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IN-SITU COMBUSTION HANDBOOK – PRINCIPLES AND PRACTICES

Final Report
November 1998

By
Partha S. Sarathi

January 1999

Performed Under Contract No. DE-AC22-94PC91008
(Original Report Number NIPER/BDM-0374)

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Bartlesville, Oklahoma

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IN-SITU COMBUSTION HANDBOOK — PRINCIPLES AND PRACTICES

by

Partha S. Sarathi

ABSTRACT

For nearly 90 years in-situ combustion technique has been used in the U.S. in attempts to improve recovery from oil reservoirs. Despite its long history and commercial success of many field projects, the process has not found widespread acceptance among operators due to the excessive number of failures of many early field trails. Most of these failures can be traced to the inappropriate application of the process in poorer prospects. Analysis of the successful projects, however, indicates that the process is applicable to a wide range of reservoirs, and the chances of failures can be minimized by careful selection of the reservoir and adopting prudent engineering practices.

The current work was undertaken to encourage operators to consider implementing this proven oil recovery process in their reservoir by presenting the state-of-the-art knowledge and best practices of fireflood in simple terms. The organization of the handbook emphasizes practical aspects of the process. Unlike the steam process, no comprehensive text currently exists that has been devoted exclusively to fireflood. Hence, equations and detailed calculation procedures needed to engineer and evaluate the performance of an in-situ combustion project are included.

The handbook includes ten chapters including the introduction chapter. The principles of the combustion process and its variations are discussed in Chapter 2. Since laboratory studies are an integral part of a fireflood project, Chapter 3 is devoted to kinetic and combustion tube studies. The reservoir geological and site selection criteria for a fireflood project site are reviewed in Chapter 4. Chapter 5 presents a step by step approach for designing fireflood projects. Case history of selected U.S. and non-U.S. combustion projects are presented in Chapter 6. The compressor and air plant requirements for combustion projects are addressed in Chapter 7. Since ignition is a critical element of fireflood, issues pertaining to the ignition of reservoirs are fully discussed in Chapter 8. The Chapter 9 covers the well completion and operational issues pertaining to fireflood. The enriched air/oxygen fireflood requirements are discussed in the final chapter.

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The author also wishes to thank the Gas Processors Association of Tulsa, OK and the Compressed Air and Gas Institute of Cleveland, Ohio for permission to include many compressor related text and charts in the monograph from their publications. Finally the author wishes to thank Mr. Thomas B. Reid of U.S. Department of Energy's National Petroleum Technology Office and Dr. David Olsen, Director UNITAR Center for their support and encouragement.

CHAPTER 1

Introduction — Background

In-situ combustion (ISC) or fireflooding, as it is sometimes called, is the oldest member of the thermal oil recovery family. Unlike steam injection processes, the technique has not found wide spread acceptance among operators, despite many economically successful field projects. Many operators consider ISC as a high risk unpromising oil recovery method. This misconception arose as a result of the excessive number of failures of many early field trials. Most of these failures can be traced to the inappropriate application of the fireflooding process in poorer prospects. 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. The operational problems associated with fireflooding are no different or severe than those encountered with other recovery techniques and are easily surmountable.

Current work was undertaken to encourage operators to consider implementing this proven oil recovery process in their reservoir by presenting the state-of-the-art in fireflooding. In-situ combustion has come a long way since its inception in the 1920s. By adopting the most current technology in planning, implementation, operation and managing firefloods, the operator can minimize the risk of failures. Both published materials and the author's knowledge of the subject are used as the basis for this work. It is further supplemented by information garnered from the detailed discussion held with current and past in-situ combustion practitioners.

Chapter 1 outlines the purpose, scope and organization of the handbook and discusses the current state-of-the-art in ISC technology. Other sections focus on the history of the technology and concluding remarks.

Purpose and Scope of the Handbook

The purpose of this handbook is to present a state-of-the-art knowledge and best practices of the ISC technology in simple terms. It is aimed at operators and engineers who are unfamiliar with this aspect of oil recovery technology.

The scope of the handbook includes, but is not limited to the following topics:

- The fundamentals of ISC processes.
- Combustion kinetics.
- Geology and site section criteria for fireflood projects.

- Engineering of an ISC project.
- Case history of past projects and lessons learned from them.
- ISC well completion and operational practices.

The organization of the monograph emphasizes practical aspects of the process. Unlike the steam process, no comprehensive text currently exists that has been devoted exclusively to ISC. Hence, equations and detailed calculation procedures needed to engineer and evaluate the performance of an ISC project are included. Important issues are clarified by providing examples drawn from past projects. The handbook includes tables, graphs, and rules-of-thumb to assist in the design of a project. Extensive references are provided on various topics to assist the reader in obtaining further details.

Organization of the Handbook

The handbook includes ten chapters including the introduction chapter. The next chapter (Chapter 2) describes the various ISC processors. Chapter 3 is devoted to kinetics and combustion tube studies. The reservoir geological and site selection criteria for an ISC project site are reviewed in Chapter 4. Chapter 5 presents a step by step approach for designing ISC projects. Case history of selected U.S. and non-U.S. combustion projects are presented in Chapter 6. Chapter 7 discusses in considerable detail the compressors and air plant requirements for a fireflood project. In Chapter 8 methods for igniting the reservoir are presented. The Chapter 9 covers the well completion practices. This chapter also briefly touches upon the environmental issues. The last chapter (Chapter 10) considers the enriched air/oxygen fireflood requirements.

Early History and Development of the In-Situ Combustion Process

In-situ combustion of reservoir crude probably occurred in the air injection projects carried out in southeastern Ohio during the early part of this century. Lewis (1916) in an unpublished internal U.S. Bureau of Mines memo contemplated the possible occurrence of combustion in projects where warm air was injected into the formation to combat paraffin deposition problems.

According to Lewis (1916) the Ohio operators originated the practice of warm air injection into the producing formation to mitigate paraffin deposition problems. In an attempt to minimize paraffin deposition and to increase the oil recovery from its Wood property lease (near Chesterhill in Morgan county, Southeastern Ohio) Cumberland Oil Company began injecting 150,000 cu. ft. per day of hot

(160°F) 40-psi compressor discharges into the shallow (600 ft.) first Cowrun sand in August 1911. The injection was continued for 40 days. Analysis of the produced gas samples taken from wells in the repressurized area showed that virtually all of the wells were making carbon dioxide (Lewis, 1917). The percentage of carbon dioxide and oxygen in the produced samples ranged from 0.7–7 and 4.3–16.48 by volume, respectively. In retrospect it is clear that prolonged injection of warm air into the reservoir resulted in the autoignition of the in-situ crude. Lewis (1917) attributed the presence of CO_2 and low oxygen content of the produced gas to the chemical reaction between in-situ crude and the oxygen of the air.

Osgood (1930) in his monumental work, "Increasing the Recovery of Petroleum" presented the detailed case histories of several early day air injection projects (1915–1925). In discussing The Empire Company's (predecessor to Cities Service Company and Oxy-USA Inc.), El Dorado, Kansas, air injection project (1925) he noted: "It was found that only 60% of the volume of air introduced was ultimately recovered from the sand, and that this gas consisted of principally carbon dioxide and nitrogen, the oxygen having been extracted from the air underground. This change was interpreted as indicating a slow combustion. Similar results have been obtained in the Bradford District, Pennsylvania. The results obviously point toward oxidation underground, either of the air or the rock minerals with which the air comes in contact."

The first planned successful in-situ combustion project in the U.S. (perhaps in the world) took place in October 1920 near the town of Marietta in southern Ohio (Mills, 1923). The Smith-Dunn Company used the in-situ combustion technique (actually cyclic combustion process) to melt paraffin and increase production. In describing the process Mills noted: "oil-soaked waste was ignited and dropped down a well, where the Smith-Dunn compressed air process was being used. Air and natural gas coming into the well made a combustible mixture, which ignited and burned for 24 hours. The fire which was confined to the bottom part of the well was then extinguished by pouring in a few buckets of water at the top of the well. The well was put to production by releasing the pressure. The rate of production was doubled".

Following this, the U.S. Bureau of Mines joined the Smith-Dunn Company in burning out another well in December 1920 (Mills, 1923). In this project, the well was bailed dry, tubing run to the bottom of the oil sand, and a drum of gasoline poured down the hole. Compressed air was then forced down the bottom of the hole through the tubing into the formation. Dropping down some burning oil soaked waste ignited the well. The fire was kept burning for several days by supplying compressed air through the tubing. The fire was then extinguished and the well was put to production by releasing the pressure. The well flowed oil along with gas. The rate of production was increased several times over what it was before the burning.

The Hope Natural Gas Company in 1922 used a similar, but more refined process to improve oil production. This project was the first to use a combustion chamber to initiate ignition. The National Petroleum News (1923) described the process in considerable detail. In his analysis of the project Mills (1923) noted that the well bottomhole temperature was raised to 2300°F and this high temperature resulted in two or three joints of tubing being burned loose, but drilled up in short time. He also noted that the intense heat fused the sand, but the fracturing and caving of the hole at these extreme temperatures offset the damage. The process resulted in considerable increase in production in a nearby well and is thus truly a combustion drive process. In order to avoid burning and parting of the tubing, he recommended the use of alloy tubing capable of withstanding high temperature.

The first patent setting out the in-situ combustion principle was issued to E.R. Walcott on June 5, 1923. This patent was applied for in 1920 few months prior to the actual beginning of the field experimentation in the U.S.A second patent also applied for in 1920 was issued to F.A. Howard on November 6, 1923.

In the summer of 1927, A.F. Melcher of Marland Oil Company (now Conoco) instigated a combustion oil recovery project in Ponca City, OK by injecting the hot exhaust gases (800°F) produced from the cracking stills of the adjacent refinery in to a very shallow oil sand, which was found at a depth of 20 ft. (Torrey, 1953). In this experiment, large manhole size holes were drilled to the top of the sand and the hot still gases injected for several months. Oil recovery from the four offset producing wells, situated in a square pattern 50 ft. away (diagonal distance) from the injector increased considerably and the experiment deemed as a success. It was reported that the bottomhole temperature at the injector was 700°F and the gas injection ceased after a few months due to excessive backpressure. Visual inspection of the sandface, after the hole has been cooled, revealed carbon deposition and clay fusion. This experiment is the first know field implementation of combustion drive process in the U.S. Following this successful experiment, Marland initiated another hot air injection pilot in the shallow South Coffeyville Pool in Nowata County, Oklahoma in December 1927 (Heath and Betzer, 1942). This experiment, however, was deemed unsuccessful because the operator was unable to maintain the air injection due to plugging of the sandface by coke.

The first theoretical paper on oil recovery by injection of hot combustion gases from primary depleted sands was published by U.S. Bureau of Mines in 1928 (Lindsly, 1928). It was estimated that approximately one billion (10^9) Btu of heat is needed to raise the temperature of 1-ac-ft. of oil sand to 700°F. This paper, as for as the author's knowledge, was the first to present the engineering and economic calculations of a then experimental process.

The first known field experiment of in-situ combustion outside the U.S. occurred in Russia in 1935 (Sheinmann et al., 1938). By mid–1940s, concept of burning a portion of the oil bearing formation for the purpose of enhancing oil production began receiving serious attention from major U.S. oil companies. In 1947, Magnolia Petroleum Company (now Mobil) and Sinclair Oil and Gas Company (now Arco) began investigating the process in the laboratory to learn about the parameters controlling the process (Kuhn & Koch, 1953; Grand & Szasz, 1954). Both Magnolia's and Sinclair's laboratory investigation culminated in field pilots in Oklahoma in 1950. Both pilots proved to be technically successful and paved way to the rapid development of this oil recovery technology.

Since the implementation of these first modern day pilots, more than 225 combustion projects were undertaken in the U.S. A good many of these projects were economically successful, while others failed for various reasons including unfavorable reservoir and fluid characteristics, poor engineering and operational problem. In general most failed pilots were small experimental projects implemented in poor prospects by unknowledgeable operators that compounded odds against success.

Current Status of In-Situ Combustion

Global ISC Activities

At the end of 1997, eight in-situ combustion projects are in operation in the U.S. producing about 5,200 barrels of oil per day. Six of these were implemented in deep light oil reservoirs and the rest in shallow heavy oil pools. Worldwide, excluding the U.S., there are 20 ISC projects in operation as of early 1998 that are producing approximately 28,900 barrels of oil per day, most of which is heavy. The known distribution of ISC projects in the world and their daily oil production are shown in Table 1.1.

TABLE 1.1 — Statistics of World's Active In-Situ Combustion Projects (as of December 31, 1997)

Country	Project Name	Operator	Date Initiated	Combustion Type	Oil Gravity, °API	No. of Injectors	No. of Producers	Current AOR, Mscf/bbl	Current Production bbl/D	Comments	Reference
U.S.A.											
1	Bellvue, LA	Bayou State	1970	wet	19	15	85	12	400	Continuation of Oxy's (Cities Service) Combustion	Moritis (1998)
2	Midway Sunset, CA	Texaco	1982	dry	11.5	10	47	7	1,000	Combustion in a previously steam-flooded lease expansion is currently underway	Moritis (1998), Hoffman (1998)
3	Medicine Pole Hill Unit ND	Continental Resources	1985	dry	39	7	17	7.2	725	Light oil combustion in a tight (5 md) carbonate reservoir	Moritis (1998), Miller (1994)
4	Buffalo, SD	Continental Resources	1979	dry	30	12	21	10.5	550	Light oil combustion in a tight (10 md) carbonate reservoir	Moritis (1998), Miller (1994)
5	W. Buffalo, SD	Continental Resources	1987	dry	30	6	15	10.9	365	Light oil combustion in a tight (10 md) carbonate reservoir	Moritis (1998), Miller (1994)
6	S. Buffalo, SD	Continental Resources	1983	dry	30	19	40	9.3	1,420	Light oil combustion in a tight (10 md) carbonate reservoir	Moritis (1998), Miller (1994)
7	W. Hackberry, LA	Amoco	1995	dry	33	--	--	15.6	280	Combustion is a means to generate flue gas *in situ* and displace advancing water column. Oil is recovered through gravity drainage.	Gillham et al. (1997)
8	Mt. Poso, CA	AERA	1997	dry	--	--	--	--	--	Combustion in a steamflooded reservoir	Glendt C. (1995)
9	Horse Creek Field, ND	Total Minatome	1996	Dry	32.2	3	11	10	400	Light oil combustion in a tight (10md) carbonate reservoir	Germain (1997)
Canada											
1	Battrum Saskatchewan	Mobil Canada	1966	wet	18	15	94	10	3,700	Horizontal wells are being utilized since 1993 to improve recovery	Moritis (1998), Ames et al. (1994)
2	Battrum Saskatchewan	Mobil Canada	1967	wet	18	7	35	10	1,200	Horizontal wells are being utilized since 1993 to improve recovery	Moritis 1998), Ames et al. (1994)
3	Battrum Saskatchewan	Mobil Canada	1965	wet	18	3	22	10	1,350	Horizontal wells are being utilized since 1993 to improve recovery	Moritis 1998), Ames et al. (1994)
4	Wabaskaw Alberta	Amoco Canada	1994	horizontal well cyclic combustion (dry)	14	1	2	--	260	Horizontal well cyclic combustion (Pressure Up Blowdown)	Fassihi et al. (1996)

TABLE 1.1 (Cont.) — Statistics of World's Active In-Situ Combustion Projects

Country	Project Name	Operator	Date Initiated	Combustion Type	Oil Gravity, °API	No. of Injectors	No. of Producers	Current AOR, Mscf/bbl	Current Production bbl/D	Comments	Reference
Albania											
1	Kasnice	--	1973	dry	12	--	--	--	130		Marko et al. (1995)
Azerbaijan											
1	Balakhany Sabunchi	--	1988	wet	16	6	35	--	600	combustion with alkaline water injection	Mamedov et al. (1995), Turta (1995)
China											
1	Kerxing-Nemangu	CNDC Nemangu	1996	Dry	29	–	–	–	–	–	–
Hungary											
1	Demjen-Kelet	--	1976	wet	39	3	9	14	270	Catalyzed wet combustion (Thermocatalytic Process)	Mamedov et al (1995), Racz (1982)
India											
1	Balol	Oil & Nat'l Gas Corp.	1990	wet	15.6	1	4	--	190	Projects likely to be expanded fieldwide in 1996	Moritis (1998), Roy Chaudhury (1995)
2	Lanwa	Oil & Nat'l Gas Corp.	1992	wet	13.5	1	4	--	165		Moritis (1998)
3	Balol	Oil & Nat'l Gas Corp.	1996	Dry	15.6	–	–	–	–	–	–Moritis (1998)
4	Santhal	Oil & Nat'l Gas Corp.	1996	Dry	17	–	–	–	–	–	–Moritis (1998)
5	Bechraii	Oil & Nat'l Gas Corp.	1996	Dry	15.6	–	–	–	–	–	–Moritis (1998)
Kazakhstan											
1	Karazhan bas	--	1981	wet	22.3	78	364	7.2	4,150	Combustion with alkaline water injection	Mamedov et al. (1995), Zhdanove et al. (1991), Bakserman et al. (1987)
Romania											
1	Saplacau de Barcau	--	1964	wet	15.9	132	507	12.3	8,800	World's largest combustion project	Turta (1995), Machedon (1995)
2	W. Videle	--	1980	dry	19	19	50	17	610		Turta (1995), Machedon (1995)
3	E. Videle	--	1979	dry	19	33	89	21	660		Turta (1995), Machedon (1995)
4	W. Balaria	--	1975	dry	19	22	60	24.5	820		Turta (1995), Machedon (1995)

TABLE 1.1 (Cont.) — Statistics of World's Active In-Situ Combustion Projects

Country	Project Name	Operator	Date Initiated	Combustion Type	Oil Gravity, °API	No. of Injectors	No. of Producers	Current AOR, Mscf/bbl	Current Production bbl/D	Comments	Reference
Romania (cont'd)	E. Balaria	--	1987	dry	16	15	47	22.5	550		Turta (1995), Machedon (1995)
Russia											
1	Okha	--	--	--	17.4	--	--	--	180	No details on this pilot project is available	Mamedov et al. (1992,1995)

According to the Oil and Gas Journal's biannual EOR survey (Moritis, 1998) about 1.3 billion b/d of oil is being produced worldwide using thermal methods, which is about 2% of the world's current oil production. Steam and hot water account for 97.8% of all thermally produced oil in the world. Combustion accounts for the rest. In the U.S. combustion accounts for about 1.2% of the 446,430 barrels of thermally produced oil. In Canada excluding the bitumen production by steam, combustion accounts for about 49% of the estimated 12,870 b/d of thermal oil production. Even though combustion accounts for less than 10% of the world's thermal projects its share of thermally produced oil is substantial.

The known distribution of ISC projects in the world and their oil production are shown in Table 1.1 Since the available information on the ISC projects outside of North America are limited, there is a chance that more ISC projects may be in operation in the world than those included in Table 1.1

Examination of this table shows that while the U.S. leads the world in the number of active ISC projects, individual projects outside the U.S. produce more oil than all the U.S. projects combined. For example, the Supalcu de Barcau project in Romania, the world's largest active ISC project, produces nearly 1.7 times as much oil as all the U.S. projects combined. However, the per well production of U.S. projects (average 28 b/d per well) are much higher than those of most countries.

U.S. ISC Activities

A total of 228 combustion projects (dry, wet, and enriched air) have been implemented in the U.S. since 1950. Thirty-seven projects were deemed commercially successful, while another 54 projects were technically successful (i.e., combustion resulted in additional oil production, but the economics are dubious). California, Texas, and Oklahoma accounted for the bulk of the combustion projects implemented in the U.S. Texas also accounted for all the oxygen (enriched air) combustion projects implemented in the U.S. Both the majors and independents were active ISC players in the U.S. The U.S. in-situ combustion activities by decade are summarized in Table 1.2.

TABLE 1.2 — U.S. In-Situ Combustion Activities

Decade	Total No. of Projects	Economically Successful Projects	Technically Successful Projects	Unsuccessful Projects	Percent of Economic Success	Percent of Technical Successful (including economic)	Percent of Failures
1950-59	42	6	10	26	14.2	38.1	61.9
1960–69	127	16	35	76	12.6	40.2	59.8
1970–79	33	12	6	15	36.4	54.5	45.5
1980–89	22	5	5	12	22.7	45.5	54.5
1990–	2	--	1	1	--	--	--
Total	**226**	**39**	**57**	**130**	**21.5**	**44.6**	**55.4**

The breakdown of projects by state is depicted in Table 1.3. Both majors and independents were active players in the U.S. A talley of projects initiated by majors and independents are shown in Table 1.4.

Examination of Table 1.2 shows a sharp decrease of new projects since 1970. However, the percent of the project considered successful (technically and/or economically) remain constant, averaging about 40%.

Examination of Table 1.3. shows that U.S. Gulf Coast states (Arkansas, Louisiana, Mississippi, and Texas) accounted for 38% of all ISC projects implemented in the U.S. and 62% of all commercially successful combustion projects. Texas and Louisiana accounted for nearly all of the combustion projects conducted in this region. Texas also accounted for all the oxygen (enriched air) combustion projects implemented in the U.S.

The following general observations can be made with regard to U.S. combustion projects.

- Majority of the past U.S. combustion projects is small experimental pilots undertaken to assertion the suitability of the process to recover heavy oil from shallow reservoir.
- Only about 20% of the U.S. combustion pilots, undertaken prior to 1980 matured to become commercial projects.
- Projects undertaken by larger operators generally tend to be more successful then those initiated by smaller independents.
- The oxygen or oxygen-enriched air combustion pilots were all technically successful, but terminated due to declining crude prices.
- The most common causes of failure of earlier pilots have been lack of reservoir continuity, channeling or bypassing of injected air, poor crude combustion characteristics, inadequate compression capacity, and well failures.
- The current emphasis is to implement combustion projects in deep light oil reservoirs, where waterflood economics are unattractive. In these reservoir combustion is used primarily as a means to generate flue gas in-situ and the thermal effects play lesser role in the production of oil.

TABLE 1.3 — Geographical Distribution of U.S. Combustion Projects

	State	Economic Success	Technical Success	Failed	Total Projects
1950–59					
1.	Arkansas	—	—	—	—
2.	California	1	2	7	10
3.	Colorado	—	—	—	—
4.	Illinois	0	1	1	2
5.	Kansas	1	0	2	3
6.	Kentucky	0	0	2	2
7.	Louisiana	1	1	0	2
8.	Missouri	—	—	—	—
9.	Montana	0	0	2	2
10.	Mississippi	0	0	1	1
11.	Nebraska	—	—	—	—
12.	New Mexico	—	—	—	—
13.	New York	0	0	1	1
14.	N. Dakota	—	—	—	—
15.	Oklahoma	2	3	0	5
16.	Pennsylvania	—	—	—	—
17.	S. Dakota	—	—	—	—
18.	Texas	0	2	7	9
19.	Utah	0	0	1	1
20.	W. Virginia	—	—	—	—
21.	Wyoming	1	1	2	4
	Total	**6**	**10**	**26**	**42**

TABLE 1.3 (Cont.) — Geographical Distribution of U.S. Combustion Projects

	State	Economic Success	Technical Success	Failed	Total Projects
1960–69					
1.	Arkansas	0	1	0	1
2.	California	3	20	26	49
3.	Colorado	0	0	1	1
4.	Illinois	0	1	0	1
5.	Kansas	1	1	4	6
6.	Kentucky	—	—	—	—
7.	Louisiana	2	0	1	3
8.	Missouri	0	0	2	2
9.	Montana	0	0	1	1
10.	Mississippi	—	—	—	—
11.	Nebraska	0	1	0	1
12.	New Mexico	—	—	—	—
13.	New York	—	—	—	—
14.	N. Dakota	—	—	—	—
15.	Oklahoma	2	3	10	13
16.	Pennsylvania	0	0	3	3
17.	S. Dakota	—	—	—	—
18.	Texas	7	8	24	39
19.	Utah	—	—	—	—
20.	W. Virginia	0	0	1	1
21.	Wyoming	1	0	3	4
	Total	**16**	**35**	**76**	**127**

TABLE 1.3 (Cont.) — Geographical Distribution of U.S. Combustion Proj.

	State	Economic Success	Technical Success	Failed	Total Projects
1970–79					
1.	Arkansas	0	0	1	1
2.	California	3	1	4	8
3.	Colorado	0	0	1	1
4.	Illinois	—	—	—	—
5.	Kansas	—	—	—	—
6.	Kentucky	—	—	—	—
7.	Louisiana	3	1	3	7
8.	Missouri	—	—	—	—
9.	Montana	—	—	—	—
10.	Mississippi	2	0	0	2
11.	Nebraska	—	—	—	—
12.	New Mexico	—	—	—	—
13.	New York	—	—	—	—
14.	N. Dakota	—	—	—	—
15.	Oklahoma	0	2	2	4
16.	Pennsylvania	—	—	—	—
17.	S. Dakota	1	0	0	1
18.	Texas	3	2	3	8
19.	Utah	0	0	1	1
20.	W. Virginia	—	—	—	—
21.	Wyoming	—	—	—	—
	Total	**12**	**6**	**15**	**33**

TABLE 1.3 (Cont.)—Geographical Distribution of U.S. Combustion Proj.

	State	Economic Success	Technical Success	Failed	Total Projects
1980–89					
1.	Arkansas	—	—	—	—
2.	California	1	1	2	4
3.	Colorado	—	—	—	—
4.	Illinois	—	—	—	—
5.	Kansas	0	0	2	2
6.	Kentucky	0	1	0	1
7.	Louisiana	0	0	4	4
8.	Missouri	—	—	—	—
9.	Montana	—	—	—	—
10.	Mississippi	—	—	—	—
11.	Nebraska	—	—	—	—
12.	New Mexico	0	0	1	1
13.	New York	—	—	—	—
14.	N. Dakota	1	0	0	1
15.	Oklahoma	—	—	—	—
16.	Pennsylvania	—	—	—	—
17.	S. Dakota	2	0	0	2
18.	Texas	0	2	4	6
19.	Utah	—	—	—	—
20.	W. Virginia	—	—	—	—
21.	Wyoming	1	0	0	1
	Total	**5**	**4**	**13**	**22**

TABLE 1.3 (Cont.)—Geographical Distribution of U.S. Combustion Proj.

	State	Economic Success	Technical Success	Failed	Total Projects
1990–					
1.	Arkansas	—	—	—	—
2.	California	—	—	—	—
3.	Colorado	—	—	—	—
4.	Illinois	—	—	—	—
5.	Kansas	—	—	—	—
6.	Kentucky	—	—	—	—
7.	Louisiana	0	1	0	1
8.	Missouri	—	—	—	—
9.	Montana	—	—	—	—
10.	Mississippi	—	—	—	—
11.	Nebraska	—	—	—	—
12.	New Mexico	—	—	—	—
13.	New York	3	—	—	—
14.	N. Dakota	—	—	—	—
15.	Oklahoma	—	—	—	—
16.	Pennsylvania	—	—	—	—
17.	S. Dakota	—	—	—	—
18.	Texas	0	0	1	1
19.	Utah	—	—	—	—
20.	W. Virginia	—	—	—	—
21.	Wyoming	—	—	—	—
	Total	**0**	**1**	**1**	**2**
	Grand Total	**39**	**56**	**131**	**226**

TABLE 1.4 — U.S. In-Situ Combustion Project Activities — Breakdown by Majors and Independents

Decade	No. of Projects	Technically & Economically Successful Projects	Technically Successful Projects	Unsuccessful Projects	Percent Successful Projects (Technical & Economical)	Percent Economically Successful Projects
Majors						
1950–59	25	5	7	13	48.0	20.0
1960–69	88	13	28	47	46.6	14.8
1970–79	19	6	2	11	42.1	31.6
1980–89	9	0	2	7	22.2	0
1990–	1	0	1	0	—	—
Total	142	24	40	78	[1]45.1	[1]16.9
Independents						
1950–59	17	1	3	13	23.5	5.9
1960–69	39	2	6	31	20.5	5.1
1970–79	14	6	2	6	57.1	42.9
1980–89	13	4	2	7	46.2	30.8
1990–	1	0	0	1	—	—
Total	84	13	13	58	[1]31.0	[1]15.5

[1] Percent total (e.g., $^{24}/_{142} = 0.169$; $^{40+24}/_{142} = 0.451$)

Assets and Liabilities of In-Situ Combustion Process

Compared to other improved oil recovery processes, in-situ combustion is a highly complex process. This complexity was not well understood by most early day in-situ combustion operators. This resulted in a high rate of project failures in the 1960s, and contributed to the misconception that ISC is a problem prone process with low probability of success. As a result, operators interest in the process waned, as reflected by the number of new project implementations since the 1970s (Table 1.2). The truth, however, is that ISC is an attractive oil recovery process and is capable of recovering a high percentage of the oil-in-place, provided the process is designed correctly and implemented in the right type of reservoir.

Like other oil recovery processes, ISC has its assets and liabilities and no general criteria can be specified to assure its success. The probability of an ISC project failure, however, can be minimized by recognizing its limitations and designing the project accordingly. In this section we enunciate the advantages and limitations of ISC process and examine critically the reasons cited for its declining popularity.

Assets of In-Situ Combustion Process

ISC is a unique oil recovery process. It can be viewed as a combination process. It encompasses some aspects of nearly every known oil recovery method. These include steam distillation, steam displacement, CO_2 flood, hydrocarbon miscible flood, immiscible gas (N_2) displacement, and water (hot and cold) flood.

Next to waterflooding, ISC is perhaps the most widely applicable improved oil recovery technique. The major assets of ISC include the following:

- Thermally, it is the most efficient oil recovery process.
- It uses air, the least expensive and the most readily available fluid as injectant.
- ISC can recover oil economically from a variety of reservoir settings. The process has proven to be economical in recovering heavy oil (10–20°API) from shallow reservoirs (less than 1,500 ft.), and light oil (>30°API) from deep reservoirs (11,000 ft.).
- Though most combustion projects are implemented in heavy oil reservoirs, it is increasingly being used to recover light oil from deep reservoirs. In the U.S., more combustion projects are in operation in light oil reservoirs than in heavy oil reservoirs.

- It is an ideal process for producing oil from thin formation. Economically, successful projects have been implemented in sandbodies ranging in thickness from 4–150 ft. The process, however, proved to be most effective in 10–50 ft. sandbodies.
- Reservoir inhomogeneities have a less detrimental effect on the combustion process than on steam injection process.
- Reservoir pressure has no effect on the technical success of the process. The process has been successfully implemented in reservoirs ranging in pressure from vacuum to 4,500 psig.
- The formation permeability has minimal effect on the process. The process has been successfully implemented in formations whose permeability ranges from 5 md to 10,000 md.
- Recovery efficiency is better than other oil recovery processes (see Table 1.5).
- The process can be implemented as a follow-up to waterflood and steamflood processes.
- The process can be applied in reservoirs where waterflood and/or steamflood is not effective. For example, in deep reservoirs (greater than 10,000 ft.), steam injection is not effective due to excessive heat losses and high lifting costs rendering waterflood economically unattractive. In such reservoirs, combustion and gas are the only processes that can be applied to recover oil economically.
- Combustion projects permit the use of wider well spacing and can result in higher ultimate oil recovery in comparison to steamflood.

TABLE 1.5 — Recovery Efficiency of In-Situ Combustion Compared to Other EOR Methods (Hasiba and Wilson, 1975)

Process	(A) Process displacement efficiency, %	(B) Areal sweep efficiency, %	(C) Vertical sweep efficiency, %	(D) Compound recovery efficiency, %
In-Situ Combustion	95	70	85	56
Steamflood	65	70	85	39
Cyclic Steam	—	—	—	20
Micro-Emulsion Flood	90	70	80	50
CO_2-Waterflood	80	50	80	32
NaOH-Waterflood	35	70	80	20

NOTE: D = (A) x (B) x (C)
Volumetric sweep efficiency = (B) x (C)

Limitations of Combustion Process

Like 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. Following are some less attractive features of ISC:

- Though 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. Relative to energy intensive steam injection operation, the costs for in-situ combustion are lower only when the formation is less than 40 ft. in thickness. For thicker reservoirs, the heat losses during a steam drive are low enough to enable the heat to be delivered at a lower cost.
- Operational problems associated with combustion are more troublesome and require a higher degree of technical sophistication to solve it. In comparison, steam injection operations are relatively problem free.
- Unlike the steam injection process design of in-situ combustion processes must be preceded by expensive laboratory investigations. This is needed to ascertain the burning characteris-

tics of the crude, fuel availability and air requirements. Thus, planning and design of a combustion project is more expensive.

- Success and failure of combustion process implemented in reservoirs of similar and widely differing characteristics preclude the development of satisfactory guidelines to screen reservoir for combustion application. Expensive pilot is the only satisfactory answer to judge the feasibility of a particular project.
- The complexity of the in-situ combustion process hinder the development of more sophisticated numerical simulators for complete performance prediction.

While considerable improvements are being made in the application of this technology, many operators still view this technology as a high-risk operation. The commercial success of this process in the deep, extremely low permeability carbonate, and clastic reservoirs in the U.S. had made operators take a second look at this process. The success of horizontal well combustion technology in the heavy oil fields of Canada have also contributed to revival of operators' interest in this process. Currently several new combustion projects are on the drawing board, and one operator contemplates on implementing this process in a deep offshore light oil reservoir.

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 in the U.S. and elsewhere. Thus future potential for oil recovery by ISC is very promising.

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CHAPTER 2 — FUNDAMENTALS OF FIREFLOODING

Introduction

In-situ combustion (ISC) is basically a gas injection oil recovery process. Unlike a conventional gas injection process, in an ISC process, heat is used as an adjuvant to improve the recovery. The heat is generated within the reservoir (in-situ) by burning a portion of the oil. Hence, the name in-situ combustion. The burning is sustained by injecting air or an oxygen rich gas into the formation. Often times this process is also called a fireflood to connote the movement of a burning front within the reservoir. The oil is driven toward the producer by a vigorous gas drive (combustion gases) and water drive (water of combustion and recondensed formation water).

The original incentive for the development of the ISC process was the tremendous volume of difficult to recover viscous oil left in the reservoir after primary production. The process, however, is not restricted to heavy oil reservoir and at the present time in the U.S. more light (3,280 B/D) than heavy (1,920 B/D) oil is being produced using this process. In other countries, however, this process is not utilized to recover light oil. It's use is generally restricted to heavy oil reservoirs not amenable to steam.

This chapter reviews the different ISC processes and their recovery mechanisms. In subsequent chapters, various aspects of ISC are discussed in detail.

In-Situ Combustion Processes

Based on the direction of the combustion front propagation in relation to the air flow, the process can be classified as forward combustion and reverse combustion. In the forward process, the combustion front advances in the general direction of air flow; whereas in reverse combustion, the combustion front moves in a direction opposite to that of the air flow. Only forward combustion is currently being practices in the field. 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 coinjected into the formation through the injection well.

Dry Combustion

In this process, air (or enriched air) is first injected into an injection well, for a short time (few days) and then, the oil in the formation is ignited. Ignition is usually induced using downhole gas burners, electric heaters or through injection of a pyrophoric agent (such as linseed oil) or a hot fluid such as the steam. In some cases, auto ignition of the in-situ crude occurs. For auto ignition to occur, the reservoir temperature must be greater than 180°F and the oil sufficiently reactive.

Once ignited, the combustion front is sustained by a continuous flow of air. The combustion or fire front can be thought of as a smoldering glow passing through the reservoir rather than a raging underground fire. As the burning front moves away from the injection well, several well characterized zones are developed in the reservoir between the injector and producer. These zones are the result of heat and mass transport and the chemical reactions that occur in a forward in-situ combustion process. The locations of the various zones in relation to each other and the injector are shown in Figure 2.1. The upper portion of this figure shows the temperature distribution and the fluid saturation from injection well to producer. The locations of the various zones are depicted in the lower portion of the figure.

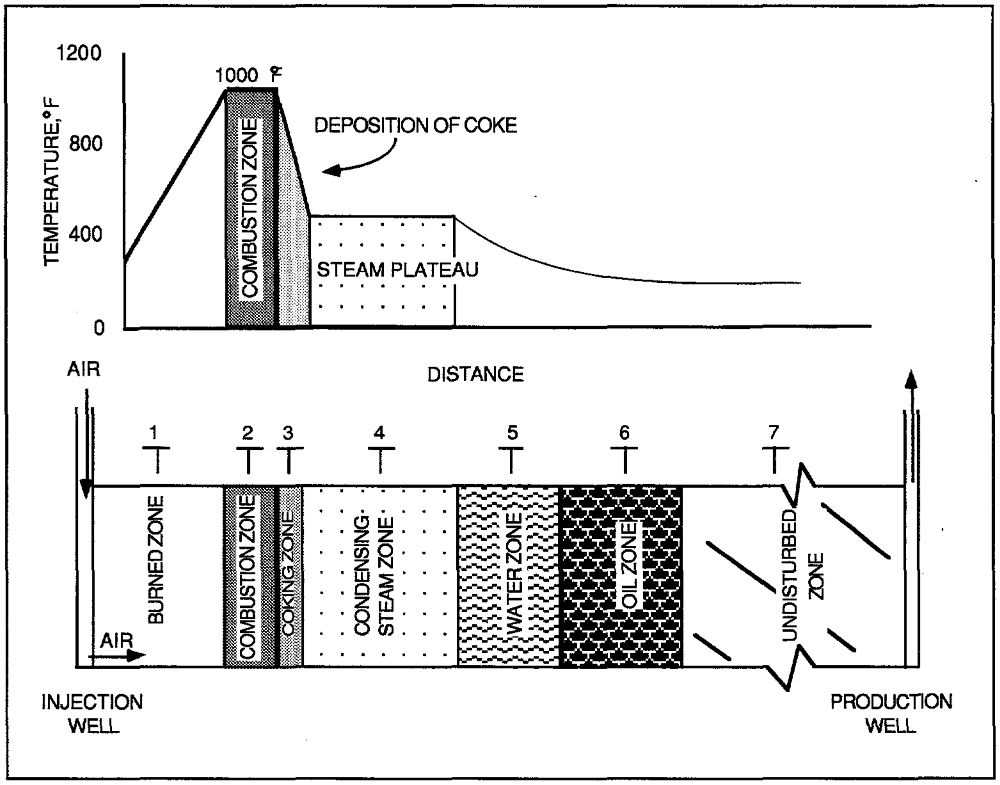

FIGURE 2.1 — In-Situ Combustion Schematic Temperature Profile

Figure 2.1 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 2.1 is easier to visualize and provide much insight on combustion process.

Starting from the injection well, the zones represented in Figure 2.1 are:

1. The burned zone.
2. The combustion zone
3. The cracking and vaporization zone.
4. The condensation (steam plateau) zone.
5. The water bank
6. The oil zone.
7. The native zone.

These zones move in the direction of air flow and are characterized as follows:

The zone adjacent to the injection well is the burned zone. As the name suggests, it is the area where the combustion had already taken place. Unless the combustion is complete, which is usually not the case in the field, the burned zone may contain some residual unburned organic solid, generally referred to as coke. Analysis of cores taken from the burned portion in the field indicate as much as 2% coke and saturated with air. The color of the burned zone is typically off-white with streaks of grays, browns and reds. Since this zone is subjected to the highest temperature for a prolonged period, they usually exhibit mineral alteration. Because of the continuous influx of ambient air, the temperature in the burned zone increases from formation temperature near the injector to near combustion temperature in the vicinity of combustion zone.

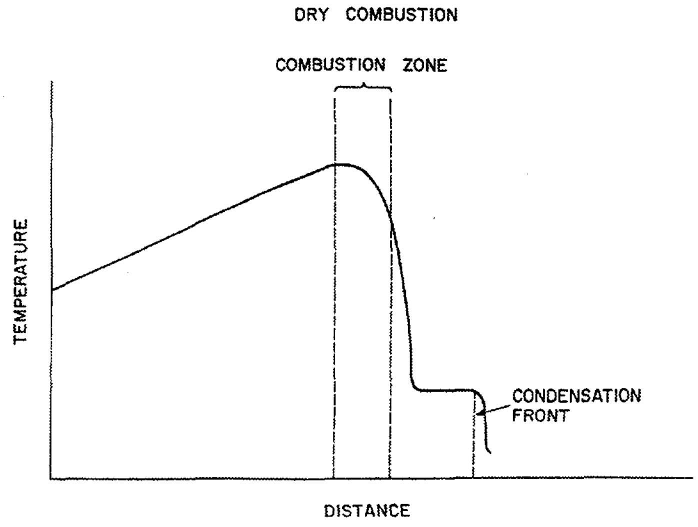

FIGURE 2.2 — Schematic of Temperature Profile for Dry Combustion (After Moore et al., 1996)

Immediately ahead of the burned zone is the combustion zone. The combustion zone is where reaction between oxygen and fuel takes place generating heat. The combustion zone is a very narrow region (usually no more than a few inches thick) (see Figure 2.2) where high temperature oxidation (burning) takes place to produce primarily water and combustion gases (carbon dioxide CO_2 and carbon monoxide CO). The fuel is predominantly coke, which is formed in the thermal cracking zone just ahead of the combustion zone. Coke is not pure carbon, but a hydrogen deficient organic material with an atomic hydrogen to carbon (H/C) ratio between 0.6 and 1.6, depending upon the thermal decomposition (coking) conditions. The temperature reached in this zone depends essentially on the nature and quantity of fuel consumed per unit volume of the rock.

Just downstream of the combustion zone lies the cracking/vaporization zone. In this zone the high temperature generated by the combustion process causes the lighter components of the crude to vaporize and the heavier components to pyrolyze (thermal cracking). The vaporized light ends are transported downstream by combustion gases and are condensed and mixed with native crude. The pyrolysis of the heavier end results in the production of CO_2, hydrocarbon and organic gases and solid organic residues. This residue, nominally defined as coke, is deposited on the rock and is the main fuel source for the combustion process.

Adjacent to the cracking zone is the condensation zone. Since the pressure gradient within this zone is usually low, the temperature within the zone is essentially flat (300–550°F) and depends upon the partial pressure of the water in the vapor phase. Hence, the condensation zone is often referred to as the steam plateau. Some of the hydrocarbon vapor entering this zone condenses and dissolves in the crude. Depending on the temperature, the oil may also undergo ‘visbreaking’ in this zone, thus reducing its viscosity. Visbreaking is a mild form of thermal cracking. This region contains steam, oil, water, and flue gases, as these fluids move toward the producing well. Field tests indicate that the steam plateau extends from 10–30 ft. ahead of the burning front.

At the leading edge of the steam plateau where the temperature is lower than the condensation temperature of steam, a hot water bank is formed. This bank is characterized by a water saturation higher than original saturation. An oil bank proceeds the water bank. This zone contains all the oil that has been displaced from upstream zones.

Beyond the oil bank lies the undisturbed zone which is yet to be affected by the combustion process, except for a possible increase in gas saturation due to flow of combustion gases (CO_2, CO, and N_2).

The overall fluid transport mechanism in a combustion process is a highly complex sequence of gas drive (combustion gases), water drive (recondensed formation water and water of combustion), steam drive, miscible gas and solvent drive.

Although the bank concept approach described above provides much insight on the combustion process, it is not a true representation of the field behavior. In the field, various zones are not readily identified and there are considerable overlaps between zones. Further, the relative locations of the various zones and the sequence in which they occur may also be different from that described previously. This difference arises mainly because of the heterogeneous nature of the reservoir. Reservoir heterogeneity causes the fluid and heat fluxes to be different at various points of the combustion region.

The fluid distribution within each of these zone is influenced by the temperature profile as well as the relative permeability characterization of the formation. The chemical properties of the oil that is left behind by the steam bank determine the amount of coke that will be laid down, which in turn determines the amount of air that must be injected to consume this coke.

Wet Combustion

In the dry forward combustion process, much of the heat generated during burning is stored in the burned sand behind the burning front and is not used for oil displacement. The heat capacity of dry air is low and, consequently, the injected air cannot transfer heat from the sand matrix as fast as it is generated. Water, on the other hand, can absorb and transport heat many times more efficiently than can air. If water is injected together with air, much of heat stored in the burned sand can be recovered and transported forward. Injection of water simultaneously or intermittently with air is commonly known as wet, partially quenched combustion. The ratio of the injected water rate to the air rate influences the rate of burning front advance and the oil displacement behavior.

The injected water absorbs heat from the burned zone, vaporizes into steam, passes through the combustion front, and releases the heat as it condenses in the cooler sections of the reservoir. Thus, the growth of the steam and water banks ahead of the burning front are accelerated, resulting in faster heat movement and oil displacement. The size of these banks and the rate of oil recovery are dependent upon the amount of water injected.

