are not as well understood as those for the forward mode. Although, the combustion process is essentially the same, its movement is not controlled by the rate of fuel burn-off but by the flow of heat. As explained in the section on dry in-situ combustion, the three things required for burning are oxygen, fuel, and elevated temperature.

During reverse burning, oxygen is present from the injection well to the combustion zone. The fuel is present throughout the formation. The factor which determines where the burning occurs is the high temperature which occurs at the producing well during ignition. As the heat generated during the burning elevates the reservoir temperature in the direction of the injector, the fire moves in that direction.



The portion of the oil burned by forward and reverse combustion is different as stated Forward combustion burns only the coke like residue, whereas the fuel burned in reverse combustion is more of an intermediate molecular weight hydrocarbon. This is because all of the mobile oil has to move through the combustion zone.

Therefore, reverse combustion consumes a greater percent of the oil in place than forward combustion.

The upgrading process of reverse combustion is very desirable for tar-like hydrocarbon deposits. Although reverse combustion not proven itself in the field.

The primary cause of failure has been the tendency of spontaneous ignition near the injection well. However, projects in the tar sands are being considered which attempt to use reverse combustion along fractures to preheat the formation. As the burn zones near the injection well, the air rate is increased, and a normal forward fireflood is commenced.

Reverse combustion can be described in four steps as follows:-

- Injection of air.
- Generation of combustion front at the production well.
- Propagation of combustion front towards injection well and production from hot bank.
- Combustion front reverses its direction as it reaches the injection well and propagates as in the forward combustion.

Advantages

- Since the region around the producer is hot, the problem of (liquid blocking) mentioned earlier in connection with the dry forward process has been eliminated .
- Can be used to recover extremely viscous oil or tar.

Disadvantages

- This process is not as efficient as dry forward combustion because lighter fractions of the oil are burned and heavier fractions are left behind the burning front.
- The possibility of a spontaneous ignition in the injector well, which will divert air for combustion near the injector well instead of near the producer.
- No reverse combustion project has ever reached commercial status.



3.9 Factors Affecting In-situ Combustion technique

ISC can be affected on its functioning due to some common effects as follows:

➤ Air flux effect :

The rate of advance of a combustion zone was nearly proportional to rate at which air was supplied to the zone & inversely proportional to the amount of residual fuel deposited. As combustion temperature & air flux increased the amount of hydrogen associated with carbon burned decreased

➤ Effect of air injection pressure :

Results indicated that , although fuel consumption does increase with pressure , the effect is not too large.

➤ Air requirement effect :

The total amount of air required to consume a pound of fuel was essentially constant for all crude oil & porous media studied.

➤ Effect of crude oil characteristics :

Experimental results showed that the fuel availability decreased as hydrogen/carbon ratio & API gravity of original crude oil increased. The fuel availability increased as the carbon residue & the viscosity increased. The lower S_o , the lower the fuel availability. The air required for combustion drive could be higher for reservoirs containing low-gravity oils than for reservoirs containing high API gravity oils.

➤ Time temperature relationship :

For low temperature oxidation (LTO): the apparent (H/C) ratio of fuel consumed is high.

For high temperature oxidation (HTO): the apparent (H/C) ratio of fuel consumed is low.



CHAPTER - 4

CHEMICAL REACTIONS ASSOCIATED WITH IN-SITU COMBUSTION



CHAPTER 4

Chemical Reactions Associated With In-Situ Combustion

The oil composition and rock mineralogy parameters play a major role on the outcome of an in-situ combustion (ISC) process in on oil recovery.

Because of the ISC dependence on the occurrence of chemical reactions between the crude oil and the injected air within the reservoir for its existence . The extant and nature of these chemical reactions as well as the heating effects they induce depends on the features of the oil-matrix system.

A qualitative and quantitative understanding of in-situ combustion chemical reactions and their influence on the process is critical to the design of the process and interpretation of the field performance.

4.1 Chemical Reactions

The chemical reactions related with the in-situ combustion process are numerous and occur over different temperature ranges. In order to simplify the studies, investigators grouped these competing reactions into three classes:

- High temperature oxidation (HTO) or combustion of the solid hydrocarbon residue (coke).
- Intermediate temperature, fuel formation reactions, and
- Low temperature oxidation (LTO),

The high temperature fuel combustion reactions are heterogeneous, in which the oxygen reacts with unutilized oil, fuel and the oxygenated compounds to give carbon oxides and water.

The LTO reactions are heterogeneous (gas/liquid) and generally results in production of partially oxygenated compounds and little or no carbon oxides. Medium temperature, fuel formation

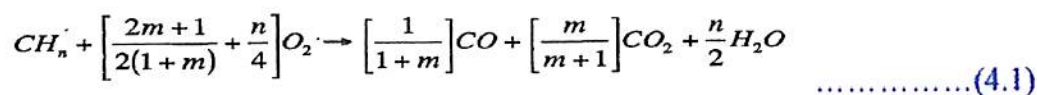


reactions involve cracking/pyrolysis of hydrocarbons which leads to the formation of coke (a heavy carbon rich, low volatility hydrocarbon fraction).

4.1.1 High Temperature Oxidation

At temperatures above 450°C the reaction between the oxygen in the injected air and the coke are often referred to as the high temperature oxidation (HTO) or combustion reactions in the ISC literatures.

HTO are heterogeneous (gas-solid and gas-liquid) reactions and are characterized by consumption of all of the oxygen in the gas phase. Carbon dioxide (CO₂), carbon monoxide (CO), and water (H₂O) are the principle products of these reactions. The stoichiometry of the HTO reaction (chemical equation) is given by:



Where,

n = atomic ratio of hydrogen to carbon,

m = molar (mole percent) ratio of produced CO₂ to CO, and

m = zero in the case of complete combustion to CO₂ and H₂O.

The heat generated from these reactions provides the thermal energy to sustain and propagate the combustion front. Studies indicate though, HTO is predominantly a heterogeneous flow reaction and the burning process involve a number of transport phenomena.

Combustion (oxidation) is a surface controlled reaction and can be broken into the following 5 steps:-

1. Diffusion of oxygen from the bulk gas stream to the fuel surface.
2. Absorption of the oxygen at the surface.



3. Chemical reaction with the fuel.

4. Desorption of the combustion products.

5. Diffusion of the products away from the surface and into bulk gas stream.

In general chemical reactions (step 3) proceed at a much faster rate than the diffusional processes. If any of these steps is inherently slower than the remaining steps, the overall combustion process will be controlled by that step. Hence, the overall combustion rate likely to be diffusion controlled.

4.1.2 Low Temperature Oxidation

Depending upon the prevailing temperature during in-situ combustion the hydrocarbons initially present in the oil undergo two types of reaction with the oxygen (injected air).

Those reactions which occur at temperatures below 400°C are defined as the low temperature oxidation (LTO) and the other being the high temperature oxidation (HTO).

LTO yields water and partially oxygenated hydrocarbons such as carboxylic acids, aldehydes, ketones, alcohols, and hydro peroxides on other hand HTO produces CO₂, CO, and water (H₂O) as its primary reaction products,.

Thus LTO can be thought of as oxygen addition reactions. LTO occurs even at low reservoir temperature and is caused by the dissolution of oxygen in the crude oil. LTO have been shown to increase the original oil's viscosities, boiling range and densities. It has been shown that LTO reaction increases the amount of fuel available for combustion and causes a substantial decline in recoverable oil from the distillation and cracking zone.

Light oils are more susceptible to LTO than heavy oils and the degree of dissolution depends upon the diffusion rate of oxygen molecules in the crude at reservoir temperature. LTO reactions



are highly complex and difficult to understand. But, it is believed that LTO reactions consist of condensation of low molecular weight components to higher molecular weight products.

Composition shows LTO has been found to increase the asphaltene content of the oil and to decrease its aromatic and resin contents.

Channeling that promotes LTO a reaction is low air fluxes in the oxidation zone resulting from reservoir heterogeneities and oxygen. Poor combustion characteristics of the crude also tend to promote LTO due to low oxygen consumption.

LTO tends to be more pronounced when oxygen, rather than air, is injected into the reservoir in heavy oil reservoirs. For rectification of this situation investigators suggest adding steam to the oxidizing gas stream. The fact behind this suggestion is that the addition of steam to the oxidizing gas stream will lower the oxygen partial pressure at the burning front and modify the kinetic reaction that creates the heat needed to promote and sustain combustion.

It is very difficult to assign a temperature range to LTO region because the carbon oxide reactions (C-C bond cleavage) are begin to occur at temperatures between 270°C and 320°C.

LTO are generally believed to occur at temperatures of less than 350°C, but this temperature range is varying from oil to oil.

LTO reactions are evidenced by a rapid increase in the oxygen uptake rate as well as the generation of carbon oxides, but their characteristics feature is that there is a decline in the oxygen reaction rate at temperatures in the range of 450-540°C. This gives rise to the negative temperature gradient region, as shown which is a temperature interval over which the oxygen uptake rate decreases as the temperature increases.”