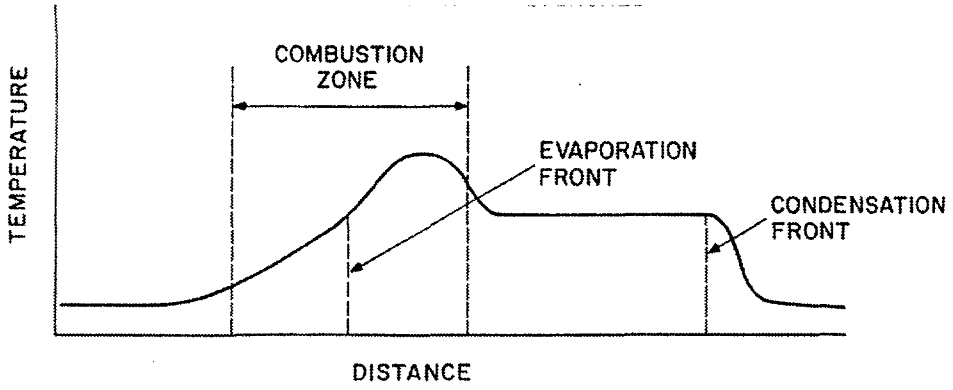

FIGURE 2.3 — Schematic of Temperature Profile for an Incomplete (Partially Quenched) Wet Combustion Process (Courtesy of UNITAR Centre, Mehta and Moore, 1996)

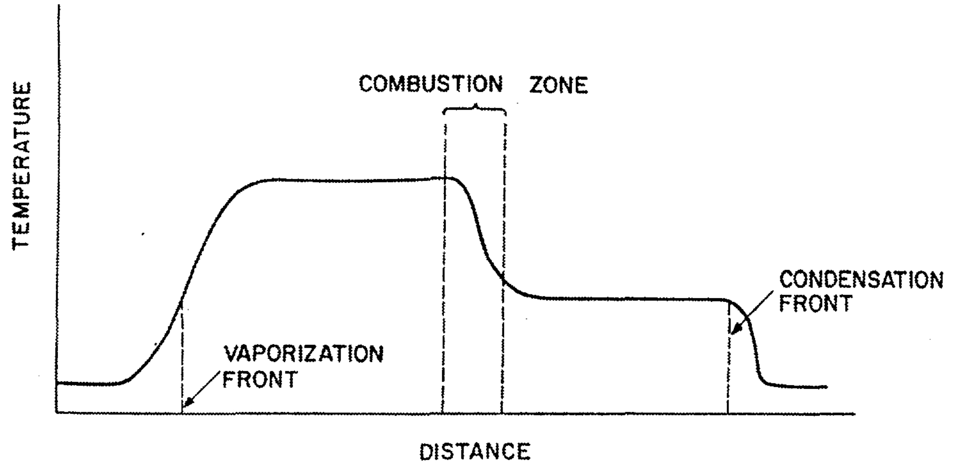

FIGURE 2.4 — Schematic of Temperature Profile for a Normal Wet Combustion Process Without Convective Heat Front (Courtesy of UNITAR Centre, Mehta and Moore, 1996)

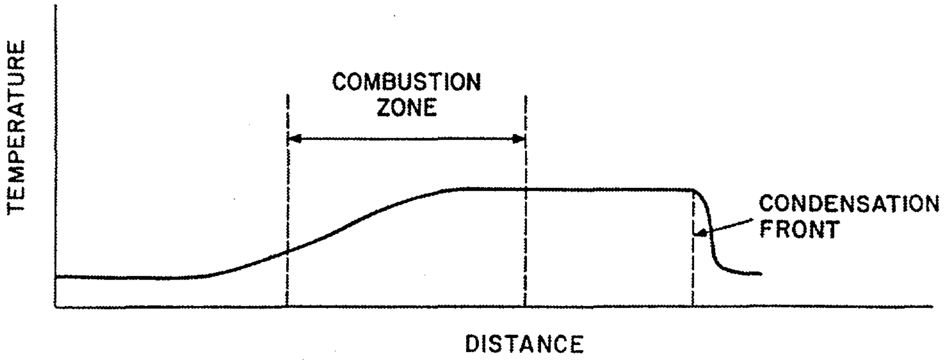

FIGURE 2.5 — Schematic of Temperature Profile for Super Wet Combustion Process (Courtesy of UNITAR Centre, Mehta and Moore, 1996)

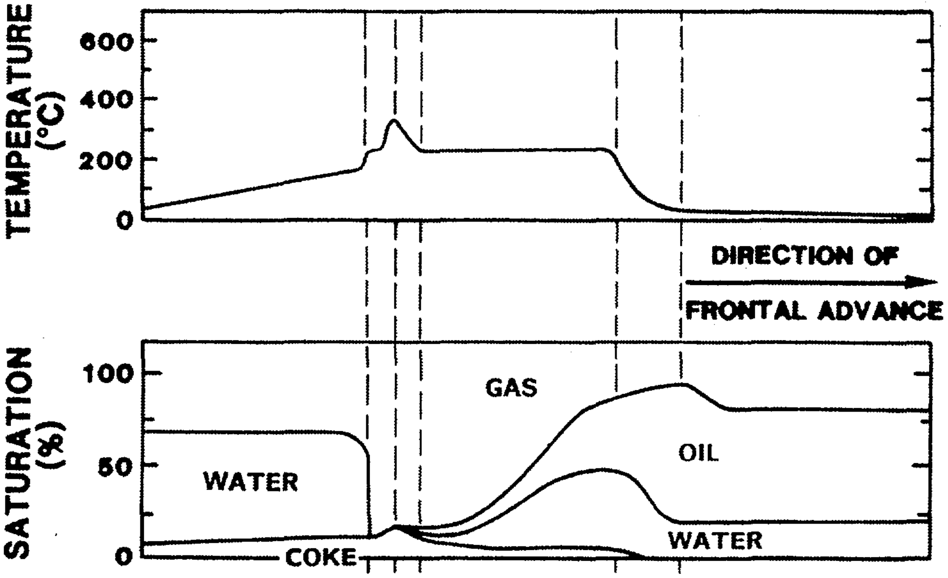

FIGURE 2.6 — Schematic of Saturation Profile for the Incomplete Wet Combustion Process (Courtesy of UNITAR Centre, Mehta and Moore, 1996)

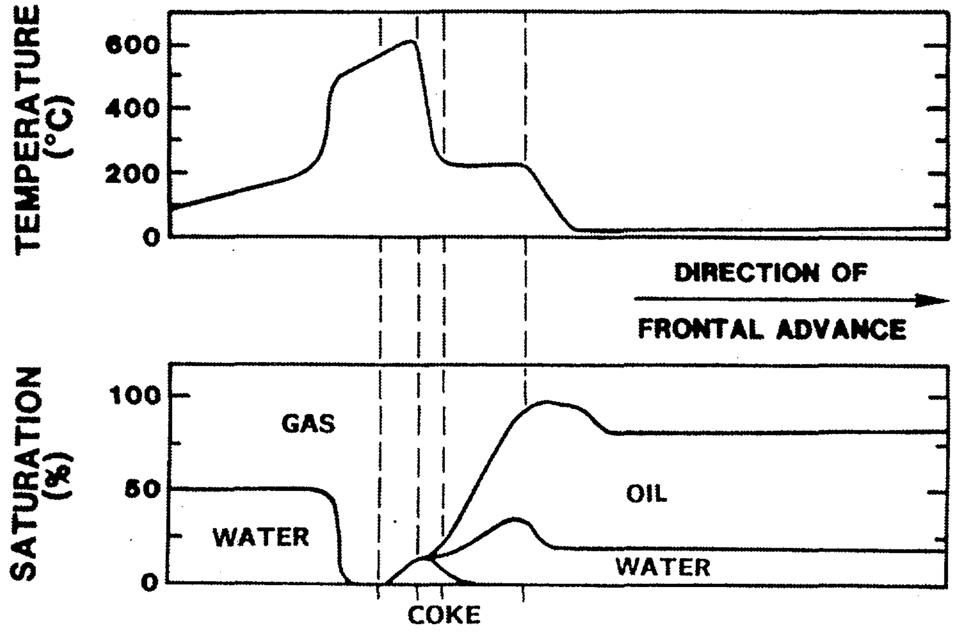

FIGURE 2.7 —Schematic of Saturation Profile for Normal Wet Combustion Process (Courtesy of UNITAR Centre, Mehta and Moore, 1996)

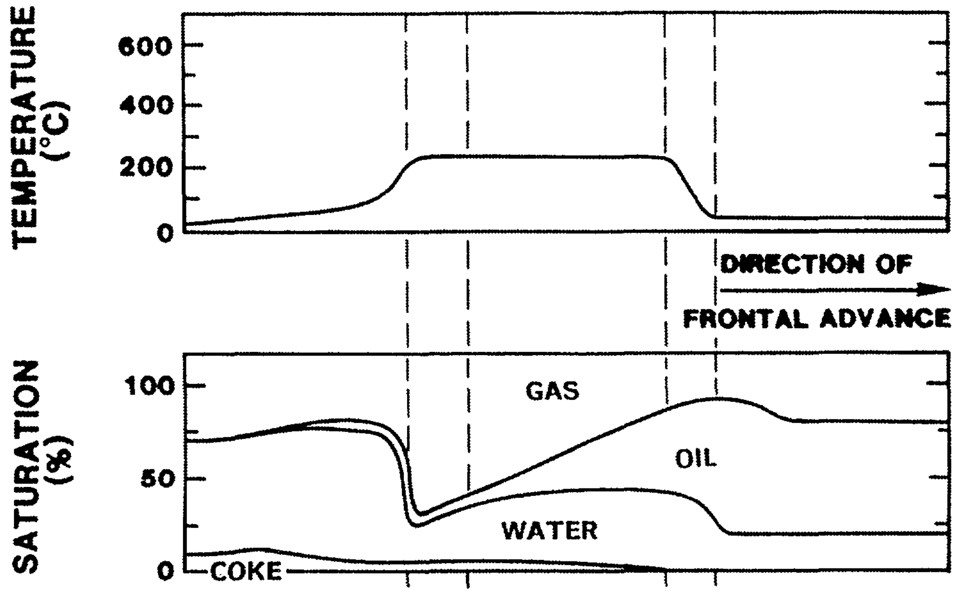

FIGURE 2.8 — Schematic of Saturation Profile for Super Wet Combustion Process (Courtesy of UNITAR Centre, Mehta and Moore, 1996)

Depending upon the injected water air ratio wet combustion process is classified as

wet combustion” (Figure 2.3) “normal wet combustion” (Figure 2.4) and super wet or

bustion (Figure 2.5). At low rates (incomplete wet combustion), the injected water

superheated steam, as it moves toward the combustion front. In this case the injected water fails to recover all the heat from the burned zone. At higher water injection rate (normal wet combustion), the injected water will recuperate all the heat from the burned zone. At even higher water injection rate (super wet combustion) the maximum temperature at the burning front declines. The operating pressure influences the temperature of the combustion zone during superwet combustion. The temperature and the saturation profiles for the three modes of wet combustion are depicted in Figures 2.6–2.8 (Moore and Mehta, 1996).

Laboratory studies and field tests have also shown that water-assisted combustion reduces the amount of oil burned as fuel. This behavior increases the amount of oil displaced but, more importantly, it decreases the quantity of air required to burn a specified volume of reservoir. The mechanism causing the fuel deposit to be decreased during wet combustion is believed to be the increased availability of hydrogen in the combustion zone. A portion of the fuel deposit hydrogenates and becomes mobilized, moving out of the combustion region unburned. The decrease in fuel deposit and air requirement can amount to over 25% improvement in process efficiency.

Quenched (super wet) combustion is a modification of the wet combustion process that attempts to decrease the air requirement even further. The process does not increase oil recovery, but increases the velocity of the combustion front and reduces compression costs. Water is injected at much higher rates than normal wet combustion. The increased heat, transported by the steam as it passes through to burn front, causes combustion temperatures to decrease. The temperature becomes lower than required for burning at the trailing edge of the front causing the oxygen to pass through the region unreacted. Therefore, a portion of the fuel deposit is bypassed, reducing air requirements.

Quenched combustion is more applicable in heavy oil reservoirs and less feasible for high gravity oils with low fuel deposits. The process has been patented and field tested by Amoco as the COFCAW method. Laboratory studies have shown that water rates from 500–1,000 bbl/million scf air result in quenching of the combustion zone and reduced air requirements. Insufficient field tests have been performed to verify the technical merits of quenched combustion. Cities Service’s experience in the Bodcau in-situ combustion project (Joseph et al., 1980) showed that a water/air ratio of 250 bbl/million scf shows much improved burning characteristics compared to dry combustion. However, ptimum water rates are very difficult to determine because they are affected by reservoir inhomogeneities. Segregation of the fluids could result in extinguishing of the firefront and sacrificing of some of the intended benefits of the process. Only operating experience in a particular reservoir will allow selection of the best water/air ratio to maximize recovery and economics.

To summarize, the dry combustion process burns part of the crude and displaces the rest. The heat utilization for displacement of oil is poor. In wet combustion processes, a smaller amount of crude is burned as fuel, and heat utilization and oil displacement are more efficient, resulting in improved recovery rates. The most important aspect of partially quenched combustion is that the burning front advances at a faster rate due to burning only part of the fuel deposit. This results in shorter project life and reduced compressed air requirements compared to dry combustion.

Reverse Combustion

In heavy oil, reservoir forward combustion is often plagued with injectivity 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 phenomena 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 combustion zone is initiated in the production well and moves toward the injector; counter current to fluid flow. The injected air has to travel through the reservoir to contact the combustion zone. The basic concept in reverse combustion is that the major portion of the heat remains between the production well and the oil when it is mobilized. Therefore, once the oil begins to move, very little cooling occurs to immobilize the oil.

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 combustion front cannot move toward the producer as long as all the oxygen is being consumed at the fire front. Thus, the combustion process is seeking the oxygen sources but can move only as fast as the heat can generate the elevated temperatures.

The portion of the oil burned by forward and reverse combustion is different. Forward combustion burns only the cokelike 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. However, the movement of oil through the high temperature zone results in considerably more cracking of the oil, improving its gravity. The upgrading process of reverse combustion is very desirable for tar-like hydrocarbon deposits.

Although reverse combustion has been demonstrated in the laboratory, it has not proven itself in the field (Trantham and Marx, 1966). 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 zone nears the injection well, the air rate is increased, and a normal forward fireflood is commenced.

Other Processes Variation

A number of variations to the basic combustion process have been proposed over the last 50 years and a few field-tested with mixed results. These variations were purportedly to improve the effectiveness of the basic (dry or wet) combustion process under certain conditions. The suggested variations include:

1. Heat wave process.
2. Cyclic dry combustion.
3. Cyclic wet combustion.
4. Burn and Turn (Pressure up-Blow down Combustion or BP process).
5. Steam-Oxygen co-injection process.
6. Steam chamber process.
7. COSH (Combustion Override Split production Horizontal well process.
8. Oxygen recycled produced gas process.

Only the first four variations have been field-tested. Moore et al. (1994) has reviewed these variations and the interested reader is directed to this reference for additional details on these process.

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CHAPTER 3 — KINETICS AND COMBUSTION TUBE STUDIES

Introduction

Unlike steam injection process, where the oil composition and rock mineralogy has minimal impact on oil recovery, these parameters play a major role on the outcome of an in-situ combustion (ISC) process. This is because, the ISC depends for its existence on the occurrence of chemical reactions between the crude oil and the injected air within the reservoir. 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. The reservoir rock minerals and the clay contents of the reservoir are known to influence the fuel formation reactions and their subsequent combustion.Hence 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.

The objective this chapter is to present an overview of the principal chemical reactions associated with the ISC process and to describe the various experimental techniques utilized to obtain process and design informations necessary for the implementation of the process in the reservoir of interest.

Chemical Reactions Associated with In-Situ Combustion

The chemical reactions associated with the in-situ combustion process are numerous and occur over different temperature ranges. Generally, in order to simplify the studies, investigators grouped these competing reactions into three classes: (1) low temperature oxidation (LTO), (2) intermediate temperature, fuel formation reactions, and (3) high temperature oxidation (HTO) or combustion of the solid hydrocarbon residue (coke).

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

Low Temperature Oxidation

During in-situ combustion the hydrocarbons initially present in the oil undergo two types of reaction with the oxygen (injected air) depending upon the prevailing temperature. Those reactions which occur at temperatures below 400°F are defined as the low temperature oxidation (LTO) and the other being the high temperature oxidation (HTO). Unlike the HTO, which produces CO_2, CO, and water (H_2O) as its primary reaction products, LTO yields water and partially oxygenated hydrocarbons such as carboxylic acids, aldehydes, ketones, alcohols, and hydroperoxides (Burger et al., 1972). 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. The degree of dissolution depends upon the diffusion rate of oxygen molecules in the crude (Burger et al., 1972) at reservoir temperature. Light oils are more susceptible to LTO than heavy oils.

LTO reactions are highly complex and not well understood. However, it is believed that LTO reactions consist of condensation of low molecular weight components to higher molecular weight products. Compositionally LTO has been found to increase the asphaltene content of the oil and to decrease its aromatic and resin contents (Moschopedis and Speight, 1975; Babu and Cormack, 1984; Adegbesan et al., 1987).

LTO have been shown to increase the original oil's viscosities, boiling range and densities (Alexander et al., 1962; Bousaid and Ramey, 1968; Severin et al.; Babu and Cormack, 1984). It has been shown that LTO reaction increases the amount of fuel available for combustion (Alexender et al., 196; Al-Saadon, 1970) and causes a substantial decline in recoverable oil from the distillation and cracking zones (Dabbous and Fulton, 1974).

Low air fluxes in the oxidation zone resulting from reservoir heterogeneities and oxygen channelling promote LTO reactions. Poor combustion characteristics of the crude also tend to promote LTO due to low oxygen consumption. In heavy oil reservoirs, LTO tends to be more pronounced when oxygen, rather than air, is injected into the reservoir. To rectify this situation some investigators recommend adding steam to the oxidizing gas stream (Scarborough and Cady, 1982). The rationale 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.

Moore (Moore, 1993) made the following observations with regard to LTO.

> "LTO are generally believed to occur at temperatures of less than 600°F, but this temperature range is very oil dependent. 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°F and 320°F. 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°F. This gives rise to the *negative temperature gradient* region, (Figure 3.1) which is a temperature interval over which the oxygen uptake rate decreases as the temperature increases."

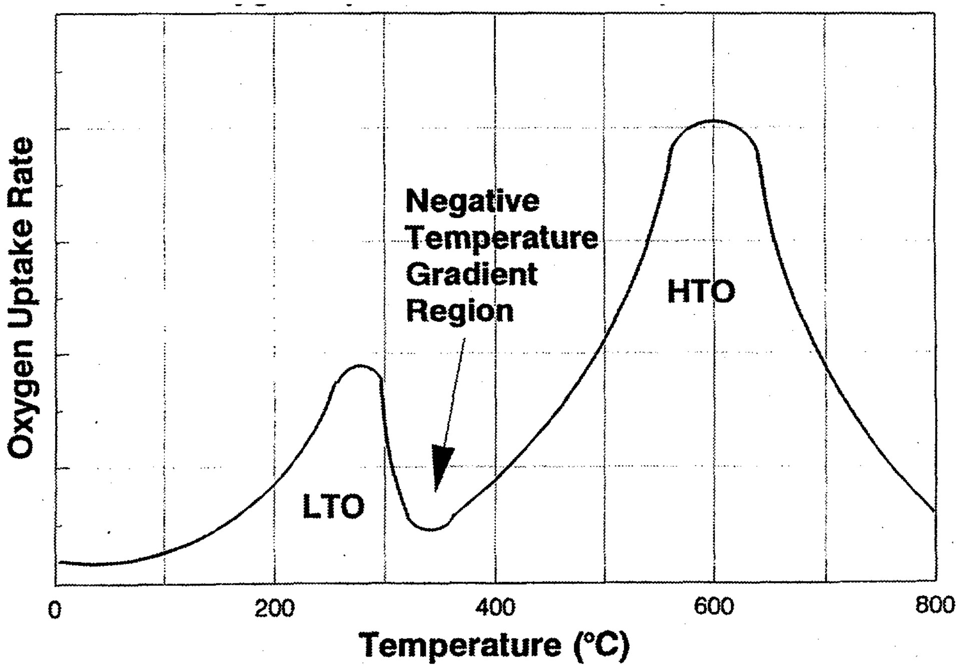

FIGURE 3.1 — Schematic of Dry Combustion Temperature Profile Showing the General Effect of Temperature on Oxygen Uptake Rate for Heavy Oils and the Negative Temperature Gradient Region (After Mehta and Moore)

Failure of the reaction temperatures to transcend the negative temperature gradient region will lead to a very low oil displacement efficiency, This is because the oxygen addition reactions cause vapor phase to shrink significantly and also make the oil less mobile. 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.

The above observations were made based on LTO study of bitumens (Athabasca oil sand). Laboratory LTO studies by Fassihi et al. (1990) 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. Yannimaras (1997) also observed similar trend in their laboratory air injection study of various light crudes. However, LTO dramatically affect the mobility of heavier crudes (i.e., those with high asphaltenes and resin contents). For these oils LTO increases both the viscosity and density which in turn affect their recovery. Pre-oxidation of the heavy crude at lower temperatures also greatly increases the fuel availability and subsequent air requirements for combustion. Thus 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 hydroperoxide intermediates. Their decomposition releases much heat and can cause the oil to autoignite (Smith and Schweyer, 1967).

The Pyrolysis Reactions

As the reservoir temperature raises, the oil undergo a chemical change called pyrolysis. Pyrolysis reactions (intermediate temperature oxidation reactions (ITO)) 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: dehydrogenation, cracking and condensation. In the dehydrogenation reactions the hydrogen atoms are stripped from the hydrocarbon molecules, while leaving the carbon atoms untouched. 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. In the case of condensation reactions, the number of carbon atoms in the molecules increases leading to the formation of heavier carbon rich hydrocarbons. The oil type and the chemical structure of its constituent hydrocarbons determine the rate and extent of the different pyrolysis reactions.

The paraffins (straight chain hydrocarbons) do not undergo condensation reactions. At 700–1250°F they undergo dehydrogenation and/or thermal cracking reactions depending upon the length of the hydrocarbon chain. In general short chain hydrocarbons (methane through butane) undergo dehydrogenation and the larger molecules undergo cracking. Cracking reactions are usually initiated by the cleavage of the carbon-carbon bond, followed by the hydrogen abstraction (dehydrogenation) reaction. The dehydrogenation molecules than recombine to form heavier molecules, eventually leading to the formation of "coke". Thus the larger straight chain molecules after prolonged heating or when subjected to sufficiently high temperature often produce "coke" and considerable amounts of volatile hydrocarbon fractions.

The aromatic compounds (benzene and other ring compounds) undergo condensation reaction rather than degradation reactions (cracking) at 1200–3000°F. In the condensation reaction the weak C-H bonds of the ringed molecules are broken and replaced by a more stable C-C bonds and leads to the formation of a less hydrogenated polyaromatic molecule. When subjected to further heating these condensation products losses more of the hydrogen and recombines to form heavier carbon rich polymolecules, eventually leading to the formation of large graphite like macromolecules.

Laboratory pyrolysis studies on heavy (14–16°API) California crudes (Abu-Khamsin et al., 1988) indicate that the pyrolysis of 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. At higher temperatures (400–540°F), 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. At still higher temperatures, (above 550°F) 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". Coke is defined as the toluene insoluble fraction of an oil and generally contains 80–90% carbon and 3–9% hydrogen. Both visbreaking and cracking reactions produce hydrogen gas and some light hydrocarbons in the gas phase. 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. High operating pressures generally lead to the formation of more fuel that is leaner in hydrogen.

Researchers at the University of Calgary have for over 20 years studied various aspects of in-situ combustion and they describe the bitumen pyrolysis reaction as:

Bitumen → Maltenes

Maltenes → Asphaltenes

Asphaltenes → Coke

Asphaltenes → Gas

Maltenes are crude oil fractions which are pentane and toluene soluble and may be further separated into saturates, aromatics, and resins using liquid chromatography. The asphaltenes are toluene soluble but pentane insoluble fraction of the bitumen. Coke is defined as the fraction insoluble in toluene. Thermal cracking of asphaltene to coke has a long induction period (initiation time). This induction period decreases as the cracking temperature increases.

High Temperature Oxidation

The reaction between the oxygen in the injected air and the coke at temperatures above 650°F are often referred to as the high temperature oxidation (HTO) or combustion reactions in the ISC literatures. Carbon dioxide (CO_2), carbon monoxide (CO), and water (H_2O) are the principle products of these reactions. HTO are heterogeneous (gas-solid and gas-liquid) reactions and are characterized by consumption of all of the oxygen in the gas phase. The stoichiometry of the HTO reaction (chemical equation) is given by:

$$CH_n + \left[\frac{2m+1}{2(1+m)} + \frac{n}{4}\right]O_2 \rightarrow \left[\frac{1}{1+m}\right]CO + \left[\frac{m}{m+1}\right]CO_2 + \frac{n}{2}H_2O \qquad (3.1)$$

where n = atomic ratio of hydrogen to carbon

m = molor (mole percent) ratio of produced CO_2 to CO

m = zero in the case of complete combustion to CO_2 and H_2O

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 steps (Scarborough and Cady, 1982):

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.

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

The issue whether the chemical reaction rate or the oxygen diffusion rate controls the combustion process is rather controversial. Some investigators (Dabbous et al., 1974; Lin et al., 1984) found that the combustion reaction was diffusion controlled, while others found it to be chemical reaction controlled (Hughes et al., 1987; Fassihi and Brigham, 1982; Burger, 1976). Islam et al., 1989, contend that the laboratory experiments are almost always conducted under rather ideal conditions, and the experiments conducted under such ideal situations permit oxygen interfacial mass transfer rate to be quite high and thus likely to mask the influence of diffusion on the combustion reactions in the reservoir. Other investigators contend that the overall combustion rate is dependent on the oxygen concentration (partial pressure) at or near the combustion front. At high air fluxes the reaction is rate controlled and at low air fluxes the reaction is diffusion limited.

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:

1. To characterize the reactivity of the oil.
2. To determine the conditions required to achieve ignition and or to determine if self ignition will take place in the reservoir upon air injection.

3. To gain insight into the nature of fuel formed and its impact on combustion.
4. To establish parameter values for the kinetic (reaction rate) models used in the numerical simulation of ISC processes.

Combustion of crude oil in porous media is not a simple reaction but follows several consecutive and competing reactions occurring through different temperature ranges (Fassihi et al., 1984). Since crude oils are made up of hundreds of compounds, an explicitly correct kinetic representation of crude oil oxidation reaction would require an inordinately large number of kinetic expression. However, this is not feasible because these compounds undergo reactions that cannot easily be described. This 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 intramolecular reactions. Detailed models for hydrocarbon oxidation reactions are available only for the simplest hydrocarbon molecules and are made up of several reaction steps (equations).

Detailed hydrocarbon oxidation model even if exist, cannot currently be included in multidimensional in-situ combustion simulators, because the computer size, speed, and cost requirements of such a treatment would be too great. Detailed oxidation models have been developed and validated for only the simplest fuel molecule and are not available for most practical fuels. However, very simple models that approximate the oxidation reaction kinetics study of crude oils in porous media have appeared in literature.

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

$$\text{Fuel} + n_1\,\text{O2} \rightarrow n_2\,\text{CO} + n_3\,\text{CO}_2 + n_4\,\text{H}_2\text{O} \qquad (3.2)$$

where the stoichiometry coefficients $\{ni\}$ 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:

$$R_c = \frac{dC_m}{dt} = kP_{O_2}^{a}C_f^{b} \qquad (3.3)$$

where

R_c = combustion rate of crude oil,

C_f = instantaneous concentration of fuel,

k = rate constant,

P_{O2} = partial pressure of oxygen,

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

b = order of reaction with respect to fuel concentration.

High temperature carbon and crude oil oxidation studies by Bousaid (Bousaid and Ramey, 1968) and others (Dabbous and Fulton, 1974) indicates first order reaction dependency on fuel concentration and 0.5–1.0 order dependency with respect to oxygen partial pressure; i.e., 'a' = 1.0 and 'b' = 0.5 to 1.0.

The reaction rate constant 'k' in Equation (3.3) is often a function of temperature and expressed by

$$k = A \exp\left(- E/_{RT}\right) \tag{3.4}$$

where

A = pre-exponential factor

E = activation energy

R = universal gas constant = 1.987 cal mole^{-1} K^{-1}

T = absolute temperature in °K

Equation (3.4) is often referred to as the Arrhenius rate equation and the constant 'A' as Arrhenius rate constant in the ISC literature. The constants in Equation (3.4) vary with oil type, pressure, and other parameters as well.

The units of the constant A, E, and R depends upon the unit selected for mass, pressure, temperature, and time. For example in the literature the pre-exponential factor 'A 'is expressed in various units such as ‘day^{-1} psi^{-1}‘, ’sec^{-1} atm.$^{-1}$‘, ‘ sec^{-1} atm.$^{-n}$‘,’ sec^{-1} Pa^{-1}‘, ‘hr^{-1} psi^{-n}‘, etc. Similarly the activation energy ‘E’ expressed variously as ‘cal/gm-mole’, ‘Btu / lb.mole’, ‘J/gm-mole’ etc. The parameters A and E are functions of rock and crude and must be established experimentally using the crude and porous medium of interest. ISC process simulators often require kinetic information to calculate the firefront advancement rate and oil recovery. Experimental determination of kinetic parameters is expensive and for a quick screening simulation the reported literature values are often used. Hence, careful attention must be paid to the units when using these kinetic data.

Factors Affecting Oxidation Reactions

Two of the most important factors in the in-situ combustion process are fuel formation and combustion. The physical and chemical processes that govern the ability of a crude to deposit fuel and its subsequent combustion (oxidation) strongly influences the economics of a combustion project. Too little fuel deposition may prevent the formation of a sustained, stable combustion front. Likewise, too large a fuel deposition will result in uneconomically high oxidizing gas requirement. The rate of propagation of the combustion front and the air requirement depend on the extent of the exothermic oxidation reactions, which are controlled by the kinetics of these processes.

A substantial investigative effort has been made over the years in the laboratory to study the many factors that affect the crude oil oxidation reactions in the reservoir. These investigations indicate that the nature and composition of the reservoir rock and the characteristics of the oil influence the thermo-oxidative characteristics of the reservoir crudes. The clay and metallic content of the rock, as well its surface area has a profound influence on fuel deposition rate and its oxidation.

Clays and fine sands, have very high specific surface area. Studies by Fassihi et al., 1984; Vossoughi et al., 1982; and Bardon and Gadelle, 1977, indicate presence of clays and fine sands in the matrix favor increased rates of coke formation. Clays are solid acid catalysts and their catalytic activities are related to their acid site density and acid strength. Increased clay content increase the acid site density and acid strength (Tanabe, 1970). Literature on catalytic cracking process (Tanabe, 1970; Venuto et al., 1979) reveals that increased acid site density and acid strength lower activation energy (smaller Arrhenius constant), and promote low temperature oxidation and coke formation reactions. This is particularly advantageous in light oil reservoirs, where fuel deposition can be less than that needed to sustain combustion. For example the success of the in-situ combustion in the previously waterflooded May — Libby light oil reservoir (40°API), La is attributed to the influence of the rock mineralogy (13.5% silt and 10.5% clay) on the fuel formation reaction (Hardy et al., 1972).

Metals and metallic additives also known to affect the nature and the amount of fuel formed. Metals are used as catalysts in the petroleum refining and chemical process industries to accelerate the hydrocarbon oxidation and cracking reactions. In studies undertaken to investigate the effect of metal contamination on hydrocarbon cracking reactions, it was found that various metals promote coke formation and the catalytic effect of these metals was found to be ordered as follows: Cu < V < Cr = Zn < Ni, with nickel about four to five times as active as vanadium (De los Rios, 1988).

Studies on the effect of reservoir minerals on in-situ combustion indicate metals promote low temperature oxidation and increase fuel deposition (Burger and Sahuquet, 1972; Fassihi, 1981; Drici and Vossoughi, 1985). Studies conducted by the researchers at Stanford University (De los Rios, 1988; Shallcross, 1989; Baena, 1990; Holt, 1992) indicate that kinetics of all three oxidation reactions, (LTO, pyrolysis, and HTO) is affected by the presence of metallic additives in the crude oil. These researchers also noted that the catalytic activity of a metal is highly dependent on the specific composition of the crude. The benefits of metallic additives in promoting and sustaining combustion in a light oil reservoir is documented by Racz (1985). The ability to initiate and propagate the combustion front in this Hungarian reservoir was attributed to the catalytic properties of the metallic additive which increased fuel concentration.

Tools and Techniques

Kinetic studies of in-situ combustion reactions are carried out using a variety of techniques. These techniques fall into two categories; qualitative and quantitative. The qualitative techniques employ thermal analysis instruments such as the 'Differential Thermal Analyzer (DTA)', 'Thermogravimetric Analyzer (TGA)', 'Differential Scanning Calorimeter (DSC)' and 'Accelerating Rate Calorimeter (ARC)'. In the quantitative technique a thin walled plug-flow type reactor cell containing a sample of oil and sand is heated in a prescribed manner until the designated maximum temperature is reached. Depending upon whether pyrolysis or oxidation was being studied, nitrogen or air flowed through the sample. The kinetic parameters are calculated from the chemical analysis of the post test core-oil samples and effluent gas.

Information on the in-situ combustion design parameters such as the fuel availability, air requirements, peak combustion temperature, oxygen utilization efficiency, etc., obtained from combustion tube tests.

Thermal Analysis Techniques

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.

TGA and DTA Techniques

In TGA 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 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. In practice, 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 (Figure 3.2).

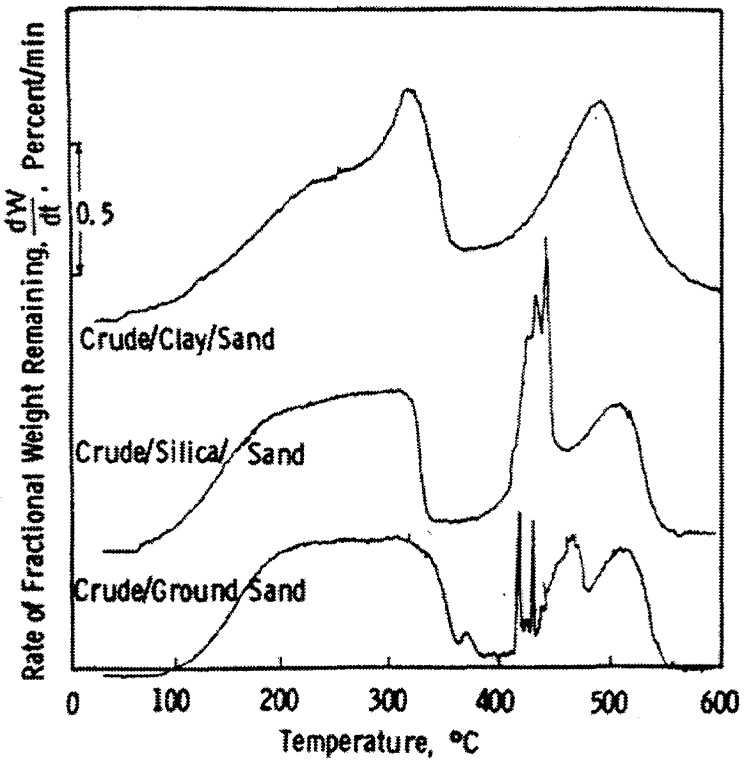

FIGURE 3.2 — Typical DTG Thermograms Showing Effect of Surface Area on Crude Oil Combustion (After Vossoushi et al., 1983)

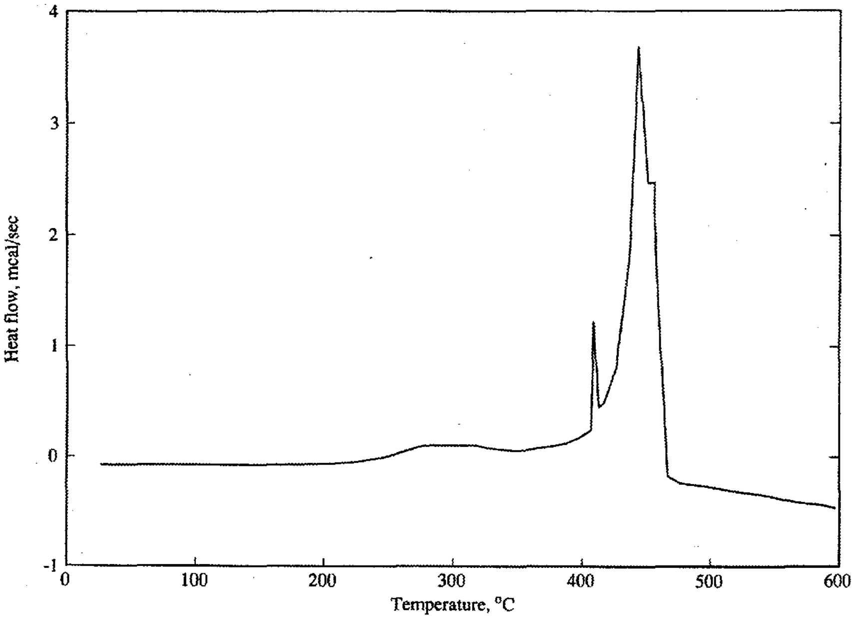

FIGURE 3.3 — Typical DTG Thermogram for a California Heavy Oil-Sand Mixture (After Mamora et al., 1993)

In DTA technique 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 3.3). The sample size affects the magnitude of the DTA curve and the height of the curve is proportional to the weight of the sample.

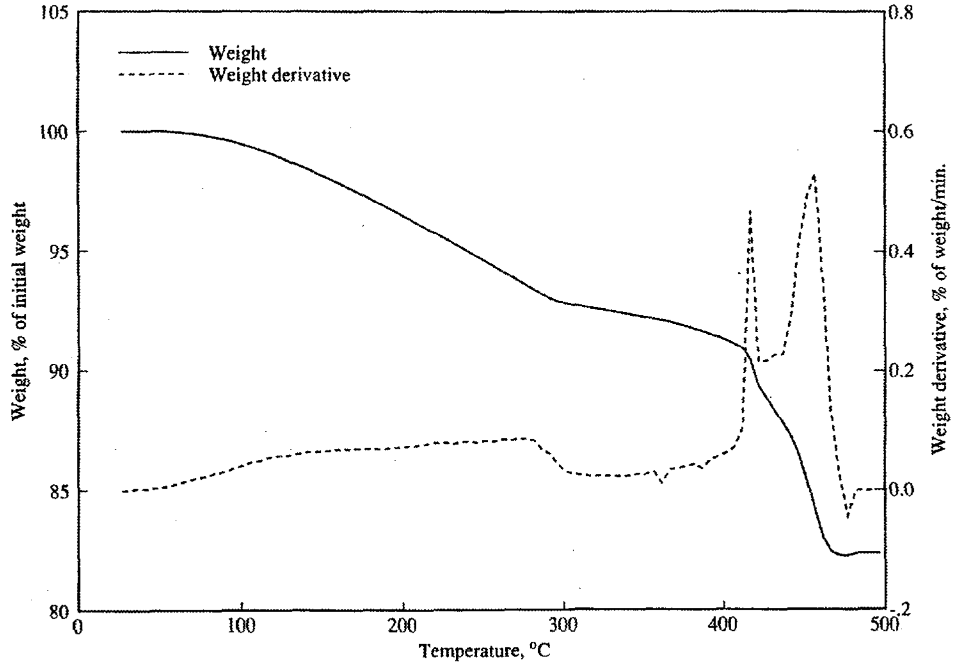

FIGURE 3.4 — Typical DTG Thermogram for a Venezuelan Extra Heavy Oil-Sand Mixture (After Mamora et al., 1993)

The TGA, DTA, and the DTG curves are known as the thermograms. Each crude oil produce 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 3.4) 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. This DTG thermogram serve as a complementary piece of information and is easier to analyze for changes from one sample to next. The DTG curves also tend 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. When there are two changes close to each other in temperature, the DTG will usually give two distinct sharp peaks. The TG, DTG, and DTA thermograms all can be used to determine the reaction kinetics. These are discussed briefly in the following paragraphs.

Determination of Kinetic Parameters from Thermogram

Several investigators (Freeman and Carroll, 1958; Coats and Redfern, 1964; Zoaks, 1968; Segal and Fatu, 1976; Reich and Stivala, 1978; Rock, 1978; Dharwadkar et al., 1978; Reich and Stivala, 1980; Dollimore, 1980) have presented procedures to determine the kinetic parameters of a reaction from the TGA data. Here we briefly outline the classical Coats and Redfern, 1964, procedure to determine the kinetic parameters. For additional information the reader is directed to the original reference.

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

$$d\alpha / dt = k\ (1 - \alpha)^n \qquad (3.5)$$

where,

α = fractional weight change of the sample

$= (w_0 - w_t) / (w_0 - w_\infty)$

w_0 = initial sample weight

w_t = sample weight at time 't'

w_∞ = final sample weight

t = time

k = specific reaction rate

n = order of the reaction

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

$$\beta = dT / dt \qquad (3.6)$$

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

Combining Equations (3.5) and (3.6) we have

$$\frac{d\alpha}{dT} = \frac{k}{\beta}(1 - \alpha)^n \tag{3.7}$$

Substituting the expression for 'k' from Equation (3.4) in Equation (3.7) we have

$$\frac{d\alpha}{dT} = \frac{A \times \exp\left(\frac{-E}{RT}\right)}{\beta}(1-\alpha)^n \tag{3.8}$$

Following Coats and Redfern, we obtain

$$\frac{1 - (1 - \alpha)^{1-n}}{1 - n} \approx \frac{ART^2}{\beta E}\left[1 - \frac{2RT}{E}\right]\exp\left(\frac{-E}{RT}\right) \quad \text{for } n \neq 1 \tag{3.9}$$

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

$$\ln\left[\frac{1 - (1 - \alpha)^{1-n}}{(1 - n)T^2}\right] = \ln\left[\frac{AR}{\beta E}\left(1 - \frac{2RT}{E}\right)\right] - \frac{E}{RT} \quad \text{for } n \neq 1 \tag{3.10}$$

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

$$\ln\left[-\ln\frac{(1 - \alpha)}{T^2}\right] = \ln\left[\frac{AR}{\beta E}\left(1 - \frac{2RT}{E}\right)\right] - \frac{E}{RT} \quad \text{for } n = 1 \tag{3.11}$$

Assuming 'n' = 1, a plot of $-\ln\left[\frac{-\ln(1 - \alpha)}{T^2}\right]$ versus 1 / T should result in a straight line of slope -E / R. The value of E obtained graphically is substituted in Equation (3.11) to calculate the pre-exponential factor A.

If 'n' is ≠ 1 then a plot of $\ln\left[\frac{1 - (1 - \alpha)^{1-n}}{T^2(1 - n)}\right]$ against 1 / T should yield a straight line for the correct value of 'n'.This trial and error procedure, though, appear straight forward is not that simple. Reich and Stivala (1978) modified and simplified Coat and Redfern's expression (Equation 3.9) and presented a computer approach (1980) to determine kinetic parameters.

As an alternative to the above we also present the Segal and Fatu's (1976) approach to the determination of the kinetic parameters from the TGA thermogram in the following.

Substituting the expression for 'k' from Equation (3.4) in Equation (3.5) we have

$$\frac{d\alpha}{dT} = A \exp\left(\frac{-E}{RT}\right)(1 - \alpha)^n \tag{3.12}$$

Taking the common logrithm we have

$$\log\left(\frac{d\alpha}{dt}\right) = n \log(1 - \alpha) - \frac{E}{2.303\,R}\left(\frac{1}{T}\right) \tag{3.13}$$

By keeping the term $\log\left(\frac{d\alpha}{dt}\right)$ constant, i.e.

$$\log\left(\frac{d\alpha}{dT}\right) = \log K \tag{3.14}$$

we get:

$$\log(1 - \alpha) = \frac{E}{4.575\,n}\left(\frac{1}{T}\right) + \frac{\log K}{n} \tag{3.15}$$

By plotting log (1 - α) against $\left(\frac{1}{T}\right)$ a straight line is obtained whose slope and intercept allow calculation of both the activation energy 'E' and the reaction order 'n'. The pre- exponential factor A can be then calculated from Equation (3.4). For further details about this approach the reader is directed to the original work.

Yoshiki and Phillips (1985) presented the following expressions for calculating kinetic parameters from the DTA data. These expressions are applicable to cylindrical cells and were obtained by modifying the original expressions presented by Bae (1972) for spherical cells. The relevant equations for an nth order reaction are listed below.

$$\left[\frac{\exp(\alpha t_f) - \exp(\alpha t_m)}{\exp(\alpha t_f) - \exp(\alpha t_a)}\right]^{\left(\exp[\alpha(t_f - t_m)] - 1\right)} = \frac{\Delta T_m}{\Delta T_a} \times \exp\left[\alpha\left(t_a - t_m\right)\right] \tag{3.16}$$

$$n = 1 - \exp\left[-\alpha\left(t_f - t_m\right)\right] \tag{3.17}$$

$$\alpha = \frac{E\phi}{RT_0^2} \tag{3.18}$$

$$\alpha t_m = \ln\left(\frac{\alpha}{B}\right) + (1 - n) \tag{3.19}$$

$$B = A_0 \exp - \left(\frac{E}{RT_0}\right) \tag{3.20}$$

where:

n = reaction order

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

$\Delta T_M = \Delta T$ at a maximum reaction rate

$\Delta T_a = \Delta T$ at t_a

ϕ = heating rate

R = universal gas constant

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

The kinetic parameters n, E, and A may be 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). 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 remain 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.

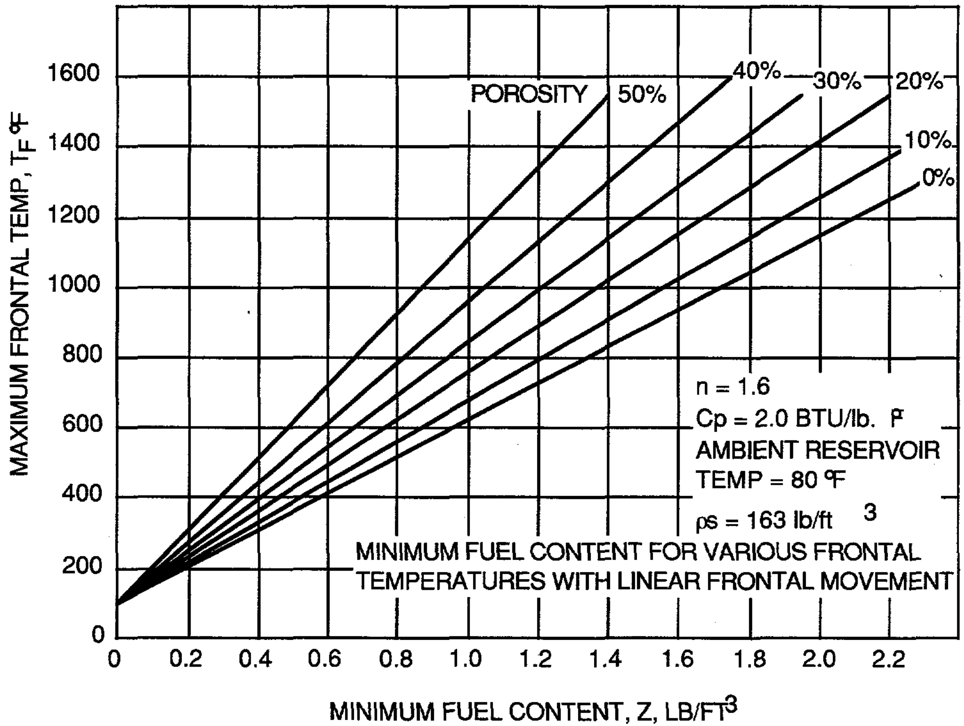

FIGURE 3.5 — Typical DTG Thermogram Showing Various Oxidation Regime (After Nickle et al., 1987)

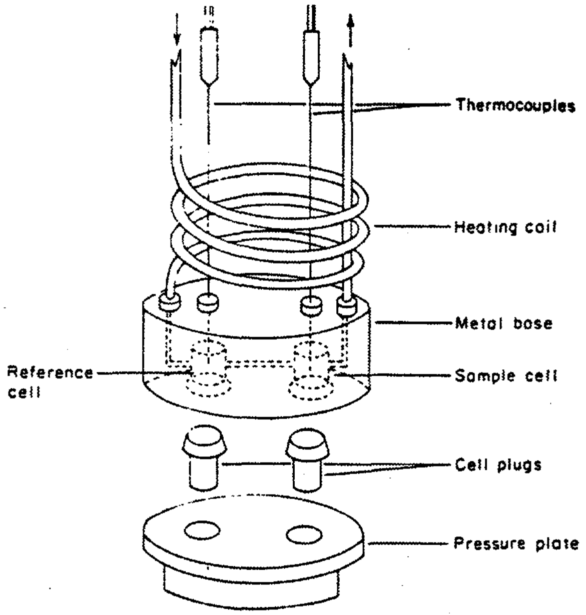

FIGURE 3.6 — Schematic Diagram of a Differential Thermal Analyzer (DTA) Cell (After Yoshiki and Phillips, 1985)

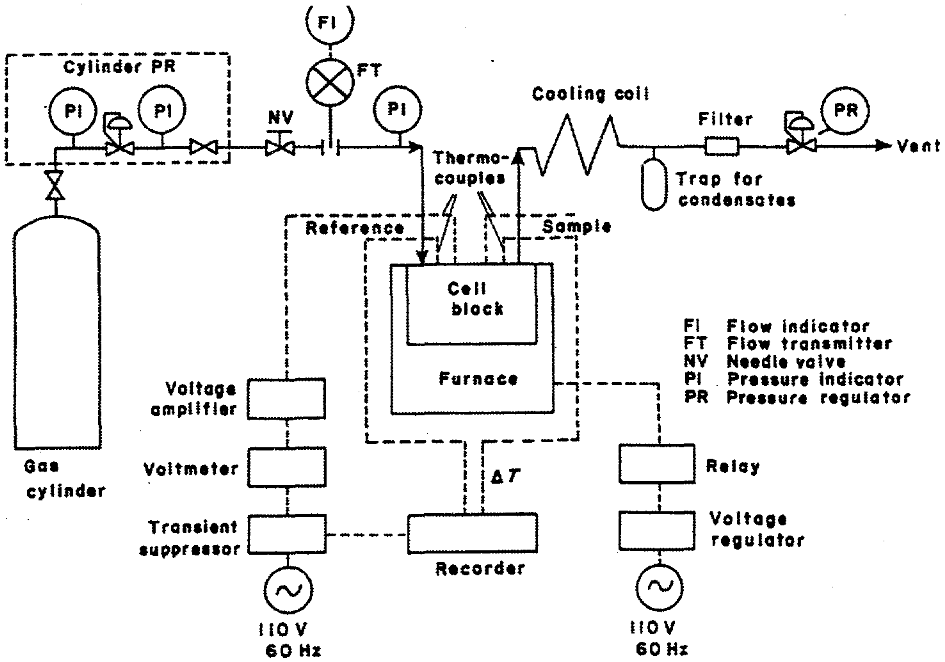

FIGURE 3.7 — Schematic Diagram of a High Pressure Thermal Analysis Experimental Set-up (After Yoshiki and Phillips, 1985)

The DSC is similar to DTA in operation and used to obtain enthalpy (heat of reaction) information and to delineate the various reaction regimes. In the DSC the energy required to keep a sample isothermal with a reference material is measured as a function of temperature. Like TGA, DSC also employ a linear heating rate to simplify the data analysis. In the DSC experiment the amount of heat released by either the exothermic combustion or the distillation/cracking of the oil samples is determined from the plot of temperature versus differential heat flow between the sample and the reference (DSC thermogram). DSC and TGA are complementary thermal analysis techniques and often used together to obtain maximum information on the oxidation/combustion reactions (Figure 3.5).

In a typical DSC experiment a known mass of sample is weighted into the sample cell and then placed on the sample platform of the DSC. A similar empty cell is placed on the reference platform of the DSC (Figures 3.6–3.7). The cells are then purged and air or nitrogen-oxygen mixture is flowed through at the desired rate. The cells are heated at the desired heating rate over the temperature of interest. The amount of heat caused by either exothermic combustion or cracking of the oil is determined from the thermogram. The amount of heat released or absorbed by the sample is proportional to the area under the thermogram. The areas are converted to the corresponding values of the heat evolved or absorbed per unit weight of the sample by applying the appropriate instrument calibration factor.

Shortcomings of Using TGA / DSC Techniques to Evaluate ISC Parameters

In the last decade procedures were developed to utilize TGA / DSC as an inexpensive and rapid screening tool for in-situ combustion (Vossoughi et al., 1985; Jha and Verkoczy, 1986; Kharrat and Vossoughi, 1985). As an alternative to combustion tube tests, these investigators proposed TGA / DSC based procedures to calculate rapidly such ISC parameters as: fuel laydown, percentage of crude consumed as fuel, combustion temperature, auto ignition temperature, minimum oil saturation required to sustain a combustion front and combustion kinetics. The attractiveness of this approach compared to combustion tube run is that the TGA/DSC techniques are less capital intensive, require fewer manpower to set-up and operate and the data analysis is less time consuming. The resource requirements of combustion tube and the thermal analysis techniques are compared in Table 3.1

TABLE 3.1 — Resource Requirements of Combustion Tube and TGA / DSC Experiments (Nickle et al., 1987)

Description	Combustion Tube	TGA / DSC
Capital ($K)	500 - 1,000	75 - 150
Lab. Space (ft^2)	100 - 300	10 - 15
Operating Expense ($K)	10 - 50	0.2 - 0.5
Core (Grams)	3,000 - 5,000	2 - 3
Man Hours	300 - 500	30 - 50

The major limitation of this approach is that these procedures often employ experimental conditions that are dissimilar to those encountered in a reservoir or in the combustion tube. Hence the results are likely to be affected by experimental variables such as the heating rate, oxygen partial pressure, purge gas flow rate, sample size, etc. Further, TGA and DSC experiments lack the fluid flow characteristics of the combustion tube test. Nickle et al. (1987) investigated the effect of experimental conditions on TGA / DSC generated ISC parameter values, in terms of heat/mass transfer limitations and reaction kinetics and arrived at the following conclusions:

- The heating rate employed in the TGA / DSC techniques significantly affects fuel laydown. The fuel laydown increases with decreasing heating rate due to increased LTO at the lower heating rates.
- Kinetic parameters derived from TGA / DSC data using a first order kinetic model are far from rigorous and are dependent on the sample heating rate. Hence the TGA / DSC heating rate must be consistent with the thermal history of the system being simulated.
- Since reservoir and crude oil minerals catalyze fuel deposition, TGA / DSC screening experiments must be performed using reservoir rock and crude.
- TGA / DSC thermograms are not affected by flow rates.
- The error in TGA sample temperature measurement (ΔT) increases with increase in: oil saturation, heating rate, sample size, purge gas flow rate, and oxygen concentration. Hence TGA analysis must be carefully designed to minimize ΔT.

- Since in-situ combustion parameters calculated from thermal analysis techniques are affected by experimental conditions, the conditions used in the TGA / DSC evaluations should mimic as closely as possible, those found in the system being simulated.

Accelerating Rate Calorimeter (ARC)

The traditional thermal analysis tools (TGA, DTA, DSC) are limited to low and medium pressure operation. The ARC is an instrument that has been developed in the early 1980s to study exothermic reaction kinetics at elevated pressure (to 10,000 psi) in the temperature range of interest (60°–900°F). The Arrhenius activation energy, pre-exponential factor, and order of reaction can all be calculated from the ARC data along with the main exotherm. Though both ARC and DSC are capable of revealing LTO and HTO reactions, ARC is better suited for studying the interval between LTO and HTO. The following discussion of ARC is based on the works of Townsend and Tou (1980), Yannimaras and Tiffin (1995), and Zelenko and Solignac (1997), supplemented by additional informations made available to the author by Amoco Exploration and Production Technology Group, Tulsa, Oklahoma (Yannimaras, 1998).

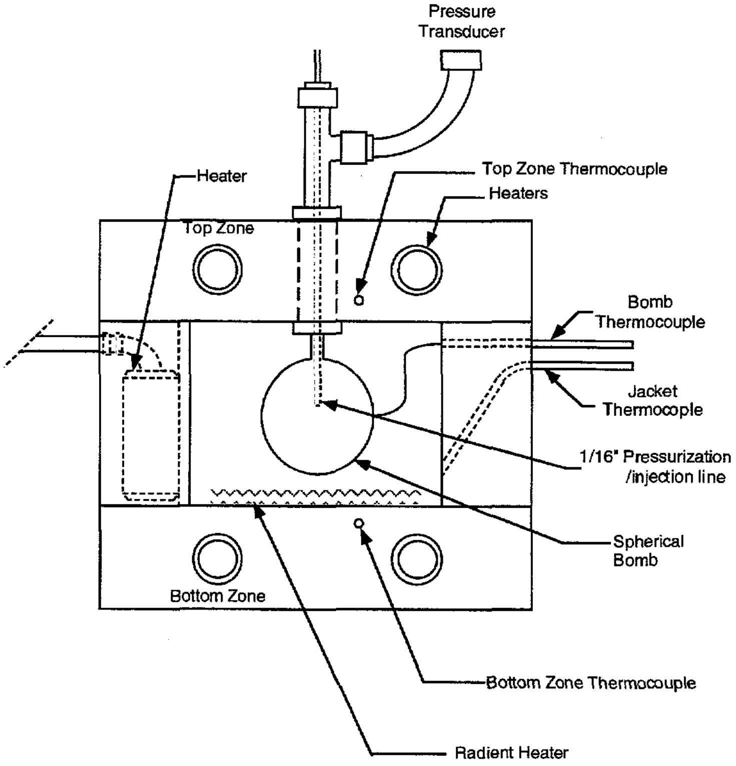

FIGURE 3.8 — High Pressure Accelerating Rate Calorimeter (ARC) Set-up (After Yannimaras and Tiffin, 1995)

ARC consist of a small (1 in. diameter) spherical sample holder (bomb), into which the reactants are placed (Figure 3.8). The bomb is then placed inside a precisely heated calorimeter. The power input to the calorimeter's heaters is controlled by maintaining the temperature difference between the bomb and the calorimeter walls to near zero. The temperatures are measured with thermocouples placed on the bomb and on the outer walls of the calorimeter which contains the heaters. The heat flow toward the outside of the bomb varies according to the difference of temperature between the bomb and the calorimeter walls. This permit the tracking of rapid exothermic reactions under strict adiabatic conditions. The key factor in the design and construction of the ARC is the maintenance of near perfect adiabatic conditions. Once a self heat rate is achieved (limit is 0.02°C / min or higher) the sample completes its thermal spiral adiabatically, with automatic recording of time, temperature, and pressure data until the exothermic reaction has gone to completion. A pressure transducer attached to the bomb head permit the pressure measurement inside the bomb.

Figure 3.8 shows a closed ARC set-up for kinetic study (Yannimaras, 1998). It consist of the main unit with the pressure vessel, power unit, thermal control unit, and X-Y plotter. A computer is used to control the operation of ARC. It also serves to collect and process data and obtain kinetic and thermal values.

A crude oil sample is usually subjected to 'closed' ARC system testing (i.e., fixed amount of air, initially at reservoir pressure, over the oil sample and near perfect adiabatic operation). The runs starts at the initial reservoir temperature. After 15 minutes, if the system does not detect a heat rate greater than the detection threshold of the calorimeter (usually 0.03–0.04°F per minute), the bomb temperature is increased by 10°F. This procedure is repeated until a significant rise in temperature due to exothermic reactions between the oil and oxygen is noted.Then, the heat rate is adjusted to achieve and maintain adiabiticity. Finally, when the heat rate drops to near zero, the bomb is heated up again to a higher temperature to see if reactions start at higher temperature. This is done up to 900°F.

The experimental results are generally presented as plots of log of the rate of exothermic heat release (°C/min) versus Temperature. Because the reaction is followed adiabatically, no heat is allowed to cross the system boundaries once combustion is underway. Thus, in the ARC plots, the presence of a trace over a temperature interval indicates a region of exothermic reaction, while the absence of experimentally recorded points indicates no reaction (Yannimaras and Tiffin, 1995).

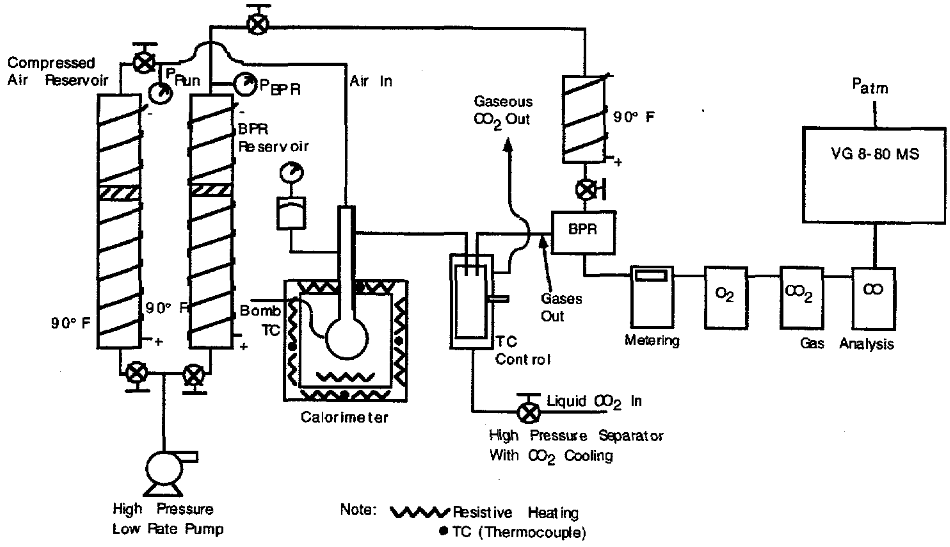

FIGURE 3.9 — Schematic of Flowing Arc System Set-up (Courtesy of Amoco Exploration and Production Technology Group and Yannimaras, 1998)

The ARC usually operates as a closed system, within its permitted pressure and temperature range. This operating mode is satisfactory for obtaining most kinetic parameters associated with the oxidation of oils. However, since in the reservoir the reaction kinetics are dynamic and affected by oxygen flux, it is highly desirable to obtain kinetic parameters under flowing conditions. Hence ARC set-up is often modified to operate it as a flowing system at any pressure up to the system's pressure limit. A schematic of such a system is shown in Figure 3.9 (Yannimaras, 1998). Flowing ARC studies indicate that the LTO / HTO kinetics from such a system tend to approach those of closed system at near zero flow rates.

ARC Theory

ARC assume a single reaction model. Starting with the Arrhenius rate expression (eqn. 3.5) and applying the mass $\left(\frac{-dC}{dt} = kC_0^n\right)$ and energy conservation equations to an adiabatic system such as the ARC and after algebraic manipulation, the following expression is obtained (Yannimaras, 1998):

$$\frac{dT}{dt} = A\exp\left(\frac{-E}{RT}\right) C_0^{N-1} \left(T_F - T_0 \right) \left[\frac{T_F - T}{T_F - T_0}\right] \tag{3.22}$$

where

T = sample (bomb) temperature, at any time during an exotherm

t = time

A = pre-exponential factor

R = universal gas constant

C_0 = initial sample concentration, constant

n = reaction order

T_F = final exotherm temperature

T_0 = initial exotherm temperature

Defining

$$k' \equiv k\, C_0^{n-1} = A \exp\left(\frac{-E}{RT}\right) C_0^{n-1} \text{ and } mT \equiv \frac{dT}{dt}$$

a quantity experimentally obtained from an ARC run we obtained

$$k_T = \left(\frac{mT}{T_F - T_0}\right)\left[\frac{T_F - T_0}{T_F - T}\right]^n \tag{3.23}$$

By plotting k' versus T, on log scales, one obtain 'n' as the slope of best fit straight line.

Also from the definition of 'k' ', we obtain

$$E = \frac{RT_1T_2}{T_2 - T_1} \ln\left(k_2 / k_1\right) \tag{3.24}$$

i.e., from the same plot, the activation energy E is determined as the slope of the best fit straight line.

Limitations of ARC Tests

ARC tests permit the rapid determination of oxidation kinetic parameters. The results, however, are only qualitative due to system's inherent shortcomings. In ARC tests the kinetic parameters (activation energy and order of reaction) are calculated assuming a single reaction model (usually a HTO reaction model). A single reaction model, however, cannot realistically represent the crude oil oxidation because the oxygen is used not only to form carbon oxides and water (HTO reaction), but also to form stable oxygenated compounds (LTO reaction). If both reactions occur simultaneously throughout the test, as usually is the case in ARC system, the kinetic parameters cannot be estimated quantitatively. In ARC the kinetic parameters are estimated based on data corresponding to the highest temperature (HTO reaction). The assumed model is then extrapolated to lower temperature and the kinetic parameters for LTO are calculated based on differences in the heat rate between the two temperature regime.

Further, data obtained from a closed ARC system is not useful for screening the candidate heavy oil for its ISC potential. This is because in a closed system due to a rapid decrease in oxygen partial pressure (mostly due to oxygen addition reactions) the reaction temperatures often fail to transcend the negative temperature gradient region and unable to reach the HTO zone. A flowing ARC device can avoid this drawback, because the oxygen pressure can be kept constant throughout the experiment. Flowing ARC device is also useful in assessing the role 'negative temperature gradient' plays in delineating the HTO mode from LTO mode during heavy oil combustion. Thus, a flowing ARC device can be used to determine qualitatively the conditions that give rise to negative temperature gradient region during an air injection process.

LTO reactions are not detrimental to the success of combustion process in light oil reservoir, because in these reservoirs, the recorded combustion front temperature is often less than 600°F (Germain and Geyelin, 1998; Fassihi and Gilham, 1994; Metwally, 1991; Pebdani et al., 1988; Struna and Poettmann, 1986; Anthony et al., 1981). This still correspond to the LTO region. On the other hand, a knowledge of the reactivity of oil and oxygen at reservoir temperature is essential to ascertain the auto ignition tendency of the crude. Unfortunately due to their poor heat detection capability at low temperature, neither of the ARC system can answer this question with any degree of certainty (Zelenko and Solignac, 1997).

Despite its shortcomings, the ARC remains a simple and useful tool to analyze qualitatively the oxidation reactions of the crudes and to study the oil reactivity at low temperature. Since it track the exothermic reaction adiabatically, ARC permits the rapid determination of kinetic parameters using only the temperatures as the variable. However, its limitations must be borne in mind when using it to screen the oils for combustion process.

Effluent Gas Analysis (EGA) Technique

The EGA is a quantitative analysis technique performed to determine the oxidation reaction kinetic parameters. In the Canadian ISC literature, this technique is often referred to as the "Ramped-Temperature Oxidation" (RTO) tests. Ramped temperature oxidation tests involve the controlled heating of recombined oil saturated cores (or oil-sand mixture) in a flow reactor under a flowing stream of air. The purpose of the test is to study the oxidation behavior and reaction kinetics of a rock-oil system under controlled conditions.

The experimental set up used for the EGA tests consisted of a flow type tubular reactor (often called a kinetic cell in the U.S.) with the appropriate instrumentation, control systems and flow loops. The kinetic cell construction details differs from laboratory to laboratory. The schematic of the kinetic cell employed at Stanford University (Mamora et al., 1993) and at the University of Calgary, Canada (Moore et al., 1995 a) is shown in Figures. 3.10 and 3.11 respectively. The schematic of Stanford University's EGA experimental set-up is shown in Figure 3.12.

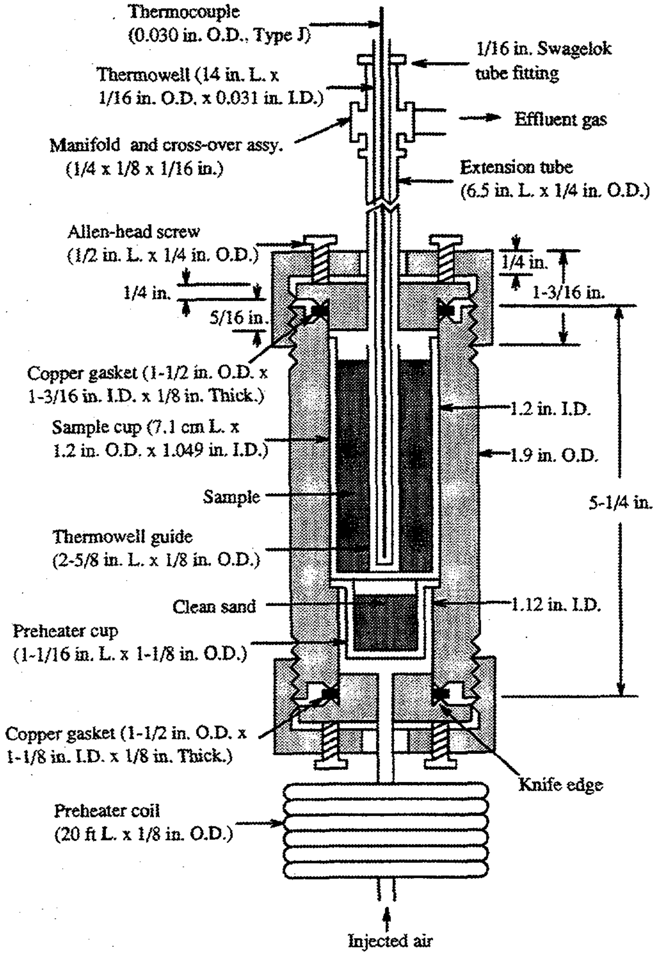

FIGURE 3.10 — Schematic of Stanford University's Kinetic Cell (After Mamora, 1993)

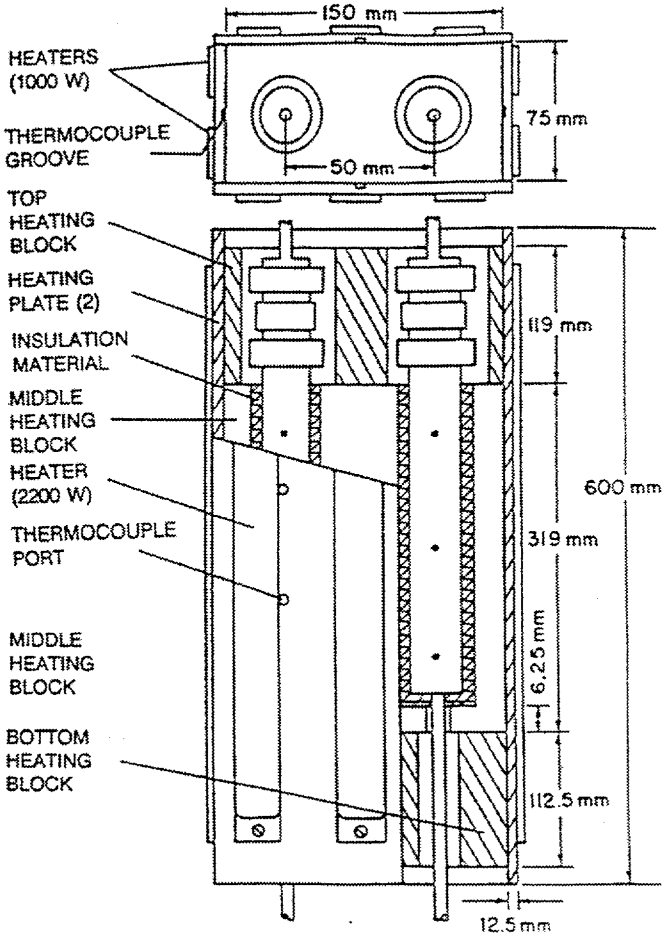

FIGURE 3.11 — Schematic of University of Calgary's Ramped Temperature Oxidation Cell (After Moore et al., 1995)

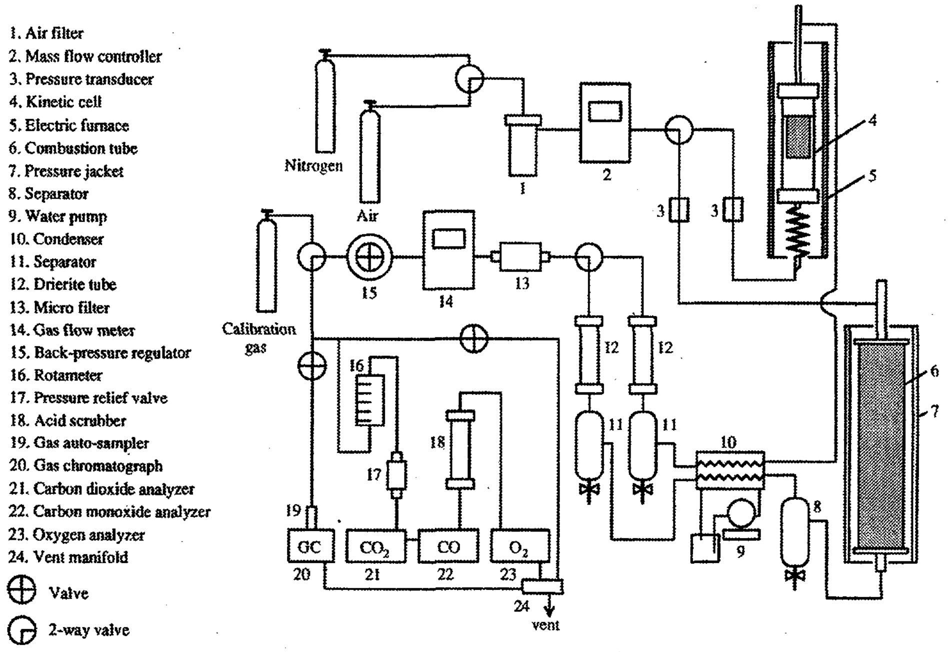

FIGURE 3.12 — Schematic of Stanford University's In-Situ Combustion Experimental Set-Up (After Mamora et al., 1993)

The reactor is packed with a pre-mixed oil and sand sample of interest and subjected to a prescribed heating schedule (20°C–40°C per hour) while air or an oxidizing gas is flown through. The heating is continued at the desired rate until their termination or once the prescribed maximum temperature is reached and then held at that temperature for the remainder of the test. The flow of air is continued until no change in the exit gas concentration could be seen.

Often a second cell is used to serve as a reference cell. The reference cell is packed only with dry core and subjected to the same heating schedule as the test cell. During the course of a run the temperatures in the corresponding zones of the active and reference cell are compared to isolate exothermic/endothermic oxidation events of the oil occurring in the active cell. Typical ramped temperature oxidation test temperature profiles illustrating various oxidation modes for the Athabasca oil sands bitumen are depicted in Figures. 3.13–3.15 (Moore et al., 1995 b).

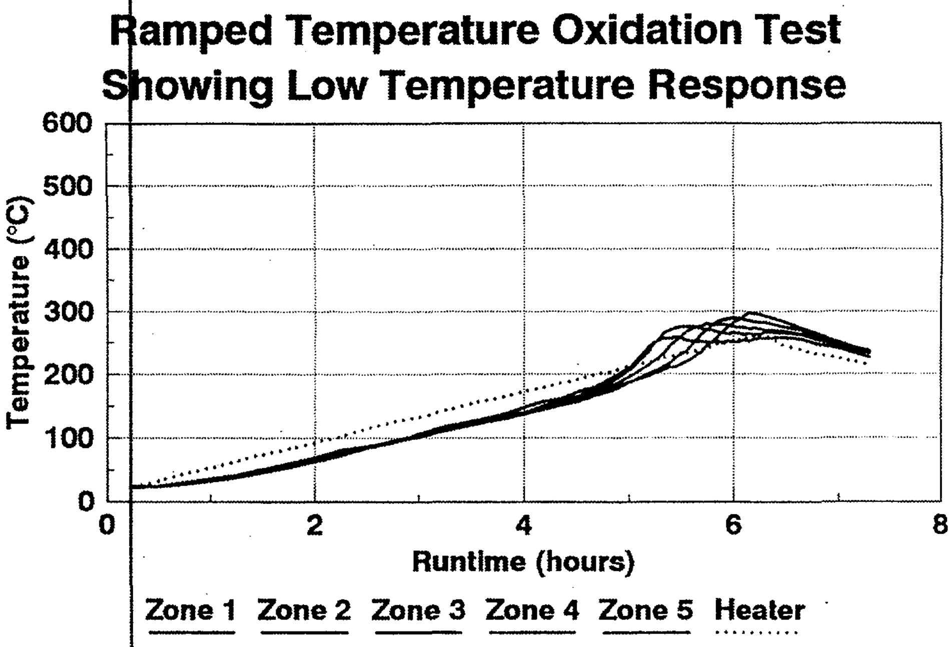

FIGURE 3.13 — Example of a Ramped Temperature Oxidation (RTO) Temperature Profile Showing LTO Response (Courtesy of UNITAR Center, Mehta, and Moore, 1996)

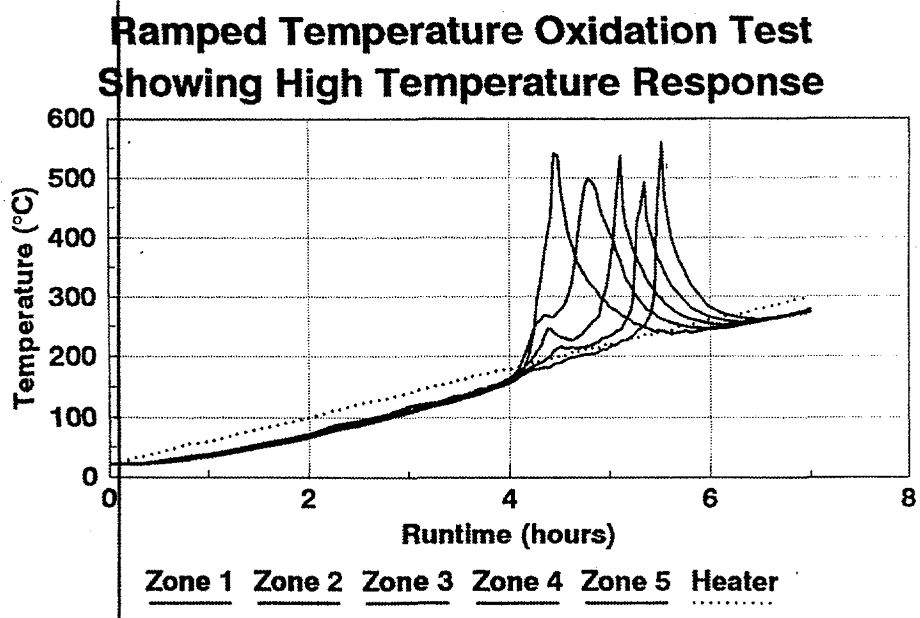

FIGURE 3.14 — Example of a RTO Temperature Profile Showing HTO Response (Courtesy of UNITAR Center, Mehta, and Moore, 1996)

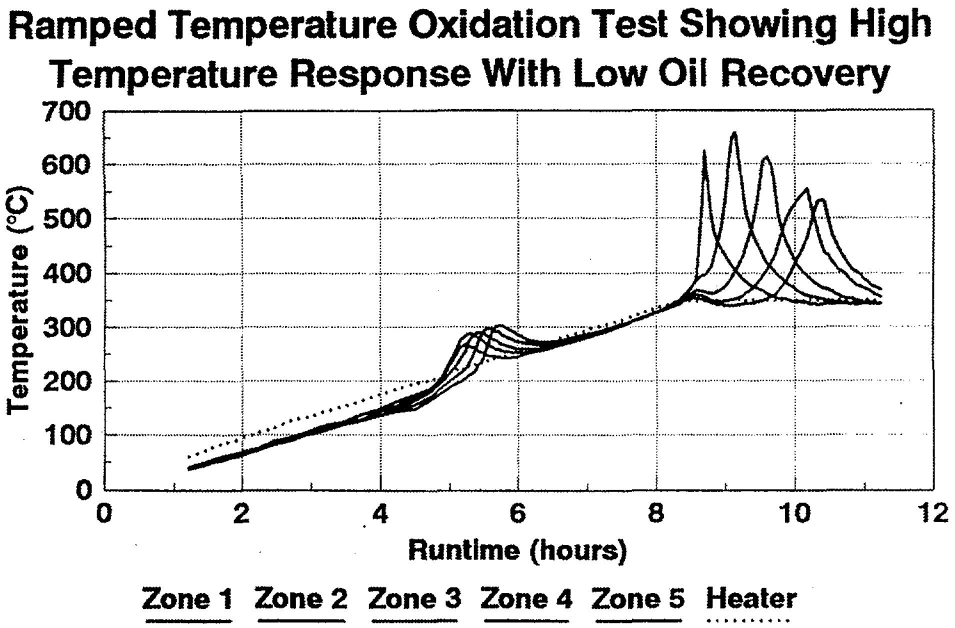

FIGURE 3.15 — Example of a RTO Temperature Profile Showing HTO Response and Low Oil Recovery (Courtesy of UNITAR Center, Mehta, and Moore, 1996)

The kinetic parameters are determined from the effluent gas analysis (Mamora et al., 1993; Burger et al., 1985; Fassihi and Brigham, 1981) as follows:

If m_o is the mass of oil present in the sample, we can define a specific reaction rate 'K' as:

$$K = \frac{\Delta m_{O_2}}{m_o \, \Delta t} = A \exp\left(\frac{-E}{RT}\right) \left(p_{O_2}\right)^n \qquad (3.25)$$

where:

Δm_{O2} = mass of oxygen used up during time Δt

p_{O2} = average oxygen partial pressure

K = mass of the oxygen used up per unit time with respect to the mass of oil m_o

R = gas constant

K can be calculated from the effluent gas data.

Assuming the order of reaction $n = 1$, a plot of $\ln(K/p_{O2})$ versus $1/T$ will yield a straight line with a slope $(-E/R)$ and intercept '$\ln(A)$'.

Due to the quantitative nature of EGA data, this technique is preferable to the thermal analysis techniques (TGA and DSC) in estimating the crude oil oxidation kinetic parameters.

Combustion Tube Tests

Introduction

Combustion tubes are the traditional tools employed in the laboratory to investigate the performance of in-situ combustion processes. A properly designed and operated combustion tube test can provide much useful information about the test rock/oil system's combustion characteristics. Some of this data can also be used for making a proper engineering and economic projection of a field test's performance. Hence laboratory combustion tube studies are the necessary first step in the design of an ISC project.

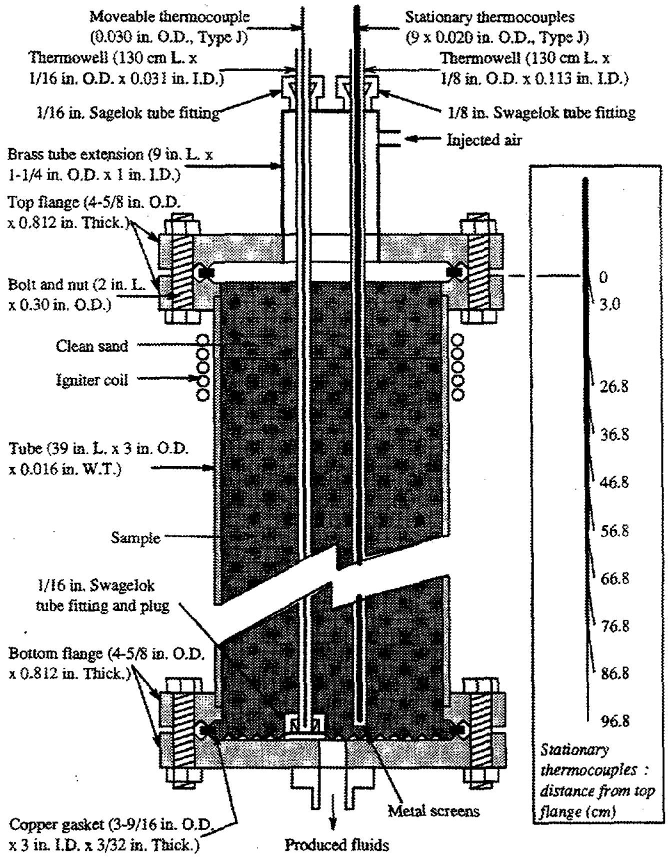

FIGURE 3.16 — Schematic of a Typical Combustion Tube Details (After Mamora et al., 1993)

The combustion tube, shown in Figure 3.16 is a thin walled stainless steel (or some other corrosion resistant material such as Inconel) cylinder housed inside a pressure jacket and packed with actual core, water and oil from the field under study. The fluid saturations in the tube are tailored to approximate reservoir conditions. The crude is ignited by injecting air, and the burning front is advanced through the tube by continuous air injection. Temperature, pressure, air injection rate, oil, water, and gas production and effluent gas composition data are collected and analyzed. From the data analysis process variables are calculated.

Comments About Combustion Tube Tests

Combustion tubes are unscaled elemental physical simulators and represents a piece of the reservoir simulated at full scale in the laboratory with the constraint of one-dimensional flow (Prasad and Slater, 1986). Combustion tube tests permit the simulation of the nature of the propagating combustion front and the resulting dynamic chemical reactions in conditions closely approximating those in a reservoir. Because the nature of the combustion front propagation is controlled by the chemical reactions and relative permeability characteristics of the reservoir system, combustion tube results can provide a qualitative feeling for the field performance. It also serve as a mean for estimating the net effect of the interrelationships between the various mechanisms which affect combustion. Hence, combustion tube tests have been accepted as a method of producing reliable data describing the insitu combustion process.

The main drawback of combustion tube tests is that they are unscaled experiments. Hence the data obtained from these experiments cannot be scaled and direct correlation of combustion tube results to the corresponding reservoir is at best tenuous. Experience has, however, shown that as long as the testing is done with actual reservoir rock and oil under proper operating conditions, the chemical reactions and the reaction stoichiometry in the tube will be the same as those occurring in the reservoir. This is because the stoichiometry of the reactions is controlled by the temperature, pressure, and chemical characteristics of the oil. The burning behavior of the oil in the tube, however, will not be the same as those in the reservoir, because it is affected by the flow rate and fluid saturations.

Further, combustion tube studies have little value in predicting bulk fluid movement. This is because a combustion tube simulates only a differential element of a reservoir. A primary consideration of any recovery process involving fluid injection is sweep efficiency. Although several theoretical models have been proposed to predict the mobility and movements of fluids within a reservoir, none have been completely successful in fireflooding. Due to the extreme temperature gradients, constant changing of fluid phases, and reaction kinetics, a rigorous prediction of flow properties is difficult. Extrapolation of combustion tube flow behavior to that in the field is unrealistic. Physical configuration vastly affects experimental simulation and prohibits scale up to reservoir conditions. Pilot test data remains the best source of information for sweep efficiencies.

In wet combustion process water and air are injected simultaneously. Three factors are associated with simultaneous air-water injection. These are:

1. Multi phase flow through the porous media.
2. Heat transfer effect.
3. Effect of water injection on burning efficiency.

Questions concerning how the air and water will distribute within the burned zone and what conditions will exist when they reach the combustion front cannot be answered from the combustion tube studies. Gravity segregation is an important consideration and its effect is eliminated in the laboratory by performing the tests with the tube in the vertical position. Laboratory tests are useful in determining the optimal water-air ratio (WAR) for wet combustion. Caution, however, should be exercised in using this information for field design purposes because WAR is sensitive to the combustion tube's heat transfer characteristics.

Although the heat losses from the combustion tube are considerably different from those of the reservoir, a direct analogy exists between the two systems. The reservoir is naturally insulated by overburden and underburden and heat losses are relatively small compared to the amount of heat generated. The laboratory tube has high heat losses due to its metal construction and limited amount of heat generated. To decrease heat losses and sustain a combustion front, strip heaters are placed around the tube. These heaters maintain an escalated isothermal condition which reduces the temperature gradient with tube surrounding and lower heat losses. In other words, the heaters simply increase the overall energy level of the system without interfering with process mechanism. The heat transfer properties and the subsequent temperature profiles are not distorted by the presence of the heating system. The heat flow through the packed tube does represent what will happen in the reservoir with certain exceptions.

Interpreting data for wet combustion is completely dependent on the heat transfer characteristics of the combustion tube. If heat losses from the tube are excessive and the combustion front is barely sustaining itself, little advantage is realized by scavenging the heat behind the front. Injected water has a cooling effect on the combustion zone, lowering its temperature and possibly quenching the process. Conversely, if high temperatures are maintained by the strip heaters (insulating system), sufficient heat is available behind the fire front to vaporize all the water injected. In this case, the energy level in the combustion zone is barely decreased by water and high burning temperatures maintain. Large quantities of water passing through the combustion zone as steam have no adverse effect on the combustion reaction. Actual conditions in the reservoir will be somewhere between the two extremes. The conditions maintained on the combustion tube are believed to be representative of those that will prevail in the field. However, as mentioned previously, extrapolating water-air ratios from laboratory to field conditions might be misleading.

The final consideration for air-water injection is if large quantities of water passing through the combustion zone how it will affect burning efficiency. As previously discussed, combustion tube tests accurately represent the reaction mechanisms. Therefore, laboratory results will satisfactorily predict combustion zone behavior.

Experience has also reveals that the tube and field data (such as the hydrogen to carbon (H-C) ratio, air-fuel ratio, fractional conversion of oxygen to carbon oxides, density of produced oil, pH of produced water, etc.) often reasonably matches well when the projects are operated in the high temperature mode.

Informations that can be derived from combustion tube tests include:

- Atomic H / C ratio of the burned fuel.
- Oxygen-fuel ratio (OFR).
- Air-fuel ratio (AFR).
- Oxygen-sand ratio (OSR).
- Excess air.
- 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.
- Characteristics of the produced fluids.

- Peak combustion temperatures.
- Stability of burn zone.

The last three piece of information, though, highly qualitative are valuable in assessing the tendency of the reservoir to burn in a stable or unstable mode.

Combustion Tubes

Description of Combustion Tube Test Set-up

Though, the design details of the combustion tube set-up vary from laboratory to laboratory, they all include four basic components: a combustion tube assembly, heating and data acquisition system, flow control system and fluid analysis system.

Figure 3.12 shows the flow and instrumentation schematics of a typical combustion tube set-up (Mamora et al., 1993).

The heart of the test facility is the combustion tube. The combustion tube assembly consist of a thin walled corrosion resistant tube housed inside a pressure jacket. The wall thickness of the tube is usually less than 0.062 inch to insure uniform heating and to minimize the heat conduction along the walls of the tube. The pressure jacket is usually fabricated out of carbon steel and designed to withstand the desired operating pressure. The annular space between the tube and the pressure jacket is filled with porous insulation and pressurized with insert gas to equalize the pressure between the inner and outer wall of the combustion tube. The pressure difference across the tube wall is small and always inward.

Combustion tubes vary as to diameter and length. Tubes as large as 8 inches in diameter and 15 ft., in length have been used in the past to simulate the process (Parish and Craig, 1969). Most current designs, however, employ smaller tubes to shorten the runtime. These tubes are generally 3–6 ft. long and 2–4 inches in diameter. Table 3.2 show the dimensions of the tube used in some selected facilities.

TABLE 3.2 — Dimensions of Combustion Tube Employed in Selected In-Situ Combustion Laboratories

Facility	Length (Ft.)	Diameter (inches)	Wall Thickness (inches)	Reference
U. of Calgary	6	4	0.042	Mehta (1997)
Stanford University	3	3	0.016	Mamora (1993)
Amoco	6	4	N.A	Yannimaras (1998)
Texaco	5	3	0.042	Bousaid (1987)
Esso Resources, Canada	4	3	0.025	Leaute and Collyer (1984)

Larger diameter tubes are preferred to smaller diameter tube because they maintain better adiabiticity and lower fluxes. Belgrave and Moore (1992) investigated the effect of tube design (diameter) on combustion tube performance and conclude that different designs operated under identical condition can produce difference results due to differences in heat loss rate from the tube wall.

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 (Dietz and Weijdema, 1963). Such high air fluxes are needed to reduce the residence time of firefront 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 (Alexander et al., 1962).

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. Though the problem of thermal interaction between the heater and the sand pack have been looked into by researchers (Leaute and Collyer, 1984; Belgrave et al., 1990a; Belgrave et al., 1990b) no satisfactory solution to the problem exist.

Combustion tube radial heat transfer studies by Belgrave and Moore (1992) indicate maintenance of near zero temperature difference between the sand pack and tube wall not necessarily imply adiabatic operation conditions. Their analyze indicate combustion tubes of different design operated under identical conditions can produce different results (temperature profiles) due to differences in the magnitude of heat losses. Their study also revealed that combustion tube diameter and length of heating zones play an important role in achieving adiabatic condition. Larger diameter tubes and shorter heating zone length can result in lower heat losses and near adiabtic conditions.

It is necessary to control closely the power input to each of the heaters to minimize axial temperature gradient and lateral heat losses from individual sand section. In every heating zone a pair of thermocouples, one fixed to the outer wall of the tube and another inserted through the wall to the tube's center is used to control the power input to the heater and maintain the wall and sand pack temperature nearly equal. Each heating zone wall temperature is usually maintained at 5°F less than the corresponding center temperature to minimize lateral heat losses and to ensure that the heaters are not sustaining and/or driving the combustion front.