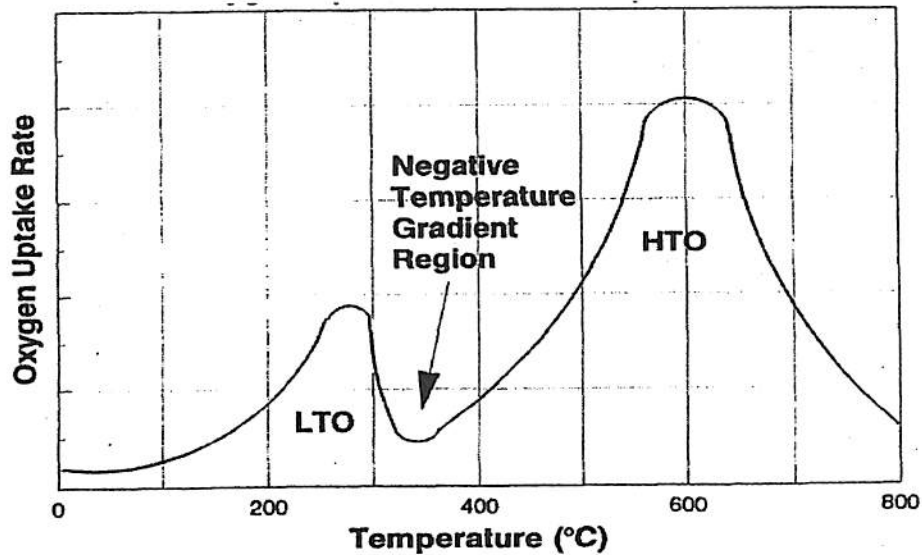


Figure 4.1: Schematic of Dry Combustion Temperature Profile Showing the General Effect of Temperature on Oxygen Uptake Rate for Heavy Oils and the Negative Temperature Gradient Region (After Mehta and Moore)

Because the dominant end product of LTO reaction is coke, prolongation of LTO reaction for an extended period can cause the oil to be permanently trapped in the pores. Failure of the reaction temperatures to propose the negative temperature gradient region will lead to very low oil displacement efficiency, because the oxygen addition reactions cause vapor phase to shrink significantly and also make the oil less mobile.

LTO study of bitumen shows the above result. LTO studies in lab. on four oils ranging from 31.1–10.1°API and from 14–54,300 cp dead oil viscosity indicate LTO has insignificant effects on either composition or viscosity of light oil (31.1 °API).

LTO of light oils does not significantly affect either their mobility or recovery. Similar trend in their laboratory air injection study of various light crudes were observed.

Sometimes, LTO dramatically affect the mobility of heavier crudes (i.e., those with high asphaltenes and resin contents). These oils has LTO increases both the viscosity and density which inurn affect their recovery. Great increases the fuel availability and subsequent air



requirements for combustion occurs due to pre-oxidation of the heavy crude at lower temperatures. Hence, conditions that promote LTO reactions must be minimized during the in-situ combustion of heavy oils.

Further, during LTO certain reactive species in the oil often produce unstable hydro peroxide intermediates. Their decomposition releases much heat and can cause the oil to auto ignite.

4.1.3 Pyrolysis Reaction

Oil undergoes a chemical change called pyrolysis due to rise in reservoir temperature. Pyrolysis reactions are often referred to as the fuel deposition reactions in the ISC literatures, because these reactions are responsible for the deposition of “coke” (a heavy carbon rich low volatility hydrocarbon fraction) for subsequent combustion.

Oil pyrolysis reactions are mainly homogeneous (gas-gas) and endothermic, (heat absorbing) and involve three kinds of reactions:

- Cracking
- Condensation
- Dehydrogenation,

In the cracking reactions, the carbon - carbon bond of the heavier hydrocarbon molecules are broken, resulting in the formation of lower carbon number (smaller) hydrocarbon molecules.

Dehydrogenation reactions shows the hydrogen atoms are stripped from the hydrocarbon molecules, while leaving the carbon atoms untouched. If condensation reactions occurs, the number of carbon atoms in the molecules increases leading to the formation of heavier carbon rich hydrocarbons. At 700 - 1250°F they undergo dehydrogenation and/or thermal cracking reactions depending upon the length of the hydrocarbon chain.

Pyrolysis of heavy crude oil in porous media goes through three overlapping stages: distillation, visbreaking, and coking. During distillation, the oil loses most of its light gravity and part of its



medium gravity fractions. Cracking reactions are usually initiated by the cleavage of the carbon-carbon bond, followed by the hydrogen abstraction (dehydrogenation) reaction. The dehydrogenated molecules then recombine to form heavier molecules, eventually leading to the formation of “coke”.

Mild cracking of the oil (visbreaking) occurs in which the hydrocarbon lose small side groups and hydrogen atoms to form less branched compounds, that are more stable and less viscous occur at higher temperatures (400-540°C),

The oil remaining in the porous medium cracks into a volatile fraction and a non volatile carbon rich hydrogen poor residue often referred to as “coke” occurs at still higher temperatures, (above 550°C).

Coke is defined as the toluene insoluble fraction of oil and generally contains 80-90% carbon and 3–9% hydrogen.. It is further observed that distillation of crude oil at low temperatures plays an important role in shaping the nature and extent of the cracking and coke formation reactions. Both visbreaking and cracking reactions produce hydrogen gas and some light hydrocarbons in the gas phase High operating pressures generally lead to the formation of more fuel that is leaner in hydrogen.

4.2 Reaction Kinetics

Reaction kinetics can be defined as the study of the rate and extent of chemical transformation of reactants to product. Though, simplistic this definition is accurate for this study. The study of reaction kinetics for the in-situ combustion process is undertaken for the following reasons:

- The reactivity of the oil characterization
- Determination of the conditions required to determine if self ignition will take place in the reservoir upon air injection or to achieve ignition.
- Gaining insight into the nature of fuel formed and its impact on combustion.

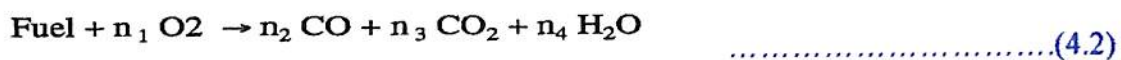


- Establishing parameter values used in the numerical simulation of ISC processes like the kinetic (reaction rate) models

Correct kinetic representation of crude oil oxidation reaction would require an inordinately large number of kinetic expressions. Combustion of crude oil in porous media is not a simple reaction but follows several consecutive and competing reactions occurring through different temperature ranges.

But, this is not feasible because these compounds undergo reactions that cannot easily be described. The complexity is linked to chemical structure of the individual hydrocarbon. Many of them contain several coexisting C-H bonds which can react successively or simultaneously and often produce intermolecular reactions.

The simplest overall reaction representing the oxidation of a typical hydrocarbon fuel is



Where the stoichiometry coefficients (n_i) are determined by the choice of fuel.

This global reaction is a convenient way of approximating the effects of many elementary reactions which actually occur in the reservoir during the combustion process. Its rate must therefore represent an appropriate average of all the individual reaction rates involved. Most researchers describe the ISC oxidation reaction rates in terms of a simple reaction rate model that assume functional dependency on carbon (fuel) concentration, and oxygen partial pressure.

This widely accepted model is given by:

$$R_c = \frac{dC_m}{dt} = k P_{O_2}^a C_f^b \dots\dots\dots(4.3)$$

Where,

R= combustion rate of crude oil,

C= instantaneous concentration of fuel,

k = rate constant,

P_{O₂} = partial pressure of oxygen,

a = order of reaction with respect to oxygen partial pressure, and



b = order of reaction with respect to fuel concentration.

The reaction rate constant 'k' in Equation is often a function of temperature and expressed by

$$k = A e^{(-E/RT)} \dots\dots\dots (4.4)$$

Where,

A = pre-exponential factor,

E = activation energy,

R = universal gas constant= 1.987 cal mole⁻¹ K⁻¹, and

T = absolute temperature in °K.

The constants in Equation vary with oil type, pressure, and other parameters as well. Equation is often referred to as the Arrhenius rate equation and the constant 'A' as Arrhenius rate constant in the ISC literature.

4.3 Thermal Analysis

Thermal gravimetric analysis (TGA) and differential scanning calorimetry are the most widely employed thermal analytical tools to study the oxidation kinetics of the combustion process. In the recent years these also utilized as a screening tool for in-situ combustion.

A more recent addition to the family of thermal analysis tools is the accelerating rate calorimeter (ARC). ARC has been used in the petroleum industry since the early 1990s mainly by 'Amoco Oil Co.', to screen oils for in-situ combustion application.

4.3.1 TGA and DTA Techniques

TGA represents a small sample of crude oil and sand is heated in the presence of flowing air and the change in weight of the sample is recorded as a function of temperature or time, i.e., $W = f(T \text{ or } t)$. If the temperature of the sample is increased as a linear function of time, the method is referred to as an non-isothermal TGA.

When pressure effects are important, the apparent weight changes are corrected for buoyancy effects based on the blank run results (Bae, 1977). In differential thermal analysis (DTA) technique the energy changes of a sample relative to a reference material are recorded as a function of temperature or time.

Usually, the sample temperature is compared continuously with the reference material temperature and the difference in temperature is recorded. In TGA technique the change in the weight of the sample (called a conventional TGA curve) or alternatively the differential of the weight change with respect to temperature dW/dT (called a 'differential thermal gravimetric (DTG)' curve) is plotted against temperature.

DTA refers the difference in temperature between the sample and the reference material is plotted against the temperature and a baseline is established by connecting the extreme end of the DTA curve by a straight line (Figure). The sample size affects the magnitude of the DTA curve and the height of the curve is proportional to the weight of the sample.

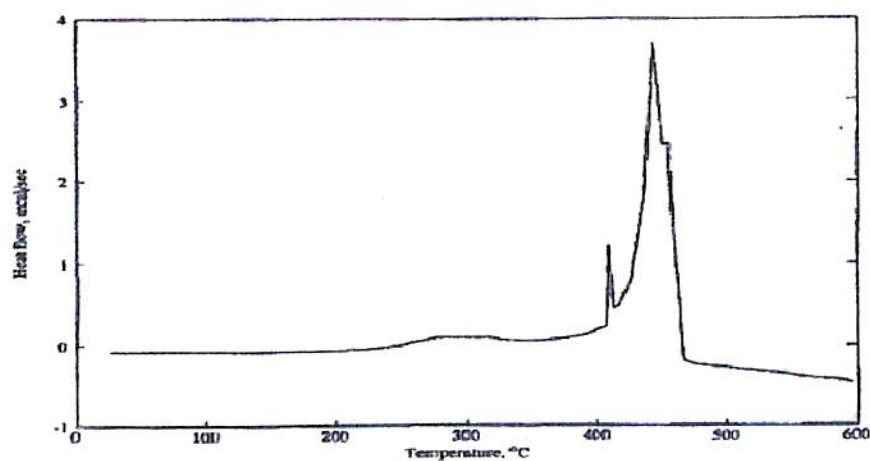


Figure 4.2: Typical DTA Plot for Californian Heavy Oil Sand Mixture

The TGA, DTA, and the DTG curves are known as the thermograms. Each crude oil produces a characteristic thermogram that is quite distinctive from the others. Both the DTA and DTG thermogram produces a series of peaks.