The tube is generally operated vertically so as to minimize gravity segregation effects. It is documented that in vertically operated tubes at high pressures, distortion of the test results may arise due to thermal convection of gas in the annular region between the tube and the pressure jacket (Smith and Perkins, 1973). Belgrave et al. (1990a), investigated this problem and found that high operating pressure, high Rayleigh number annulus gases and use of high permeability annulus insulation likely to intensify annular convective circulation and increase heat losses. They recommend the use of low molecular weight, low specific heat capacity (low Rayleigh number) gas such as helium and a low permeability (less porous) insulating material in the annulus to minimize convection induced heat transfer.

Operating Procedures

A typical combustion tube run is performed by first packing the tube with the native reservoir rock or graded sand. If field core is to be used for the test, it is first crushed, homogenized and mixed with additional amount of oil and synthetic brine before being packed into the tube. All mixing and packing is usually done in an enclosed area. A portion of the mixture packed into the tube and the results from the fluid saturation measurements allow calculation of porosity and volumetric saturation of each fluid phase.

In an alternative packing procedure adopted by some U.S. laboratories, the tube is packed with crushed core material in 500-g increments. Each increment is packed to the same volume to ensure uniform porosity. Alternating 500-g sand samples are saturated with methanol to facilitate packing. Approximately 1/2 in. of 20–40 mesh silica sand is packed at each end of the tube to prevent the production lines from plugging by fine migration. Following packing, the tube is saturated with methanol and thermocouples are inserted into place. The pack is then successively flushed with pentane and nitrogen to clean and dry the sandpack. The pack is then saturated with synthetic reservoir brine and the porosity and permeability established. Crude oils are then injected until immobile water saturation is obtained. This technique known as the restored state procedure have shown to reproduce the fuel lay down results better than other packing procedures.

The tube pack is then pressurized with nitrogen to the required operating pressure and checked for leaks. The pressure jacket is also pressurized simultaneously with an inert gas such as helium.

After being pressure tested, the tube pack is then heated to the reservoir temperature. Nitrogen once again is flowed through the tube to establish gas permeability and produce mobile fluids. The produced gas composition is continuously monitored and the displaced liquids (if any) are collected. After the whole tube had attained the reservoir temperature and no more liquids being produced, the inlet end band heaters are activated. The inlet sand face temperature is gradually raised to 650°F (500°F for wet combustion) while flowing nitrogen to facilitate combustion. The nitrogen flow rate is gradually increased to the test design air flow rate. When the desired injection end sand face temperature is attained, nitrogen injection is stopped and air flow at the desired operating flux begins. Here the flux is defined as the volumetric injection rate of air measured at standard condition of 14.7 psia and 60°F divided by the cross sectional area of the tube. Ignition is usually observed immediately upon switching to air injection. The thermocouples at the inlet end record significant increase in temperature upon ignition. Confirmation is also obtained with effluent gas composition.

Typical air flux employed in a 4 in. tube is about 100 Scf/ft.^{2} - hr. (Oxygen flux 21 Scf/ft.^{2} - hr). From time to time the flux is increased to help reduce heat losses, minimize LTO and improve the stability of the burning zone.

For wet combustion tests, after the whole tube is at the reservoir temperature and no more liquids are being produced, the nitrogen flow rate is decreased a little and water injection into the tube is started. The water flow rate is gradually increased until the Water-Nitrogen ratio is equal to the desired Water-Air ratio (WAR) for the desired wet combustion mode (normal or superwet).

Next, with both water and nitrogen flowing, the inlet end heaters are turned on. When the desired ignition temperature (usually 500°F) is approached, the nitrogen flow is stopped and air injection commences. The flow rate of both air and water are then gradually adjusted to obtain the desired WAR. For a normal wet combustion test, a WAR of 1.1 $ft.^3$ water/Mscf air is recommended.

Data recorded during the run include air injection rates (also water injection rates for wet combustion), injection pressure, temperature at each thermocouple location (center line and wall), produced oil, water and effluent gas volumes and rate and produced gas composition. The effluent gases are analyzed for oxygen, carbon dioxide, carbon monoxide, hydrogen, hydrocarbons, hydrogen sulfide and nitrogen. The energy input to each heater is also recorded.

All the data (except the volumes) are recorded during the stabilized propagation of the front in the tube after the initial ignition transient effects had settled down. The stabilized burning period in a tube is that period during which the combustion front velocity, the air injection flux and the average effluent gas composition are approximately constant. This is necessary because the tube pack assume to represent a reservoir element located at some distance downstream of the combustion front and is unaffected by transient start-up effects.

After the combustion tube run, the following measurements are usually made to facilitate characterizing the run:

- Post test core analysis to provide axial profile of extractable oil, coke, and water.
- Oil properties (density, viscosity, acid number and elemental analysis).
- Composition of produced oil samples in terms of Maltenes (saturates, aromatic and resins) and asphaltenes.
- Produced water pH and ion analysis.

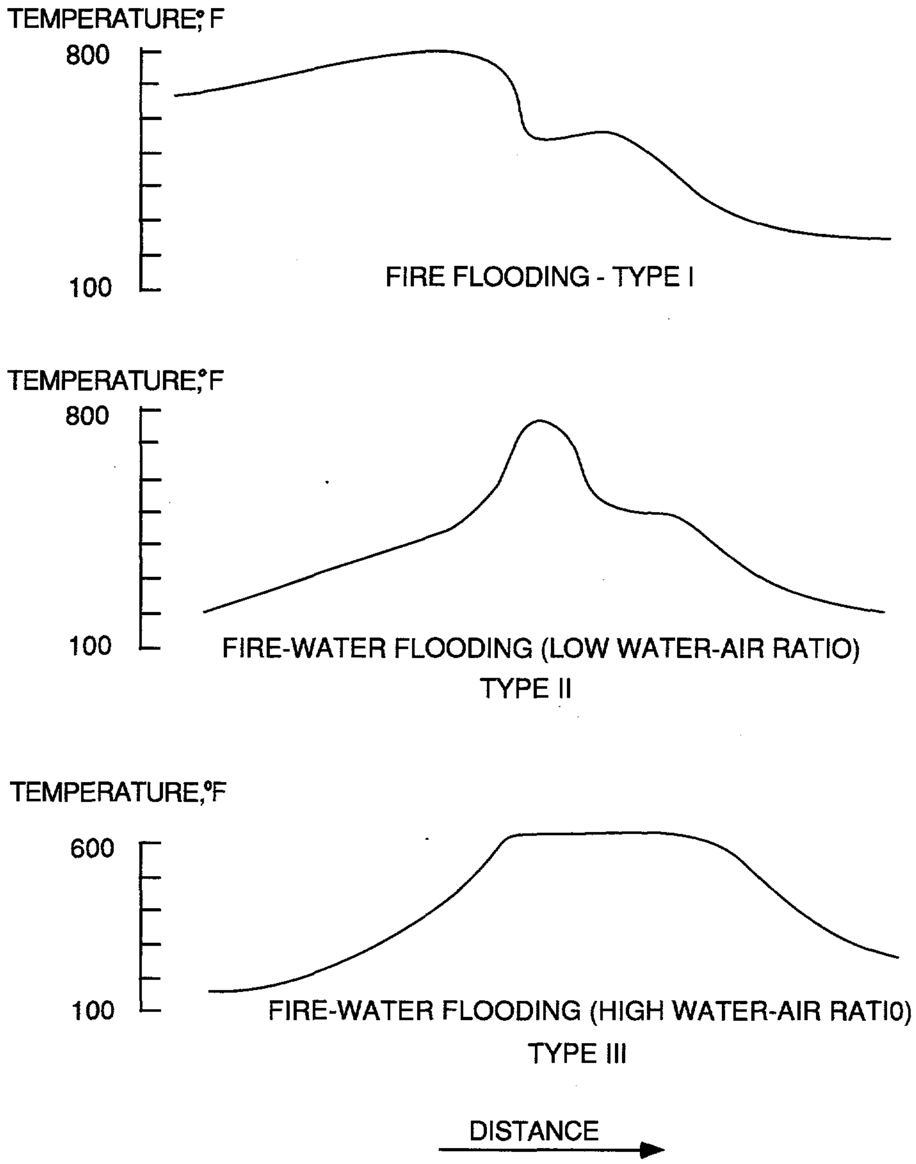

FIGURE 3.17 — Comparative Temperature Profiles

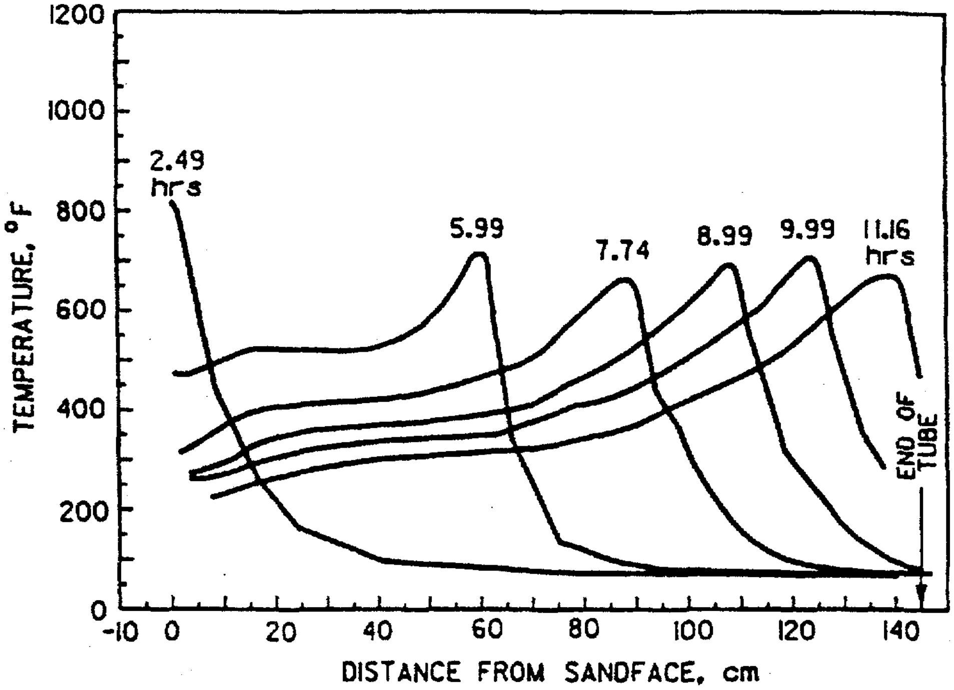

FIGURE 3.18 — Probe Temperature Profile as a Function of Time for a Dry In-Situ Combustion Tube Run (After Bousaid, 1987)

Temperature measurements made during a tube run can be used to monitor the frontal advancement of the burn. Depending upon the combustion mode three different types of temperature profiles are observed as shown in Figure 3.17. The Type I profile is for dry combustion (WAR=0); type II profile is observed where water is injected at relatively low values of the WAR (normal wet combustion) and type III profile is observed when the tube is operated in super wet combustion mode.

Figure 3.18 shows the typical temperature profile for a dry combustion run in a clean silica sand pack. The temperature history at 2.49 hour is characteristics of the profile that might be obtained when an heater is used to obtain ignition. The profile at 5.99 hours is more nearly represent the temperature distribution obtained in a dry combustion run. The temperature rise from initial reservoir temperature to the peak temperature at the combustion front and drops off sharply ahead of the combustion front to a value corresponding to the steam temperature at the model pressure. The steam zone which is also known as a steam plateau is characterized by a flat temperature distribution. The temperature of the stream plateau is determined primarily by the air injection pressure. Since in dry combustion only air is injected, the size of the steam plateau developed is likely to be small and depends upon the initial connate water saturation. Ahead of the steam plateau, temperature drops gradually to the initial formation temperature.

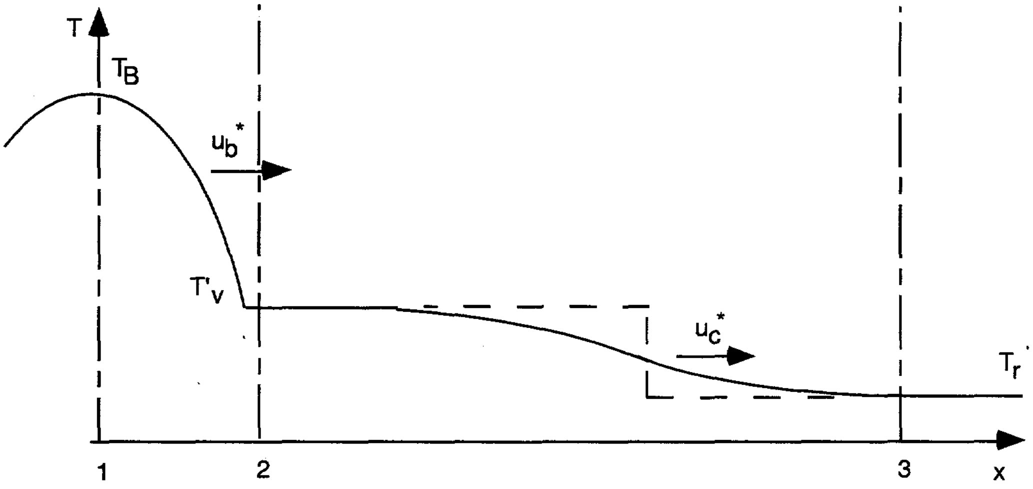

FIGURE 3.19 — Dry Combustion: Schematic Temperature Profile Downstream from the Temperature Peak (After Burger et al., 1985)

The frontal advancement of the combustion zone (combustion front velocity) can be determine the slope of peak temperature (or a representative high temperature) location (measured from the injection end) versus time curve. In Figure 3.19 a schematic of the temperature profile downstream from the temperature peak, T_B is the peak temperature, U_b is the combustion front velocity, T_v is the steam plateau temperature, U_c is the steam zone velocity and T_r is the original reservoir temperature.

For dry combustion the combustion front velocity is a function of air flux and fuel concentration. Combustion front velocity is directly proportional to the amount of oxygen supplied (air flux) and inversely proportional to the amount of fuel laydown at constant air flux. Thus the minimum rate of advance is fixed by the amount of fuel that must be burned at the minimum air flux. The minimum air flux in any given situation is the lowest flux that will sustain and advance the combustion front. The minimum air flux and the corresponding combustion front velocity are important factors in the design and economics of a combustion operation, because they determine the compressor capacity required for a given well spacing. In dry combustion the combustion front and the steam zone advances at essentially at the same rate.

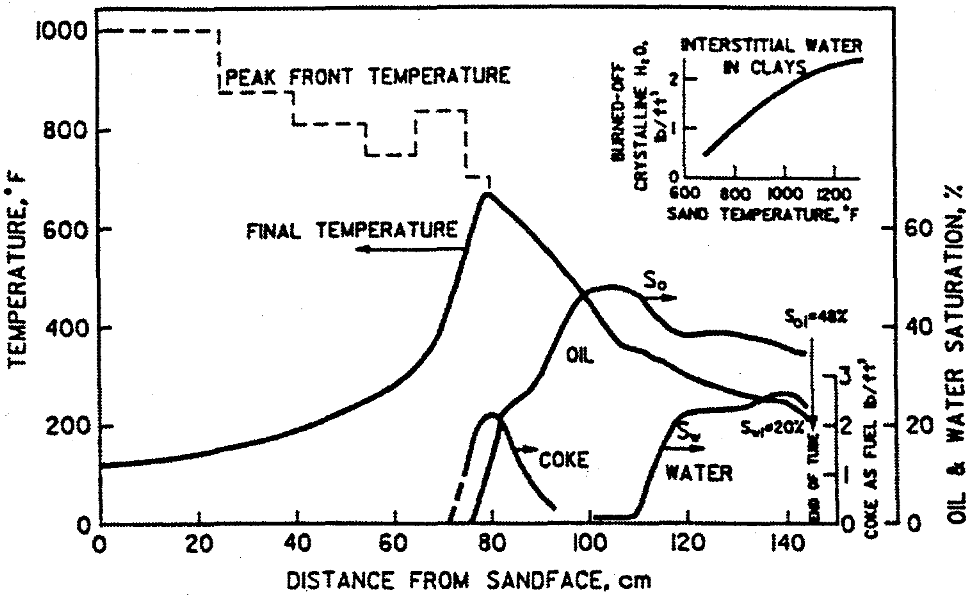

FIGURE 3.20 — Temperature Profile for Dry Combustion, Reflecting the Effect of Native Core Material (After Bousaid, 1987)

Native reservoir rock contain clays and minerals and often contribute to increased fuel laydown. Hence combustion front velocity in runs performed using native core materials are usually slower than when performed using clean sand under identical run conditions. This is clearly evident from the native core run temperature profiles (Figure 3.20) where the temperature drops less sharply compare to Figure 3.18.

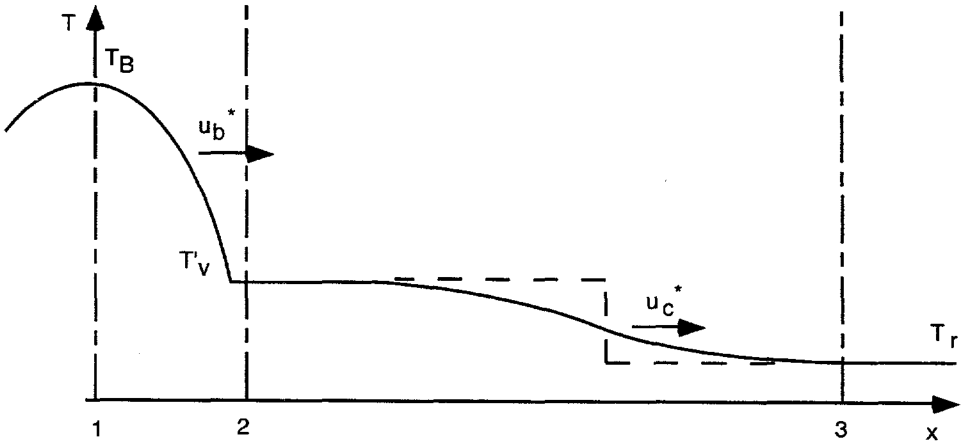

FIGURE 3.21 — Wet Combustion: Schematic Temperature Profile Downstream from the Temperature Peak (After Burger et al., 1985)

In the case of normal wet combustion (type II profile) water is injected at relatively low values of the WAR. The temperature profile (Figure 3.21) is similar to the dry combustion except that the temperature decreases much more rapidly behind the combustion front and the steam plateau is elongated by the additional heat transported downstream. The steam front advance at a much slower but at a uniform rate than the combustion front. In a stable wet combustion test, the combustion front usually progresses much more quickly than the vaporization front (trailing edge of the combustion zone where the water vaporizes). The maximum temperatures attained in the combustion zone are nearly independent of WAR and at about the same level as for dry combustion.

The type III profile is observed at higher WAR values where partially quenched combustion is maintained at the steam plateau temperature. In this profile the temperature increases from reservoir conditions, levels off at steam temperature, and then decreases. No temperature above the steam plateau level are observed. In this mode both the combustion and the vaporization zones progresses at nearly the same rate.

Analysis of Combustion Tube Data

As mentioned earlier, combustion tube tests provide many useful information about influence of operating parameters on the process. Data obtained from a tube run include the combustion front temperature, the composition and volume of the effluents, the amounts of oil and water produced, etc. Process parameters such as the fuel deposition, air requirement, etc., are then calculated from these data.

In the following, procedures for analyzing the combustion tube data are detailed. These procedures are made available to the author by Dr. Gardon Moore and Dr. Raj Mehta of University of Calgary, Canada. The author wish to express his gratitude for their help.

High Temperature Combustion Stoichiometry

There are many chemical reactions that occur in the tube during combustion. These include low temperature oxidation of oil, thermal cracking or pyrolysis, and high temperature oxidation. Even though significant LTO and pyrolysis reactions do occur in the tube, generally only the HTO reaction is assumed to represent the process and used to analyses the combustion tube data. In this section we present combustion tube data analysis based on HTO stoichiometry. In a subsequent section modification of the procedure to account for reactions other than the assumed HTO are presented.

The basic chemical expression that describes the combustion of coke can be written as:

$$C_x H_y + a\,O_2 + RaN_2 \rightarrow b\,CO_2 + d\,CO + f\,O_2 + j\,H_2O + RaN_2 \qquad (3.25)$$

$$\text{i.e.}\quad R = \left(\frac{y_{N_2}}{y_{O_2}}\right)_{Feed\,\text{Gas}} \qquad (3.26)$$

where 'R' is the ratio of mole fraction of nitrogen to oxygen in the feed gas. (a, b, d, f, j are stoichiometric coefficients).

Performing an element balance we have,

[Carbon] $x = b + d$ (3.27)

[Oxygen] $a = b + \frac{d}{2} + f + \frac{j}{2}$ (3.28)

[Hydrogen $y = 2j$ (3.29)

$$1.\ \text{Apparent atomic H / C ratio} = \frac{y}{x} \qquad (3.30)$$

$$= \frac{4\left(a - b - \frac{d}{2} - f\right)}{(b+d)} \qquad (3.31)$$

2. The *Oxygen-Fuel* ratio is the minimum volume of oxygen required to burn a unit mass of fuel which has an equivalent atomic H/C ratio given by Equation (3.30)

$$\text{Oxygen / Fuel Ratio} = \frac{(a) \times (moles\ O_2)}{\text{moles fuel}} \qquad (3.32)$$

$$\text{Molecular mass of fuel} = (12.011\,x + 1.008\,y) \qquad (3.33)$$

Where 12.011 = atomic mass of carbon and 1.008 = atomic mass of hydrogen

Assuming that the oxygen consumption is measured in standard volume and the fuel in kg. (or lb_m) per unit volume of formation we have:

$$\frac{O_2}{F} = \frac{23.64\ a}{(12\ 011\ x + 1\ 008\ y)}\ m^3\ (ST)\Big/kg \qquad (3.33a)$$

or

$$= \frac{379\ a}{(12.011\ x + 1.008\ y)}\ scf\Big/lb_m \qquad (3.33b)$$

In the above expression the reference condition is:

m^3 / (ST) = 101.325 kPa and 15°C

scf = 14.696 psi and 60°F

In Equation (3.33a) the constant 23.64 refers to the volume (in standard cubic meter) occupied by one mole of gas at the reference condition and the constant 379 (in Equation 3.33b) refers to the volume (in standard cubic feet) occupied by one mole of the gas also at the reference condition.

3. *Air / Fuel Ratio:* It is the volume of air required to burn a unit mass of fuel and is a function of the amount of carbon and hydrogen in the fuel and the nitrogen-oxygen ratio of air (Equation 3.26)

$$\text{Air/fuel ratio} = \frac{23.64\,(1 + R) \times a}{(12.011\ x + 1.008\ y)}\ m^3\ (ST)\ /kg \qquad (3.34a)$$

$$\text{or} \quad = \frac{379\,(1 + R) \times a}{(12.011\ x + 1.008\ y)}\ scf\ /lb_m \qquad (3.34b)$$

4. *Fraction of reacted O_2 converted to carbon oxides*: This parameter is an indicative of the degree of LTO occurring in the combustion tube. During the test not all of the injected oxygen is consumed in generating carbon oxides or water. Some fraction of the consumed oxygen reacts with oil to form oxygenated compounds

Fraction of reacted O_2 converted to carbon oxides

$$f_{O_2 R} = \frac{\left(b - \frac{d}{2}\right)}{(a - f)} \qquad (3.35)$$

Assuming the composition of normal air to be 21% O_2 and 79% N_2, we have

$$R = 79 / 21 = 3.76 \qquad (3.36)$$

Evaluation of Combustion Parameters from Effluent Gas Analysis:

Assuming normalized gas composition the combustion parameters can be calculated in terms of stoichiometric coefficients a, b, d, and f as follows:

The numerical values of a, b, d, and f are:

$$a = \frac{[N_2]}{R} \quad f = [0_2]$$

$$b = [CO_2]$$

$$d = [CO]$$

where [ ] denotes normalized composition in mole percent.

Thus:

$$H/C = \frac{4\left(\frac{[N_2]}{R} - [CO_2] - \frac{[CO]}{2} - [O_2]\right)}{\left([CO_2] + [CO]\right)} \qquad (3.38)$$

$$4\frac{[N_2]}{R} - [CO_2] - \frac{[CO]}{2} - [O_2]$$

$\therefore$ H/C =

$([CO_2] + [CO]$

$$\text{O}_2\text{/Fuel} = \frac{23.64\frac{[N_2]}{R}379\frac{N_2}{R}}{12.011([CO_2]+[CO]) + 4.032\left(\frac{[N_2]}{R} - [CO_2] - [O_2]\right)}$$

$$\text{Air/Fuel} = \frac{23.64(1+R)\frac{[N_2]}{R}}{12.011([CO_2]+[CO]) + 4.032\left(\frac{[N_2]}{R} - [CO_2] - \frac{[CO]}{2} - [O_2]\right)}$$

Fractional conversion of injected O_2 to Carbon Oxides = f_{o_2} where

$$f_{o_2} = \frac{\left([CO_2] + \frac{[CO]}{2}\right)}{\frac{[N_2]}{R}}$$

Fractional conversion of reacted O_2 to Carbon Oxides = f_{o_2R}

$$f_{o_2R} = \frac{\left([CO_2] + \frac{[CO]}{2}\right)}{\left(\frac{[N_2]}{R} - [O_2]\right)}$$

Fraction O_2 utilized:

$$Y = \frac{\frac{[N_2]}{R} - [O_2]}{[N_2]} = 1 - R\frac{[O_2]}{[N_2]}$$

Excess Oxygen

$$= \frac{(1-Y)}{Y}$$

Alternate Form of High Temperature Combustion Equation:

1. Start with basic equation:

$$C_xH_y + aO_2 + [R]aN_2 \rightarrow bCO + dCO + fO_2 + jH_2O + [R]aN_2$$

2. Divide basic equation by x:

$$CH_{y/x} + \frac{a}{x}O_2 + \frac{[R]\cdot a}{x}N_2 \rightarrow \frac{b}{x}CO_2 + \frac{d}{x}CO + \frac{f}{x}O_2 + \frac{j}{x}H_2O + \frac{[R]\cdot a}{x}N_2$$

3. Let n = H/C ratio = y/x

$$\text{m} = \frac{[CO_2]}{[CO]} \text{ ratio } \frac{b}{d}$$

$$\therefore \frac{b}{x} = \frac{b}{(b+d)} = \frac{m}{(m+1)}$$

$$\frac{d}{x} = \frac{d}{(b+d)} = \frac{m}{(m+1)}$$

$$\frac{j}{x} = \frac{y}{2x} = \frac{n}{2}$$

$$\frac{a}{x} = \frac{b}{x} + \frac{1}{2}\left(\frac{d}{x}\right) + \frac{f}{x} + \frac{1}{2}\left(\frac{j}{x}\right)$$

Where $\left(\frac{f}{x}\right)$ is calculated from the overall oxygen utilization (Y) using the relationship:

$$Y = \frac{(a-f)}{a}$$

$$\therefore \frac{f}{x} = \frac{a}{x}[1-Y]$$

$$\therefore \frac{a}{x} = \frac{1}{y}\left(\frac{m}{m+1} + \frac{1}{2(m+1)} + \frac{n}{4}\right)$$

$$= \frac{1}{y}\left(\frac{2m+1}{2m+2} + \frac{n}{4}\right)$$

The combustion equation can then be written as:

$$CH_n + \left(\frac{2m+1}{2m+2} + \frac{n}{4}\right)O_2 + \frac{R}{Y}\left(\frac{2m+1}{2m+2} + \frac{n}{4}\right)N_2 \rightarrow$$
$$\frac{m}{m+1}CO_2 + \frac{1}{m+1}CO + \frac{(1-Y)}{Y}\left(\frac{2m+1}{2m+2} + \frac{n}{4}\right)O_2 + \frac{n}{2}H_2O$$
$$+\frac{R}{Y}\left(\frac{2m+1}{2m+2} + \frac{n}{4}\right)N_2$$

This form is the combustion equation originally proposed by Benham and Poeltmann (1958) is useful for evaluating the product gas composition for assumed values of ‘n’ (H/C ratio) and ‘m’ ($[CO_2]/[CO]$ ratio). This is the common form employed by many practitioners.

Based on the above, the combustion parameters corresponding to assumed values of the apparent H/C ratio [n] and $[CO_2]/[CO]$ ratio [m] are:

1. O_2/Fuel Ratio $= \dfrac{379\frac{a}{x}}{\left(12.011 + 1.008\frac{y}{x}\right)}$

$\therefore O_2$/Fuel $= \dfrac{\frac{379}{Y}\left(\frac{2m+1}{2m+2} + \frac{n}{4}\right)}{(12.011 + 1.008n)} scf/lbm$

2. Air/Fuel = (1+R)(O_2/Fuel Ratio)

3. Fraction Reacted O_2 converted to Carbon Oxides (CO_2 and CO).

$$f_{o_2R} = \frac{\left(\frac{b}{x} + \frac{d/x}{2}\right)}{\left(\frac{a}{x} - \frac{f}{x}\right)} = \frac{\left(\frac{b}{x}\right)}{\frac{a}{x}\left(1 - \frac{f}{a}\right)}$$

$$= \frac{\left(\frac{m}{m+1} + \frac{1}{2}\left(\frac{1}{m+1}\right) \frac{}{} \right)}{\frac{1}{Y}\left(\frac{2m+1}{2m+2} + \frac{n}{4}\right) \bullet Y}$$

$$f_{o_2R} = \frac{\left(\frac{2m+1}{2m+2}\right)}{\left(\frac{2m+1}{1m+2} + \frac{n}{4}\right)}$$

4. Fractional O_2 utilization = Y

5. Excess Air = $\frac{[1-Y]}{Y}$

Examples of Combustion Parameter Calculation from Typical Product Gas Composition

In the following section we present several examples to illustrate the combustion parameter calculation from the produced gas for various combustion mode (dry, wet, superwet, etc.)

Consider the following product gas composition which corresponds to the average composition during the stabilized portion of a dry combustion tube test on a Louisiana Heavy Oil Core.

Component	Mole Percent	Normalized Mole Percent
CO_2	11.2	11.3
CO	3.8	3.8
O_2	4.4	4.4
N_2	80.0	80.5
H_2	0.1	
C_1+	0.43	
H_2S	0.07	
	100.0	100.0

The Composition of the feed air was 21% oxygen and 79% nitrogen, hence:

$$R = \frac{y_{n_2}}{y_{o_2}} = \frac{0.79}{0.21} = 3.76$$

The combustion parameters are:

H/C Ratio

$$= \frac{4\left[\frac{[N_2]}{R} - [CO_2] - \frac{[CO]}{2} - [O_2]\right]}{\left[[CO_2] + [CO]\right]}$$

$$= 4\left[\frac{80.5}{3.76} - [11.3] - \frac{[3.8]}{2} - [4.4]\right]$$

$$[(11.3) + (3.8)]$$

$$= 4\frac{[21.41 - 11.3 - 1.9 - 4.4]}{15.1}$$

$$= 1.009$$

O$_2$/Fuel Ratio $$= \frac{379\frac{[N_2]}{R}}{12.011([CO_2] + [CO]) + 4.032\left[\frac{[N_2]}{R} - [CO_2] - \frac{[CO]}{2} - [O_2]\right]}$$

$$= \frac{379\frac{[80.5]}{376}}{12.011([11.3] + [3.8]) + 4.032\left[\frac{[80.5]}{3.76} - [11.3] - \frac{[3.8]}{2} - [4.4]\right]}$$

= 41.25 scf/lbm

Air/Fuel Ratio $$= [1 + R] \bullet [O_2 / FuelRatio]$$

$$= [1 + 3.76] \bullet [41.25]$$

$$= 196.35 scf / lbm$$

Fractional Conversion of Reacted O_2 to Carbon Oxides:

$$f_{o_2R} = \left[\frac{[CO_2] + \frac{[CO]}{2}}{\frac{[N_2]}{R} - [O_2]}\right]$$

$$= \frac{\left[11.3 + \frac{[3.8]}{2}\right]}{\frac{[80.5]}{3.76} - [4.4]}$$

$$= 0.776$$

Oxygen Utilization:

$$Y = \frac{\left[\frac{[N_2]}{R} - [O_2]\right]}{\frac{[N_2]}{R}}$$

$$= \frac{\frac{[80.5]}{376} - 4.4}{\frac{[80.5]}{3.76}} = \frac{17.01}{21.41}$$

$$= 0.795$$

Excess Air $= \frac{[1-Y]}{Y} = \frac{[1-0.795]}{0.795} = 0.258$

$$\frac{([CO_2]+[CO])}{[CO]} Ratio = \frac{([11.3]+[3.8])}{[3.8]} = 3.97$$

$$\frac{([CO_2]+[CO])}{[N_2]} Ratio = \frac{([11.3]+[3.8])}{[80.5]} = 0.188$$

Following are examples of product gas compositions and combustion parameters corresponding to different burning conditions.

Typical Produced Gas Compositions Dry or Normal Wet Combustion

Feed Gas Composition (mole %)	
Oxygen	21.00
Nitrogen	78.00
Argon	1.00
"R"	3.71

Product Gas Compositions (mole%)		
COMPONENT	UNNORMALIZED	NORMALIZED
CO_2	14.00	14.19
CO	3.60	3.65
O_2	0.00	0.00
N_2	81.08	82.16
H_2	0.20	0.00
C_1+	0.92	0.00
H_2S	0.20	0.00
TOTAL	100.00	100.00

	Calculated Gas-Phase Parameters	(Scf/lbm)
H/C Ratio	1.37	
O_2/Fuel Ratio (m^3(ST)/kg)	2.19	35.1
Air/Fuel Ratio (m^3(ST).kg)	10.32	165.4
Injected $O_2$to Cox's (%)	72.38	
Reacted O_2Utilization (%)	100.00	
Excess Air (%)	0.00	
(CO_2+CO)/CO Ratio	4.89	
(CO_2+CO)/N_2Ratio	0.22	

Typical Produced Gas Compositions for a ATHABASBCA Oil Sand Super Wet Combustion at 5520 KPa

Feed Gas Composition (mole %)	
Oxygen	21.00
Nitrogen	78.00
Argon	1.00
"R"	3.71

Product Gas Compositions (mole%)		
Component	**Unnormalized**	**Normalized**
CO_2	8.07	8.09
CO	2.10	2.10
O_2	0.05	0.05
N_2	89.59	89.76
H_2	0.00	0.00
C_1+	0.19	0.00
H_2S	0.00	0.00
TOTAL	100.00	100.00

	Calculated Gas-Phase Parameters	(Scf/lbm)
H/C Ratio	5.88	
O_2/Fuel Ratio (m^3(ST)/kg)	3.13	50.2
Air/Fuel Ratio (m^3(ST).kg)	14.74	236.3
Injected $O_2$to Cox's (%)	37.81	
Reacted O_2Utilization (%)	37.89	
O_2Utilization (%)	99.79	
Excess Air (%)	0.21	
(CO_2+CO)/CO Ratio	4.84	
(CO_2+CO)/N_2Ratio	0.11	

Typical Produced Gas Compositions for a Athabasca Oil Sand Superwet Combustion at 2760 Kpa Steam Bank Temperature: 215°C

Feed Gas Composition (mole %)	
Oxygen	21.00
Nitrogen	78.00
Argon	1.00
"R"	3.71

Product Gas Compositions (mole%)		
Component	Unnormalized	Normalized
CO_2	5.83	5.86
CO	1.58	1.59
O_2	0.87	0.87
N_2	91.25	91.68
H_2	0.00	0.00
C_1+	0.47	0.00
H_2S	0.00	0.00
TOTAL	100.00	100.00

	Calculated Gas-Phase Parameters	(Scf/lbm)
H/C Ratio	9.22	
O_2/Fuel Ratio (m^3(ST)/kg)	3.68	59.0
Air/Fuel Ratio (m^3(ST).kg)	17.35	278.1
Injected $O_2$to Cox's (%)	26.95	
Reacted O_2Utilization (%)	27.94	
O_2Utilization (%)	96.46	
Excess Air (%)	3.67	
(CO_2+CO)/CO Ratio	4.69	
(CO_2+CO)/N_2Ratio	0.08	

Typical Produced Gas Compositions for a ATHABASCA Oil Sand Dry Combustion Run (Prior to Stall)

Feed Gas Composition (mole %)	
Oxygen	21.00
Nitrogen	78.00
Argon	1.00
"R"	3.71

Product Gas Compositions (mole%)		
Component	**Unnormalized**	**Normalized**
CO_2	15.06	15.18
CO	2.44	2.46
O_2	0.00	0.00
N_2	81.72	82.36
H_2	0.00	0.00
C_1+	0.75	0.00
H_2S	0.03	0.00
TOTAL	100.00	100.00

	Calculated Gas-Phase Parameters	(Scf/lbm)
H/C Ratio	1.31	
O_2/Fuel Ratio (m^3(ST)/kg)	2.23	35.7
Air/Fuel Ratio (m^3(ST).kg)	10.51	168.5
Injected $O_2$to Cox's (%)	73.99	
Reacted O_2 Utilization (%)	73.99	
O_2 Utilization (%)	100.00	
Excess Air (%)	0.00	
(CO_2+CO)/CO Ratio	7.17	
(CO_2+CO)/N_2Ratio	0.21	

Typical Produced Gas Compositions for a Athabasca Oil Sand Dry Combustion Run (Post Stall Analysis)

Feed Gas Composition (mole %)	
Oxygen	21.00
Nitrogen	78.00
Argon	1.00
"R"	3.71

Product Gas Compositions (mole%)		
Component	Unnormalized	Normalized
CO_2	5.82	5.82
CO	1.25	1.25
O_2	1.97	1.97
N_2	90.96	90.96
H_2	0.00	0.00
C_1+	0.00	0.00
H_2S	0.00	0.00
TOTAL	100.00	100.00

	Calculated Gas-Phase Parameters	(Scf/lbm)
H/C Ratio	9.09	
O_2/Fuel Ratio (m^3(ST)/kg)	3.87	62.0
Air/Fuel Ratio (m^3(ST).kg)	18.23	292.2
Injected $O_2$to Cox's (%)	26.32	
Reacted O_2 Utilization (%)	28.62	
O_2 Utilization (%)	91.96	
Excess Air (%)	8.75	
(CO_2+CO)/CO Ratio	5.66	
(CO_2+CO)/N_2Ratio	0.08	

Typical Product Gas Compositions for an Enriched Air Dry Combustion Run at 4100 kPa — Athabasca Oil Sand

Feed Gas Composition (mole %)	
Oxygen	21.00
Nitrogen	78.00
Argon	1.00
"R"	3.71

Product Gas Compassions (mole%)		
Component	**Unnormalized**	**Normalized**
CO_2	79.45	83.27
CO	8.86	9.29
O_2	0.27	0.28
N_2	6.83	7.16
H_2	0.80	0.00
C_1+	3.38	0.00
H_2S	0.41	0.00
TOTAL	100.00	100.00

	Calculated Gas-Phase Parameters	(Scf/lbm)
H/C Ratio	1.81	
O_2/Fuel Ratio (m^3(ST)/kg)	2.40	38.5
Air/Fuel Ratio (m^3(ST).kg)	2.53	40.6
Injected $O_2$to Cox's (%)	67.64	
Reacted O_2 Utilization (%)	67.79	
O_2 Utilization (%)	99.78	
Excess Air (%)	0.22	
(CO_2+CO)/CO Ratio	9.97	
(CO_2+CO)/N_2Ratio	12.93	

Modifications of Equation to Account for Reactions Other Than Assumed High Temperature Combustion

In this section, we present combustion tube data analysis for reactions other than high temperature oxidation. These reactions other than high temperature oxidation. These reactions include: low temperature oxidation (LTO), carbonate decomposition, and burning of a previously oxidized fuel.

(a) LTO Reactions

$$C_xH_y + aO_2 + (R)aN_2 \rightarrow bCO_2 + fO_2 + jH_2O$$

$$+(R)N_2 + \Delta_{o_2}a$$

where Δ_{02} = fraction of injected oxygen which is reacted with the hydrocarbon to form liquid-or solid-phase oxidized components.

$$\frac{H}{C} = \frac{y}{x} = \frac{4\left(a(1-\Delta_{o_2}) - b - \frac{d}{2} - f\right)}{(b+d}$$

$$\frac{H}{C} = \frac{4\frac{([N_2])}{R}(1-\Delta_{o_2}) - [CO_2] - \frac{[CO]}{2} - [O_2]}{([CO_2]+[CO])}$$

(b) Carbonate Decomposition:

$$C_xH_y + aO_2 + (R)aN_2 + \Delta_{co_2}bCO_2 \rightarrow bCO_2 + dCO + fO_2$$

$$+jH_2O + (R)aN_2$$

Δ_{CO_2} = fraction of produced CO_2 resulting from carbonate decomposition.

$$\frac{H}{C} = \frac{y}{x} = \frac{4\left(a - b(1-\Delta_{co}) - \frac{d}{2} - f\right)}{b+d}$$

$$\frac{H}{C}=\frac{4\left(\frac{[N_2]}{R}-[CO_2](1-\Delta_{co_2})-[O_2]\right)}{([CO_2]+[CO])}$$

(c) Burning a Previously Oxidized Fuel:

$$C_xH_yO_z+aO_2+(R)aN_2\rightarrow bCO_2+dCO+fO_2+jH_2O+(R)aN_2$$

$$\frac{H}{C}=\frac{4\left(a+\frac{z}{2}-b-\frac{d}{2}-f\right)}{(b+d)}$$

$$\frac{H}{C}=\frac{\frac{4([N_2])}{R}+\frac{z}{2}-[CO_2]-\frac{[CO]}{2}-[O_2]}{([CO_2])+[CO]}$$

Laboratory experiments conducted under isothermal conditions suggest that up to 0.3g O_2/g initial oil can be chemically stored in the hydrocarbons. The nature of the oxidized component can not be exactly described, but it appears to be in an immobile and non-extractable fraction which we normally designate as coke.

The H/C ratio of the oxidized component is generally unknown, but for the purposes of illustration assume an H/C of the original oil.

Hence, for an oil having an original H/C of 1.5 but containing an oxygen content of 0.3g O_2/g oil, based on 1 gram of original oil.

Atoms: carbon $$=\frac{(1g)\left(\frac{1gatomC}{gmolfuel}\right)}{(12.011+1.5(1.008))g/gmol}=0.0739$$

Atoms: hydrogen $$=\frac{(1g)\left(\frac{1.5gatomsH}{gmolfuel}\right)}{(12.011+1.5(1.008))g/gmol}=0.1109$$

Atoms: oxygen $= \dfrac{0.3g}{32g/gmol} \bullet \dfrac{2gatoms}{gmol} = 0.0188$

Assuming that fuel is expressed asd ($C_xH_yO_z = x\ (CH_{y/x}\ O_{z/x})$

$$\therefore \frac{y}{x} = 1.5$$

$$\frac{z}{x} = \frac{0.0188}{0.0739} = 0.25$$

Hence, in the equation for combustion of an oxidized fuel:

$$Z = 0.25x = 0.25\ ([CO_2] + [CO])$$

When this term is added, it will cause the apparent the H/C ratio to increase.

Example Calculation to Illustrate Combustion of an Oxidized Fuel

Basic Stoichiometry:

$$C_xH_yO_z + aO_2 + RaN_2 \rightarrow bCO_2 + dCO + fO_2 + jH_2O + R\left(\frac{a}{x}\right)N_2$$

$$CH_{y/x}O_{z/x} + \frac{a}{x}O_2 + R\left(\frac{a}{x}\right)N_2 \rightarrow \frac{b}{x}CO_2 + \frac{d}{x}CO + \frac{f}{x}O_2 + \frac{j}{x}H_2O + R\left(\frac{a}{x}\right)N_2$$

Again letting:

$$n = \frac{y}{x} = \text{H. C. ratio}$$

$$m = \frac{CO_2}{CO} = \frac{b}{d}$$

$$\frac{b}{x} = \frac{m}{m+1}$$

$$\frac{d}{x} = \frac{1}{m+1}$$

$$\frac{j}{x} = \frac{1}{2}\left(\frac{y}{x}\right)$$

$$\frac{f}{x} = \frac{a}{x}(1-Y)$$

where Y = fraction of injected O_2 which is utilized.

From the oxygen balance:

$$\frac{1}{2}\left(\frac{z}{x}\right)+\frac{a}{x}=\frac{b}{x}+\frac{1}{2}\left(\frac{d}{x}\right)+\frac{f}{x}+\frac{1}{2}\left(\frac{j}{x}\right)$$

Solving for $\frac{a}{x}$

$$\frac{a}{x}=\frac{b}{x}+\frac{1}{2}\left(\frac{d}{x}\right)+\frac{a}{x}(1-Y)+\frac{1}{4}\left(\frac{y}{x}\right)$$

$$\frac{a}{x}=\frac{1}{Y}\left(\frac{m}{m+1}+\frac{1}{2}\left(\frac{1}{m+1}\right)+\frac{n}{4}-\frac{1}{2}\left(\frac{z}{x}\right)\right)$$

$$\frac{a}{x}=\frac{1}{Y}\left(\frac{2m+1}{2m+2}+\frac{n}{4}-\frac{1}{2}\left(\frac{z}{x}\right)\right)$$

Hence, per mole (gmol or kmol or pmole) of $CH_{y/x}\,O_{z/x}$, the moles of product are:

Component	**Basic Relationship**	**Moles per Mole Fuel**
CO_2	$\frac{b}{x}$	$\frac{m}{m+1}$
CO	$\frac{d}{x}$	$\frac{1}{m+1}$
O_2	$(1-Y)\left(\frac{a}{x}\right)$	$\frac{(1-Y)}{Y}\left(\frac{2m+1}{2m+2}+\frac{n}{4}-\frac{1}{2}\left(\frac{z}{x}\right)\right)$
N_2	$R\left(\frac{a}{x}\right)$	$\frac{R}{Y}\left(\frac{2m+1}{2m+2}+\frac{n}{4}-\frac{1}{2}\left(\frac{z}{x}\right)\right)$
H_2O	$\frac{j}{x}=\frac{1}{2}\left(\frac{y}{x}\right)$	$\frac{n}{2}$

On dry basis (excluding H_2O):

$$\text{Total moles} = \frac{m}{m+1}+\left(\frac{1}{m+1}\right)+\left(\frac{1-Y+R}{R}\right)\left(\frac{2m+1}{2m+2}+\frac{n}{4}-\frac{1}{2}\left(\frac{z}{x}\right)\right)$$

$$= 1+\left(\frac{1-Y+R}{Y}\right)\left(\frac{2m+1}{2m+2}+\frac{n}{4}-\frac{1}{2}\left(\frac{z}{x}\right)\right)$$

To illustrate product gas compositions and conventional combustion parameters (i.e., parameters which do not account for the oxidized nature of the fuel), consider the following examples:

	Oxidized Components	**Formula**
1.	Formic Acid	HCOOH
2.	Acetic Acid	CH_3COOH
3.	Perbenzoic Acid (Peroxybenzoic Acid)	$C_6H_5CO_2OH$
4.	Oxalic Acid	HOOCCOOH

Note on Sample Calculations:

1. Have assumed: $Y = \%\ O_2$ utilization = 100%

$$m = \frac{(CO_2)}{(CO)} = 10$$

2. Have input nominal composition of air as:

$y_{o_2} = 20.946\%$

$y_{N_2} = 78.084\%$

$y_{A_r} = 0.934\%$

and have included argon in product gas.

3. Have used factor 23.6445 $\frac{m^3(ST)}{kmol}$ in air/fuel calculations.

Product Gas Composition and Conventional Combustion Parameters Corresponding to the Combustion of an Oxidized Hydrocarbon

Example Calculation

Feed Gas Composition (mole %)

Oxygen	20.946
Nitrogen	78.084
Argon	0.934
N_2/O_2	3.728
A_r/N_2	0.012

Assumed O_2 Utilization (%) 100

Assumed (CO_2/CO) Ratio 10

Elemental Analysis of Fuel

Name	**Formic Acid**	**Acetic Acid**	**Perbenzoic Acid**	**Oxalic Acid**	**Peracetic Acid**
Formula	**HCOOH**	**CH_3COOH**	**$C_6H_5CO_2OH$**	**HOOCCOOH**	**CH_3CO_3H**
Atoms					
Carbon	1	2	7	2	2
Hydrogen	2	4	6	2	2
Oxygen	2	2	3	4	3
H/C=y/x	2	2	0.857	1	2
O/C=z/x	2	1	0.429	2	1.5

Moles Product Gas on a Dry Basis

Component	Formic Acid Moles	Acetic Acid Moles	Perbenzoic Acid Moles	Oxalic Acid Moles	Peracetic Acid Moles
CO_2	0.909	0.909	0.909	0.909	0.909
CO	0.091	0.091	0.091	0.091	0.091
O_2	0.000	0.000	0.000	0.000	0.000
N_2	1.694	3.558	3.558	0.763	2.626
A_r	0.020	0.043	0.043	0.009	0.031
Total	2.715	4.601	4.601	1.772	3.658

Composition of Product Gas on Dry Basis

Component	Formic Acid Mole %	Acetic Acid Mole %	Perbenzoic Acid Mole %	Oxalic Acid Mole %	Peracetic Acid Mole %
CO_2	33.49	19.76	19.76	51.31	24.85
CO	3.35	1.98	1.98	5.13	2.49
O_2	0.00	0.00	0.00	0.00	0.00
N_2	62.42	77.34	77.34	43.04	71.80
A_r	0.75	0.93	0.93	0.51	0.86
Total	100.00	100.00	100.00	100.00	100.00

Conventional Combustion Parameters

(i.e., No Accounting for Oxidized Fuel)

Apparent H/C Ratio	-2.00	0.000	0.000	-3.000	-1.000
O_2/Fuel Ratio (m^3(st)/kg)	1.075	1.879	1.879	0.538	1.514
Air/Fuel Ratio (m^3(st)/kg)	5.084	8.884	8.884	2.544	7.158
Injected O_2 to Cox's (%)	210.000	100.000	100.000	466.667	135.484
Reacted O_2 to Cox's (%)	210.000	100.000	100.000	466.667	135.484
O_2 Utilization (%)	100.000	100.000	100.000	100.000	100.000
Excess Air (%)	0.000	0.000	0.000	0.000	0.000
(CO_2+CO)/CO Ratio	11.000	11.000	11.000	11.000	11.000
(CO_2+CO)/N_2 Ratio	0.590	0.281	0.281	1.311	0.381

Typical Product Gas Compositions Superwet, Enriched Air Combustion at 5520 kPa (ATHABASCA) Steam Bank Temperature: 270°C

Feed Gas Composition (mole %)

Oxygen	94.00
Nitrogen	6.00
Argon	0.00
"R"	0.06

Product Gas Compositions (mole %)

Component	Unnormalized	Normalized
CO_2	75.76	76.70
CO	14.24	14.42
O_2	0.50	0.51
N_2	8.27	8.37
H_2	0.15	0.00
C_{1+}	1.07	0.00
H_2S	0.00	0.00
Total	100.00	100.00

Calculated Gas-Phase Parameters

H/C Ratio	2.05
O_2/Fuel Ratio (m_3(st)/kg)	2.42 (38.79 scf/lbm)
Air/Fuel Ratio (m_3(st)/kg)	2.57 (41.2 scf/lbm)
Injected $O_2$to Cox's (%)	63.97
Reacted O_2 to Cox's (%)	64.22
O_2 Utilization (%)	99.61
Excess Air (%)	0.39
(CO_2+CO)/CO Ratio	6.32
(CO_2+CO)/N_2 Ratio	10.88

“Abnormal” Product Gas Compositions Normal Wet Combustion in a Carbonate Core

Feed Gas Composition (mole %)

Oxygen	21.00
Nitrogen	78.00
Argon	1.00
“R”	3.71

Product Gas Compositions (mole %)

Component	Unnormalized	Normalized
CO_2	30.00	30.15
CO	1.50	1.51
O_2	0.00	0.00
N_2	68.00	68.34
H_2	0.00	0.00
C_{1+}	0.40	0.00
H_2S	0.10	0.00
Total	100.00	100.00

Calculated Gas-Phase Parameters

H/C Ratio	-1.58
O_2/Fuel Ratio (m_3(st)/kg)	1.32 (21.16 scf/lbm)
Air/Fuel Ratio (m_3(st)/kg)	6.22 (99.71 scf/lbm)
Injected $O_2$to Cox's (%)	167.96
Reacted O_2 to Cox's (%)	167.96
O_2 Utilization (%)	100.00
Excess Air (%)	0.00
(CO_2+CO)/CO Ratio	21.00
(CO_2+CO)/N_2 Ratio	0.46

Analysis of Air and Fuel Requirements For Combustion Tube Tests

The following section provides actual combustion tube data from the University of Calgary Test No. 115, AOSTRA Test No. 29. This was a dry combustion tube test which was performed at a pressure of 2760 kPa using normal air on Athabasca Oil Sands core.

It should be noted that the calculations presented are based on combustion tube data. The procedures outlined are the same as would be used for a field project for evaluating the combustion parameters and amount of fuel consumed. Direct calculation of the air requirement and fuel requirement for a field project is not normally possible due to the lack of direct information on the volume of the burned zone or on the velocity of combustion front. Post-burn coring and temperature observation wells can provide this information, but these data are not normally obtained. Another difference between field and laboratory calculations is the uncertainty associated with relating the air injected at a given injector to the gas produced at a given production well which is in communication with that injector. White (1983) describes the calculations normally applied to the prorations of produced gas back to the different air injectors.

The calculations presented relate to the following parameters:

1. Overall Parameters.
2. Stabilized Parameters.
    a. Based on Average Gas Analysis.
    b. Based on Incremental Production of Individual Components on Stabilized Portion of Test.

Storage of air in the swept zone or the chemical storage of oxygen in the hydrocarbon has been neglected in the calculations presented. This is the normal procedure for normal air tests. Storage effect however, must be accounted for in high oxygen concentration air tests, particularly at high pressures.

Analyzing Combustion Tube Data

Initial mass of sand	22593g
Initial mass of oil	5355g
Initial mass of water	669g

Air injection rate	0.367 m^3(ST)/h
Total air injected	4.440 m^3(ST) [21% O_2, Balance N_2]

Product Gas Cumulative Volume [m^3(ST)]

Nitrogen	3.606
Oxygen	0.010
CO_2	0.670
CO	0.177

Oil recovered as liquid	4743 g

Volume of swept	0.0143 m^3

$$\text{Liquid hydrocarbon recovery} = \frac{4743g}{5355g} \times 100 = 88.6\%$$

Cross-sectional Area of Combustion Tube = $7.767 \times 10^{-3} m^2$

A. Overall Parameters

Amount of Carbon Burned:

Moles C = Moles CO_2 + Moles CO

Moles CO_2 = $\dfrac{0.670 m^3(ST)}{23.6445 \dfrac{m^3(ST)}{kmol}} = 0.028 kmol$

Moles CO = $\dfrac{0.177 m^3(ST)}{23.6445 \dfrac{m^3(ST)}{kmol}} = 0.007 kmol$

Moles C = Moles CO_2+Moles CO

= [0.028 + 0.007] = 0.0352 kmol

Mass C consumed = 0.0325 kmol x 12 kg/kmol

= 0.420 kg

Amount O_2 Consumed:

Moles O_2 consumed = Moles O_2 injected — Moles O_2 produced

$$= \frac{[4.440 x 0.21 - 0.010] m^3(ST)}{23.6445 \dfrac{m^3(ST)}{kmol}}$$

= 0.039 kmol

Hydrogen Consumption and Water of Combustion:

Moles O_2 Reacted to form Water of Combustion:

$$\text{Moles } O_2 \text{ consumed} - \text{Moles } CO_2 - \frac{MolesCO}{2}$$

$$= \quad [0.039 - 0.028 - \frac{0.007}{2}]$$

$$= \quad 0.008 \text{ kmol}$$

Since 2 moles H_2 react with 1 mole O_2 to form $_2$ moles H_2O

Moles H_2 reacted = 2(0.008) = 0/016 kmol

Mass H2 reacted = 0/016 kmol x $\frac{2kg}{kmol}$ = 0.032 kg

Mass H_2O Formed = 2(0.0080) kmol x 18 $\frac{kg}{kmol}$

= 0.288 kg

Total Fuel Consumed:

= Mass Carbon + Mass Hydrogen

= 0.420 kg + 0.032 kg

= 0.452 kg

Overall H/C Ratio:

$$\text{Atomic H/C} = \frac{0.016 kmolH_2 x \frac{2katoms}{kmol}}{0.035 kmolCx \frac{1katom}{1kmol}} = 0.91$$

Alternate Calculation for H/C Ratio:

$$\text{Atomic H/C} = \frac{0.032kgH_2}{0.420kgC} x \frac{1kmolH_2}{2.0kgH_2} x \frac{2katomH}{1kmolH_2} x \frac{12kgC}{kmolC} x \frac{1kmol}{katoms}$$

$$\text{Atomic H/C} = \frac{0.032x12}{0.420} = 0.91$$

Fuel Requirements:

$$\text{FR} = \frac{MassFuel}{VolumeofSweptCore}$$

Mass Fuel = 0.452 kg

Volume of Swept Core = 0.0143 m^3

$$\text{Fuel Requirement} = \frac{0.452kg}{0.0143m^3} = 31.6 \text{ kg/m}^3$$

Air Requirements:

$$\text{AR} = \frac{VolumeAir\left[m^3(ST)\right]}{VolumeofSweptCore}$$

$$= \frac{4.440m^3(ST)}{0.0143m^3}$$

$$= 310 \text{ m}^3\text{(ST)/m}^3$$

Some authors quote fuel requirements as $\frac{kg}{100kgsand}$

On this basis:

$$\text{Fuel Requirements} = \frac{0.452kg}{22.593kgsand}$$

$$= \frac{0.0200kgfuel}{kgsand}$$

$$\text{Fuel Requirements} = 2.00\ \frac{kgfuel}{100kgsand}$$

B. Stabilized Parameters

Based on the rate of advance of the 500°C leading edge [0.75 to 11.75 hours]:

$$\text{Front Velocity} = U_b = 0.144\text{m/h}$$

The air flux (as measured at the inlet to the tube) was:

$$AF = \frac{InjectionRate\left[m^3(ST)/h\right]}{X - \sec tionalareaofcore\left[m^2\right]}$$

$$= \frac{0.367m^3(ST)/h}{7.767x10^{-3}m^2}$$

$$= 47.3\ m^3(ST)/m^2h$$

Hence the air requirements based on the air injection flux is:

$$\text{Stabilized AR} = \frac{47.3\frac{m^3(ST)}{m^2h}}{0.144m/h} = 328\frac{m^3(ST)}{m^3}$$

which is slightly higher thabn the overall value for the air requirement, which was

$$310\frac{m^3(ST)}{m^3}$$

Good agreement indicates that run was stable which is consistent with the long period of stabilizing burning.

Two methods can be used to evaluate the stabilized air and fuel requirements and the stabilized combustion parameters.

Method 1:

This method is based on Numerical Average of Product Gas Composition and Injection Flux over the Stabilized Period.

The average product gas composition during the stabilized period was:

Compound	Mole %	Normalized (Mole %)
CO_2	14.47	14.65
CO	3.67	3.72
O_2	0.21	0.21
N_2	80.43	81.42
H_2	0.27	-
C_1+	0.85	-
H_2S	0.10	—
	100.0	100.0

H/C Ratio = 1.14 Based on Injection Flux.

O_2/Fuel Ratio = 2.15 m^3(ST)/kg Air Requirement=328 m^3(ST/m^3

Air/Fuel Ratio = 10.11 m^3(ST)/kg Fuel Req. = $\frac{Air\,Req.}{Air\,/\,FuelRatio}$

O_2 Utilization = 99.0% $\quad = \quad \dfrac{328m^3(ST)/m^3}{10.11m^3(ST)/kg}$

$\dfrac{(CO_2+CO)}{CO} = 4.94 \quad = \quad 32.1\ kg/m^3$

The advantage of this method (based on average product gas analysis) is that it is independent of product gas flow metering equipment. However, it can only be used if the product gas analysis is relatively constant.

Method 2:

This method is based on Incremental Production Rate:

For the time period from 0.75 to 11.75 h, cumulative production of product gases was:

Component	Volume [m3(ST)]	kmol(1)
N_2	3.123	0.132
O_2	0.008	0.0003
CO_2	0.579	0.0245
CO	0.148	0.00626

(1)kmol = Volume (m^3(ST))/23.6445 m^3/kmol.

$$\text{Mass C} = (\text{Moles Carbon})\left(\frac{12kg}{kmol}\right)$$

$$= (\text{Moles } CO_2 + \text{Moles CO})\left(\frac{12kg}{kmol}\right)$$

$$= (0.0245+0.00626)\text{kmoles}\left(\frac{12kg}{kmol}\right)$$

$$= (0.0308\text{ kmol})\ (12\text{ kg/kmol})$$

Mass C = 0.369 kg

Moles O_2 Reacted = (Moles O_2 Injected – Moles O_2 Produced)

$$= \left(\frac{MolesN_2}{\left(y_{N_2} / y_{o_2}\right)_{feed}} - MolesO_2\text{Pr}\,oduced \right)$$

$$= \left(\frac{0.132kmol}{\left(\frac{0.78}{0.21}\right)} - 0.0003kmol \right)$$

Moles O_2 Reacted = 0.0352 kmol

∴ Moles O_2 in H_2O (or L.T.O.)

$$= \left(MolesO_2reacted - MolesCO_2 - \frac{MolesCO}{2} \right)$$

$$= \left(\frac{0.132kmol}{\left(\frac{0.78}{0.21}\right)} - 0.0003kmol \right)$$

Moles O_2 in H_2O = 0.0076 kmol

Moles H_2 reacted = 0.0151 kmol x $\frac{2kg}{kmol}$ = 0.0303 kg

Mass Fuel = ∴ Mass H_2 + Mass C

= (0.0303 + 0.369) kg

= 0.3993 kg

$$\therefore \text{Air/Fuel Ratio} = \frac{\frac{N_2\left(m^3(ST)\right)}{\left(\frac{0.79}{3.71}\right)}\left(1 + \frac{0.79}{0.21}\right)}{0.3993kg}$$

$$= \frac{(3.123m^3(ST))(1+3.71)}{(3.71)(0.3993)}$$

$$= \quad 9.93 \ \frac{m^3(ST)}{kg}$$

Volume of Core Swept = (U$_b$) (X-sectional Area) (Time Period)

= (0.144 m/h) (7.767 x 10^{-3} m^2) (11.75 - 0.75)h

= 0.0123 m^3

∴ Air Requirement $$= \frac{\frac{(VolumeN_2)}{(3.71)} \bullet (4.71)}{0.0123m^3}$$

$$= \frac{3.965m^3(ST)}{0.0123m^3}$$

= 322 m^3 (ST)/m^3

Fuel Requirement $$= \frac{MassFuel}{VolumeSwept}$$

$$= \frac{0.3993kg}{0.0123m^3}$$

= 32.5 kg/m^3

Stabilized H/C Ratio:

Atomic H/C $$= \frac{MassH_2}{MassCarbon} x \frac{12kg}{kmolC} x \frac{1kmolC}{katomC} x \frac{1katomH}{1kgH}$$

98

Stablized $\left(\frac{CO_2 + CO}{CO}\right)$

$$= \frac{\left(0.579m^3(ST) + 0.148m^3(ST)\right)}{0.148m^3(ST)}$$

$$= 4.91$$

Stablized O_2 utilization $= \dfrac{\left(\dfrac{VolumeN_2}{3.71} - VolumeO_2\right)}{\left(\dfrac{VolumeN_2}{3.71}\right)}$

$$= \frac{\left(\dfrac{3.123}{3.71} - 0.008\right)m^3(ST)}{\left(\dfrac{3.123}{3.71}\right)m^3(ST)}$$

$$= 0.990$$

The stabilization combustion stoichiometry can be expressed as:

$$\text{CHn+ } \frac{1}{Y}\left(\frac{2m+1}{2m+2} + \frac{n}{4}\right)O_2 + \frac{R}{Y}\left(\frac{2m+1}{2m+2} + \frac{n}{4}\right)N_2 \rightarrow$$

$$\frac{m}{m+1}CO_2 + \frac{1}{m+1}CO + \frac{(1-Y)}{Y}\left(\frac{2m+1}{2m+2} + \frac{n}{4}\right)O_2$$

$$+\frac{n}{2}H_2O + \frac{R}{Y}\left(\frac{2m+1}{2m+2} + \frac{n}{4}\right)N_2$$

Since $m = \dfrac{(CO_2)}{(CO)} = \dfrac{(CO_2 + CO)}{CO} - 1$

$m + 1 = 4.91$; $m = 3.91$

$n = H/C = 0.98$

Y = fraction O_2 utilized = 0.990

$$\therefore \left(\frac{2m+1}{2m+2} + \frac{n}{4}\right) = 1.143$$

$$\frac{1}{Y}\left(\frac{2m+1}{2m+2}+\frac{n}{4}\right)=1.155$$

$$\frac{R}{Y}\left(\frac{2m+1}{2m+2}+\frac{n}{4}\right)=(3.71)(1.155)=4.284$$

$$\frac{m}{m+1}=\frac{3.91}{4.91}=0.796$$

$$\frac{1}{m+1}=\frac{1}{4.91}=0.204$$

$$\frac{1-Y}{Y}\left(\frac{2m+1}{2m+2}+\frac{n}{4}\right)=0.012$$

$$\frac{n}{2}=\frac{0.98}{2}=0.49$$

$CH_{0.98}$+1.155 0_2+4.284 N_2-0.796 CO_2+0.204 CO

+ 0.012 O_2+0.49 H_2O + 4.284 N_2

This is the form of the stoichiometric equation which is often input into numerical simulators.

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CHAPTER 4 — EVALUATION OF AN IN-SITU COMBUSTION PROSPECT

Introduction

Several factors must be taken into consideration when evaluating candidate reservoirs for in-situ combustion application.These include site geology, reservoir rock and fluid properties, crude oil characteristics, and reservoir geometries.

This chapter discusses the geological, reservoir and fluid properties requirements and their relative importance to a reservoir engineer evaluating the properties for a particular in-situ combustion project.

Geologic Characterization

Reservoir geological characteristics played a major role in the outcome of many past ISC projects. Examination of the reservoir characteristics of the California, Oklahoma, and Texas fireflood projects (states that account for more than 70% of the implemented US 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.

Lack of good sand continuity (due to complex lateral facies variations) and channeling have been cited as one of the cause of failure of many California firefloods (Simm, 1967). Since ISC is an interwell drive process good horizontal continuity is critical to the success of the project. Gaps in formation overburden or leaky interzonal seals in stratified reservoirs can allow fluid to leak into overlying strata and reduce the effectiveness of the injectant. Fractures and joint trends, however subtle, may create preferential flow channels which influence recovery efficiency.Therefore, a knowledge of the geologic characteristic of the site is important for the proper evaluation of a prospect for ISC. Earlougher et al. (1970) in analyzing the performance of the Fry in-situ combustion project, Illinois indicated that the reservoir geology played a prominent role in the outcome this project and stressed that an understanding of the reservoir geology is essential to the design and successful operation of a combustion project.

The objective of a geological reservoir description should be 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 key geological parameters to be considered when selecting a site for a fireflood project include: 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.

Lateral and Vertical Extent of Reservoirs.

The continuity of individual sand layers within the producing formation, especially in thin, lenticular sands is a factor of major importance to the successful operation of fireflood. In-situ combustion require significantly more capital investment per unit of production than waterflood because of the need for ancillary equipment, such as the air compressors, has high operating costs and is manpower intensive.This higher cost means that the volume of oil in place per unit area must be above a certain minimum to make the project economically viable. In thin reservoir, the total oil in place is a function of porosity, oil saturation and areal extent of the reservoir.

The success of the combustion projects in the thin and often poor quality south Texas strandplain/barrier island (lagoon and near shore environment deposits) reservoirs such as the Glen Hummel and Gloriana in-situ combustion projects (Buchwald et al., 1973), the North Government Wells combustion project (Casey, 1971), the Charco Redondo fireflood (Howard et al., 1976), and the West Casa Blanca project (Eskew, 1972) is in part can be attributed to the excellent lateral continuity of the sands.These reservoirs consist of multiple, thin, blanket type oil column that are more widespread and separated by shale stringers and tightly cemented mudstones. This made it an ideal geometry for achieving favorable sweep during combustion.

The failure of many early California fireflood projects such as those undertaken in the early 1960s in such fields as Ojai, White Wolf, Placerita Canyon, Pleito Creek, and Tepusquet Canyon can also be attributed in part to the lack of reservoir continuity. The formation at these sites, though, exhibit excellent porosity, good permeability and good oil saturation composed of a series of overlapping sand lenses, separated by interbedded impermeable shale layers. The poor lateral continuity and compartmentalization resulting from complex lateral facies variation did not permit the free movement of fluids. The general lack of areal continuity and poor understanding of the geology of the site by early operators contributed to the failure of the process in these reservoirs. Many of these pilots were unfortunate in site choice because they were done in properties that did not prove to be economic as primary producing cases.

Hence lateral and vertical extent of a reservoir is one of the key parameter to consider in the site selection process for an ISC project.The degree and extent of lateral and vertical reservoir continuity significantly affect the performance of the ISC process. Clean, well sorted sands tend to have good horizontal and vertical continuity. Reservoir continuity can be reduced by disseminated finer grains, by the local occurrence of various types of shale interbeds, and cementation materials.The study of setting in which the sands were deposited can give an approximation of the reservoir continuity in lateral and vertical perspective. A complete characterization of facies distribution would help to predict how reservoir performance can be affected by flow barriers.

Vertical Depth

Depth of the reservoir is not an handicap to the implementation of ISC process. Economically successful projects have been implemented in reservoirs ranging in depth from 300–1,1500 ft. Depth, however, is a factor in terms of temperature, pressure and well cost. Shallower depth (less than 200 ft.) 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 are usually hot enough, that spontaneous ignition of in-situ hydrocarbon is likely upon air injection.

Deeper reservoirs generally contain lighter oils and air injection at high pressure into these reservoir can offer some unique technical opportunities for improved oil recovery. Apart from combustion and the attendant oil recovery by displacement, other reservoir mechanisms also contribute to oil recovery. These include: reservoir pressurization, flue gas stripping of the light ends of reservoir oil by the combustion gases, oil swelling and high pressure miscibility effects (Yannimaras et al., 1991). With greater injection pressures greater injective capacity can be obtained. Thus, with greater injective capacity, well spacing can be enlarged.

Well drilling and completion costs, however, increases with depth. Larger compressors are needed to meet the injection pressure requirements. Larger compressors are more expensive to purchase, operate and maintain. Depth also effects the fluid lifting costs, especially in wet combustion process.Thus economic considerations will impose a practical upper depth limit. This may be on the order of 12,000–12,500 feet.

Reservoir Thickness

Sand thickness is one of the important parameters for the combustion process. The large difference in density between air and the reservoir fluids gives the air a tendency to override the oil column and consequently bypass much of the oil if the reservoir exceed a critical thickness. A thin oil sand tend to counter this override tendency and favor a more uniform displacement and vertical sweep. In a thin heavy oil reservoir, 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 a thick sand (Boberg, 1988). If the sand, however, is too thin high overburden heat losses may drop the temperature below that necessary to sustain a combustion front and can lead to low temperature oxidations and loss of recovery. Preferably pay thickness should at least be four feet and should not exceed 50 feet. It is preferable that very thin reservoirs (less than 8 ft. thick pay) considered for fireflood be contain multiply stacked thin sand separated by non communicating vertical barriers to take advantage of heat conduction in the vertical direction.This can not only minimize the heat losses to the overburden but can also aid in promoting and sustaining high temperature combustion mode in heavy oil reservoirs. The Fry in-situ combustion project in Illinois (Hewitt and Morgan, 1965; Bleakley, 1971) is a prime example of an successful in-situ combustion project implemented in multiple thin sand (less than 5 ft. thick) reservoir.

Formation thickness is also an important consideration in reservoirs containing oil not readily susceptible to auto-ignition. In such reservoirs the near well-bore area must be heated to a high temperature to initiate ignition. If the 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. Formations up to 60 ft. thick have been ignited using artificial ignition techniques.

Structural Attitude 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 crude affected by combustion (Gates and Skalar, 1971). In the steeply dipping Webster reservoir, the combustion project was initiated as a crestal drive in part, to heat the oil at the top of the structure and promote migration of oil toward the flanks of the anticline

(Soustek, 1994). Dip and the resulting gravity dominance played a major role in the economic success of the Santa Fe Energy Co.'s (now part of Texaco) Midway Sunset Combustion project.

Turta (1995) recommend locating the ISC pilot at the uppermost part of the structure. The reason behind this recommendation is that the burned volume of the pilot located at the upper part of the reservoir can be more accurately be determine and both the air-oil ratio (AOR) and the incremental oil recovery due to combustion can be estimated more reliably. Also by locating the pilot updip, resaturation of the burned zone can be avoided in case the air injection is terminated due to compressor failure.

Overburden Competence

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. Gaps in oil sand overburden or leaky interzonal seals in stratified reservoirs can allow fluid 'leaks' into overlying strata.

Reservoir Heterogeneities

Reservoir heterogeneities impacting 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.

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. 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.

Fractures and joints are secondary properties that may create preferential flow channels and influence the recovery. A thin zone of high permeability at the top of the reservoir extending from one well to another constitutes a hazard to fireflood by thiefing air and starving the fire front of needed oxygen.

Directional permeability resulting from the anisotropic characteristics of the reservoir has a major influence in the performance of many in-situ combustion project. These include the Iola fireflood in Kansas (Hardy and Raiford, 1975), Fry in-situ combustion project in Illinois (Earlougher et al., 1970) and the Webster fireflood, in the Midway Sunset field, California (Soustek et al., 1994). 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. Directional permeability can cause air to flow more freely in one direction than in any other direction and result in uneven burn.Existence of directional permeability alone is not a sufficient cause to reject a site for fireflood. By selectively locating the wells in the direction of permeability, the recovery can be maximize.

Presence of free gas caps or thin layer of high gas saturation at the top of the sand is not a desirable geological feature for fireflood operation because they can act as a thief zone for injected air and promote uneven burning. Presence of bottom water leg or aquifer, though, not desirable from the point of anisotropy is not an impediment to the success of a fireflood project. Many successful projects as the Glen Hummel, Gloriana, Trix-Liz, N. government Wells fireflood in Texas were implemented in reservoirs with active aquifers. In these projects the aquifer not only provided pressure support to the reservoir but also acted as a conduit to transfer the heat ahead of combustion front.

Though, reservoir heterogeneity can have adverse effect on project performance their impact can be minimize through recognition of the distinctive architecture of the reservoir and tailoring the project to accommodate this architecture. Firefloods implemented in highly heterogeneous reservoirs also often require unique reservoir management strategies to make the project economically viable. Some examples of successful fireflood projects where the combination of unique engineering design and reservoir management strategies overcame the many conditions considered adverse to the success of the process include Unocal's Brea-Olinda fireflood in Orange County, California (Showalter, 1974), Mobil's Moco fireflood in the Midway-Sunset field (Curtis, 1989; Soustek, 1994), and Mobil's North Government Wells fireflood in South Texas (Casey, 1971).

Rock Properties

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

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 a 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. However, there are many instances of economically successful firefloods in sandbodies with relatively poor permeability profiles (Casey, 1971; Soustek, 1994). In the Mobil's Webster reservoir combustion project, where sand bodies are lenticular and anisotropic, the success of the project was attributed to tailoring the operating policy to suit the reservoir architecture. In this reservoir the burn front advanced more rapidly through the high permeability medium to coarse-grained sands than through finer-grained, thin medium bedded sands, reflecting the influence of anisotropy on the lateral rate of movement of burn. Proper reservoir surveillance and modification of production strategy based on the timely identification of heat breakthroughs were cited as the keys to the success of the project (Soustek, 1994).

Thus from an oil recovery and sweep efficiency aspect the degree to which a particular profile correlates from one well to another is more important than the exact shape or dimensions of that particular profile.

Permeability

The actual value of permeability has very little effect on the mechanics of combustion process. Economically successful firefloods have been implemented in less than 10 millidarcy carbonate light oil reservoirs (Miller, 1995). The only requirement for permeability is that is 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 injectivity and promote low temperature oxidation. In such reservoirs a permeability greater than 100 millidarcies would be necessary.

Porosity

High porosity is desirable, since it directly reflects the volume of hydrocarbons that the rock can hold. In the U.S., economically successful firefloods have been implemented in reservoirs whose average porosity range from a low of 0.16 to high 0.38. 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 fireflood is dependent more on the actual value of the oil saturation-porosity product (fSo) than on porosity. Porosity lower than 0.2 is acceptable only if the oil saturation is greater than 0.45.

Oil Saturation

A 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 laydown is lower somewhat lower oil saturation is acceptable.

Composition of Reservoir Matrix

The economics and applicability of fireflood in a reservoir is dictated to a large extent by the nature and amount of fuel formed in the reservoir. If sufficient fuel is not deposited the combustion front will not be self-sustaining. Conversely if excessive fuel is deposited, the process may result in dismal economics due to high air requirements, high power cost and low oil recovery rate. Considerable laboratory and some field evidence exists indicating that the mineralogical composition of the reservoir rock and chemical composition of the crude oil can effect the amount of fuel available to sustain combustion.

Actual laboratory measurements of fuel formed using reservoir rock and crude indicate rock type is probably more important than the crude properties, particularly in light oil reservoirs in determining the amount of fuel deposition in the reservoir (Earlougher et al., 1970). The clay and metallic content of the rock, as well its surface area has a profound influence on fuel deposition rate and its oxidation. Presence of clays and fine sands in the matrix favor increased rates of fuel formation.

Increase clay content particularly kaolonite and illite favor increased rates of fuel formation by favoring low temperature oxidation reaction. Rock minerals such as pyrite, calcite, and siderite also favor fuel-forming reactions. Low air fluxes resulting from reservoir hetrogeneneities and oxygen channeling also promote low temperature oxidation and fuel formation reaction.

Results from the Fry in-situ combustion project showed fuel deposition varied with the lithologic characteristics of the rock. In the laboratory tests a very fine to fine grained sandstone containing significant amount of pyrite and siderite deposited a greater amount of the fuel than medium grained sandstone containing similar amount of pyrite. Similarly medium grained sandstone core containing large amount of clay material yielded the largest amount of fuel (3.3 lb./cu.ft. rock).

Effect of Well Spacing

Problems may arise in two ways when determining 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. Many of the sand bodies in the U.S. where fireflood had been implement are not continuous sheets of sand, but are lenticular in shape. These sand bodies frequently exhibit anisotropy parallel to the bedding.The permeability of the sand in one direction therefore is greater than in another. In such anisotropic, lenticular reservoirs, it is advisable from a stratigraphic standpoint drill injection wells at right angle to the direction of high permeability trend and at closer spacing. The production wells can be drilled along the trend on a wider spacing (600 ft. or greater). Such a flood pattern had been adopted in some of the fireflood projects, implemented in the narrow "shoestring" pools of S.E. Kansas.

Prospect Screening

Assessing the suitability of a prospect for an oil recovery process consists of (1) evaluating available information about the reservoir, oil, rock, water, geology and previous performance, (2) supplementing available information with certain relevant laboratory screening tests, and selecting the candidate reservoir that best match the process requirement.

In-situ combustion has been successfully implemented in reservoirs with widely differing rock, fluid, and geological characteristics. This render the development of satisfactory guidelines to screen reservoirs for combustion application difficult. Since the success of a combustion project depend to a large degree on the geologic characteristics of the reservoir, any proposed guidelines for selecting reservoir for combustion application must include the rock, fluid, as well the geological requirements. An applicability criterion for combustion process is given in this section. It is intended as informational guide rather than absolute constraints. These are general guidelines that reflect current technology and economic climate. Each prospect should be examined closely on an individual basis and engineering judgement applied before a decision can be made to pilot test the reservoir.

Screening Criteria

Oil

Viscosity: Preferably less than 5,000 cp at reservoir condition.

Gravity: 10–40°API

Composition: low asphaltic, low heavy metal content crude. Heavy metal (Va, Ni, etc.) should be preferably less than 50 ppm.

Water

Connate water properties are not critical.

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.

Reservoir

Depth: 300 – 12500 ft.

Thickness: 5- 50 ft.

Permeability: Not critical

Porosity: > 0.18

Oil concentration: 700 bbl/ac-ft, fSo > 0.09

Transmissibility: $\frac{kh}{\mu_0} \geq 20$ md-ft/cp

Favorable Factors

1. High reservoir temperature
2. Low vertical permeability
3. Good lateral continuity
4. Multiple thin sand layers
5. Good overburden competence
6. High dip
7. Uniform permeability profile

Factors Which Increase Risk

Extensive fractures

Large gas caps

Strong water drive

Highly heterogeneous reservoir

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CHAPTER 5 — ENGINEERING OF AN IN-SITU COMBUSTION PROJECT

In-Situ Combustion Performance Parameters

Several variables affect the performance of an in-situ combustion process. The most important parameters are fuel deposit, air requirement, air flux, air injection rate, air-oil ratio, injection pressure, and oil recovery rate.

Fuel Deposit

The quantity and type of fuel deposit is an important variable and is expressed as pounds of fuel per cubic foot of formation. The fuel burned per reservoir volume determines how much heat is generated. It also determines the amount of air required, the rate of burning front advance, the rate of oil recovery, and project life.

Fuel deposition is a function of crude oil properties, oil saturation, formation permeability, and temperature in the combustion zone. Fuel deposition can be determined experimentally using a combustion tube (Figure 5.1). Laboratory combustion tube tests have indicated that, in general, higher fuel depositions are expected with heavier and more viscous crudes. Figure 5.2 shows a correlation of fuel deposit with oil gravity obtained from laboratory studies. Based on laboratory combustion tests in preserved or restored cores and from field data, Chu (1982) presented the following regression correlation (Equation 5.1) to calculate fuel content for field projects.

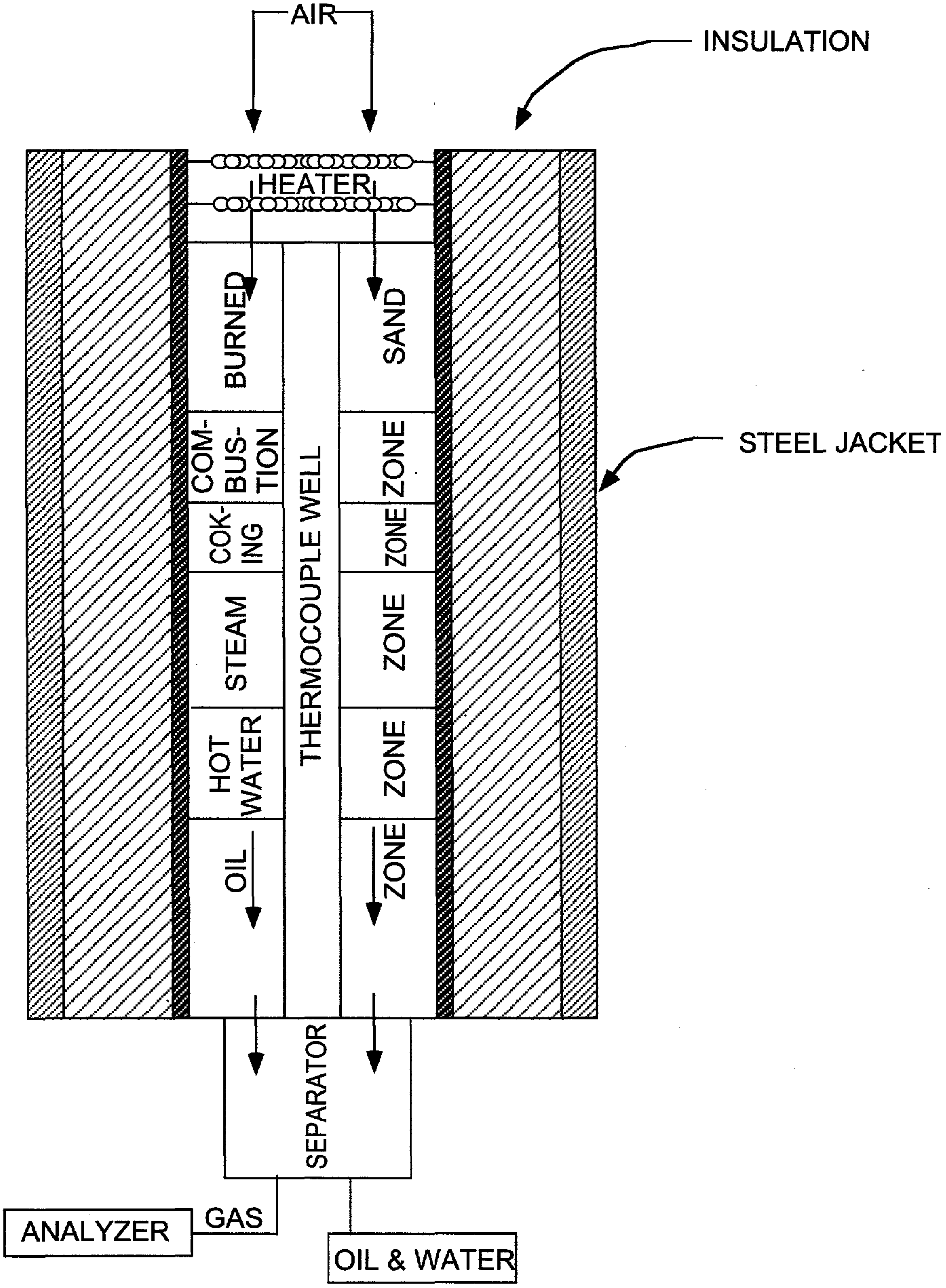


FIGURE 5.1 — Schematic of a Laboratory Combustion Tube, Depicting Various Combustion Process Mechanisms

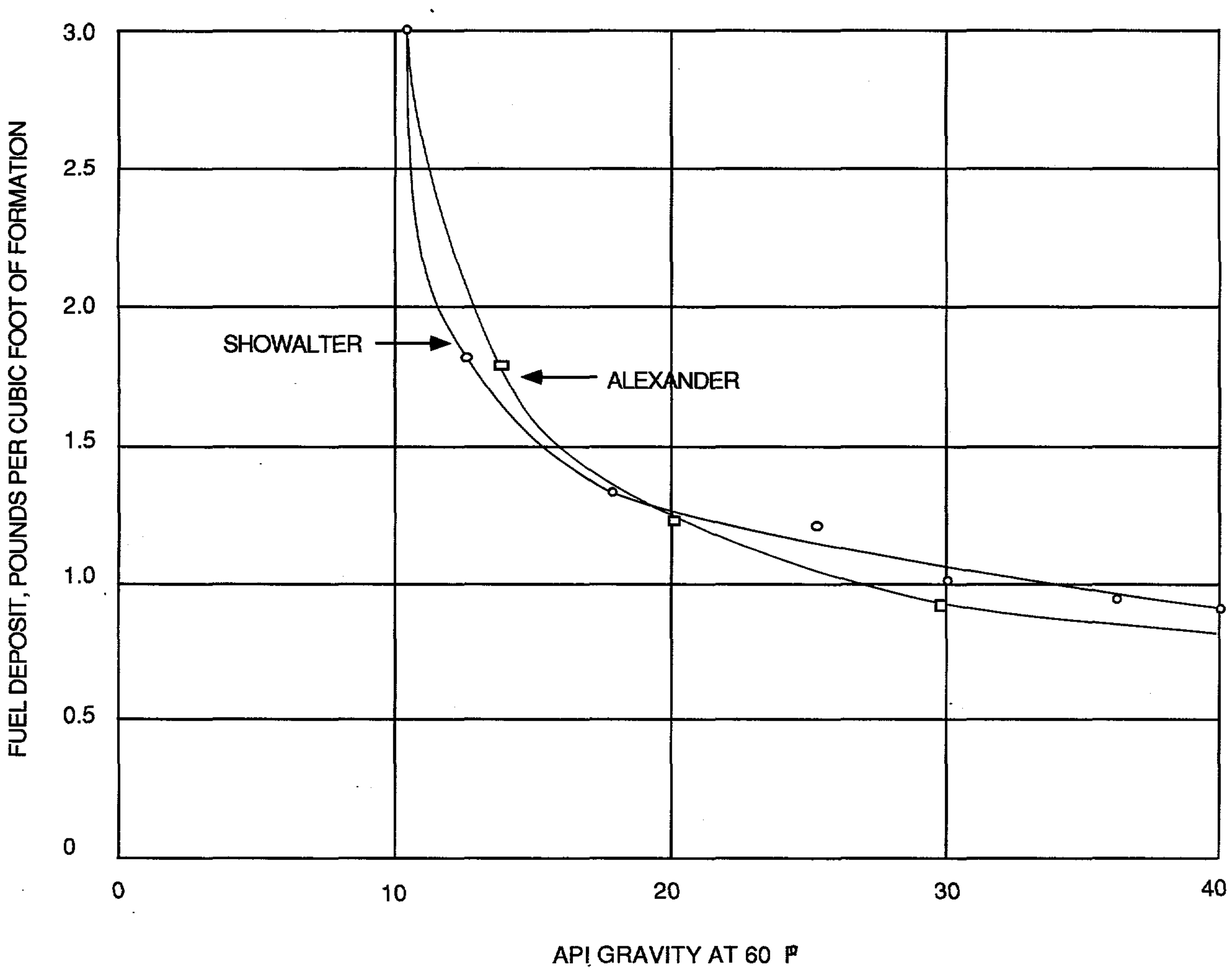


FIGURE 5.2 — Relationship Between Crude Gravity and Fuel Deposit

$$M = -0.12 + 0.00262h + 0.000114k + 2.23\,S_o + 0.000242(kh/\mu) - 0.000189z - 0.000652\mu \quad (5.1)$$

where M = fuel content (lb/ft.3), h = reservoir thickness (ft.), k = permeability (md), So = oil saturation (fraction), m = viscosity at reservoir temperature (cp), and z = depth (ft.).

The foregoing correlation can be used as a first approximation for the fuel deposition of a crude for a prospective field project. Actual combustion tube tests can be conducted later to obtain a more refined estimate.

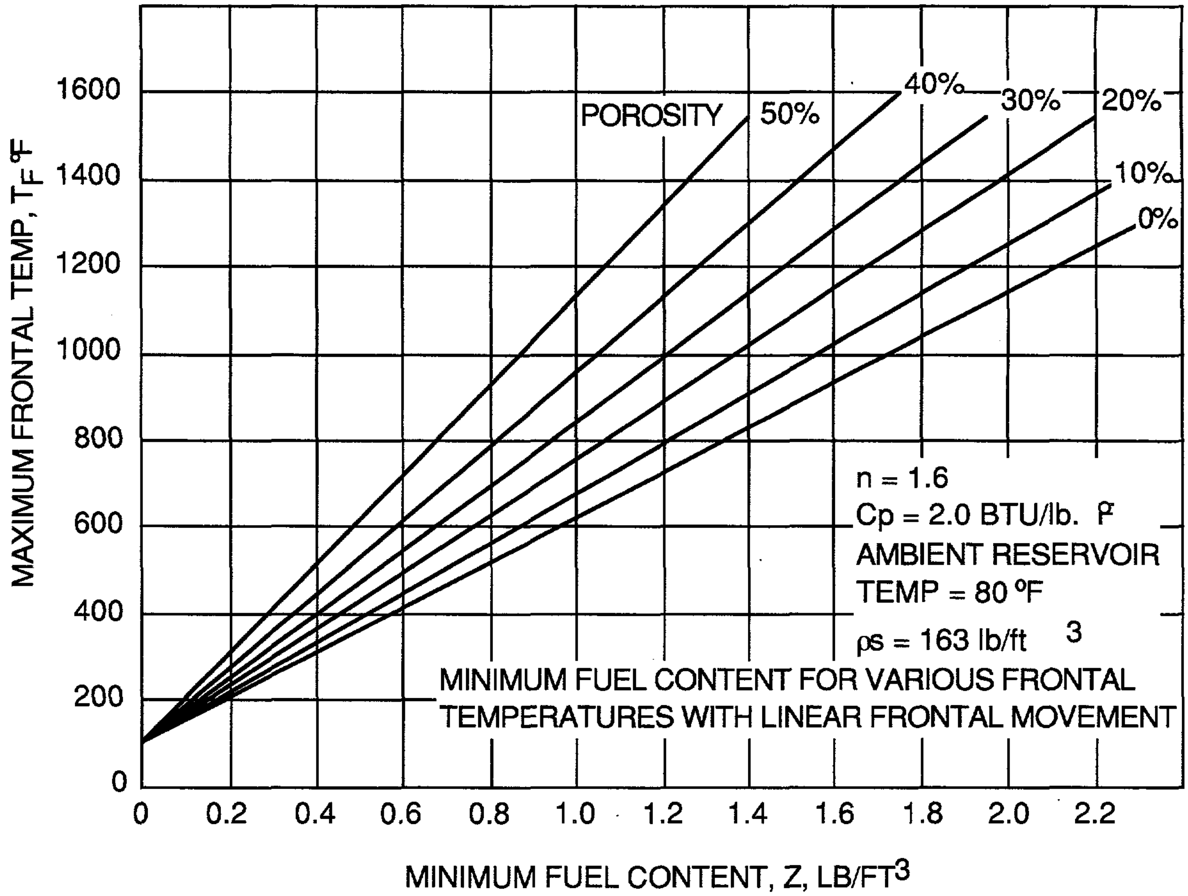


FIGURE 5.3 — Minimum Fuel Content Required to Support a Fixed Frontal Temperature

Figure 5.3 shows graphically, the minimum fuel requirement to maintain a fixed combustion front temperature as a function of porosity.