The areas under the DTG thermogram peaks (Figure) are proportional to the total weight change of the sample. The conventional thermal gravimetric analyzer can plot on the same graph both the TGA and the DTG curves automatically.

The DTG curve also tends to be more reproducible than the TGA thermograms and give accurate information of the beginning, the maximum, and end of weight change and is a reproducible fingerprint of the oil. The DTG will usually give two distinct sharp peaks, when there are two changes close to each other in temperature.

The TG, DTG, and DTA thermograms all can be used to determine the reaction kinetics.

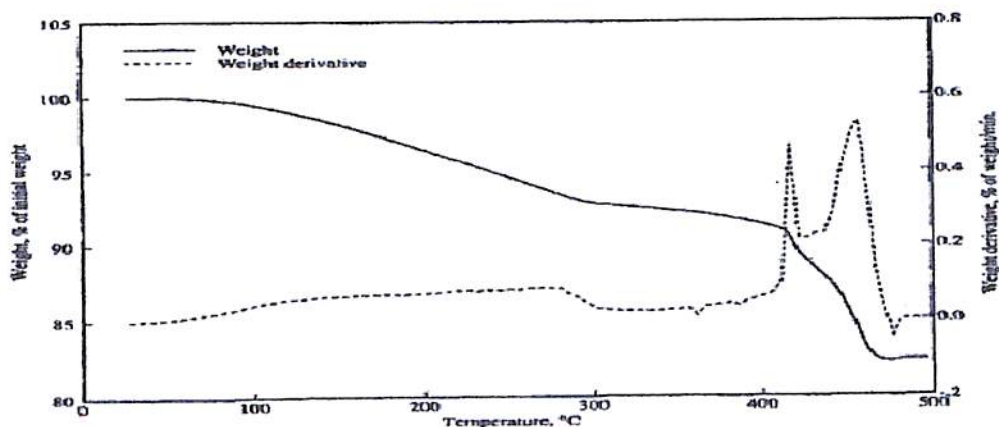


Figure 4.3: Typical DTG thermogram for Venezuelan Extra Heavy Oil Sand Mixture



4.3.2 Determination of Kinetic Parameters from Thermogram

The rate of change of weight of a sample (rate of reaction) is related to the reaction rate as:

$$d\alpha / dt = k (1 - \alpha)^n \dots\dots\dots(4.5)$$

Where α (fractional weight change of the sample) = $(W_0 - w) / (W_0 - W_m)$

W_0 = initial sample weight

W_t = sample weight at time

W_m = final sample weight

$t = t - t_e$

k = specific reaction rate

n = order of the reaction

Now let the temperature be linearly increased at a constant rate ' β ' defined as

$$\beta = dT / dt \dots\dots\dots(4.6)$$

Here 'T' is the temperature at time 't'.

Combining Equations (4.5) and (4.6) we have

$$\frac{d\alpha}{dT} = \frac{k}{\beta} (1 - \alpha)^n \dots\dots\dots(4.7)$$

Substituting the expression for 'k' from Equation (4.4) in Equation (4.7) we have

$$\frac{d\alpha}{dT} = \frac{A \times \exp\left(\frac{-E}{RT}\right)}{\beta} (1 - \alpha)^n \dots\dots\dots(4.8)$$

Following Coats and Redfern, we obtain

$$\frac{1 - (1 - \alpha)^{1-n}}{1 - n} = \frac{ART^2}{\beta E} \left[1 - \frac{2RT}{E} \right] \exp\left(\frac{-E}{RT}\right) \text{ for } n \neq 1 \dots\dots\dots(4.9)$$

For large values of E / RT , and taking natural logarithm



$$\ln \left[\frac{1 - (1 - \alpha)^{1-n}}{(1 - n) T^2} \right] = \ln \left[\frac{AR}{\beta E} \left(1 - \frac{2RT}{E} \right) \right] - \frac{E}{RT} \quad \text{for } n \neq 1 \quad \dots\dots\dots (4.10) \quad \&$$

similarly for $n = 1$ one has for large values of E / RT

$$\ln \left[-\ln \frac{(1 - \alpha)}{T^2} \right] = \ln \left[\frac{AR}{\beta E} \left(1 - \frac{2RT}{E} \right) \right] - \frac{E}{RT} \quad \text{for } n = 1 \quad \dots\dots\dots (4.11)$$

Substituting the expression for 'k' from Equation (4.4) in Equation (4.5) we have

$$\frac{d\alpha}{dT} = A \exp \left(\frac{-E}{RT} \right) (1 - \alpha)^n \quad \dots\dots\dots (4.12)$$

Taking the common logarithm, we have

$$\log \left(\frac{d\alpha}{dt} \right) = n \log (1 - \alpha) - \frac{E}{2.303 R} \left(\frac{1}{T} \right) \quad \dots\dots\dots (4.13)$$

By keeping the term $\log (d\alpha/dt)$ constant, i.e.

$$\log \left(\frac{d\alpha}{dT} \right) = \log K \quad \dots\dots\dots (4.14)$$

We get,

$$\log (1 - \alpha) - \frac{E}{4.575 n} \left(\frac{1}{T} \right) + \frac{\log K}{n} \quad \dots\dots\dots (4.15)$$

By plotting $\log (1 - \alpha)$ against $(1/T)$, a straight line is obtained whose slope and intercept allow T calculation of both the activation energy 'E' and the reaction order 'n'. The pre- exponential factor A can be then calculated from Equation (4.4).

$$\left[\frac{\exp(\alpha t_1) - \exp(\alpha t_m)}{\exp(\alpha t_1) - \exp(\alpha t_2)} \right]^{[\exp(\alpha(t_1 - t_2))]} = \frac{\Delta T_m}{\Delta T_2} \times \exp [\alpha (t_1 - t_2)] \quad \dots\dots\dots (4.16)$$

$$\alpha = \frac{E\phi}{RT_0^2}$$

$$\alpha t_m = \ln \left(\frac{\alpha}{B} \right) + (1 - n)$$

$$B = A_0 \exp - \left(\frac{E}{RT_0} \right) \quad \dots\dots\dots (4.17)$$

where:

E = activation energy



A_0 = Arrhenius pre-exponential factor

t_m = time of maximum reaction rate

t_f = time of completion of reaction

t_a = time of any point along DTA curve

ΔT_M = ΔT at a maximum reaction rate

ΔT_a = ΔT at t .

Φ = heating rate

R = universal gas constant

T_0 = temperature at which DTA curve departs from the baseline.

In a nonoxidative atmosphere, weight loss below 500°F is due primarily to distillation with thermal cracking becoming the predominant process at higher temperatures. Only the carbon rich material remains above 1000°F. In an oxidative environment the TGA and DSC curves are more complex. At low temperature, low temperature oxidation competes with distillation and at intermediate temperature combustion competes with cracking.

The kinetic parameters n , E , and A maybe easily determined from the above expressions. The weight loss mechanism associated with the DTG peaks for crude oils have been identified by several investigators (Vossoughi et al., 1985; Drici and Vossoughi, 1985; Kharrat and Vossoughi, 1985; Jha and Verkoczy, 1986; Verkoczy and Jha, 1986).



CHAPTER - 5

SCREENING CRITERIA FOR IN-SITU COMBUSTION METHOD



CHAPTER 5

Screening Criteria of In-Situ Combustion Method

Geological characteristics of reservoir plays a major role in the outcome of many past ISC projects. The account for more than 70% of the implemented ISC projects indicate that the structure, lateral continuity, and physical characteristics of the individual sand layers within the reservoir as well as the reservoir heterogeneities played a significant role in the performance of these projects as study and research of the reservoir characteristics of the in situ combustion projects states.

Geological reservoir description aims to provide a clear, concise picture of the qualitative and quantitative parameters of the reservoir so that the engineer can design a scheme that most appropriately matches the reservoir conditions.

The degree and extent of lateral and vertical reservoir continuity, depth, thickness, structural attitude and dip, overburden competence, reservoir heterogeneities, and of presence of gas cap and aquifer are the key geological parameters to be considered when selecting a site for a fireflood project.

5.1 Reservoir Thickness

An important parameter for the combustion process is sand thickness. Air has a tendency to override the oil column and consequently by pass much of the oil if the reservoir exceeds a critical thickness. This tendency is due to large difference in density between air and the reservoir fluids.

Rapid transfer of heat to the bottom of the sand will permit combustion front to advance at the bottom more rapidly than it would be possible in thick sand in a thin heavy oil reservoir. Sometimes if sand is too thin high overburden heat losses may drop the temperature below that



necessary to sustain a combustion front and can lead to LTO and loss of recovery. Mainly pay thickness should at least be four feet and should not exceed 50 feet. It not only minimizes the heat losses to the overburden but can also aid in promoting and sustaining high temperature combustion mode in heavy oil reservoirs.

In reservoirs containing oil not readily susceptible to auto-ignition formation thickness is also an important consideration In such reservoirs the near well-bore area must be heated to a high temperature to initiate ignition.

Formations up to 60 ft. thick have been ignited using artificial ignition techniques. Formation is very thick (>50 ft.) the amount of heat needed to raise the well-bore vicinity above the oil's auto-ignition temperature can be very large and expensive.