Air Requirements

The volume of air required to burn a unit volume of the reservoir based on stoichiometric analysis of the combustion gas produced from combustion tube is shown in Figure 5.4. In the absence of laboratory data, this figure can be used for preliminary estimates of air requirements. The air requirements determine the compression capacity needed, and is one of the more important parameters due to its effect on the overall project economics. The amount of air required to burn a unit mass of fuel is a function of the amount of carbon and hydrogen in the fuel and the ratio of carbon dioxide to carbon monoxide produced by the combustion, as shown in Figure 5.5. The hydrogen-to-carbon ratio of the fuel deposited during a fireflood usually ranges between 0.1 and 0.15.

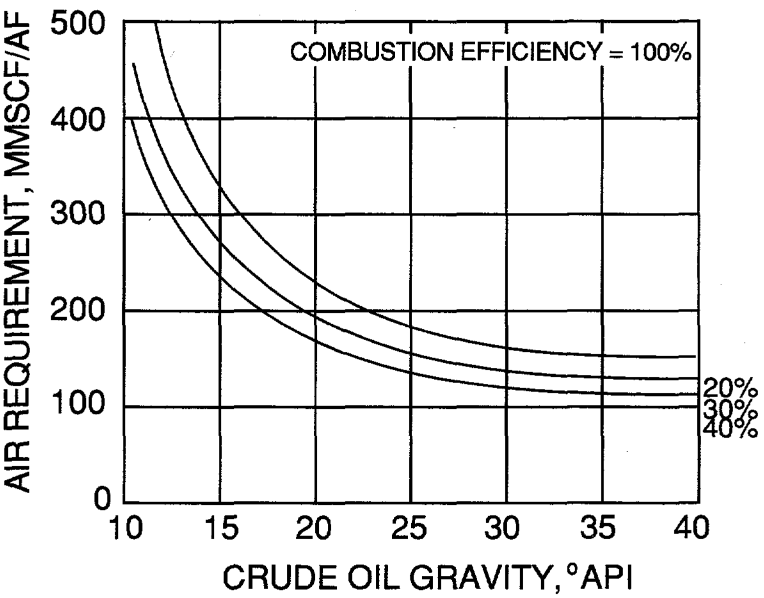


FIGURE 5.4 — Relationship Between Oil Gravity and Air Requirement (assumes 100% combustion)

For most firefloods, a value of 180 scf air/lb fuel is often used when laboratory data are not available. Based on field performance data, Chu (1982) presented the following regression equation (Equation 5.2) that relates air requirements to reservoir properties:

$$A = 4.72 + 0.03656h + 9.996S_o + 0.000691k \qquad (5.2)$$

where A = the air requirement (million scf/ac-ft.). Lacking sufficient laboratory data to calculate the stoichiometric air requirements, the previous equation can be used to obtain a rough estimate of the air requirement. The equation does not account for the crude's burning characteristics. Based on reported data, estimated air requirement in million scf/ac-ft. is about ten times the fuel content in lb/ft.3 of burned volume. For example, if the fuel content is 1.5 lb/ft.3, the air requirement will be about 15 million scf/ac-ft.

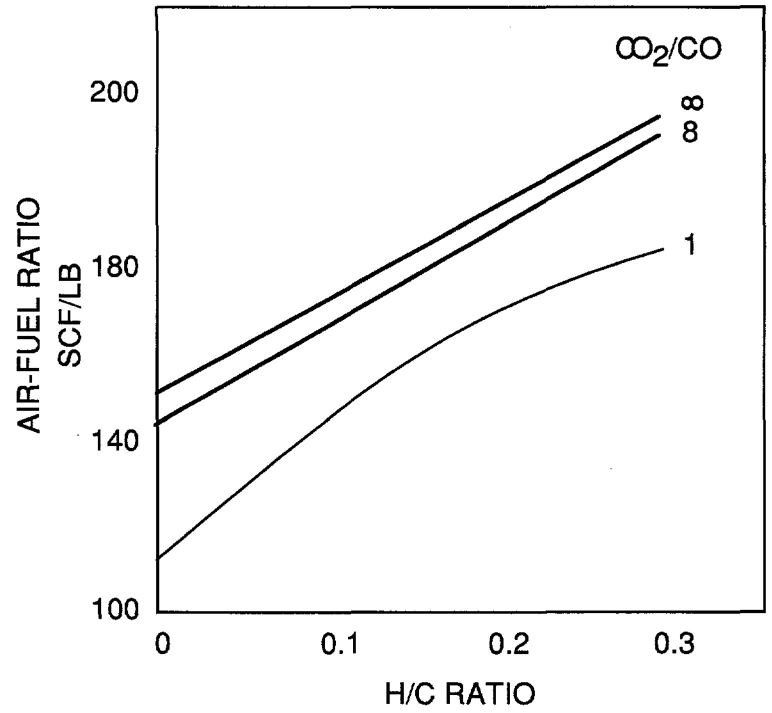


FIGURE 5.5 — Air Requirement for Combustion

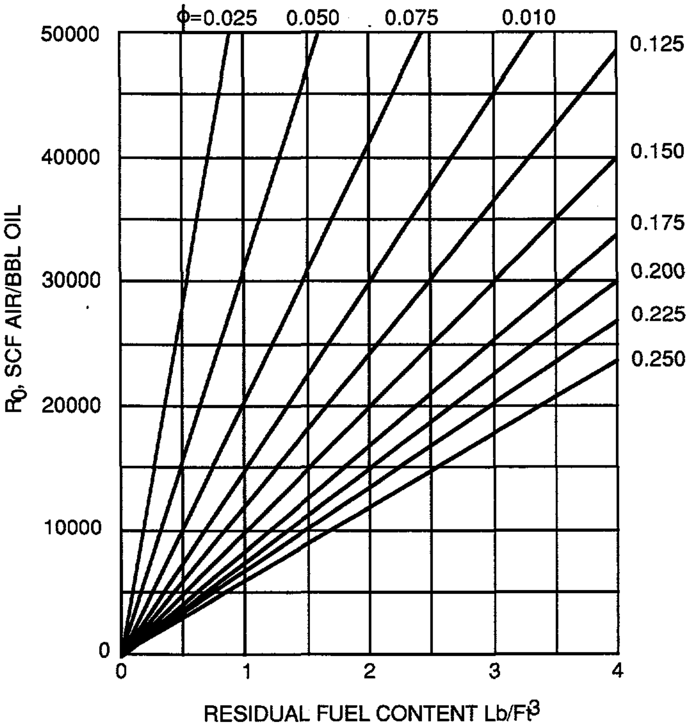


FIGURE 5.6 — The Teonetical Air Required to Move a Barrel of Oil in the Reservoir is Shown as a Function of Fuel Content and Porosity

Air Flux

The combustion front can move only as fast as air is supplied to consume the amount of fuel deposited, since all the fuel must be burned. Laboratory tests indicate that at relatively high air fluxes, the combustion is quite vigorous, resulting in combustion temperatures of about 1,000°F for nominal fuel deposition (1.5 lb/ft.^{3}). However, lower air fluxes result in lower combustion temperatures. As air flux is reduced further, the process approaches a point where the heat losses exceed the rate of heat generation, and the combustion front is extinguished. Thus, the minimum air flux is a function of both the fuel deposition and heat losses. In a field situation, the air flux required to sustain combustion increases with oil gravity and decreases with pay thickness (see Figure 5.7).

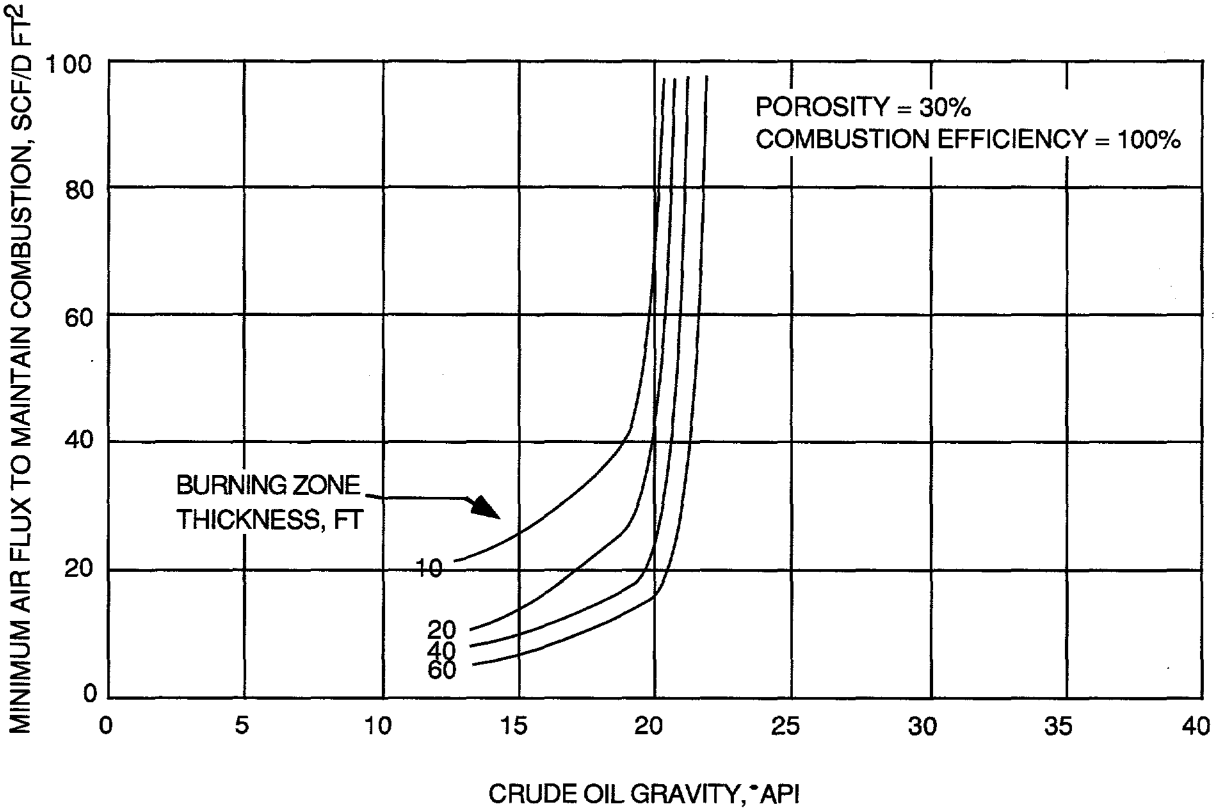


FIGURE 5.7 — Relationship Between Crude Gravity and Required Minimum Air Flux

For Mobil's Midway-Sunset combustion project, the minimum burning rate of 0.15 ft./day translates into an air flux of 2.15 scf/hr/ft.^{3}. The calculated velocity of the combustion front movement for various air flux and hydrogen\carbon ratios is shown in Figure 5.8.

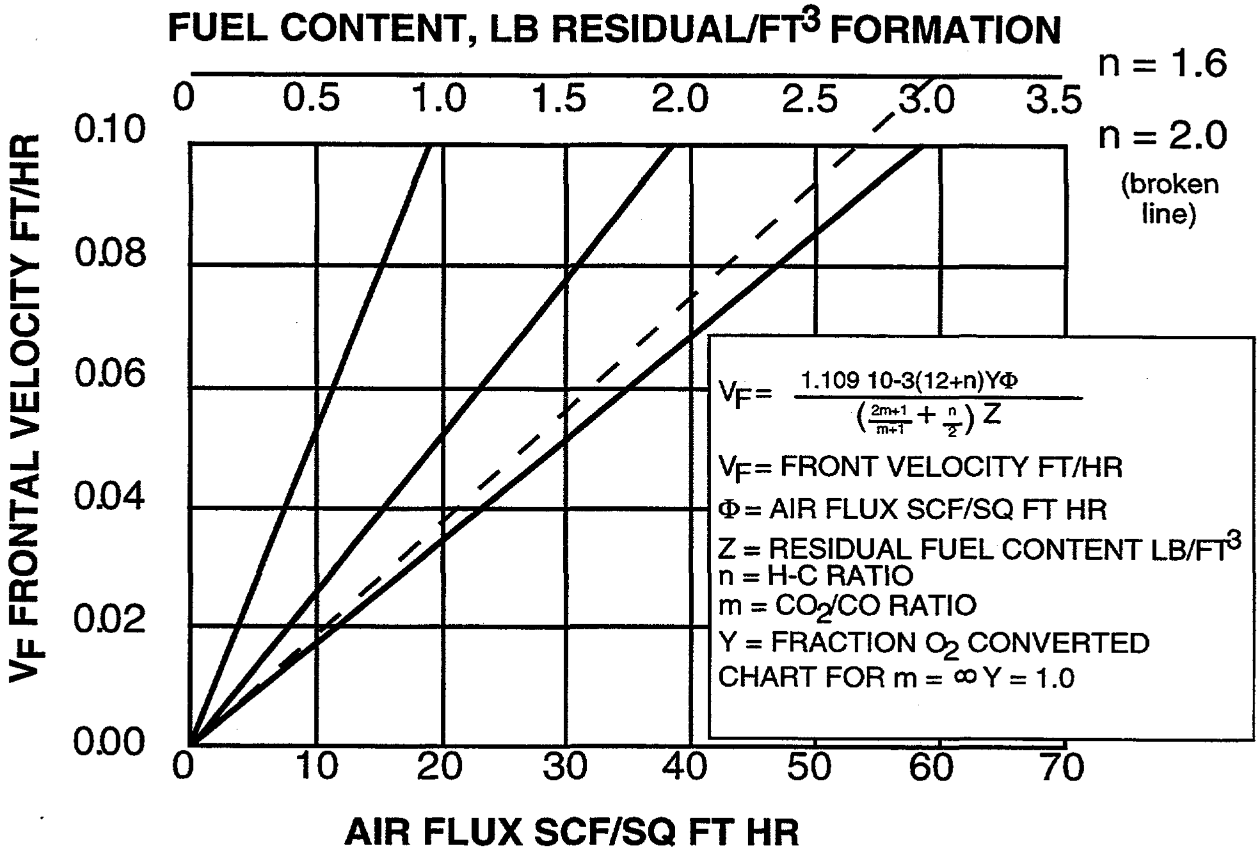


FIGURE 5.8 — Point Velocity of Combustion Front Movement as Described by Accompanying Equation

Air-Oil Ratio

The air-oil ratio (AOR) is the single most important economic parameter in fireflooding. It is a measure of the quantity of air that must be injected to recover a barrel of oil. It is used along with unit air cost to determine the air injection cost per barrel of oil produced. The AOR is a function of the oil in place and the fuel burned.

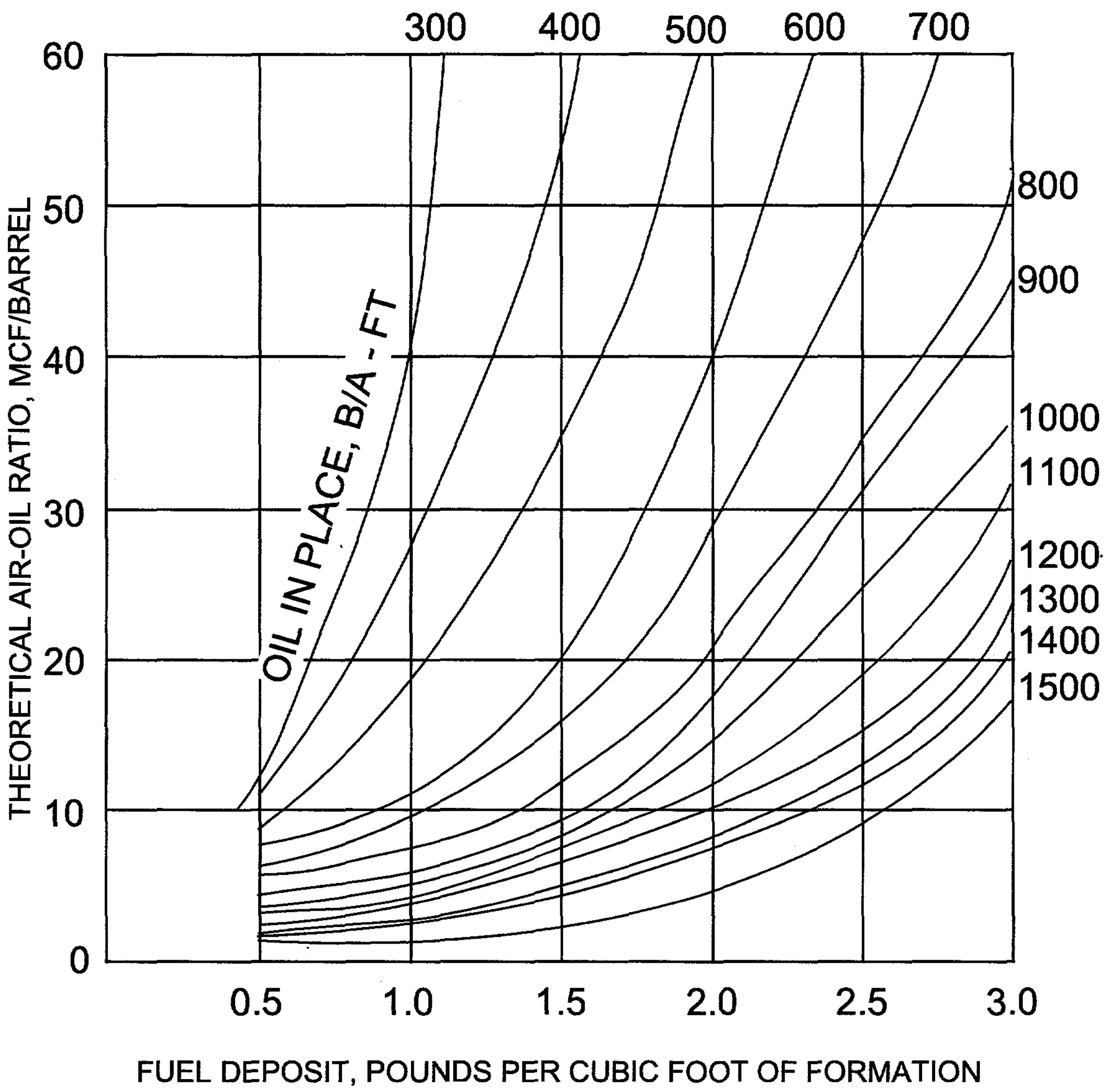


FIGURE 5.9 — Theoretical Air-Oil Ration vs Fuel Deposit (Assuming 100% Recovery of Displaced Oil)

Figure 5.9 shows the relationship between oil saturation, fuel content and theoretical air-oil ratio. The theoretical air-oil ratio is the volume of air injected per barrel of oil displaced from the burned volume. The oil displaced is equivalent to the oil in place less the oil burned as fuel. In comparison, the produced air-oil ratio is based on the air requirement of 180 scf/lb of fuel burned. For example, if the oil in place were 1,000 bbl/ac-ft. and fuel consumption were 1.0 lb/ft.[3] of reservoir, the AOR would be 7,850 scf/bbl for the swept region.

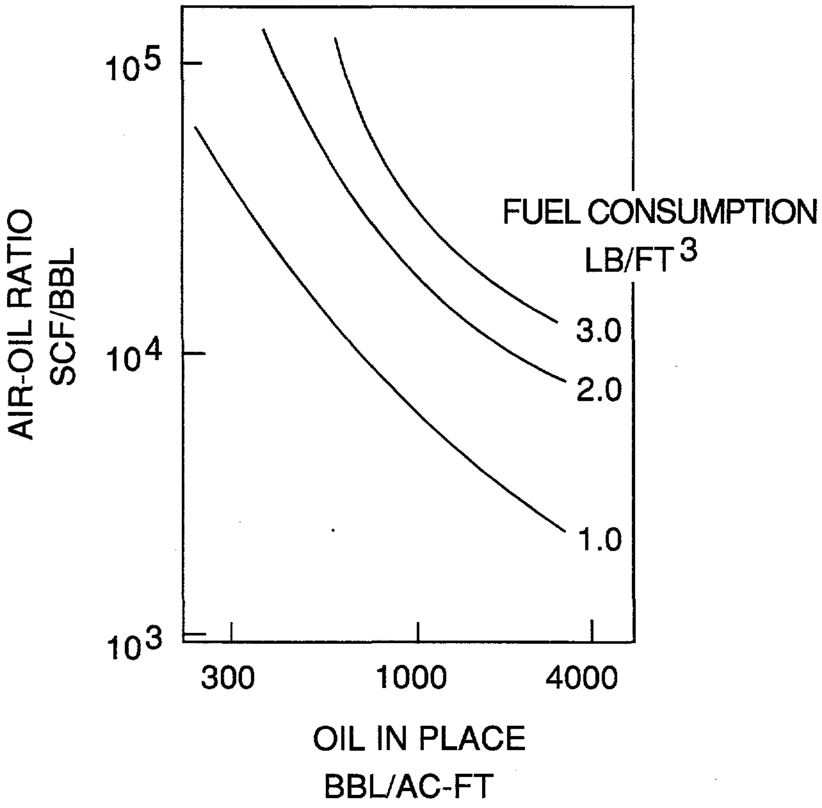


FIGURE 5.10 — Air-Oil Ratio as a Function of Oil in Place and Fuel Consumption

The following regression correlation developed by Chu (1982) from the performance history of field projects can be used (Equation 5.3) for estimating AOR (mcf/bbl) in terms of reservoir rock and fluid properties:

$$AOR = 21.45 + 0.0222h + 0.001065k + 0.002645\mu - 76.76\phi S_o \tag{5.3}$$

where ϕ = porosity.

The AOR is affected by the geometry of the oil field well pattern. A common practice in the field projects is to convert four inverted 5–spot patterns to one nine-spot pattern, thereby reducing by half the air injection rate while burning the same reservoir volume with only a small reduction in productivity.

Injection Pressure

A major expense in a combustion project is the cost of compressing air. The size of the compressor depends not only on the required air injection rate, but also on the discharge pressure required. Air injection pressure is dependent primarily on the permeability of the formation to air, selected air injection rate, well spacing, and formation depth.

The preferred way of determining the required air injection pressure is to run actual air injection tests in the field. For design purposes, the values obtained from such tests should be increased by some reasonable factor (such as 30%) to take care of any unexpected pressure increases during combustion operation. Nelson and McNeil (1961), on the basis of several field tests (for a large number of adjacent 5–spot pattern), suggested the following formula to calculate the necessary injection pressure:

$$P_{iw}^2 = P_w^2 + \frac{i_a \mu_a (T + 460)}{0.703\, k_a\, h} \left[\ln\left(\frac{a^2}{r_w V_b t} \right) - 1.238 \right] \tag{5.4}$$

where P_{iw} = injection well bottomhole pressure (psia), P_w = production well bottomhole pressure (psia), i_a = maximum air injection rate (scf/day), μ_a = viscosity of air (cp), T = reservoir temperature (°F), k_a = effective permeability to air (md), h = net pay thickness (ft.), a = well spacing (ft.), r_w = production well radius (ft.), V_b = burning zone velocity (ft./day), and t = time to reach maximum air rate (day).

Oil Recovery Rate

In the laboratory, the oil recovery for an ISC recovery program usually ranges between 60% and 90% of oil in place. This high oil recovery usually results from burning mobile crudes in high-porosity sandpacks containing high initial oil saturation. Oil recoveries in the field are much lower than laboratory oil recoveries due to lower horizontal and vertical sweep efficiencies. Graphical correlations have appeared in the literature to estimate oil recovery (Brigham et al., 1980). These correlations may be used in preliminary design work. However, they may not be valid outside the range of data used for their development. These correlations are fully discussed in a later section.

In-Situ Combustion Project Design

Several authors have presented procedures to engineer an in-situ combustion project (Nelson and McNeil, 1961; Gates and Ramey, 1980; Brigham et al., 1980; Fassihi et al., 1981; Naji and Poettmann, 1991). These were developed based on reported field performance data. The calculations are relatively simple and can be carried out using a spreadsheet program or a programmable calculator.

In the following we present the Nelson and McNeil, Gates and Ramey, and Brigham et al. method to engineer a dry in-situ combustion project.

Nelson-McNeil Method

Nelson and McNeil (1961) presented an engineering procedure to evaluate the performance of a dry in-situ combustion project. Although a large number of assumptions were made, the method is based on considerable field experience and may give reasonable estimates. They presented equations to calculate:

1. Total project air requirement.
2. Air injection rate.
3. Total oil recovery.
4. Oil production rate.

The method, though, relatively simple require experimental combustion tube data to calculate fuel lay-down and air requirement. A step-by-step procedure to calculate oil and water production is described below.

Fuel consumption and air requirement are calculated based on laboratory experiments. In Equation 5.5 to 5.16 the following nomenclature is employed.

D = Inside diameter of the combustion tube, ft.

L = Length of the pack burned, ft.

ϕ = Porosity, fraction

V_g = Volume of the produced gas, scf

N_{2a} = Volume fraction of nitrogen in injected air

O_{2a} = Volume fraction of oxygen in injected air

N_{2g} = Volume fraction of nitrogen in produced gas

O_{2g} = Volume fraction of oxygen in produced gas

CO_{2g} = Volume fraction of carbon dioxide in produced gas

CO_g = Volume fraction of carbon monoxide in produced gas

It is assumed that the nitrogen is completely inert in the reaction, and all the injected nitrogen is produced.

Carbon in the fuel burned = Wc = (CO_2 produced + CO produced) × (12/379) =
$[(V_g \times CO_{2g}) + (V_g \times CO_g)] \times (12/379)$ lb. (5.5)

Water formed by combustion = W_w = 2[(Oxygen injected – Unreacted oxygen produced) – (CO_2 produced) - 0.5 (CO produced)] × (18/379)

$W_w = 2[(V_g \times N_{2g} \times O_{2a}/N_{2a}) - (V_g \times O_{2g}) - (V_g \times CO_{2g}) - 0.5\,(V_g \times CO_g)] \times (18/379)$ lb. (5.6)

Hydrogen in the fuel burned = W_H = 2[(Oxygen injected – Unreacted oxygen produced) – (CO_2 produced) – 0.5((CO produced)] × (2/379)

$$W_H = 2[(V_g \times N_{2g} \times O_{2a}/N_{2a}) - (V_g \times CO_{2g}) - 0.5(V_g \times CO_g)] \times (2/379) \text{ lb.} \qquad (5.7)$$

Total fuel consumed = $W_F = W_c + W_H$ lb (5.8)

Volume of sand burned = $V_b = (\pi \times D^2/4) \times L$ (5.9)

Pounds of fuel consumed per cu.ft. of sand burned = W = (WF/Vb) (5.10)

Pounds of fuel consumed per ac-ft. of reservoir burned = $W_R = (43560\ W) \times (1-\phi_R)/(1-\phi_P)$ (5.11)

Where ϕ_R = porosity of the reservoir and ϕ_P = porosity of the sand pack.

The next step is to compute the total air injected and the volume of the reservoir sand burned.

Total air injection V_a = (N_2 injected + O_2 injected) scf

$$V_a = [V_g \times N_{2g} + (V_g \times N_{2g})\ (O_{2a}/N_{2a})] \text{ scf} \qquad (5.12)$$

The air injected per pound of fuel consumed = V_a/W_F (scf/lb) (5.13)

Air injected per cubic feet of reservoir sand burned = $A = (V_a/W_F) \times (W) \times [(1-\phi_R)/(1-\phi_P)]$

$$= (4\, V_a\, F)/(\pi D^2 L) \text{ (scf/cu.ft.)} \qquad (5.14)$$

Where $F = (1-\phi_R)/(1-\phi_P)$

Assuming an areal sweep efficiency of 62.6%, the air required in MMscf per acre-ft in the 5-spot pattern is computed as:

$$\text{Air injected per ac-ft of pattern} = (0.626 \times 43560 \times A \times 10^6) \text{ (MMscf/ac-ft)} \qquad (5.15)$$

The total air requirement for a given pattern V_T = (Air injected/ac-ft) ×
(Volume of sand burned in ac-ft) (5.16)

Let 'u' be air flux or the volume of air required per square foot of burning front per day

$$u = Av \text{ (scf/day-sq ft.)} \qquad (5.17)$$

Where 'v' = burning front advancement rate, ft/d and 'A' = air injected / cu.ft. of reservoir sand burned.

In a combustion project the air flux will be different from point-to-point along the combustion front, depending upon the relative location of the injector and the producers and the position of the combustion front. If the air flux at a location is insufficient to support combustion, the fire goes out and results in limited areal sweep. Nelson and McNeil (1961) for calculation purpose introduced a dimensional flow term (i_D) to calculate the air injection rate necessary to achieve a given sweep efficiency of the combustion zone.

This dimensional flow term, iD is calculated as:

$$i_D = i_a/(u_{min}\ ah \qquad (5.18)$$

where i_a = maximum pattern air injection rate, scf/day

u_{min} = minimum air flux required to sustain combustion, scf/day-sq.ft. of burning front area.

Nelson and McNeil presented the following table showing sweep efficiencies corresponding to various values of i_D.

TABLE 5.3 — Relation between Dimensional Flow Term i_D and Areal Sweep Efficiency

i_D	**Areal Sweep Efficiency at Breakthrough**
3.39	50.0%
4.77	55.0%
6.06	57.5%
∞	62.6%

Although the total air requirement for the 5–spot pattern was calculated previously on the basis of 62.6% sweep efficiency, it can be seen from the above table that infinitely high air rates would be required to achieve this areal sweep efficiency in practice. Nelson and McNeil suggest that in the air rate calculation one should use a sweep efficiency that will give a reasonable value of i_D.

In the design method proposed by Nelson and McNeil, the air injection rate depends on the desired rate of advance of the burning front. They found a satisfactory burning rate of 0.125–0.5 ft/day. In the proposed method, a maximum air rate based on the minimum burning rate of 0.125 ft/day and55% areal sweep (i_D = 4.77) is first determined.

$$\text{Air rate (scf/day)} = i_a = i_D u_{min} ah = 4.77\ A\ (0.125)\ ah \qquad (5.19)$$

Then a time schedule is chosen so that the air rate would increase gradually to the maximum rate, hold at this rate for a definite period, and then reduce gradually to zero (Figure 5.11).

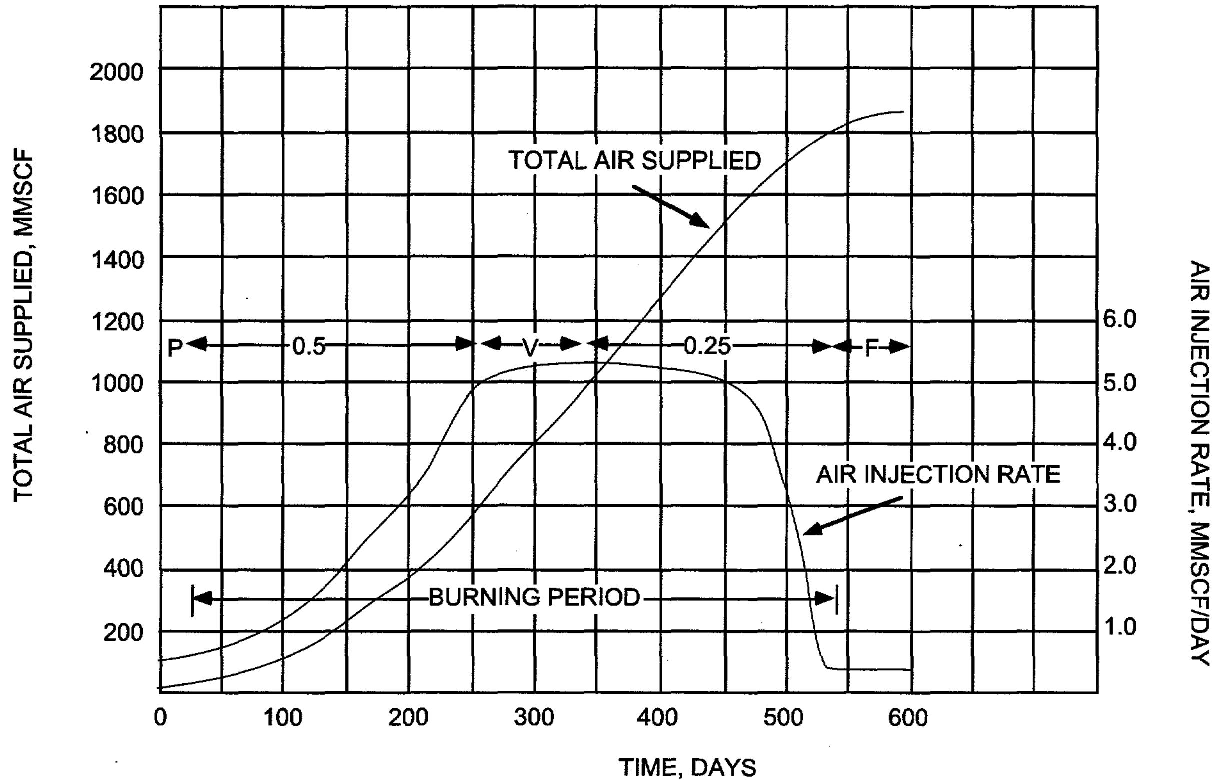


FIGURE 5.11 — Air Requirements for Inverted Developed 5-Acre, 5-Spot Well Pattern with 30 ft. Formation Thickness

Field tests indicate that the movement of the burning front during the early stages of burning is essentially radial and about 10% of the pattern area will have been swept during the radial displacement of the front. Nelson and McNeil contend that if the front velocity (v_1) in the increasing rate period exceeds the minimum burning velocity by a factor of three or greater, the constant maximum injection rate will be reached before 10% of the pattern area has been swept regardless of the pattern size.

If r_1 is the radial distance in feet at the end of the increasing air injection rate period, and r_f is the radial distance to the burning front ($r_f \geq r_1$), the air flux rate in scf/day during the radial phase of the displacement, can be calculated from the following equation:

$$i_a = 2\pi r_f h A v_1 \qquad (5.20)$$

Air injection rates, for a range of values of rf are calculated until the maximum air rate specified by Equation (5.19) has been reached. Beyond this point, the air flux rates will began to decline, and the burning front advance rate will be slowed.

The time in days (t_1) required for the increasing rate period of the operation may be calculated as follows:

$$t_1 = r_1/v_1 = i_a/2\pi hAv_1^2 \tag{5.21}$$

The volume (V_1) of air injected during this period in MMscf is:

$$V_1 = 0.5(t_1 i_a) \tag{5.22}$$

Next during the final stage of the burning operation decreasing air injection rate will be used and the air rate is decreased linearly from the maximum rate i_a to zero. For the purpose of balancing a burning operation, Nelson and McNeil assumed that the volume of air V_3 injected over time, t_3 during the final stage of burning is identical to the volume injected during the increasing air injection rate period. Thus, by this assumption:

$$V_3 = V_1 \text{ and } t_3 = t_1 \tag{5.23}$$

If V_T is total volume of air injected to burn the 5–spot pattern in the field (Equation 5.16), then the volume of air V_2 injected at the constant (maximum) rate period will be

$$V_2 = V_T - V_1 - V_3 \text{ MMscf} \tag{5.24}$$

The time in days required for this part of the operation is

$$t_2 = V_2 \times 10^6 / i_a \tag{5.25}$$

The total time required in days for the entire burning operation is

$$t_t = t_1 + t_2 + t_3 \qquad (5.26)$$

In the design of an in-situ combustion, knowledge of air injection pressure is needed to size the compression facilities. The most reliable method of determining the required air injection pressure is to run actual air injection tests in the field. However, this is not possible or practical in most situations. For preliminary appraisals of in-situ combustion projects, Nelson and McNeil recommend the use of following expression to estimate injection pressure. This expression was developed modifying the steady state radial flow equation for a compressible fluid in a developed 5–spot pattern.

$$P_{iw}^2 = P_w^2 + \left(\frac{i_a \mu_a T_f}{0.703 k_g h}\right) \times \left[1n \frac{a^2}{r_w v_1 t_1} - 1.238\right] \qquad (5.27)$$

Where:

P_{iw} = injection well bottom hole pressure, psia

P_w = production well bottom hole pressure, psia

i_a = maximum air injection rate, scf/day

μ_a = viscosity of air, centipoise

T_f = formation temperature, °R

a = well spacing, ft.

t_1 = time to reach maximum air rate, days

k_g = effective permeability to air, md

h = formation thickness, ft.

r_w = production well radius, ft.

In Equation (5.27) P_w is usually low and can safely assumed to be atmospheric, because the producer will be kept drained at the time of maximum injection pressure. The effective permeability $_{kg}$ is usually not known and must be estimated. If no information is available on which to estimate k_g, Nelson and McNeil recommend that a value of 5% of the specific permeability be used. T_f can be measured in the field and μa can be estimated from correlation at this temperature. Since additional pressure beyond that indicated by Equation (5.27) will occur in the injection system and in the injection well, the compressor must be sized for pressure higher than indicated by eqn. 5.27.

The oil production mechanism in a combustion process is complex and the total amount of oil displaced by the combustion front is dependent on the volumetric sweep of the front. Field data indicate that in addition to the oil displaced by the front to the producer, considerable volume of oil are also produced as a result of depletion of unburned but heated regions adjacent to the burned zone. The volumetric efficiency is a product of invasion efficiency E_I and areal sweepo efficiency E_A.

$$\text{i.e., } Ev = E_I \times E_A \qquad (5.28)$$

If the areal and invasion efficiencies are assumed to be in the range of 55%, the overall efficiency is calculated as 30%.

Assuming the specific gravity of the oil consumed as fuel (coke) as 1.0 (10°API oil), Nelson and McNeil gave the following expression to calculate the oil displaced per acre-feet of the reservoir burned:

$$N_1 = 43560\left(\frac{S_o\varphi_R}{5.615} - \frac{WF}{350}\right)\frac{bbl}{ac-ft.} \qquad (5.29)$$

where:

S_o = oil saturation in % pore space

350 = density of 10° API oil

Post burned cores taken from many combustion projects indicate that in heavy oil reservoirs, more than half of the oil in the regions not contacted by the fire front may have been produced by a combination of gravity drainage and hot gas drive. Nelson and McNeil indicate that for preliminary design purposes, 40% of the produced oil can be assumed to have come from the unburned region of the reservoir. The equation for the oil displaced from the unburned region of the reservoir is:

$$N_2 = 43560\left(\frac{0.4S_o\phi_R}{5.615}\right)\frac{bbl}{ac-ft.} \tag{5.30}$$

The total oil recovery N_3 from the burned and unburned region is given by:

$$N_3 = E_v \times N_1 + (1-E_v) \times N_2 \tag{5.31}$$

The overall recovery efficiency is:

$$E_R = \frac{N_3 \times 5.615}{43560 \times S_o \times \phi_R} \tag{5.32}$$

The total water production due to in-situ combustion is calculated as the sum of combustion water plus the water originally present in the burned zone. This assumes that the water contained in the unburned region is immobile and remains constant through out the burning process. Then the total water produced in barrels per acre-feet of reservoir rock in the well pattern is calculated as:

$$W_p = \frac{43560\ E_v}{100}\left(\frac{4W_w F}{350\pi\ D^2 L} + \frac{S_w\phi_R}{5.615}\right) \tag{5.33}$$

In-situ combustion field tests indicates that though the production-rate history vary widely from one reservoir to another, the oil production rates are low during the initial air injection phase and increases rapidly as the heat of combustion approaches the producer. The peak production generally occurs during the first half of the operating schedule. In the absence of specific information, for the purpose of project design the oil production rate can be assumed to be proportional to air injection rate. This implies a constant injected air to produced oil ratio and the oil producing rate curve will have the same shape as the air injection rate curve.

The daily oil production N_p is calculated by multiplying the average daily air injection rate by the barrels of oil produced per MMscf of air injected.

Thus,

$$N_p = \left[\frac{E_v N_1}{100} + \frac{(100 - E_v)N_2}{100}\right] \times \frac{10^6}{43560 \times 0.626 \times A}\,\frac{\text{bbl}}{MMscf} \tag{5.34}$$

If the initial water saturation is immobile, no water will be produced during the initial air injection phase. As the combustion front progresses toward the producer, water production will increase due to the formation of a water bank. The water production rate usually will accelerate once the flush production from the oil bank ceases. To facilitate the estimation of water production rate, Nelson and McNeil recommend that the produced water oil ratio to remain constant. This implies that the barrels of water produced per MMscf of air injected will be a constant:

$$W'_p = \frac{E_v \times 10^6}{0.626A}\left[\frac{4W_w F}{(350)\pi D^2 L} + \frac{S_w \phi_R}{5.615}\right]\frac{bbl.\ \text{water}}{MMscf\ \text{air}} \tag{5.35}$$

In the following an example problem is presented to illustrate Nelson and McNeil's design procedure.

Using the data given (Table 5.4), calculate the following:

1. The total air requirement per acre-ft. for a 5–spot pattern assuming an areal sweep efficiency of 62.6%.
2. The total air needed for a 5–spot pattern.
3. The air flux for a burning-front advance rate of 0.125 ft./day.
4. The maximum air rate for the field pattern at a frontal advance rate of 0.5 ft./day.
5. The time required to reach the maximum air rate.
6. The volume of air injected to reach the maximum air rate.
7. The volume of air injected during the constant-rate period.
8. The duration of the constant rate period and the total time for the entire operation.
9. The maximum air-injection pressure required (let $\mu_{air} = 0.0186$ cp).

10. The compressor-plant horsepower required for an operating sequence of four patterns assuming three stages of compression and a compressor horsepower requirement of 80 million scf/day/stage.
11. The oil displaced from the burned reservoir, the oil displaced from the unburned reservoir, and the total oil recovery and over-all oil-recovery efficiency.
12. The oil recovered per million scf of air injected.
13. The maximum oil production rate.

Solution

Laboratory Data: The combustion tube experiments showed that the fuel consumes per acre-ft. of reservoir burned was 87,120 lb/acre-ft. and the air requirement was 388 scf/ft.^{3}.

TABLE 5.4 — Field Data

Pattern area	5 ac
Distance between injection and production wells	330 ft
Formation thickness	30 ft
Formation temperature	85°F
Production bottomhole pressure	14.7 psia
Porosity	35%
Specific permeability	500 md
Oil saturation	55%
Water saturation	40%
Volumetric sweep efficiency	30%
Production well radius	0.276 ft

Solution

The laboratory data gives the fuel burned as 87,120 lb/acre-ft. For on oil gravity of 1.0, the fuel burned becomes:

$$\frac{87{,}120\text{lbs/acre - ft}}{350\text{lbs/B}} = 248.91 \text{ B/acre - ft}$$

Each item of the method is calculated below.

1. The air requirement for the laboratory experiment was 388 scf/ft.[3]. This can be converted to acre-ft. as

$$10^{-6}\frac{\text{mmscf}}{\text{scf}}\left(388\frac{\text{scf}}{\text{ft}^3}\right)\left(43{,}560\frac{\text{ft}^2}{\text{acre}}\right) = 16.9\frac{\text{mmscf}}{\text{acre - ft}}$$

For a 5–spot pattern with areal sweep efficiency of 62.6%, the total air requirement is

$$\left(16.9\frac{\text{mmscf}}{\text{acre - ft}}\right)(0.626) = 10.58\frac{\text{mmscf}}{\text{acre - ft}}$$

2. The total air needed for the 5–spot pattern is thus

$$\text{Total Air} = \left(388\frac{\text{scf}}{\text{ft}^3}\right)(0.626)(\text{Volume of 5 - spot})$$

$$\text{Volume of 5 - spot} = 2L^2h$$

where L = distance between injector and producer, and h = formation thickness.

$$\text{Total Air} = \left(388\frac{\text{scf}}{\text{ft}^3}\right)(0.626)(2)(330)^2(30)10^{-6}\frac{\text{mmscf}}{\text{scf}} = 1{,}587 \text{ mmscf}$$

3. The air flux for a burning front advance rate of 0.125 ft./day is

$$\text{Air Flux} = \left(388\frac{\text{scf}}{\text{ft}^3}\right)\left(0.125\frac{\text{ft}}{\text{D}}\right) = 48.5\frac{\text{scf}}{\text{ft}^2\text{D}}$$

4. The maximum air rate is approximated by the relation

$$\text{Maximum Air Rate} = (\text{Air Flux})(4.77)(L)(h) \times 10^{-6}$$

$$= (48.5)(4.77)(330)(30)10^{-6}$$

$$= 2.29 \text{ million scf/day}$$

5. The time required to reach the maximum air rate is

$$\text{Time} = \frac{2.29 \times 10^{6} \frac{\text{scf}}{\text{D}}}{2\pi h \left(388 \frac{\text{scf}}{\text{ft}^3}\right)(v_1)^2}$$

where v_1 = maximum frontal advance rate of 0.5 ft./day.

$$t_1 = \text{Time} = \frac{2.29 \times 10^{6} \frac{\text{scf}}{\text{D}}}{2\pi(30)(388)(0.5)^2} = 125.3 \text{ days}$$

6. The volume of air injected for this period is

$$V_1 = \frac{(125.3 \text{ days})\left(2.29 \frac{\text{mmscf}}{\text{D}}\right)}{2}$$

V_1 = 143.4 million scf

7. The volume of air injected during the constant rate period is (See Figure 5.12)

$V_2 = V_{TOT} - 2(143.4)$

$V_2 = 1587 - 2(143.4)$

V_2 = 1300 million scf

8. The duration of the constant rate period is

$$t_2 = \frac{1300\text{mmscf}}{2.29\frac{\text{mmscf}}{\text{D}}} = 567.75 \text{ days}$$

The total time for the entire burning operation is

$t_{TOT} = t_2 + 2t_1$

$t_{TOT} = 567.75 + 2(125.3)$

$t_{TOT} = 818.35$ days = 2.24 years

9. The maximum air injection pressure is given by

$$P_{iw}{}^2 + P_w{}^2 + \left(q_a\mu_a\, T_f/0.703k_g h\right) \bullet \left[ln\left(a^2/r_w v_1 t_1\right) - 1.238\right]$$

where

$$P_w = 14.7 \text{ psia}$$

$$q_a = 2.29\text{scf/D}$$

$$\mu_a = 0.0186 \text{ cp}$$

$$T_f = 85°F + 460 = 545°R$$

$$k_g = 5\%(\text{ksp}) = (0.05)(500) = 24\text{md}$$

$$h = 30 \text{ ft}$$

$$a = 330 \text{ ft}$$

$$r_x = 0.276 \text{ ft}$$

$$v_1 = 0.5 \text{ ft/D}$$

$$t = 125.3\text{days}$$

$$P_{iw}^2 = (14.7)^2 + \frac{(2.29)(10^6)(0.0186)(545)}{(0.703)(25)(30)}$$

$$\left\{ ln\left[\frac{(330)^2}{(0.276)(0.5)(125.3)}\right] - 1.238 \right\}$$

$$P_{iw}^2 = 216.1 + 4.403 \times 10^4 \left[ln\left(6.29 \times 10^3 - 1.238\right)\right]$$

$$P_{iw}^2 = 216.1 + 4.403 \times 10^4 (7.51)$$

$$P_{iw}^2 = 216.1 + 3.307 \times 10^5 = 3.309 \times 10^5$$

$$P_{iw} = 575 \text{ psia}$$

10. The compressor horsepower requirement for a four pattern sequence is given by

$$\text{bhp} = (4)\left(2.29\frac{\text{mmscf}}{\text{D}}\right)(3 \text{ stages})\left(88\frac{\text{bhp}}{\text{mmscf, stage}}\right)^*$$

$$\text{bhp} = 2418.2 \text{ bhp}$$

This is the horsepower required per stage for an 85% overall efficiency and a 5 psi pressure drop across the interstage coolers.

11. The oil displaced per acre-ft. burned is given by

$$N_1 = \left(43{,}560\frac{\text{ft}^2}{\text{acre}}\right)\left[\left(S_o\phi/5.61\times10^4\right) - \frac{WF}{350}\right]$$

$$N_1 = (43{,}560)\left[\frac{(55)(35)}{5.61\times10^4} - \frac{2.0}{350}\right] = 1.246\times10^3\,\frac{\text{B}}{\text{acre - ft}}$$

where S_o = oil saturation, ϕ = porosity, and WF = fuel consumed per ft.³.

$$WF = \left(87{,}120\frac{\text{lb}}{\text{acre}-\text{ft}}\right)\left(\frac{1}{43{,}560\text{ft}^2/\text{acre}}\right) = 2.0\text{lb}/\text{ft}^3$$

The oil displaced from the unburned reservoir is

$$N_2 = (43{,}560)\left(\frac{S_o\phi}{5.61\times10^4}E_{avg}\right)$$

where E_{avg} = average efficiency of recovery from the unburned portion of reservoir. Let E_{avg} = 40%. Then,

$$N_2 = \frac{43{,}560(55)(35)(0.4)}{5.61\times10^4} = 598.0\ \text{B/acre - ft}$$

The total oil recovery is

$$N_3 = \frac{E_v N_1}{100} + \frac{(100 - E_v)N_2}{100}$$

where E_v = volumetric sweep efficiency.

Let $E_v = 30\%$. Then,

$$N_3 = \frac{30}{100}\left(1.246 \times 10^3\right) + \frac{(100-30)}{100}(598)$$

$$N_3 = 792.3 \text{ B/acre-ft}$$

The overall recovery efficiency is given by

$$E_R = \frac{N_3\left(5.61 \times 10^6\right)}{43{,}560 S_o \phi_R}$$

$$= \frac{(792.3 \text{ B/acre-ft})\left(5.61 \times 10^6\right)}{(43.560)(55)(35)}$$

$$E_R = 53\%$$

12. The oil recovered per million scf of air injected is

$$\frac{\text{oil}}{\text{air}} = \frac{792.3 \text{ B/acre-ft}}{10.58 \text{ mmscf/acre-ft}} = 74.9 \text{ B/mmscf}$$

13. The maximum oil production rate is

$$N_3 = \left(74.9 \frac{\text{B}}{\text{mmscf}}\right)\left(2.29 \frac{\text{mmscf}}{\text{D}}\right) = 171.5 \text{ B/D}$$

In-Situ Combustion: Oil — Volume Burned Method

Gates and Ramey (1980) presented an engineering method for calculating air-oil ratios and oil recovery as a function of volume of reservoir burned. Their oil recovery-volume burned method is based on laboratory data and pilot and field data from Mobil's South Belridge project. The method provides a means for making engineering and economic evaluations for the design and monitoring of ISC projects. The reliability of the method is presently limited to reservoirs with characteristics similar to South Belridge; that is, heavy oil (13°API), high permeability (3,000 md), high porosity (0.34%), and high oil content (1,700 bbl/ac-ft.).

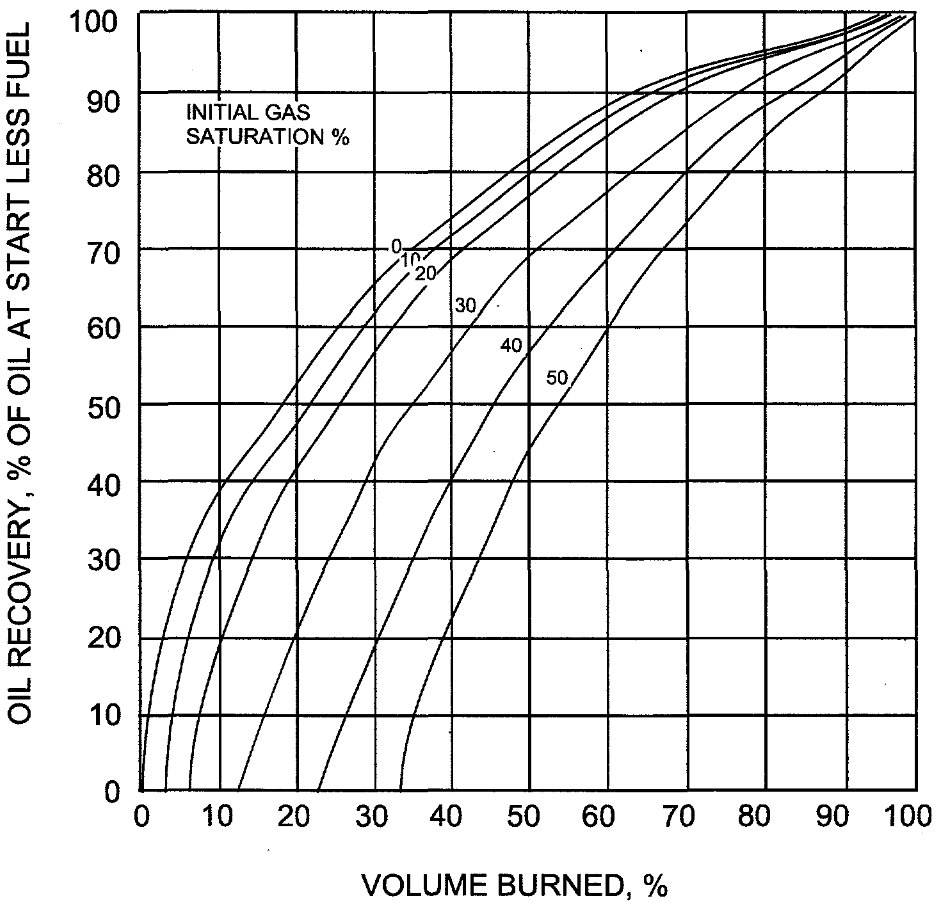


FIGURE 5.12 — Estimated Oil Recovery vs Volume Burned

The basis for the design method is the observed relationship between oil displaced and the bulk reservoir swept by the burning front. (Figure 5.12) If the initial oil and the fuel per unit volume burned remained constant, the relationship between displaced oil and volume burned would be linear.

In actual cases, the oil recovered is greater than predicted because of other recovery mechanisms (e.g., hot water drive, steam drive, hot gas drive, miscible phase displacement, or expansion and gravity drainage) acting on the oil ahead of the burning front. Gates and Ramey (1980) showed that several factors influenced the oil recovery–volume burned relationship, including initial oil and gas and fuel concentration. The Gates and Ramey method is discussed in much more detail in the following section. Here, the salient features of this design methodology is summarized.

The fuel concentration is the oil which remains and is burned as the burning front progresses. It depends upon the oil and formation characteristics and the burning conditions. The fuel concentration is the largest factor by far in determining the air requirement. Gates and Ramey (1980) present five separate approaches to determine the fuel concentration. The fuel concentration normally increases as oil gravity decreases. Hence for low gravitates, percent oil recovery is reduced and the air required is increased. Often, however, this is more than offset by the high oil content of heavy oil reservoirs. The cumulative air-oil ratio for the Gates and Ramey method is less than required for pure frontal displacement.

When the leading edge of the burning front arrives at the producing wells, excess air which has bypassed part of the burning front will be produced. Excess air may be controlled by judicious production-well operating techniques. For example, production wells producing gases with substantial oxygen concentration may be shut in.

Use of the method developed by Gates and Ramey requires the following data.

- Initial oil-in-place.
- Initial gas saturation.
- Fuel concentration, from laboratory data.
- Air required to burn the fuel, from laboratory experiment.
- Oxygen utilization, from laboratory experiment.

These data, together with the various graphical correlations (developed on the basis of field operational data) presented by Gates and Ramey (1980) can be used to estimate the air-oil ratio, instantaneous oil rate, and cumulative oil production. These are fully discussed in the following.

Methodology

To determine the amount of displaced oil, initial oil and gas saturations must be determined using conventional well logging, coring, material balance or tracer techniques. The displaced oil is the initial oil minus the final oil minus the burned oil. Fuel concentration (C_f) is another important parameter in evaluating an in-situ combustion project. Fluid properties, lithology of formation and operating conditions all affect the value of C_f.

Several methods can be used to estimate C_f. They are: a) coring the reservoir as the combustion progresses; b) measuring the water cut and correlating with C_f by material balance; c) averaging the value of C_f obtained from combustion tube runs with natural core; d) history-matching the combustion behavior in the field using a numerical simulation; and e) using the burning velocity/air flux correlation. In the absence of other data, engineering calculations can be made using correlations of fuel concentration vs oil gravity to determine C_f. (Alexander et al., 1962; Showalter, 1963)

To compute the cost of air compression, the value of the combustion air requirement should be determined. This can be calculated if oxygen utilization (U_t) and the volume of air needed to burn a unit weight of fuel (AFR) are known. AFR can be from the combustion chemistry. After the burning front breakthrough, more air must be injected to compensate for the air produced because of channeling. Knowing the AOR, the oil production rate can be determined if the air compressor capacity is known. The data for air requirement, fuel concentration, initial oil and gas saturations, and oxygen utilization can be combined with an oil-recovery/volume-burned correlation to make an estimate of the potential of an in-situ combustion project.

Fassihi et al. (1981) developed an algorithm based on this method and presented a set of equations to quickly estimate the oil recovery, AOR, oil rates, and economic limits of in-situ combustion projects. These equations were developed by regressing and curve fitting the oil recovery — volume burned curves. The developed equations are shown in Table 5.2. In this table the expression for the fuel concentration (fuel lay down) C_f is based on the combustion tube gas analysis. However, if the valve of C_f and air-fuel ratio (AFR) is available, they can be used independently. In the absence of other data, C_f can be estimated using Figure 5.5. (Alexander et al., 1962; Showalter, 1963)

The above set of equations can be solved readily using spreadsheet program or a programmable calculator. The cumulative and current AOR, oil recovered, and time are calculated for each burned volume.

TABLE 5.5 — Equations to Calculate In-Situ Combustion Performance (Volume Burned Method)

$$H/C=\frac{4\left[0.2658\,\mathrm{N}_2-CO_2-O_2-0.5CO\right]}{CO_2+\mathrm{CO}} \qquad (5.36)$$

$$C_f=\frac{1.209\leftrightarrow 10^{-3}q_g[CO_2+CO][12+\mathrm{H/C}]}{V_f{r_t}^2} \qquad (5.37)$$

$$AFR=\frac{479.7\,\mathrm{N}_2}{(\mathrm{CO}_2+\mathrm{CO})\left(12+H/C\right)} \qquad (5.38)$$

$$B=\frac{\mathrm{C_f}}{\rho_\mathrm{f}}\cdot\frac{43560}{350} \qquad (5.39)$$

$$R=S_{oi}-\mathrm{B} \qquad (5.40)$$

$$N_p=\frac{(N_p\,\%)(R)(A)(H)}{100} \qquad (5.41)$$

$$\text{Excel Air }\frac{0.9(N_p\,\%)-15.85}{100} \qquad (5.42)$$

$$\mathrm{ASR}=\mathrm{C_f}\,.\,\mathrm{AFR}\,(43.56) \qquad (5.43)$$

$$\mathrm{V_B}(0)=0.147143\,\mathrm{S_g}+0.010714\,\mathrm{S_g^2} \qquad (5.44)$$

$$\mathrm{X}=\frac{\mathrm{V_B}-\mathrm{V_B}(0)}{100-\mathrm{V_B}(0)} \qquad (5.45)$$

$$\text{Maximum Deviation} = \text{M.D.} = 26.82295 - 0.46787\mathrm{S_g} \qquad (5.46)$$

$$Y=\frac{\text{Deviation}}{\text{Maximum Deviation}}=6.77526\,\mathrm{X}-15.947794\,\mathrm{X}^2+16.187187\,\mathrm{X}^3-7.014659\,\mathrm{X}^4 \qquad (5.47)$$

$$\frac{\mathrm{dY}}{\mathrm{dX}}=6.775267-31.895588\,\mathrm{X}+48.561561\,\mathrm{X}^2-28.058636\,\mathrm{X}^3 \qquad (5.48)$$

$$\frac{100}{100-V_B(0)}+\frac{\text{M.D.}\qquad \mathrm{dY}}{100\text{-}V_B(0)dX} \qquad (5.49)$$

$$\text{Current AOR} = \frac{\text{ASR}}{(\text{Slope})(\text{R})} \tag{5.50}$$

$$\text{N}_{\text{p}}\,\% = 100\,\text{X} + (\text{Y})(\text{M.D.}) \tag{5.51}$$

$$N_p = \frac{(N_p\,\%)(R)(A)(H)}{100} \tag{5.52}$$

$$\text{Air Required} = \frac{(\text{ASR})(\text{A})(\text{H})\,\text{V}_{\text{B}}}{100} \tag{5.53}$$

$$\text{Cum. AOR} = \frac{\text{Air Required}}{\text{N}_{\text{p}}} \tag{5.54}$$

$$\text{Time} = \frac{\text{Air Required}}{\text{Air Injection Rate}\,(\text{q})} \tag{5.55}$$

$$\text{Excess Air} = \frac{0.9\,(\text{N}_{\text{p}}\,\%) - 15.85}{100} \tag{5.56}$$

$$\text{Total AOR} = \text{Current AOR}\,(1 + \text{Excess Air}) \tag{5.57}$$

In the above equations:

A = Pattern area, acres

AFR = Air/Fuel Ratio, Mscf/lb

ASR = Air/Sand Ratio, Mscf/ac-ft.

B = Fuel consumed, bbl/ac-ft.

C_f = Fuel concentration, lb/cu.ft. of rock

CO_2 = Carbon dioxide concentration in the produced gas (%)

CO = Carbon monoxide concentration in the produced gas (%)

Cum. AOR = Cumulative Air/Oil ratio, Mscf/bbl

Cur. AOR = Current Air/Oil ratio, Mscf/bbl

H = Thickness, ft.

H/C = Hydrogen to Carbon ratio in the fuel

N^2 = Nitrogen concentration in the produced gas (%)

N_p = Oil recovered, bbl

$N_p\%$ = Oil recovered, % of pore volume.

O_2 = Oxygen concentration in the produced gas

q = Field air injection rate, Mscf/D

q_g = Air flow rate through the combustion tube, Scf/Hr.

r_t = Combustion tube radius, ft.

R = Ultimate recovery, bbl/ft.

S_g = Gas saturation (%)

S_{oi} = Initial oil saturation, bbl/ac-ft.

V_B = Volume burned, % of bulk volume.

V_f = Combustion front velocity in the tube, ft./hr.

r_f = Fuel specific gravity

Satman — Brigham Correlations

Satman and Brigham (Satman et al., 1981; Brigham et al., 1980) correlated the injection production history from 12 dry combustion projects and presented two correlation to predict the field wide oil recovery of dry in-situ combustion process. They developed an analytical model describing the heat transfer processes and movement of the steam plateau ahead of the combustion zone. The results of laboratory combustion tube runs were used to verify the model results. The model was then applied to field data to develop correlation to predict field scale recovery of dry in-situ combustion processes. They used a combination of engineering and statistical approach (multiple linear regression analysis) to develop the correlation. The correlation work is summarized in the following.

Correlation Technique

The first step in the development of the oil recovery correlation was to plot the cumulative incremental oil production (CIOP) versus the cumulative air injected (CAI) for the 12 field wide tests as shown in Figure 5.13. Here cumulative incremental oil is only that recovery caused by the combustion process itself. In Figure 5.14, both coordinates were normalized for field size by dividing the abscissa by the oil in place at the start of combustion (OIP) and the ordinate by dividing by the original oil in place (OOIP) to yield the fractional recovery.

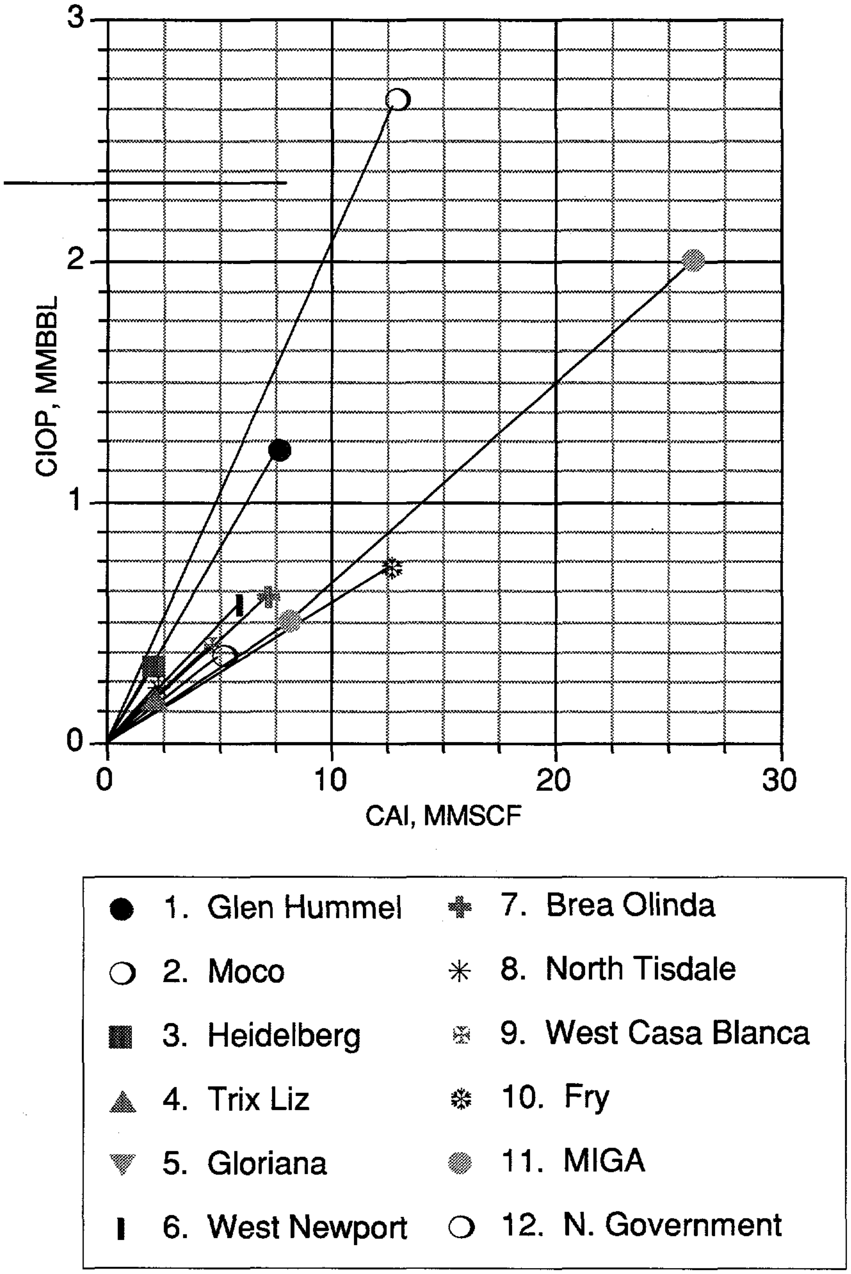


FIGURE 5.13 — Incremental Oil Production vs Cumulative Air Injection for Fieldwide Combustion Tests (After Satman et al., 1981)

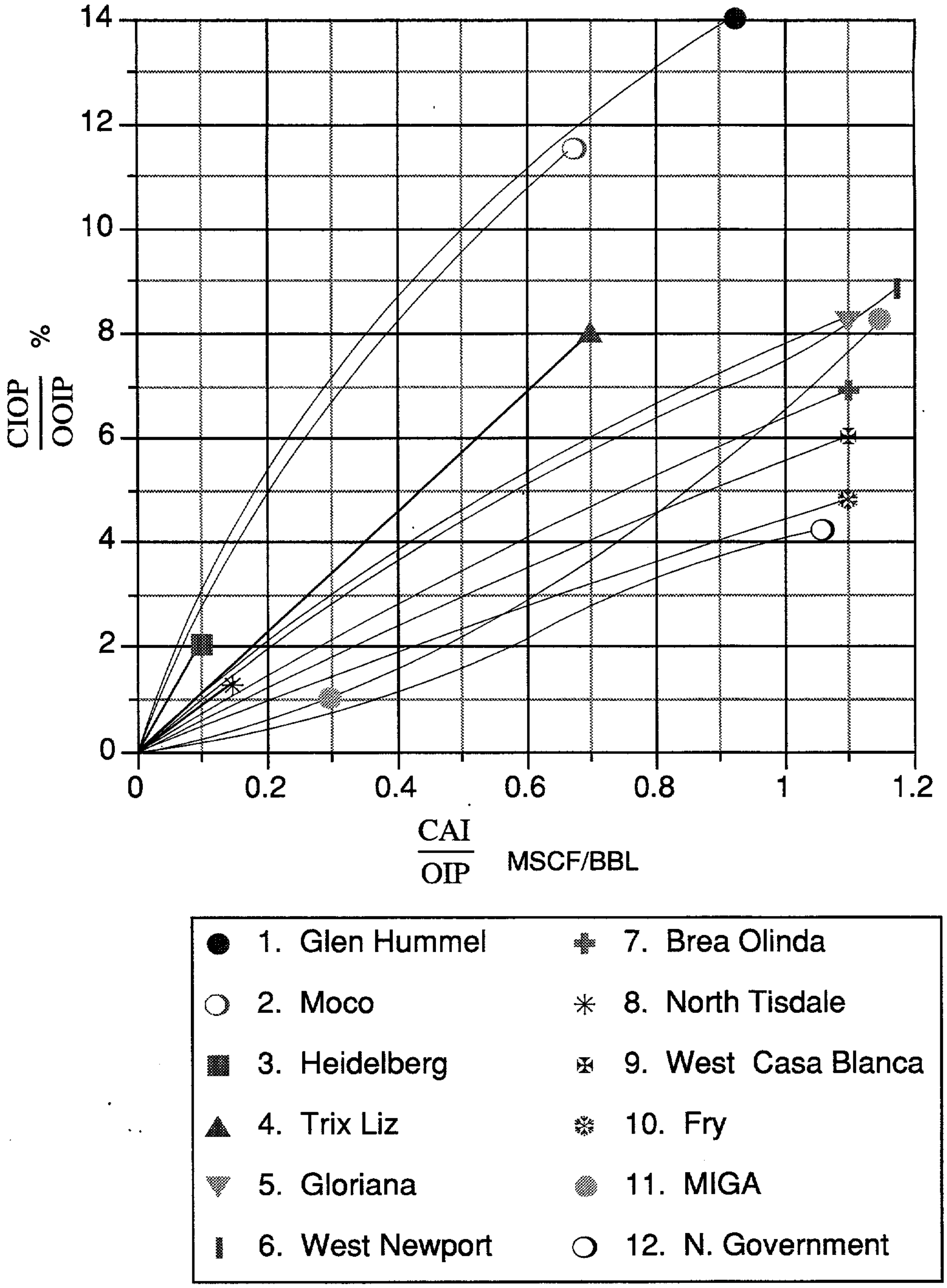


FIGURE 5.14 — Dimensionless Cumulative Incremental Oil Production vs Air Injection for Fieldwide Combustion Tests (After Satman et al., 1981)

It must be recognized that the air injection is really a measure of the amount of heat added to the reservoir, because in all combustion operations a given volume of air supplies nearly a fixed amount of heat from combustion. Since a large percentage of the heat added to the reservoir is stored in the rock and left behind by the combustion front rock volume is an important parameter in the oil recovery calculation. The rock volume is calculated as:

$$\text{Rock Volume} = \frac{OIP}{\varphi S_o}(1 - \varnothing) \tag{5.58}$$

Since, in combustion projects the oxygen utilization rarely reaches 100%, the effective air injected is less than the actual volume injected. Hence the next step in the correlation development technique is to divide the abscissa by the rock volume and multiply it by the oxygen utilization, factor (O_2U_t). Thus

$$\text{Abscissa} = \text{CAI} \left[\frac{\phi S_o}{OIP}\right]\left[\frac{O_2U_t}{1-\phi}\right] \tag{5.59}$$

Since some of the oil in place is burned and therefore not available for recovery, the ordinate must be modified to account for this fact. The ordinate is modified by adding the fuel burned (FB) to the CIOP. Thus

$$\text{Ordinate} = \frac{CIOP + FB}{OOIP} \tag{5.60}$$

The results shown in Figure 5.15, using these parameters is clear improvement.

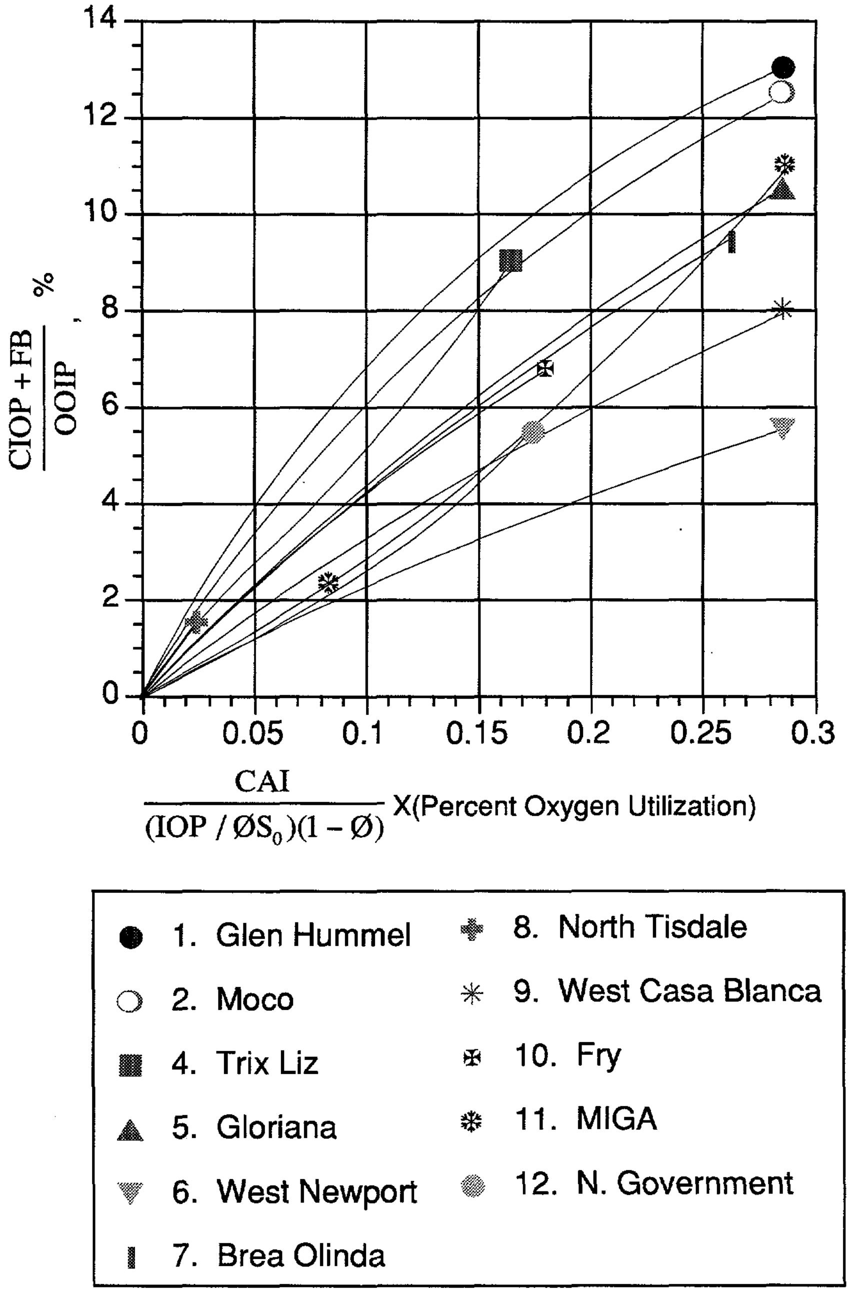


FIGURE 5.15 — Effects of Fuel Burned, Rock Volume, and Oxygen Utilization on Cumulative Incremental Oil vs Air Injection for Fieldwide Combustion Tests (After Satman et al., 1981)

The correlation of Figure 5.15 was further improved using the multiple linear regression analysis to include additional parameters expected to be of important, but not accounted for in Figure 5.15. These include, the formation thickness (h), oil saturation (SO), and oil visocity (mo). The ordinate in Figure 5.15 was correlated against the abscissa as a linear function of oil saturation, thickness, and oil viscosity to yield.

$$Y = 36.53\ (2.0\ S_0 - 0.0010\ h - 0.0082\ \mu_0)\ X \qquad (5.61)$$

$$\text{Where } Y\ (\%) = \frac{CIOP + FB}{OOIP} \times 100 \qquad (5.62)$$

$$\text{And } X\left(\frac{MSCF}{bbl}\right) = \frac{CAI(O_2U_t)}{(OIP/\phi S_0)(1-\phi)} = \left({}^{air}\!/_{oil}\,ratio\right) \qquad (5.63)$$

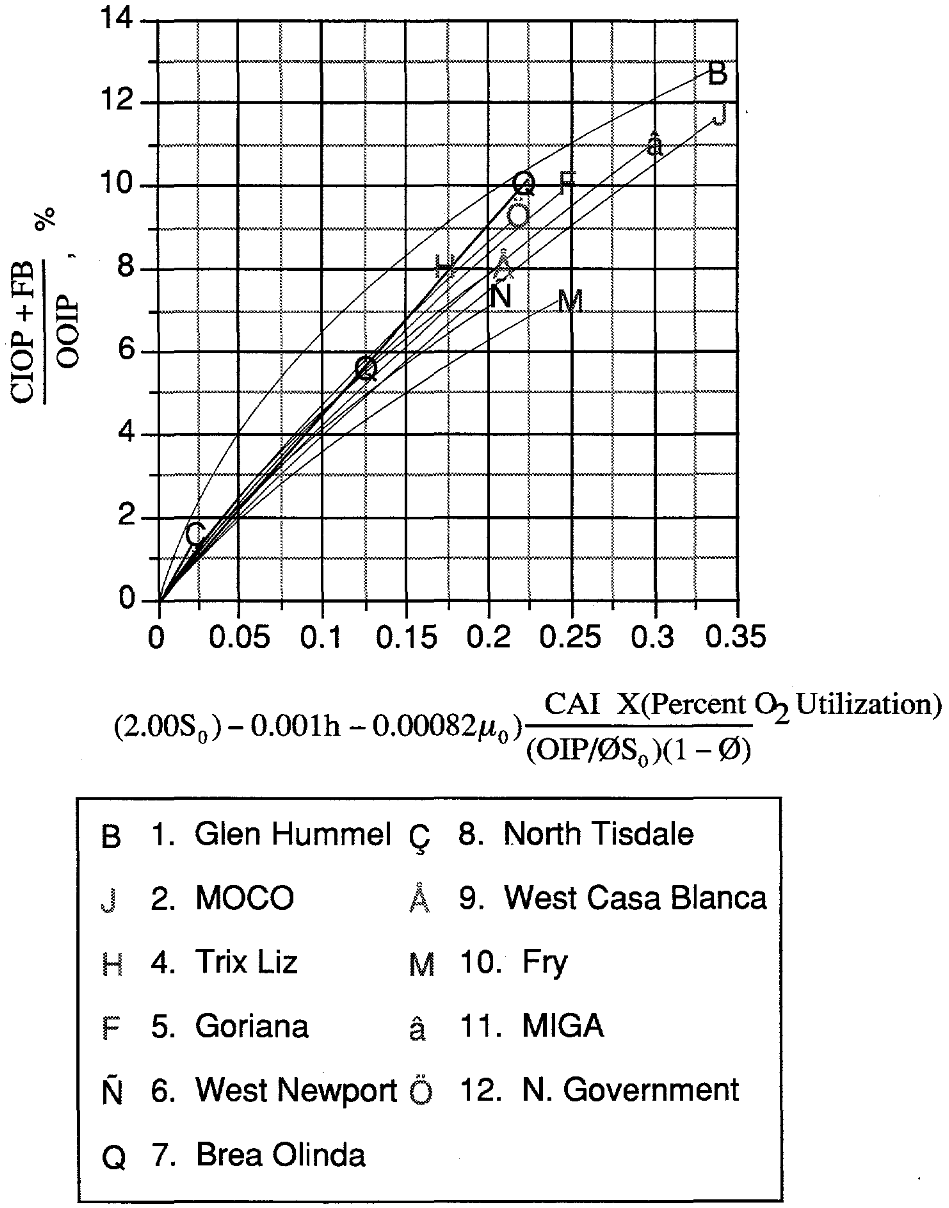


FIGURE 5.16 — Multiple Linear Regression Analysis and Data on Figure 5.16 (After Satman et al., 1981)

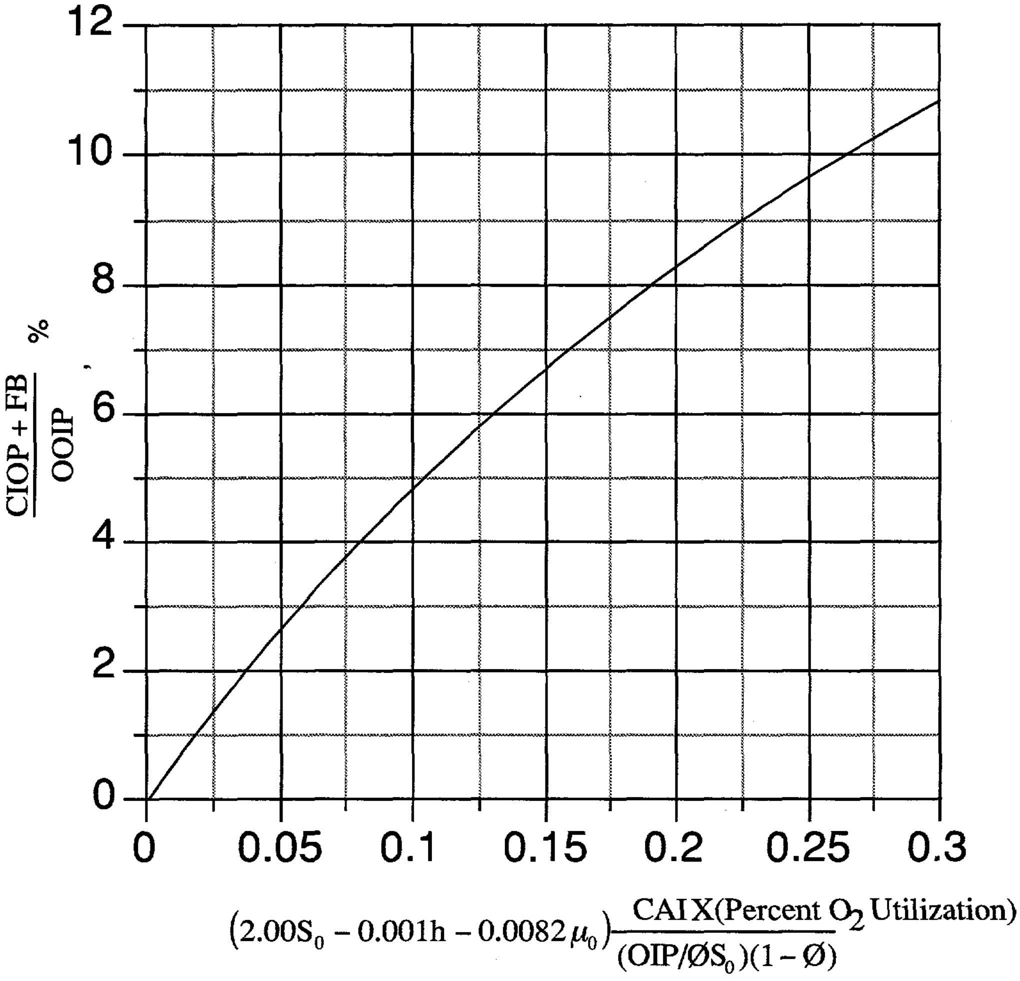


FIGURE 5.17 — First Correlation Curve for Dry In-Situ Combustion Field Cases (After Satman et al., 1981)

Figure 5.16 shows the actual values of the recovery function (Y) versus the valves on the right-hand side of the correlation and indicates considerable improvement in the resulting correlation. A smooth curve drawn through the data Figure 5.16 yields the general recovery correlation curve shown in Figure 5.17. The correlation in Fig 5.17 can be used to predicts dry combustion oil recovery as a function of air injected, given the values of S_0, h, μ_0, ϕ, oxygen utilization (O_2 U_t), and fuel content. The first four of these are readily available, while the last two are normally must be obtained from laboratory combustion tube data.

Caution must be exercised on the use of this correlation. This correlation may not be valid if any of the parameters are outside the range of data used to develop it. The ranges of oil saturation, oil viscosity, and reservoir thickness used to develop the correlation were:

$0.36 < S_0 < 0.79$

$10 < \mu_0 < 700$ cp

$4.4 < h < 150$ ft.

It should be noted that the above relationship is linear with viscosity, with a negative coefficient and thus will predict a lower recovery if the in-situ visocity is of the order of several thousand centipoises. To rectify this deficiency, Satman et al. modified the right-hand side of the equation to yield the following correlation.

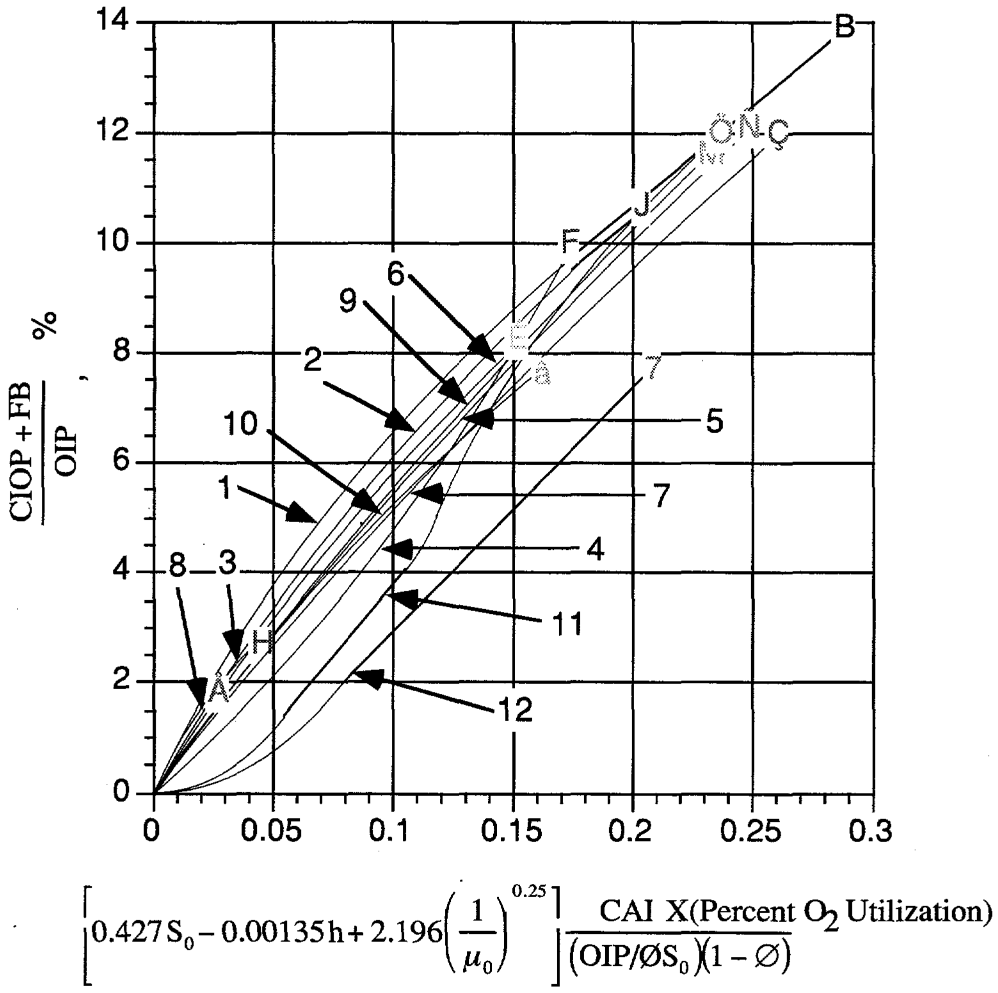
$$Y = 47.0 \left[0.427S_0 - 0.00135h + 2.196\left(\frac{1}{\mu_o}\right)^{0.25}\right]X \qquad (5.64)$$

$$Y\ (\%) = \frac{CIOP + FB}{OIP} \text{ x } 100 \qquad (5.65)$$

And

$$X \left[\frac{MSCF}{bbl}\right] = \frac{CAI \times (O_2U_t\ )}{\left(OIP/\phi S_o\right)(1-\phi)} \qquad (5.66)$$

Figure 5.18 shows the actual values of the recovery function (Y) versus the values on the right hand side of Eq. 5.64 for each of the 12 fields. Comparison of figure 5.16 shows that the second correlation (Eq. 5.64) fits the field data considerably better than does the first (Eq. 5.61).



B	1. Glen Hummel	Ç	7. Brea Olinda
J	2. Moco	Å	8. North Tisdale
H	3. Heidelberg	M	9. West Casa Blanca
F	4. Trix Liz	â	10. Fry
Ñ	5. Gloriana	Ö	11. MIGA
É	6. West Newport	7	12. N. Government

FIGURE 5.18 — Data for the Second Correlation Curve (After Satman et al., 1981)

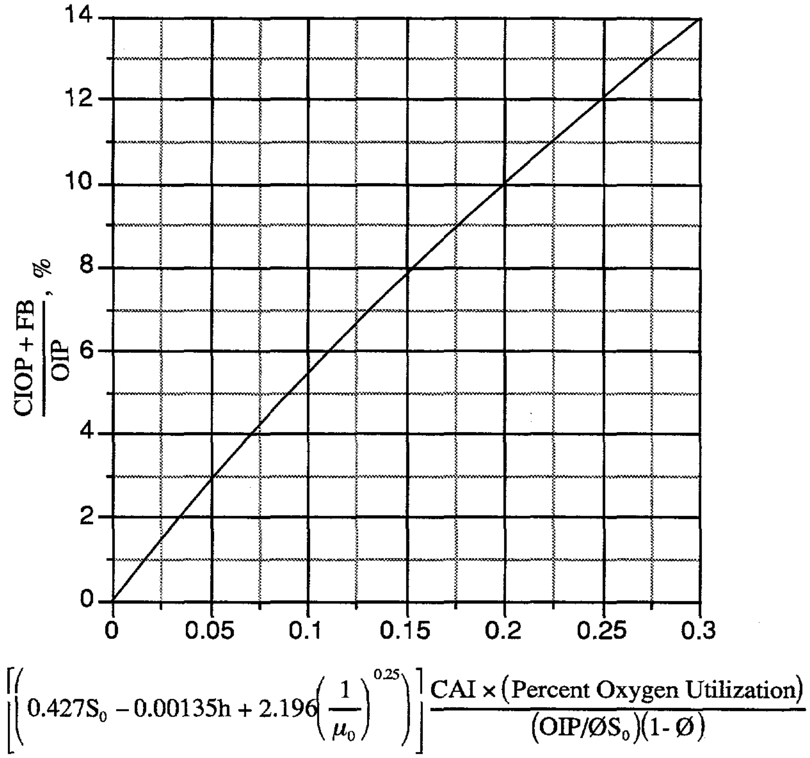


FIGURE 5.19 — Second Correlation Curve for Dry In-Situ Combustion Field Cases (After Satman et al., 1981)

Although the second correlation (Figure 5.19) is better, it is also limited in its applicability to the same ranges of parameter as the first correlation. Unlike, the first correlation, Eq. 5.64 predict oil recovery better for reservoirs containing 700 cp or greater viscosity oils. However, if the oil visocity is 10 cp or less the first correlation should be used to predict recovery. Further whenever there has been considerable recovery prior to the onset of in-situ combustion, the second correlation is preferable to the first one. In general, for most application, the use of second correlation is recommended.