An ideal geometry for achieving favorable sweep during combustion can be the success of the combustion projects in the thin and often poor quality strand plain/ barrier island (lagoon and near shore environment deposits) is attributed to the excellent lateral continuity of the sands. Such reservoirs consist of multiple, thin, blanket type oil column that are more widespread and separated by shale stringers and tightly cemented mudstones.

Some failure of early California ISC projects such as those undertaken in the early 1960s in such fields as Ojai, White Wolf, Canyon can also be attributed in part to the lack of reservoir continuity. The poor lateral continuity and compartmentalization resulting from complex lateral facies variation did not permit the free movement of fluids.

Although, formation exhibit excellent porosity, good permeability and good oil saturation composed of a series of overlapping sand lenses, separated by interbedded impermeable shale layers.

The degree and extent of lateral and vertical reservoir continuity significantly affect the performance of the ISC process.



5.2 Vertical Depth

Another aspect that cannot be ignored in ISC process is depth of the reservoir. Depth from 300-11500 ft are proven to be economically successful projects that have been implemented in reservoirs in past.

Depth is a factor in terms of temperature, pressure and well cost.

- Shallower depth (less than 200ft.) would severely limit the pressure at which air could be injected.
- With increasing depth, air injection pressure generally increases with a corresponding increase in compression cost (larger compressor).
- Deeper reservoirs generally contain lighter oils and air injection at high pressure into these reservoirs can offer some unique technical opportunities for improved oil recovery. Deeper reservoirs are usually hot enough, that spontaneous ignition of in-situ hydrocarbon is likely upon air injection.

Reservoir pressurization, flue gas stripping of the light ends of reservoir oil by the combustion gases, oil swelling and high pressure miscibility apart from combustion and the attendant oil recovery by displacement, other reservoir mechanisms also contributes to oil recovery.

With greater injection pressures greater injective capacity can be obtained. Thus, with greater injective capacity, well spacing can be enlarged.

5.3 Structural Altitude and Dip

Structural attitude and dip are important consideration in the location of wells for a combustion project. Injected air and combustion front movement will be more rapid toward up dip wells than toward wells low on the structure.



In dipping reservoirs it is advisable to locate the air injectors down dip and production wells up the structure to compensate for the expected flow of air up dip. In steeply dipping reservoirs some operators preferred injecting air at the top of the structure to take advantage of gravity in the recovery of hot mobile trade affected by combustion.

In the steeply dipping Webster reservoir, the combustion project was initiated as a crested drive in part, to heat the oil at the top of the structure and promote migration of oil toward the flanks of the anticline. Dip and the resulting gravity dominance played a major role in the economic success of the ISC project.

5.4 Overburden Competence

Gaps in oil sand overburden or leaky inter-zonal seals in stratified reservoirs can allow fluid 'leaks' into overlying strata. The producing formation at the project site must site have sufficient and competent overburden so as to confine the injected air within the pay zone.

5.5 Reservoir Heterogeneities

In-situ combustion recovery performance include permeability barriers to lateral and vertical flow, natural fractures, high permeability thief zones, directional permeability, presence of gas cap and aquifers are the impact of reservoir heterogeneities.

Vertical barriers can also act as a seal to upward migration of injected air and may result in a more uniform burning in relatively thick reservoirs. As a negative effect, horizontal permeability barriers can reduce the reservoir continuity and recovery.

Permeability barriers can have both positive and negative effect upon the in-situ combustion process. As a positive effect, vertical permeability barriers can divide a thick reservoir into smaller units, which may be more compatible with the in-situ combustion process.



Fractures and joints are secondary properties that may create preferential flow channels and influence the recovery. Grain size and its orientation contribute to the existence of directional permeability in a heterogeneous reservoir. Often the orientation of the medium to coarse grained sands establish the direction of high permeability zone.

5.6 Sand Uniformity and Texture

Oil sands often vary considerably in their characteristics both vertically and laterally. The degree to which heterogeneous sand approaches homogeneity or uniformity, however, impact the fireflood performance. Actual grain size and grading, shape of grains, character and amount of cementing material determines the physical characteristics and properties of the reservoir. The size, shape and sorting of the grains determine the porosity and permeability of sand. Coarse, well-sorted and rounded sand grains result in a high porosity, high permeability reservoir.

The permeability profile (permeability variation) as determined from core analysis, is valuable information for determining the relative homogeneity of the sand. Generally the greater the degree of uniformity exhibited in a profile more uniform the burn will be.

5.7 Rock Properties

The key rock properties of interest to an engineer evaluating a prospect for the application of ISC process are, sand texture, permeability and its distribution, porosity, and composition of rock matrix. In many ISCs, especially those implemented in light oil reservoirs rock composition is more important than oil properties in determining the amount of fuel available for combustion.

5.8 Permeability

The permeability of a rock is a measure of its specific flow capacity and can be determined only by a flow experiment. Since permeability depends upon continuity of pore space, there is not, in theory (nor in practice), any unique relation between the porosity of a rock and its permeability (except that a rock must have a non-zero porosity if it is to have a non-zero permeability). For unconsolidated rocks it is possible to establish relations between porosity, and either some



measure of apparent pore diameter, or of specific surface, and permeability (e.g . Kozeny model), but these have a limited application

The actual value of permeability has very little effect on the mechanics of combustion process. Economically successful ISCs have been implemented in less than 10 md carbonate light oil reservoirs.

The only requirement for permeability is that it must be adequate to permit air injection at a pressure compatible with overburden at an acceptable compression cost. In viscous heavy oil reservoirs too, low permeability may fail to provide the minimum air flux needed for sustained combustion.

Low permeability also increases air injection pressure requirements and compression costs, and prolongs the operation. Low permeability in a viscous (greater than 100 cp.) shallow reservoir can limit the infectivity and promote LTO. In such reservoirs a permeability greater than 100 md would be necessary.

5.9 Porosity

Processes subsequent to sedimentation - cementation, recrystallization, solution, weathering, fracturing - can modify substantially the proportion and distribution of void space, and in some circumstances it may be necessary to define a system as a dual porosity system having primary and secondary porosity, although since it is the physical nature of the porosity that is of interest, these may be defined as coarse and fine porosities.

- High porosity is desirable, since it directly reflects the volume of hydrocarbons that the rock can hold. As porosity decreases, the amount of heat stored in the rock increases.
- A lower porosity will not have a significant impact on overall energy utilization in wet combustion process because part of the heat stored in the burned volume of the reservoirs will be recovered through scavenging operations.



The main impact of porosity will be in its oil content. The economic success of a ISC is dependent more on the actual value of the oil saturation- porosity product ($f(S_o)*\phi$) than on porosity. Porosity lower than 0.2 is acceptable, only if the oil saturation is greater than 0.45.

5.10 Oil Saturation

Minimum oil content (the product of oil saturation and porosity) is necessary in order to offset the consumption of oil as fuel in an in-situ combustion process. A widely accepted rule-of-thumb in the industry is that if fSo is less than 0.09 or 700 bbl/ac-ft. dry combustion should be eliminated from further consideration.

This arbitrary cutoff simply implies that the reservoir should have enough recoverable oil to cover the energy requirements of the process and supply additional production to make the process economically attractive. For wet combustion where the fuel lay down is lower somewhat lower oil saturation is acceptable.

5.11 Effect of Well Spacing

If the well spacing is too close, the combustion front may experience early gas breakthrough, while if the well spacing is too large, the oil production rate will be slow, thus prolonging the life of the project and making the economic unattractive.

Hence, the well spacing should be in the optimum range to maximize oil recovery. Geological considerations are quite important in determining the optimum flood pattern and well spacing. The wells should be spaced to fit the geological pattern of the sand. Some sand bodies frequently exhibit anisotropy parallel to the bedding.



5.12 Preliminary Screening Criteria

5.13.1 Oil

- Viscosity: Preferably less than 5000 cp at reservoir condition.
- Gravity: 10-40 °API
- Composition: Low asphaltic, low heavy metal content crude. Heavy metal (V, Ni, etc.) should be preferably less than 50 ppm.

5.13.2 Water

- Connate water properties are not critical.

5.13.3 Lithology

- Heavy oil reservoir: Low clay content; low in minerals that promote increased fuel formation such as pyrite, calcite, and siderite as well low in heavy metals.
- Light oil reservoirs: Lithology that tends to promote fuel deposition is preferred.

5.13.4 Reservoir

- Depth: 300 – 12500 ft.
- Thickness: 5-50 ft.
- Permeability: Not critical
- Porosity: >0.18
- Oil concentration: 700 bbl/ac-ft, $F_{so} > 0.09$
- Transmissibility: $kh \sim 0$ to 20 md-ft/cp



5.13.5 Favourable Factors

- High reservoir temperature
- Low vertical permeability
- Good lateral continuity
- Multiple thin sand layers
- Good overburden competence
- High dip
- Uniform Permeability profile

5.13.6 Factors Which Increase Risk

- Extensive fractures
- Large gas caps
- Strong water drive
- Highly heterogeneous reservoir



CHAPTER- 6

A CASE STUDY ON IN-SITU COMBUSTION

METHOD



CHAPTER 6

A Case study on In-Situ Combustion Method

On one of the light oil fields of India is taken for experiment. Properties of the crude oil changes from pool to pool Specification of field sample are as follows:

- The crude has asphaltene content of about 0.5-0.9 % (w/w).
- The reservoir crude has 37° API gravity (at 60°F) and STO density of 0.8267 g/cc (at 60°F).
- The reservoir temperature is 76-80°C. Resin content in the oil is of the order of 15 %.

6.1 Details of Experiment

The test was conducted at a pressure of 1350 psi using normal air. The core was initially heated to reservoir temperature (76°C). Temperature of zone 1 was increased to ignition temperature 350°C to observe the front behavior.

6.2 In-Situ Combustion Tube

Thermocouples are mounted along axial length of the tube; total 28 thermocouples are fixed in this tube to record the temperature from different locations.

12 Thermocouples are mounted at the mid-point of each zone to detect temperature of the core. And on Outer side 12 Thermocouples are fixed to detect the temperature of wall.

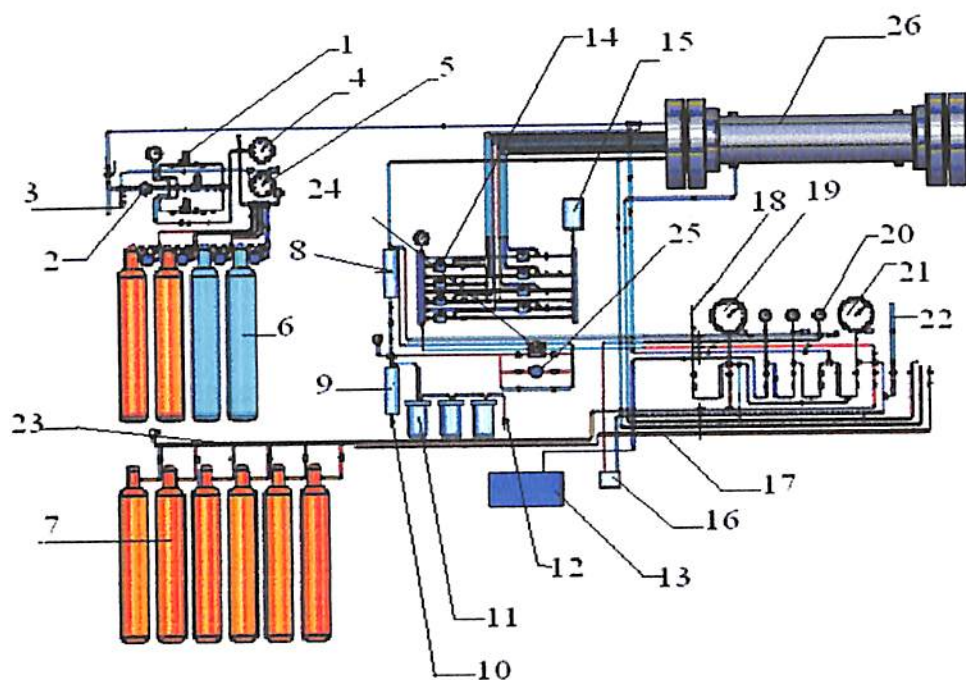


Figure 6.1: Schematic of Combustion Tube Lab Setup

- | | |
|------------------------------------|--------------------------------|
| 1. MF Control Valve | 14. Pressure Transducers |
| 2. BPR (Back Pressure Regulator) | 15. H ₂ O Reservoir |
| 3. Vent | 16. DP Cell |
| 4. MF Inlet | 17. Mass Flow Production |
| 5. CT Inlet | 18. Annulus Vent |
| 6. Air Cylinder | 19. Annulus |
| 7. He Cylinder | 20. Separator |
| 8. HP Separator | 21. Bias |
| 9. LP Separator | 22. Bias Vent |
| 10. Oil Out | 23. He Manifold |
| 11. Condensers | 24. Control Valve |
| 12. Gas out to GC & Wet test meter | 25. BPR |
| 13. H ₂ O Pump | 26. Combustion Tube |



Three Thermocouples are kept for observing the temperature in annulus and one Thermocouple is fixed at injection side near igniter. In addition to this the system also provides the power consumption of each heater.

For recording the pressure, 8 pressure taps are incorporated in tube out of which 6 pressure taps kept on tube in equal distance.

One sand trap (separator) to handle the fluid during initial purging, one high pressure separator and one low pressure separator is kept at production site to handle produced fluids.

The separated gas passes through back pressure regulator than the gas passes through moisture extractors and enters into gas chromatograph. One wet test meter is kept in gas line after GC to measure the produced gas. All separators and production lines are coiled with heat strips to avoid oil blockage due to oil congealing.

1st pressure tap is fixed with injection line and 8th pressure tap connected to production end of the tube. Pressure readings are recorded at the same rate of temperature reading.

High pressure cylinders are connected to mass flow (injection) system to feed the gas into tube. Rate of injection is controlled through mass flow controller.

Helium cylinders are connected to bias system to pressurize the system to run pressure, which includes bias, annulus and combustion tube. Bias is a reference pressure to control the pressure in tube.

The laboratory combustion tubes described in the literature use one of two basic designs:

1. Insulated tubes.
2. Near adiabatic tubes.



With insulated tubes heat loss is minimized by insulation alone. Operation of insulated tubes requires high air fluxes, of the order of 70-100 times those actually used in the reservoir. Such high air fluxes are needed to reduce the residence time of fire front in the tube, and hence the heat losses. Such high fluxes are often difficult to sustain in the tube due high pressure drops across the core. In addition at high fluxes, air requirement and fuel availability may increase with increasing flux.

Near adiabatic operation should allow combustion front to propagate at lower fluxes. To minimize the heat loss from the tube wall and to maintain adiabatic conditions in the tube, most current designs employ tube assemblies with compensating heaters.

These are narrow width (1-2 inch wide) band heaters mounted along the length of the tube at equally spaced interval and are designed to match the wall (heater) temperature with the tube's center temperature at each heating zone. A major concern with the use of heater is how to minimize the possibility of the heaters influencing the movement of the combustion front.

6.3 Burning procedure

Normally all tube tests were performed on native cores, due to high fraction of shale and coal in the core, the experiment was carried out with synthetic sand of 100 mesh size. The sand is divided into 1 kg samples and wetting with 7% wt by mass of Methanol. Lifted the tube in vertical position and poured prepared each core sample in tube and manually tamped.

Each sample occupied 75-80 mm length of the tube, after completion of packing the tube was capped with production flange. The core thermocouples inserted within the core through tube assembly. All pressure taps were connected to tube. Tube brought down to horizontal position and pressurized up to 100 psi to check leaks. After leak test Nitrogen was injected for 12 hrs for Methanol evaporation by keeping tube in vertical position.



Thin walled shroud was placed on tube. Then expanded silica (perlite) was poured in gaps between tube and shroud. The tube was inserted in pressure jacket. Vacuum pump was connected to injection, production and annulus for vacuum creation.

Water flooding was carried out with synthetic brine (similar to reservoir water). Once flooding was completed, all pressure taps and the production end were opened for line filling. This exercise confirms that the tube was filled with water in all sides. Permeability test was conducted by operating water pump and differential cell connected to computer to generate differential pressure graph. All pipe connections are removed and lifted the tube into vertical position.

Thermocouples and heaters were connected to control panel, then oil injected in tube until the oil comes out from production side. Mass flow calibration was carried out and the system was checked up before final experiment.

The test was carried out to know the effect of native core interaction on the creation, propagation and sustainability of the front using uniform air injection flux ($33.86 \text{ m}^3 \text{ (ST)/m}^2\text{h}$) through out the experiment. At the start of run, Helium was injected into the core to pressurize it to the specified run pressure of 1350 psi.

At the same time the core was preheated to the reservoir temperature of 76°C . Ignition was carried out at high temperature (350°C) in order to establish high temperature mode of front. The maximum temperature observed during the run was 822°C which occurred in zone 2. After 10.10 hrs air injection was terminated and Helium injection was started at $33.80 \text{ m}^3 \text{ (ST)/m}^2\text{h}$. The whole process lasted for 12.82 hrs when final bleed off was started. Data was recorded at regular time intervals.

6.4 System pressurization

Instrumentation air supplied to back pressure regulator at 50 psi at production side for pneumatic function of valve. Annulus/Bias and combustion injection valves are opened for pressurization. Helium gas was feed slowly to all these areas simultaneously.

All the heaters were switched on and increased the temperature step by step up to reservoir temperature of 76°C. Helium was injected into system at increasing rate until desired run pressure attained. Once the system reaches to run pressure, stopped helium feeding from bias side and initiated helium injection from mass flow side for purging.

Annulus pressure increased to 70 psi above the tube pressure to balance the system pressure and to avoid damage to tube. Information that can be derived from combustion tube tests include:

- Apparent fuel consumption.
- Liquid hydrocarbon (oil) recovery from swept zone.
- Effect of the injected water-air ratio (in the case of wet combustion process) on the process parameters
- Atomic H / C ratio of the burned fuel.
- Oxygen-fuel ratio (OFR).
- Air-fuel ratio (AFR).
- Oxygen-sand ratio (OSR).
- Excess air..
- Characteristics of the produced fluids
- Peak combustion temperatures.
- Stability of burn zone.

6.5 Case Study on In-Situ Combustion

The experiment was carried out on one of the light oil fields of India:

Table 6.1: Field Details

Field
Formation	Sandstone
Porosity, %	16-30
Average Oil saturation, %	40
Res. Temperature, ° C	76-80



Gravity, ° API	37
Oil Density, g/cc	0.8267
Thickness, m	2-6 (Effective)
Permeability, md	8-90 (Avg. value = 20-30)
Initial Reservoir Pressure, psi	1351

6.5.1 Experiment Details

6.5.1.1 Core Preparation

Core material is checked and any shale stringers or other non permeable and non representative material is removed. Existing fluids are extracted by using a toluene wash and the core is heated it is then crushed and packed into the tube.

Normally all tube tests were performed on native cores. This experiment was carried out with synthetic sand of 16 mesh size. At initial we prepare 16 mesh sand mixture along with oil and water in a jar and injected at depth 1080 mm from injection end. After this we prepare 20/30 mesh sand mixture, followed by 100 mesh native core. Now we add 20/30 mesh sand followed by 16 mesh size sand.

6.5.1.2 Core Packing and Flooding

In this run, mixture of synthetic sand and core of 60-100 mesh size in the ratio 70:30 was used to pack the tube. The premix packing was carried out by mixing oil, brine and sand+core in predetermined ratio.

One kg sample of rock material mixed with calculated proportion of oil and water. Then, this mixture was thoroughly mixed to make it homogeneous. After premix packing of the tube, thermocouples were inserted in the tube. Leak check was carried out and tube was inserted in pressure jacket for carrying out the experiment.



Table 6.2: Core Packing Data

S. No.	Type of core	Oil (g)	Water (g)	Wt of sand (g)
1	16 mesh	60.8	48.2	476.8
2	20-30 mesh	60.7	48.1	506.4
3	Core +syn sand	124.1	98.4	963.6
4	Core +syn sand	124.1	98.4	993.8
5	Core +syn sand	124.1	98.4	993.2
6	Core +syn sand	124.1	98.4	986.4
7	Core +syn sand	124.1	98.4	1006.4
8	Core +syn sand	124.1	98.4	1012.0
9	Core +syn sand	124.1	98.4	999.8
10	Core +syn sand	124.1	98.4	982.4
11	Core +syn sand	124.1	98.4	985.8
12	Core +syn sand	124.1	98.4	1000.8
13	Core +syn sand	124.1	98.4	1008.0
14	Core +syn sand	124.1	98.4	986.0
15	Core +syn sand	124.1	98.4	985.8
16	Core +syn sand	124.1	98.4	1001.2
17	Core +syn sand	124.1	98.4	997.0
18	Core +syn sand	124.1	98.4	998.6
19	Core +syn sand	124.1	98.4	984.0
20	Core +syn sand	124.1	98.4	1005.4
21	Core +syn sand	124.1	98.4	1026.6
22	Core +syn sand	112.0	89.0	906.4
23	20-30 mesh	60.8	48.1	483.6
24	16 mesh	96.0	78.0	657.0

6.5.1.3 Initial sand pack properties

Table 6.3: Initial Sand Pack Properties

Details	Run	unit
Total weight of core + frac sand	21.735	Kg
Pore volume	5.76	Ltrs
Porosity	41.25	%
Fluid saturations at initial stage		
Oil	85.7	%
Water	14.3	%
Gas	0	%
Fluid saturations at Ignition		
Oil	55	%
Water	8.8	%
Gas	36.2	%
Permeability	6	Darcy
Temperature	76	°C
Ignition temperature	250	°C
Mole percent of O ₂ in feed gas	21.22	%

6.5.1.4 Temperature Profiles

The Run was conducted to generate the combustion parameters with native core pack. In this run oil was ignited at high temperature 350°C and peak temperature reached to 822 °C (zone 2). The front was sustained and propagated with stable velocity in all zones.

Temperatures recorded were around 600°C. Presence of clay and coal in native core increased the reactions and produced more fuel resulting in high temperature of 600° C or more in all zones.



Table 6.4: Peak Temperatures

Zone	Runtime (Hrs)	Temperature, °C
1	0.20	494.50
2	1.20	822.50
3	2.27	653.25
4	3.17	611.68
5	4.35	573.09
6	5.43	578.02
7	6.53	617.04
8	7.57	532.88
9	9.07	584.94
10	9.98	616.46
11	11.12	623.94
12	12.28	284.64

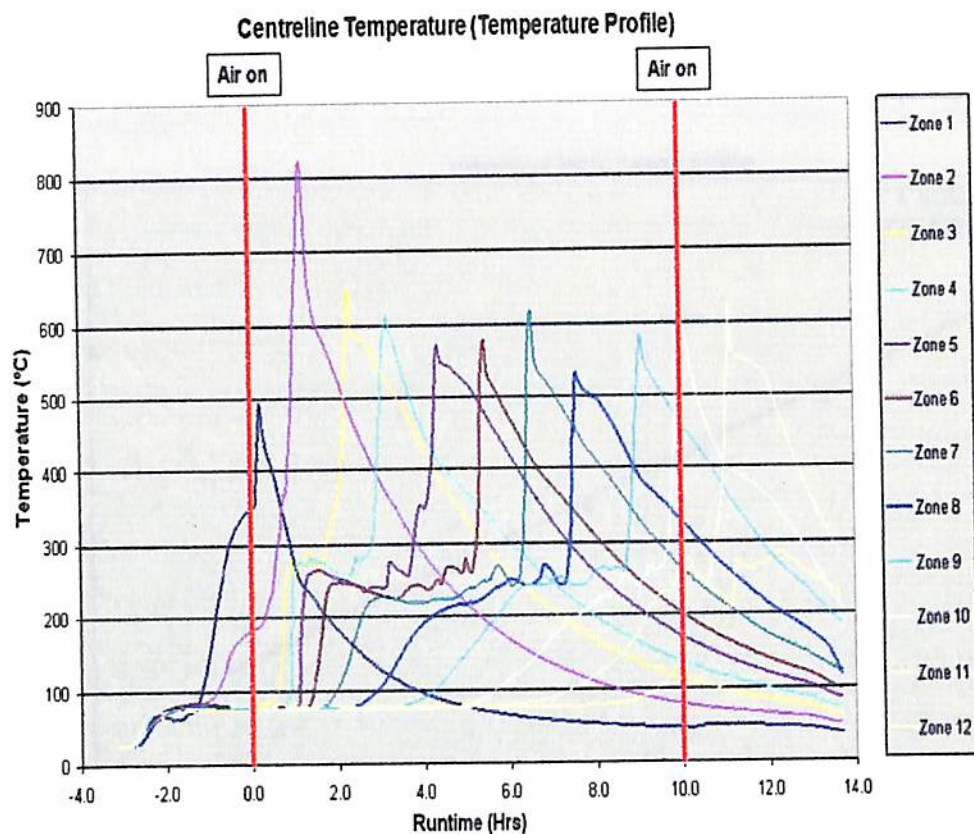


Figure 6.2: Temperature Profiles

6.5.1.5 Stabilized Combustion Period

Combustion front velocities are based on the rate of a specified temperature level at the leading edge of the high temperature region.

In the Run, stabilized combustion period was considered from zone 4 to zone 10 over the time period of 2.85 hrs to 9.93 hrs. The combustion behavior in presence of native core indicates that the mineralogy of the core plays major role in increasing complexity of reactions and deposition of more fuel. The increased fuel deposition has resulted in increase in temperature of combustion front. The Gas chromatograph data also indicates high mole percent of CO_2 , CO and minimal un-reacted oxygen. Sometimes clay also increases the fuel deposition due to increase in surface area

and absorption characteristics. The combustion front velocity (450°C leading edge) in the Run was 0.15 m/h at uniform flux of $33.86 \text{ m}^3 \text{ (ST)/m}^2\text{h}$ from zone 4 to zone 10.

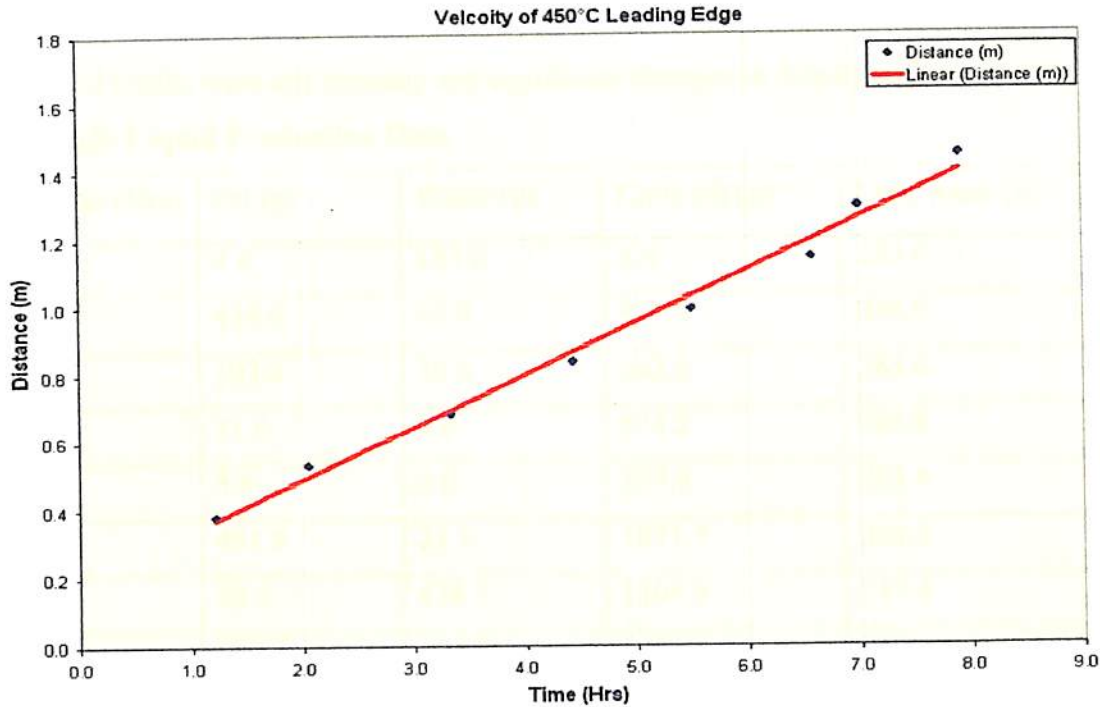


Figure 6.3: Velocity at 450°C Leading Edge

6.5.1.6 Air and Fuel Requirements

Nelson-Mcneil (1961) method was used to determine the overall air and fuel requirements. Air and fuel requirements are calculated for stabilized period between zones 4 to 10. The overall air to fuel was $9.35 \text{ m}^3/\text{kg}$ of fuel. The air and fuel requirements were $280.27 \text{ m}^3 \text{ (ST)/m}^3$ and 29.97 kg/m^3 respectively. The overall oxygen utilization was 99.8%.



6.5.1.7 Liquid Production History

Liquid production collected based upon the mode of injection to calculate the oil recovery. Specific gravity of oil was measured for each sample, collected during experiment. The measured results were not showing any significant changes in density and viscosity of oil.

Table 6.5: Liquid Production Data

Runtime (Hrs)	Oil (g)	Water (g)	Cum. oil (g)	Cum water (g)
-2.87	4.4	183.0	4.4	183.0
-2.42	434.6	65.0	439.0	248.0
-2.15	103.6	35.6	542.6	283.6
-1.53	31.6	0.0	574.2	283.6
0.00	5.6	0.0	579.8	283.6
0.47	491.9	21.1	1071.7	304.7
1.25	32.9	438.7	1104.6	743.4
2.30	250.8	104.0	1355.4	847.4
3.17	202.1	223.7	1557.4	1071.2
4.37	101.2	186.2	1658.6	1257.4
5.43	29.0	145.0	1687.6	1402.4
6.53	272.4	218.4	1960.1	1620.7
7.55	119.0	260.2	2079.1	1880.9
9.07	30.2	295.0	2109.3	2175.9
9.97	176.5	210.5	2285.8	2386.4
11.80	195.0	48.0	2480.8	2434.4
12.8	48.2	114.0	2529.0	2548.4
Total	2529.0	2548.4		



6.5.1.8 Produced Gas Analysis

HP 5830 Gas chromatograph automatically analyses the gas composition in 15 min cycle. This GC is set to detect H₂, O₂, N₂, CO₂, CO and light hydrocarbon fractions up to C₆₊. H₂S gas was measured with the help of Dragger Tube.

High percentage (17-18%) of CO₂ was observed during this run. H₂S of 15 ppm was observed at runtime 9.93 hrs by the Dragger tube which increased to 200 ppm (maximum) during last stage of the run.

Probably mineralogy of core played major role in generation of H₂S and high percentage of CO₂. The stabilised period for this run was considered from zone 4 to 10 which corresponds to the runtime 2.85 hrs to 9.93 hrs. Methane gas was also observed, though its percentage was ranging from 0.07 to 0.13 %.

To confirm the analysis of online GC, a parallel GC data was used to analyse the produced gases.

Table 6.6: Produced Gas Composition

Runtime (Hrs)	O ₂ %	N ₂ %	CO %	CO ₂ %	CH ₄ %	C ₂ H ₆ %	H ₂ S (ppm)
0.05	0.00	44.44	0.00	31.93	23.62	0.00	
0.40	4.63	43.00	0.00	32.14	20.22	0.00	
0.75	4.41	53.43	0.00	28.00	14.15	0.00	
1.10	4.03	84.63	1.03	8.88	1.43	0.00	
1.45	0.31	92.26	3.56	3.52	0.34	0.00	
1.80	0.10	89.81	3.18	6.78	0.13	0.00	
2.15	0.07	83.48	2.27	13.81	0.10	0.00	
2.50	0.06	81.26	1.98	16.28	0.09	0.00	
2.85	0.06	80.05	1.79	17.68	0.09	0.00	



3.20	0.06	79.51	1.67	18.32	0.09	0.00	
3.55	0.06	79.38	1.62	18.51	0.09	0.00	
3.90	0.06	79.20	1.55	18.77	0.09	0.00	
4.25	0.05	79.13	1.56	18.86	0.09	0.00	
4.62	0.05	79.34	1.75	18.51	0.09	0.00	
4.97	0.05	79.56	1.96	18.11	0.09	0.00	
5.32	0.05	79.71	2.05	17.90	0.08	0.00	
5.67	0.05	79.87	2.06	17.75	0.08	0.00	
6.02	0.05	80.02	2.01	17.69	0.08	0.00	
6.35	0.05	80.08	1.90	17.76	0.08	0.00	
6.70	0.06	80.17	1.90	17.68	0.08	0.00	
7.05	0.06	80.35	1.88	17.52	0.08	0.00	
7.40	0.06	80.44	1.77	17.55	0.09	0.00	
7.77	0.06	80.48	1.76	17.54	0.08	0.00	
8.12	0.06	80.59	1.88	17.32	0.08	0.00	
8.48	0.06	80.69	2.00	17.09	0.08	0.00	
8.85	0.06	80.92	2.12	16.71	0.08	0.00	
9.20	0.06	81.11	2.16	16.48	0.08	0.00	
9.57	0.06	81.07	2.07	16.49	0.07	0.12	
9.93	0.06	80.99	1.88	16.77	0.08	0.10	15
10.30	0.06	80.81	1.71	17.12	0.08	0.09	20
10.67	0.06	80.58	1.57	17.49	0.08	0.09	30
11.03	0.06	80.58	1.43	17.64	0.08	.08.	90
11.40	0.06	80.69	1.44	17.52	0.08	0.08	150
11.72	0.06	80.70	1.48	17.44	0.08	0.09	200

Stabilized composition of produced gases (for zone 4 to 10 zone)

CO 1.89 %,
CO₂ 17.80 %,
N₂ 80.20 %,
O₂ 0.005%.

6.5.1.9 Differential Scanning Calorimeter

DSC (Differential Scanning calorimeter) is used to measure heat flow into or out of a sample as it is exposed to a controlled thermal profile. DSC provides both qualitative and quantitative information about material transitions and also provides the temperature at which the transition occurred.

It also indicates that the heat is involved in the reaction and kinetics. Furthermore with advent of easy to use computer based data analysis programs. Kinetics provides vital information like rapid automatic calculation of reaction order, activation energy, pre exponential factor and rate constant.

Kinetic model of any material provides valuable information for: process development and prediction of optimum reaction temperatures, process control by optimization of reaction advancement or conversion, estimation of material life time.

Uses of DSC:

- Kinetics of oil in oxidative and inert environment.
- Heat capacity of oil and rock.
- Simulated distillation of crude oil.
- Determination of crackable part of crude oil
- Determination of input parameter for start simulator.
- Investigating the feasibility of application of air injection
- Monitoring of on going combustion process.
- Thermal behavior of oil.
- Oxidative stability of oil.

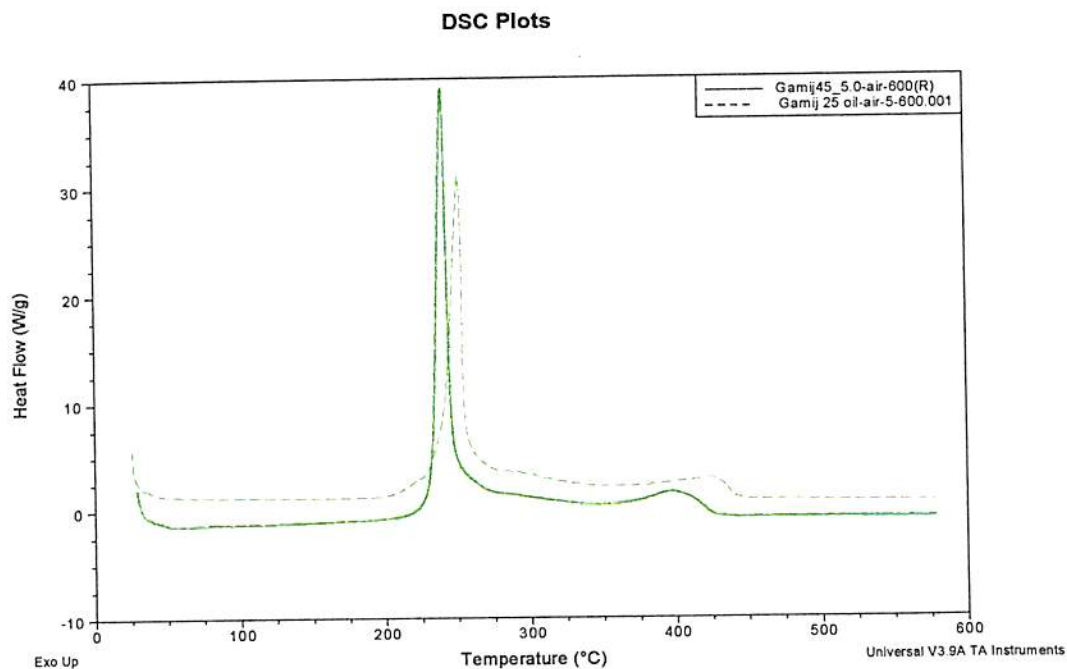


Figure 6.4: DSC Plot

6.5.1.10 Post combustion analysis

After completion of test, tube was taken out from pressure jacket and prepared for core extraction. Core thermocouples were removed before unpacking the core from production end. Core samples were taken out in regular intervals of 80 mm (1000 gms) Liquid samples collected during combustion run were analyzed.

Laboratory procedure for Post combustion analysis

Coke:

1. Weight a porcelain crucible. Record weight.



2. Add about 60 gm of extracted core to the crucible. Use only one sample to represent each core sample (one for core 1-1, one for core 1-2 etc. make sure core was well mixed before weight).
3. Place in a furnace and to keep 600C overnight. Remember sample belongs to which number.
4. Shut off furnace. Open and cool it.
5. Measure weight of crucible with core. Record weight and determine the weight loss. This loss is assumed to be same for the whole sample.
6. Calculate the % loss per core sample.

Table 6.7: Oil Balance

S. No.	Parameter	Run	Units
1	Initial oil in system	2748	g
2	Oil produced as liquid	2529	g
3	Oil produced as gas	2	g
4	Oil consumed as fuel	231	g
5	Residual hydrocarbons in pack	0	g
6	Oil in lines	12	g
7	Total produced	2774	g
8	Difference	-26	g
9	Percent error	-0.9	%

Table 6.8: Water Balance

S. No.	Parameter	Run	Units
1	Initial water in system	2615	g
2	Water in core	2181	g
3	Water drained during oil flood	-----	g
4	Net water in core	2181	g

5	Water generated by combustion	86	g
6	Total in	2701	g
7	Water produced as liquid	2548	g
8	Water produced as gas	0	g
9	Residual water in pack	100	g
10	Total out	2648	g
11	Difference	53	g
12	Percent error	2.0	%

6.5.1.11 Core Unpacking Data

After completion of run, tube was taken out from pressure jacket and prepared for core extraction. Core thermocouples were removed before unpacking the core from production end. Core samples were taken out in regular intervals of 80 mm (1000 g).

The unpacked core turns to red in the Run due to high temperature exposure. No saturations were observed in core except few centimetres from production side.

Table 6.9: Core Unpacking Data

S. No.	Sample	Wt of core (g)	Depth (mm)	Remarks
1	16 mesh	757.6	65	water saturation
2	20-30 mesh	459.6	105	oil+ water saturation
3	Native core+syn sand	471.4	145	burned sand
4	Native core+syn sand	146.6	150	burned sand
5	Native core+syn sand	593.8	200	burned sand
6	Native core+syn sand	808.2	270	burned sand
7	Native core+syn sand	1096.6	355	burned sand



8	Native core+syn sand	1609.8	480	burned sand
9	Native core+syn sand	1978.4	650	burned sand
10	Native core+syn sand	2718.0	860	burned sand
11	Native core+syn sand	1900.2	1030	burned sand
12	Native core+syn sand	1665.0	1165	burned sand
13	Native core+syn sand	1199.0	1226	burned sand
14	Native core+syn sand	1521.4	1380	burned sand
15	Native core+syn sand	1552.6	1520	burned sand
16	Native core+syn sand	2408.0	1740	burned sand
17	16 mesh	870.2	1830	burned sand
	Total	21756.4		

Table 6.10: Calculation of Combustion Parameters

Calculations		Run	Units
1	Injected air composition		
	Nitrogen	78.18	%
	Carbon dioxide	0	%
	Oxygen	21.82	%
	Carbon mono oxide	0	%
2	Composition of gas produced		
	Nitrogen	0.802	fraction
	Carbon dioxide	0.177	fraction
	Oxygen	0.001	fraction
	Carbon mono oxide	0.019	fraction
	C ₁	0	fraction
3	Reservoir Porosity	23	%
4	Sand Pack		
	Oil	4.583	Kg



	Sand	21.947	Kg
	Water	0.494	Kg
5	Density of sand	2.65	gm/cc
6	Porosity of Pack	0.425	Fraction
7	Volume of produced gas		
	Gas flow meter reading last (V2)	2298	ltr.
	Gas flow meter reading first (V1)	859	ltr.
	Volume of produced gas	1.439	m ³
8	Length of Burned Zone	1.8288	M
9	Nitrogen Injected		
	(Equal to Nitrogen Produced)	1.154	m ³
10	Oxygen Injected	0.322	m ³
11	Total Air Injected		
	(Nitrogen + Oxygen)	1.476	m ³
12	Carbon in fuel consumed, Wc		
	$w_t = (CO_2 + CO) * 12 / 0.224 * 1 / 1000$	0.148	Kg
13	Water formed by combustion, Ww		
	$2(O_2 \text{ inj} - O_2 \text{ produced} - CO_2 - 1/2 CO) * 18 / 22.4$	0.090	Kg
14	Hydrogen in fuel consumed	0.010	Kg
15	Total fuel consumed		
	Wt of H + Wt of C	0.158	Kg
16	Volume of sand burned		
	$\pi/4 * D^2 * L$ (length of burnt zone)	0.01	m ³



17	Kg of fuel consumed/ M ³ of burnt volume	22.65	kg/m ³ of Res. Rock
18	Kg of fuel burnt/ m³ of Reservoir Rock		
	(Kg of fuel consumed/ m ³ of burnt volume)*(1-Res. Porosity)/(1-sand pack porosity)	30.33	kg/m ³ of Res. Rock
19	Air Injected/ kg of fuel consumed	9.34	m ³ /kg
20	(Air Injected/kg of fuel consumed) / m ³ of sand burnt	211.80	m ³ /m ³
21	Air Injected / m³ of Reservoir Rock		
	(Air Injected / kg of fuel) /(kg of fuel burnt/ m ³ of Reservoir Rock)	283.28	m ³ (ST)/m ³
22	Air flux		
	Avg. rate/ π * radius square	32.56	m ³ (ST)/m ² h
23	H/C ratio		
	$4\{[N_2]/R-[CO_2]-[CO]/2-[O_2]\}/\{([CO_2]+[CO])(12+(H/C))\}$	0.814	
24	R (Ratio of Nitrogen to Oxygen in feed gas)	3.58	
25	Air to Fuel Ratio		
	$23.6445(R+1)/R([N_2]/R)/(CO_2+CO)*(12+H/C)$	2.02	
26	Percentage of reacted oxygen converted to carbon oxides	82.52	%



6.6 Calculations

1. Carbon in fuel consumed, W_c

$$\begin{aligned} &= (\text{CO}_2 + \text{CO}) * 12 / 0.0224 * 1 / 1000 \\ &= [(0.177 * 1.439) + (0.019 * 1.439)] * 12 / 0.0224 * 1 / 1000 \\ &= [0.255 + 0.027] * 12 / 0.0224 * 1 / 1000 \\ &= 0.148 \text{ kg} \end{aligned}$$

2. Water formed by combustion, W_w

$$\begin{aligned} &= 2 (\text{O}_2 \text{ inj} - \text{O}_2 \text{ produced} - \text{CO}_2 - 1/2 \text{ CO}) * 18 / 22.4 \\ &= 2 (0.322 - 0.001 - 0.254 - 0.011) * 18 / 22.4 \\ &= 0.090 \text{ kg} \end{aligned}$$

3. Hydrogen in fuel consumed = 0.010 kg

4. Total fuel consumed

$$\begin{aligned} &= \text{Wt of H} + \text{Wt of C} \\ &= 0.148 + 0.010 \\ &= 0.158 \text{ kg} \end{aligned}$$

5. Volume of sand burned

$$\begin{aligned} &= \pi / 4 * D^2 * L \text{ (length of burnt zone)} \\ &= \pi / 4 * (0.0985)^2 * 1.8288 \\ &= 0.01 \text{ m}^3 \end{aligned}$$

6. Kg of fuel burnt/ m^3 of Reservoir Rock

$$\begin{aligned} &= (\text{Kg of fuel consumed} / \text{m}^3 \text{ of burnt volume}) * (1 - \text{Res. Porosity}) / (1 - \text{sand pack porosity}) \\ &= 22.65 * (1 - 0.23) / (1 - 0.425) \\ &= 30.33 \text{ kg} / \text{m}^3 \text{ of Res. Rock} \end{aligned}$$

7. Air Injected/kg of fuel consumed

$$= 1.476 / 0.158 = 9.34 \text{ m}^3 / \text{kg}$$



8. Air Injected/m³ of Reservoir Rock

$$\begin{aligned} &= (\text{Air Injected} / \text{kg of fuel}) / (\text{m}^3 \text{ of Reservoir Rock} / \text{kg of fuel burnt}) \\ &= 9.34 * 30.33 = 283.28 \text{ m}^3 \text{ (ST)}/\text{m}^3 \end{aligned}$$

9. Air flux

$$\begin{aligned} &= \text{Avg. rate}/\pi * \text{radius square} \\ &= 32.56 \text{ m}^3 \text{ (ST)}/\text{m}^2 \text{ h} \end{aligned}$$

10. R (Ratio of Nitrogen to Oxygen in feed gas)

$$= 78.18/21.82 = 3.58$$

11. H/C ratio

$$\begin{aligned} &= 4 \{ [N_2]/R - [CO_2] - [CO]/2 - [O_2] \} / \{ ([CO_2] + [CO])(12 + (H/C)) \} \\ &= 4 \{ 1.154/3.58 - 0.254 - 0.011 - 0.001 \} / \{ (0.254 + 0.022)(12 + 0.01/0.148) \} \\ &= 0.814 \end{aligned}$$

12. Air to Fuel Ratio

$$\begin{aligned} &= 23.6445(R+1)/R([N_2]/R)/(CO_2 + CO)*(12+H/C) \\ &= 23.6445(3.58+1)/3.58(1.154/3.58)/(0.022+0.254)*(12+0.814) \\ &= 2.02 \end{aligned}$$

13. Percentage of reacted oxygen converted to carbon oxides

$$\begin{aligned} &= 100[(CO_2) + (CO)]/2/(N_2/R - O_2) \\ &= 100[(0.254) + 0.011]/[(1.154/3.58) - 0.001] = 82.52 \% \end{aligned}$$



6.7 Conclusion

This experiment was conducted with a mixture of synthetic sand & native core of a light oil well field (mixed in the ratio of 70:30) at 1350 psi and 76 °C.

The main conclusions derived from the experiments are:

- Front could be created, sustained and propagated.
- Overall oil recovery : 92%
- Operating air flux: 32.56 m³ (ST)/m²h. (avg. air flux)
- Stabilized air requirement: 283.28 m³(ST)/m³
- Stabilized fuel requirement (zone 4 to10) : 29.97 kg/m³
- Maximum Peak temperature : 822.5 °C (zone 2)
- H/C ratio : 0.814
- Oxygen utilization : 99.8 %
- Air to fuel : 2.02
- Percent composition of produced gases: CO 1.89%, CO₂ 17.8 %, N₂ 80.02, %, O₂ 0.005% and H₂S 200 ppm.
- Laboratory results demonstrate that front could be created, sustained and propagated in all experiments carried out on the oil. H₂S gas and high percentage of CO₂ was observed in produced gases of the Run, particularly when the front reached in last stage. Probably presence of Coal and Pyrite in native core seems to be cause of the generation of H₂S gas.
- A shift in DSC Thermogram when oil mixed with native core and synthetic sand has been observed. The initiation of oxidation was observed around 200°C for pure oil. However, DSC Thermogram of oil in the presence of native core/synthetic sand showed initiation of oxidation occurred at lower temperature than that of pure oil. This indicates that core act as catalyst during the initiation of oxidation.
- Native core played major role in high temperature reactions and production of H₂S gas. The effect of kinetics at experiment pressure will add more meaningful information in understanding the mechanism.



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