Application of Correlation

To test the validity of the developed correlation, Satman et al. (1981) used the correlation to calculate the performance of eight dry in-situ combustion pilots. In Figure 5.20, the field data were plotted. This figure can be used to determine the air injected/oil produced ratios. The Figure 5.20 is then re-plotted in Figure 5.21 by taking into consideration the rock volume, fuel burned, and oxygen utilization. Finally the second correlation was used to improve the results of Figure 5.20 as shown in Figure 5.22. In general, this plot confirms the validity of the developed correlation.

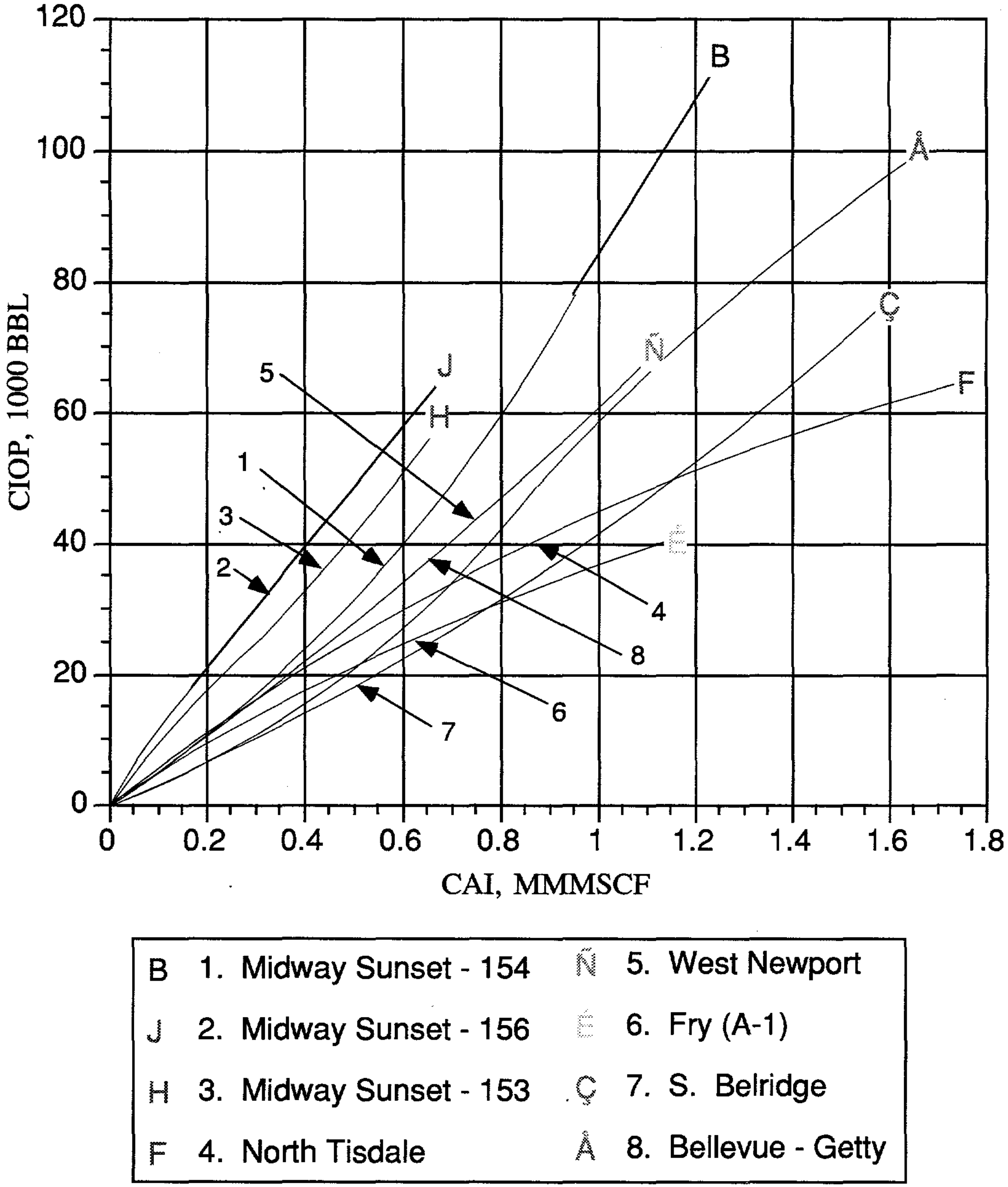


FIGURE 5.20 — Cumulative Incremental Oil Production vs Cumulative Air Injection for Pilot Dry Combustion Tests (After Satman et al., 1981)

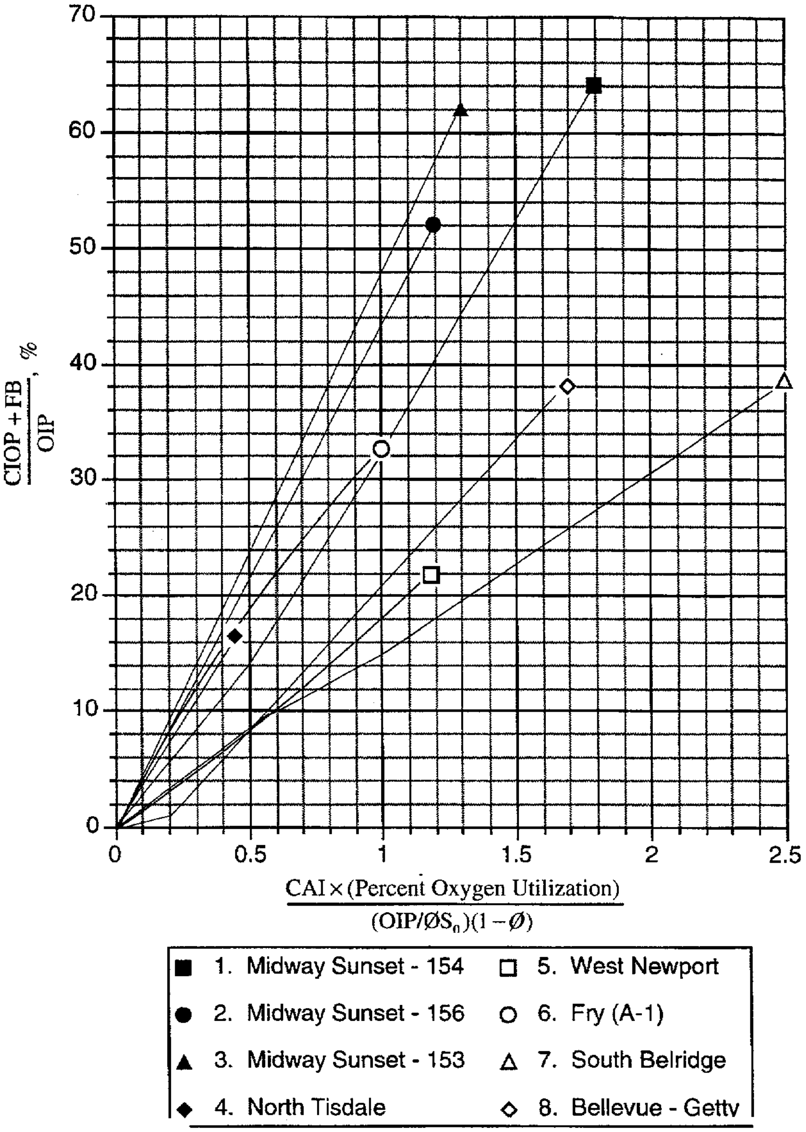


FIGURE 5.21 — Effects of Fuel, Rock Volume, and Oxygen Utilization for Pilot Dry Combustion Tests (After Satman et al., 1981)

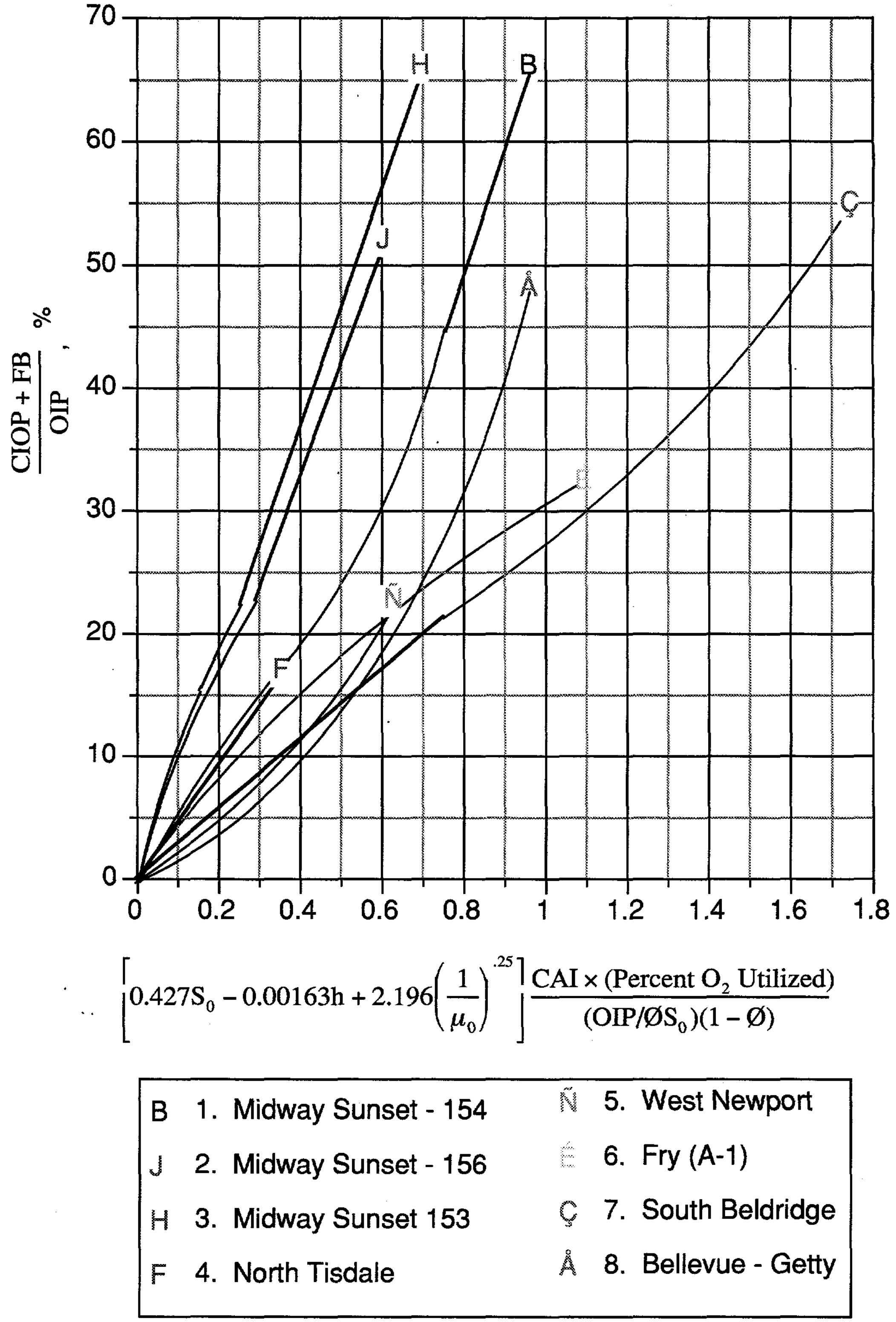


FIGURE 5.22 — Dry Combustion Field Performance Prediction Using Second Correlation

The Thermal Task Group of the National Petroleum Council (NPC) developed an In-Situ Combustion predictive model (ICPM) for use in the 1982–1984 NPC study on the In-Situ Combustion recovery potential. They adopted the Satman-Brigham correlation as the basis for the ICPM. The ICPM contains an extensive set of default equations to calculate the non-critical reservoir and fluid properties, and economic criteria. A method to predict wet combustion performance was added to ICPM by NPC based on the work of Garon and Wygal (1974). The U.S. Department of Energy (DOE) supported the NPC study and has maintained the model since the NPC study was completed. ICPM can be used to predict the recovery performance and economics of dry and wet combustion processes on field wide basis.

Details of the model development and the computer source code are presented in an U.S. DOE report (1986). This report can be obtained free by contacting the U.S. DOE'S National Petroleum Technology Office (NPTO) in Tulsa, Oklahoma. A ready to run version of the model can be downloaded from the NPTO web site, 'www.npto.doe.gov'.

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CHAPTER 6 — IN-SITU COMBUSTION CASE HISTORIES AND PERFORMANCE ANALYSIS

Since early 1950, more than 270 field tests have been conducted in the U.S. and elsewhere in the world. A large number of the field tests were conducted in reservoir situations that were not suited to fireflooding and therefore the results reflect only where the method should not be attempted. Oil industry economics have changed considerably during the period in which the field tests were conducted so results that indicated an economic failure at one point in time might have considerable merit now. However, all costs have increased along with the price of oil, and the availability of fuel has changed considerably, which makes it necessary to make a complete reevaluation of each prospect.

In the following five firefloods will be reviewed in detail to present the latitude to which this method has been used, from the very shallow low pressure reservoir of the General Crude, New Port Beach, California fireflood to Gulf's deep Heidelberg Cotton Valley Air Injection Pressure Maintenance Project.

Miga Fireflood

In 1964, Mene Grande Oil Company started a fireflood in the Miga P_{2-3} Sand reservoir. (Terwilliger et al., 1974). This test had been preceded by two small volume fireflood tests in the nearby Melones area.

There is a tremendous volume of heavy oil at moderate depths (2,000–4,000 ft.) in the south end of the Eastern Venezuela tertiary basin. Development of these reservoirs was possible because a supply of lighter gravity blend oil was available from nearby fields. However, the recovery from the reservoirs containing 10–15°API oils was very low. Solution gas drive recovery was of the order of 5% of the oil-in-place, and because of the poor mobility ratio between water and the very viscous oil, water drive recoveries were not much better and in some cases were even worse. Even though the industry experience with fireflooding was rather limited in 1958, it appeared that this method could be used to increase the recovery from the Eastern Venezuela heavy oil reservoirs from a few percent to more than half of the oil-in-place.

The Miga fireflood was designed to furnish basic data on the applicability of the fireflooding process to these heavy oil reservoirs. Although the reservoir oil viscosity is a few hundred centipoises, the very high permeability causes the per well productivity to be in the range of 100–300 B/D. The

Miga P_{2-3} reservoir was chosen because it was nearly depleted, was small compared to other reservoirs in the area, had only a few completions in deeper reservoirs, and was completely closed with a limited aquifer at one end. With these features it was expected that response to the fireflood would be rather rapid, and injection versus production could be closely controlled.

The test has been very successful from a technical standpoint. However, it has been economically unsuccessful because of the depressed price of heavy oil.

Table 6.1 is a summary of the reservoir properties and project performance. The porosity of 22.6% is much lower than was originally calculated for this unconsolidated sand. The early numbers were based on routine core analyses of conventional cores, and more recent values are from rubber sleeve cores and density logs that have been run in new wells. The estimated ultimate primary recovery was determined from individual well decline curves and a comparison with other similar reservoirs.

Reservoir Description

The project was performed in the Miga Field, P_{2-3} Sand, MG–517 Reservoir of Eastern Venezuela. It is one of the several P_{2-3} reservoirs scattered throughout both Miga and the neighboring Oleos Fields. The updip seal is a combination of faulting and sand thinning. The channel sand becomes tighter as it thins, therefore the 10–foot isopack is considered to be the lateral limit. The downdip limit is formed by the original oil/water contact and a fault. There may have been a very small gas cap at the updip limit of the reservoir.

TABLE 6.1 — Miga Thermal Recovery Project (Eastern Venezuela $P_{2\text{–}3}$ Sand)

• Depth		4,050 ft.
• Thickness		15–25 ft.
• Permeability		1–10 Darcys
• Porosity		22.6%
• Gravity		13° API
• Oil Viscosity		280 cp
• Temperature		146°F
• Total Oil Production		4,396,162 bbl
• Oil Production (Post Air)		3,624,383 bbl
• Oil Production by Combustion		3,236,162 bbl
• Cumulative Air Injection		39,948 MMScf
• Cumulative AOR		11,023 Scf/bbl
STOIIP 23,200,000 bbl	Oil Prod. (Prim.)	771,779 bbl

The reservoir was developed in 1958 and was soon producing 1,000 B/D. After about a year the production began to decline. An attempt was made to arrest the decline by injecting natural gas in the most updip Well MG–525, the same well that was later to be used for air injection. The production rate was hampered rather than helped by the gas injection, as inferred from the dip in production rate in 1961 and 1962. The reservoir was then shut-in while the fireflood facilities were being installed. The increase in production rate in 1964 was the combined effect of the shut-in period and the fireflood. The decline in production in late 1964 was a deliberate effort to curtail liquid production and encourage gas production.

The total oil produced by the fireflood was more than twice the estimated ultimate primary recovery. No other method of secondary or enhanced recovery would have been as successful as fireflooding in this reservoir.

Project Production Response

Air injection was begun at a rate of 9 MMScf/D and was increased to 15 MMCfd in late 1964. The rate was decreased to 9 MMScfd in 1969 when part of the air plant capacity was used to start a fireflood in another reservoir. The air-oil ratio increased for a short period of time in 1965 when oil production was being curtailed to permit equilibrium liquid saturation conditions to be established.

The early breakthrough to the producing wells indicates that oil displacement by the gas drive is practically nil. The combustion reaction moving through the reservoir is required to displace the oil. The composition of the fireflood flue gas stabilized very early, indicating complete utilization of the injected air. The composition of the gas has been very constant throughout the life of the project, indicating that there has been no deterioration of the fireflood.

In a fireflood there seems to be no one well that is typical; therefore, Well 524, which was close to the original air injection well, and Well 817, which was at the other end of the reservoir, were used as examples. The oil production at Well 524 declined from 300 BOPD to 150 BOPD before the injection point was moved to the other end of the reservoir. The decline is possibly a result of asphalt precipitation around the wellbore caused by the solvent action of the carbon dioxide from the fireflood flue gas. A rapid rise in the water production in 1970 and 1971 is a result of injecting water in the original air injection well. This was done to recover some of the heat that was left in the reservoir around the air injection well.

The gas-oil ratio was erratic at Well 524 in the early life of the fireflood. This was in part caused by the deliberate curtailment of the liquid production. However, it leveled out and was relatively constant until the injection point was changed.

The gas composition stabilized rather quickly at Well 524, even though it was 3,000 ft. from the air injection well. The carbon dioxide content exceeded 16% and was very steady, indicating that there was no oxygen bypassing the combustion front.

Well 817 was not drilled until the air compression capacity was increased and more producing capacity was required. Upon completion, its response to the fireflood was immediate. The producing rate declined slightly until the injection point was changed from a distance of 7,500 ft. away to only 2,000 ft. away.

Although Well 817 was one of the better producers, its gas-oil ratio was poorer (higher) than the average of 11,300 cu ft./bbl.

The early values of carbon dioxide exceeding the fireflood flue gas carbon dioxide was probably a result of the oil in the reservoir around the newly drilled well having a large amount of carbon dioxide in solution. When the well was put on production and the local reservoir pressure lowered, the carbon dioxide came out of solution. The nitrogen production from this well was more erratic than the average for no apparent reason.

Conclusions

Fireflooding is a technically feasible recovery process for the Miga reservoir and should be applicable to other heavy oil reserves involving similar properties.

- Has recovered 50% of the oil-in-place
- Has recovered more than twice the ultimate primary reserves.
- No bypassing or channeling of the fire occurred.
- No significant operating problems were encountered.

Cotton Valley Air Injection Project

Chevron's (formerly Gulf) Cotton Valley air injection project (West Heidelberg Field, Jasper County, Mississippi) began in December 1971, with the start of air injection into the 11,000 ft. Cotton Valley No. 5 sand. Like the Miga project, it is another example of how successful fireflooding can be when applied in a suitable reservoir.

The Cotton Valley No. 5 sand (CV5) is one of 14 sands in the Cotton Valley formation which are identifiable. Eight of the sands are productive, but only the No. 5 and No. 4 sands are of appreciable significance. Both of these sands are extensively developed and cover about 400 surface acres on the western flank of the field.

The CV5 sand occurs at an average depth of 10,850 ft. subsea. Average sand thickness is 35 ft. The trap is a monocline having a dip of about 8° from east to west. The eastern updip limit of the sand is bounded by a salt intrusion and the downdip limit by a zone of thick asphaltic oil which effectively seals the Cotton Valley formation from any active water drive.

Core analyses for the CV5 sand indicated 17.8% porosity, 60–80 md permeability and 15% interstitial water saturation. Original reservoir pressure was 5,045 psia. Reservoir fluid analyses indicated a bubblepoint pressure of 930 psia and an oil viscosity of 6 cp at the original reservoir pressure and reservoir temperature of 220°F. Oil gravity was 23°API.

As of June, 1981 (no data published beyond this date), cumulative oil production from the CV5 sand by air injection was 2.07 MMstb or 16% of the estimated 13 MMstb of oil originally in place. The oil production rate at that time for the CV5 sand was 1,100 Stb/D from eight producers compared to 60 Stb/D at the start of air injection. Peak oil production rates have been as high as 2,000 Stb/D. The air injection averages at that time was 5 MMscf/D and the cumulative air-oil ratio for the nine and a half year project was 2,660 Scf air/STB of produced oil.

Encouraged by the good response of the No. 5 sand to air injection, the project was expanded in December 1977 to include the next larger No. 4 sand. The plan called for drilling new wells in the No. 5 sand and increasing the air injection rate from 1 MMscf/D to 5 MMscf/D. The existing No. 5 sand producers would be recompleted in the next higher No. 4 sand. The No. 4 sand would then be produced by pressure maintenance by reinjecting flue gas produced from the No. 5 sand back into the No. 4 sand.

Project oil production from the No. 4 sand began in December 1977, followed by the start of flue gas injection in June 1978. In January 1980, a dual air injection well was completed to inject air separately, through isolated tubing strings, into both the No. 4 and No. 5 sands.

As of June 1981, cumulative project oil production from the No. 4 sand was 186,000 Stb or about 2% of the 12 MMstb of oil originally in place. The injection rates at that time for the No. 4 sand were 2.5 MMscf/D of flue gas and about 1 MMscf/D of air. Air injection was temporarily reduced in the No. 4 sand pending repairs on the dual air injection well. Oil production at that time from the No. 4 sand was 560 Stb/D from 5 producers. The cumulative air-oil ratio was 2,505 Scf/Stb.

The known status of the Cotton Valley air injection project is summarized in Table 6.2.

TABLE 6.2 — June 1981 Status of the Cotton Valley Air Injection Project

	CV5	CV4
Cumulative Project Oil Recovery, MMstb	2.07	0.186
Cumulative Project Recovery Factor, %	16	2
Oil Production Rate, Stb/D	1,100	560
Cumulative Air-Oil Ratio, Scf/Stb	2,662	2,505
Air Injection Rate, MMscf/D	5	1
Flue Gas Injection rate, MMscf/D	0	2.5
Number of Injection Wells	2	2
Number of Production Wells*	8	5
Average reservoir Pressure, psi	3,250	2,850
Original Oil in Place, MMstb	13	12
Estimated Reservoir Fuel Consumption, lb/ft.^{3}	1.4	1.4

* All production wells on flowing status.

West Newport Fireflood

The West Newport fireflood was started in 1958 in the center of Mobil's (at that time G.E. Kadane & Sons) (and later General Crude) Banning lease. the fireflood was essentially a series of irregular inverted 5–spot patterns. The major reservoir being burned was the "B" sand with a net thickness of about 500 ft. consisting of a highly porous and permeable oil sand with scattered shale stringers which had little continuity. Depth of the "B" sand was from 1,400–2,000 ft. and contained a 15°API crude with a viscosity of 3,700 cp at reservoir temperature. At that time there were a total of

245 producers, some of which produced from the "A" and "C" sand reservoirs. There were 35 air injectors in the "B" sand and 1 in an "A" sand pilot. Production was 4,000 BOPD with 18,000 BWPD. The "B" sand was productive over 590 acres. Original oil in place was estimated at 120,000,000 barrels. Cumulative oil production at 1–1–76 was about 40,000,000 barrels or 33%. Air injection plant capacity was about 24.0 MMscfpd with the injection rate at that time being 11.0 MMscfpd at 550 psi. The air-oil ratio (AOR) ranged from 2–4 Mcf per barrel with the ratio at that time averaging about 3 Mcf per barrel.

Producing Wells

Producing wells were completed by drilling a 9–7/8 in. hole to the top of the "B" sand where 7 in. casing was set and cemented to the surface with Class "G" cement containing 4% gel and 35% silica flour. A 6-1/8 in. hole was drilled to the base of the "B" sand and underreamed to 12 in. A 5 in. liner was set and gravel packed with no liner hanger being used. All wells were produced by beam-type pumping units. Producing rates were kept up by cyclic steaming all but "hot" wells every six months with 6,000–8,000 barrel treatments. Problems with sand production were kept to a minimum by use of the gravel packed liners. Each well was equipped with a small gas scrubber and orifice meter to measure gas flow rate and temperature from the annulus. Downhole temperature profiles and gas sampling were periodically carried out.

"Hot" wells were producing wells that were being approached by the firefront which was indicated by increasing temperatures and volumes of flue gas. When a well was about to enter the "hot" stage, the normal sucker rod string was replaced by a hollow rod string (1 in. pipe), but was pumped up the tubing in a normal manner. The hollow rod string was utilized as a conduit for a thermocouple circuit with the temperature sensing element being placed opposite the hottest section in the wellbore. The thermocouple was used to measure downhole temperature and automatically controlled a water injection system used for cooling the downhole producing string and also controlled backpressure on the annulus by restricting flue gas flow. If downhole temperature increased above 275°F, water injection was automatically started and maintained at a rate sufficient to keep temperature at or below that level. At the same time, the rate of flue gas flow was restricted to a selected "optimum" dependent on fluid production rate. In this manner, the fireflood front was slowed and diverted away from the "hot" well allowing the well to be produced much longer. This technique appeared to be successful and allowed hot wells to be produced for several years longer, substantially increasing oil recovery and reducing corrosion problems. Mobil (General Crude) believed that this technique increased sweep efficiency particularly in a reservoir of this thickness.

Injection Wells

Air injection wells were completed by drilling a 7–7/8 in. hole to the base of the "B" sand and cementing to the surface with the same high temperature cement mix used on producing wells. An interval in the bottom third of the "B" sand was jet perforated and 2–3/8 in. tubing run. Steam injection was carried for at least 24 hours and then air injection started at low rates. Ignition was spontaneous and occurred in one hour to one week. Mobil (General Crude) utilized a portable, high pressure, low volume compressor for this stage of air injection. Ignition was evidenced by a 300–500 psi injection pressure drop and sometimes was felt physically. Air injection was continued for about two months when the tubing string was replaced by plastic lined 2-3/8 in. tubing with a packer. Injection rates were very gradually increased to a preselected rate determined by pattern size, producer proximity and injection well performance. The average air injection rate at that time was about 3,120 Mcfpd per well. Mobil (General Crude) operating and engineering personnel believed strongly in using low air injection rates, particularly on start-up. Attempts at backflowing air injection wells had caused severe plugging and was not recommended.

Production Facilities

Production was gathered at a central battery where it came in at about 120°F. A reverse emulsion breaker, oil soluble wax inhibitor and defoamer were added at a freewater knockout with steam coils where the temperature was raised to about 150°F. Additional emulsion breaker was added and the fluid went through two large horizontal heater-treaters which raised the temperature to 215°F. Fluid production then went to settling tanks for retention time and oil was split off to sales storage. Water was sent to a nearby sewage plant for disposal. This plant furnished Mobil (General Crude) with a volume of 670 BTU/Mcf methane gas of organic origin sufficient to fire one of the treating plant steam generators.

Emulsion problems had been very severe in this project but were now being satisfactorily handled. Best results were obtained from Magna Chemicals Products such as EX–257, MEP–1, etc.

Produced gas was removed and sent to the incinerators for disposal. This gas averaged 6% methane or 60–80 BTU/cu ft. and had a maximum of about 170 BTU/cu ft. It was enriched with purchased gas as necessary to cause combustion to take place at 2100°F with the flue gas being stacked at about 275°F. The heat generated by this process was scavenged by a radiant heat section and generated steam for producing operations. Operation of the incinerators had been satisfactory from an ecological viewpoint. These systems were designed by Heater Technology, Inc. and Combustion Engineering (now NATCO).

Comments

This project was apparently an economical operation. Mobil (General Crude) had learned much about fireflooding in the 18 years the project had been under way. The post project analysis indicated good sweep efficiency for a reservoir of this thickness. This may have been due mainly to operation's policy of fireflood control and low air injection rates. On an overall basis, Mobil (General Crude) tried to maintain a voidage rate 14% greater than the air injection rate.

The personnel of Mobil (General Crude) were highly involved in their project and had developed some excellent equipment and techniques to improve recovery and efficiency of the fireflood process.

Table 6.3 summarized the available general information regarding this fireflood. These were made available to the author by an engineer formerly associated with this project.

TABLE 6.3 — Mobil (General Crude) West New Port Fireflood

Reservoir Properties

Reservoir	West Newport Field-Banning Lease 20x10^6 B produced (120x10^6 OIP)		
Depth	Zone	A	800–1,200 ft.
		B	1,400–1,800 ft.
		C	–2,200 ft.
Porosity	high		
Permeability1	D		
Viscosity	3,500–4,500 cp @ 110°F		
API	15		
Reservoir Temperature	110°F		
Sulfur	1–5%		
Sand Thickness			
Dip	2°		
Acreage	590		
Pattern	5–spot		

TABLE 6.3 (cont.) — Mobil (General Crude) West New Port Fireflood

Operating Parameters

Number of wells		
Injectors	36	
Production	245	
Oil Production	4,000 B/D	
Water Production	18,000 B/D	
Steam used		
Steam pressure	Air pressure	500 psi
	at generator	
	at wellhead	
Steam Quality Oil burned as fuel	Natural gas — some from sewage plant (600 BTU/cu ft.)	
	Air/oil ratio	3,000 CF/B
Water/oil ratio	4.5	
Best well	140 B/D	

Oil/Water Treatment Scheme

Initial water separator tanks—heat from 120°F to 135°F.

25% oil in water goes into heater treaters.

Magna Chem EX 257 emulsion breaker.

2–3% oil in water goes to local sewage plant.

3% water in oil to refinery.

Iron sulfide problem.

Air Compressors

2 stage, 500 psi output

22 x 10^6 CFD capability—using 11 x 10^6 CFD

No. of units: 1 – 2,000 HP
2 – 600 HP
3 – 1,000 HP

TABLE 6.3 (cont.) — Mobil (General Crude) West New Port Fireflood

Combustion Gas Utilization

They use their combustion off gas to generate steam.

BTU content: 60–80 average (6% methane) 170 maximum
(per cu ft.)

Gas manifold pressure, 28 psi

5 units are used to generate steam (each use 1.5×10^6 CFD).

The flame temperature is monitored and natural gas is used to enrich the fireflood flue gas automatically.

Steam capacity 580 B/D, 60% quality

Exhaust temperature kept above 270°F to eliminate sulfuric acid formation.

Generate 14% more fireflood flue gas than air injected.

Ignition of Wells

Warm up with steam—then change to air

1 hour to 1 week to ignite

Obvious ignition—felt on surface

Casing	
Injectors	7-7/8 in. hole, 5-1/2 in. casing to TD cement to surface, perforate bottom 100 ft.
Producers	9-7/8 in. hole, 7 in. casing to top "B" zone underream to 12 in., ru 5-1/2 in. liner and gravel pack
Rigs	2 company owned
Rig Cost	$55–60/hr drilling $40/hr workover
Hole Cost	$46,000 with pump

All 1980 Dollars

Paris Valley Combinations Thermal Drive

Husky Oil Company, with the support from U.S. DOE (then ERDA), initiated a wet in-situ combustion pilot augmented with cyclic steam stimulation, within the Paris Valley field, Monterey County, California, in March 1975. The purpose of this test was to assess the technical and economic feasibility of these thermal recovery techniques within an unconsolidated sandstone reservoir that never produced economic quantities of oil due to the very viscous nature of the crude.

Wet combustion, in lieu of other thermal techniques, was selected as the oil recovery process in Paris Valley field, because it was thought the heterogeneous permeability profile would permit heat to breakthrough to the producers and improve the vertical sweep while the well produces at an elevated temperature. Also, to match the production with displacement prior to the heat breakthrough stimulation of producers by steam was proposed.

The pilot site was in the southwest part of the Paris Valley field in T21S-R9E, Monterey County, California, about 160 miles south of San Francisco. Geologically, the Paris Valley field consists of unconsolidated, oil bearing miocene sands that were deposited along the ancient shoreline of the Salinas basin--commonly referred to as the Gabilan shelf. The pilot was in the Ansberry sand, which is found at an average depth of 800 ft. from the surface. The Ansberry sand is separated into three distinct zones, referred to as the Upper, Middle, and Lower Lobes. The Middle Lobe is thin and contained insignificant amounts of oil. The total net oil sand thickness in the pilot area varies from 4–84 ft., while Upper Lobe net oil sand thickness varies from 4–24 ft. and the Lower Lobe from 9–58 ft.

The pilot was designed to operate in five staggered line drive patterns. Eighteen producers and five air injection wells were drilled in the pilot area (Figure 6.1). Nine wells (1, 8, 9, 10, 12, 13, 15, 16, and 18) were completed in the Upper Lobe, six were completed in the Lower Lobe, and eight wells in the full interval of the Ansberry sand, including the Upper, Middle, and Lower Lobes. The air injectors were completed down-dip from the center of each pattern in an effort to compensate for the expected directional flow of air up-dip. Two temperature observation wells were also drilled for monitoring and data gathering. All the wells were cored and logged to characterize the formation. The core materials from Well 3 were utilized to evaluate the combustion characteristics of the Ansberry sand. The pertinent reservoir and combustion characteristics are presented in Table 6.4

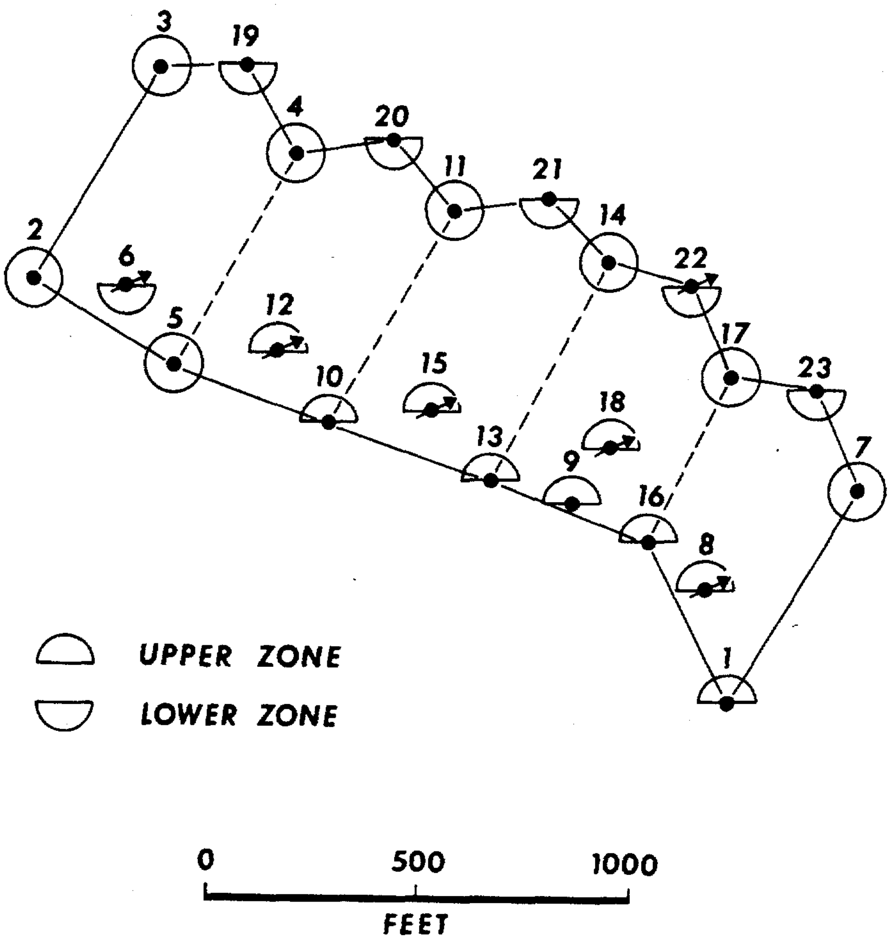

FIGURE 6.1 — Paris Valley In-Situ Combustion Project Well Pattern Map

TABLE 6.4 — Average Reservoir and Combustion Characteristics of Ansberry Sand Paris Valley Field[6]

Reservoir depth, ft.	800
Porosity, % PV	32.2
Permeability, mD	3,748
Oil saturation, % PV	63.7
Water saturation, % PV	36.3
Oil in place, bbl/ac-ft.	1,801
Oil in the pilot area, MM STB	2.6
Average net pay thickness, ft.	58
Reservoir pressure, psia	235
Reservoir temperature, °F	87
Oil gravity, °API	10.5
Oil viscosity, cP at reservoir temperatures	
Upper Lobe	227,000
Lower Lobe	23,000
Formation volume factor, STB/RB	1.0
Fuel requirement: Lbs/ft.^{3}	2.33
Bbl/ac-ft.	295
Air required for combustion: Scf/ft.^{3}	417
Mscf/ac-ft.	18,165
Oil displaced from burned zone, bbl/ac-ft.	1,296

Initial combustion test was initiated in January 1976 using a rental compressor, due to operational problem with the main compressor equipment. The initial testing was concluded in September 1976 after injecting 60 MMscf of air. The purpose of the test was to establish the formation air injectivity and to determine the air injection rate. The first well was ignited utilizing a downhole gas burner, which was set immediately above the perforation. The use of downhole burner was, however, discontinued in later ignition operation because it was found that the formation could be autoignited by injecting steam to supply the heat requirement for ignition.

After completing several repairs to the main compressor air injection was resumed in May 1977 in Wells 6, 8, 12, 15, and 18. It became quickly apparent that the injectivities in wells completed in the Upper Lobe were significantly lower than Well 6, completed in the Lower Lobe. Air injection and burning appeared to have been retained in the Lower Lobe of the Ansberry sand. Leading edge of the heat zone reached updip wells completed in the Lower Lobe, but did not reach the upstructute wells. High injection pressure became necessary to inject air into the Upper Lobe, which contained the most viscous oil. High injection pressure resulted in severe channeling of air upstructure into Well 21. Air injection was halted in August 1977 due to first stage piston failure. After repairing the compressor, air injection was resumed in January 1978 in Wells 6, 12, 15 and 22. Air injection into Well 18 was discontinued due to mechanical problems with the surrounding wells. Air injection was terminated in February 1979, due to operations problems.

Well 21 was the only well that produced incremental oil from combustion operation. After heat broke through in the well, a cooling system was installed in the well to prevent the bottomhole temperature from exceeding 350° F. However, failure of the cooling pump caused the bottomhole temperatures in Well 21 to exceed 700° F and damage the liner. Attempts to replace the damaged liner were unsuccessful and eliminated any further chance of producing the well. Heat also broke through in several other wells (Nos. 4, 11, 14, and 17), but combustion gas and high water production prevented these wells from being kept pumped off and producing the oil.

Only 61% of the injected air was recovered in the producing wells. The balance was probably flowed outside the pilot area. Tracer tests indicated the migration of unrecoverable air outside the pilot area. Significantly high operating costs were incurred during the operation of the pilot. The electric power costs for air compression increases by 233%. Required well work was impeded by high casing pressure in the producing wells. Damage to producing wells from severe channeling of the combustion gas resulted in expensive workovers. Oil production rates were not sufficient to offset the high operating costs and continue the project. In view of the problem prone operations and poor oil production, the pilot was terminated in March 1979 as uneconomical. The total operating costs for the pilot were \$3.317 million or \$23.89/bbl. The pilot did not generate any profit at 1978 oil price of \$24.bbl.

Project Performance Analysis

In spite of possessing many of the desirable attributes (thicker pay, high oil saturation, good lateral continuity, high permeability and porosity) that one would like to see in a candidate reservoir for combustion, the Paris Valley combustion project was unsuccessful and failed to produce significant incremental oil. While there are several interrelated reasons for failure, two factors adversely affected the project performance: (1) high oil viscosity in the Upper Lobe and (2) operational problems resulting from poor planning. The vast difference that existed in the viscosity of oil produced from the Upper and Lower Lobe had a very significant effect on the project performance. The Upper Lobe produced an oil that was ten times as viscous as that from the Lower Lobe. The viscous oil in the Upper Lobe caused a viscous oil block to form and much higher air injection pressure was needed than for the lower viscosity Lower Lobe. This resulted in a pressure gradient sufficient to allow the injected air to break into the Lower Lobe. This channeling of air into the Lower Lobe caused much of the injected air to bypass the upper zone and starve the Upper Lobe combustion front of oxygen. Combustion front stalling appeared to occur as characterized by a low static temperature profile in the Upper Lobe.

The maximum observed temperature in the observation wells completed in the Upper Lobe never exceeded 500°F indicating the occurrence of low temperature oxidation (LTO) reactions. Since this temperature was within the negative temperature gradient range (See Chapter 3) it is suspected that the failure of the reaction temperature to transcend the negative temperature gradient region could partly explain the poor oil recovery from the Upper Lobe. Air injection into the Lower Lobe was no problem and the lower zone exhibited good burning characteristics as evidenced by high observation well temperature (greater than 750° F). However, the channeling of air from the Upper Lobe into the Lower Lobe affected efficiency of downhole pumps in the Lower Lobe.

Frequent compressor failures also hastened the demise of the project. When air injection was interrupted due to compressor failure, backflow occurs. Due to the unconsolidated nature of the formation, the backflow resulted in severe sanding at the injection wells and costly workover. Further, when air injection was interrupted, vertical drainage resaturated the burned zones. This resaturated rock was hot and must be burned again before the burning front can proceed. This increased the overall air requirement of the project. In at least one instant, the backflow of the combustion gases into an injection well resulted in an explosive mixture and damaging detonation when the air injection resumed.

In the final analysis, the project failed due to poor selection of test site and planning. The combustion tube tests indicated an air-oil ration (AOR) requirement of 18.2 Mscf/bbl that was above the values reported for the economically successful fireflood projects. As a general rule, for both technical and economic success, the AOR should be below 18 Mscf/bbl. Electric log and core analysis of the project wells gave reliable results for porosity, permeability, and oil saturation, but did not indicate the vast difference in the viscosity of oil produced from the Upper and Lower Lobe. A production test from a well open to both zones was used for the productivity calculation and average viscosity. The result was very misleading, and the project was designed based on this information. This resulted in the purchase of an undersized compressor, which later proved to be totally inadequate for delivering air at the desired injection pressure. The situation could have been avoided, had each zone been tested separately and oil viscosity from individual zones determined prior to the design of the project.

While the effective permeability in both zones were almost equal, injectivities were widely different. This was not recognized during the planning and design stage. The viscous oil in the Upper Lobe caused a viscous oil block to form which necessitated a much higher air injection pressure that exceeded the compressor design pressure. Each zone should have been tested separately by an extended air injection tests, prior to committing to the project.

The reservoir structure that was assumed for the Paris Valley Project was later determined to be incorrect. While it was assumed that injection was in the down-structure wells, in actuality these were in the wrong side of a syncline. This resulted in migration of air and combustion front away from the pattern. The situation could have been avoided, had some wells outside the project area been included in the analysis to determine the reservoir structure, even if it required drill additional wells.

To minimize project capital costs, no backup system was included for the surface facility, such as a cooling water pump. Mechanical failure of the cooling water pump resulted in the loss of a producer with heat breakthrough. It is prudent to have a backup for critical equipment.

Bodcau In-Situ Combustion Project (Sarathi and Olsen, 1994)

The Bodcau fireflood was a DOE-industry cost-shared in-situ combustion project that was both technically and economically successful. In 1971, Cities Service (now Oxy USA) began a pilot combustion test in the Bellevue Field, located in northwestern Louisiana, which was later expanded to a leasewide operation. The success of this in-situ combustion project prompted Cities Service Company to enter into a cost-sharing contract with the U.S. Department of Energy (then ERDA) to demonstrate the efficiency and economics of a commercial scale wet in-situ combustion process and to test techniques for increasing vertical sweep efficiency while reducing overall project time.

The Bodcau in-situ combustion project was conducted in the Bellevue Field, located about 18 miles northeast of Shreveport, LA, on the eastern edge of Bossier Parish. The demonstration site, located in the southwest quarter of Section 11–T19N–R11W (Figure 6.2) was part of Cities Service Oil Company's (now OXY-USA) Bodcau Fee B lease. The Upper Cretaceous Nacatoch sand, found at 400 ft. depth, is the main producing sand in the field. The demonstration site was selected based on the data from five evaluation wells. The log and core data obtained from these wells were utilized in mapping the structure and pay thickness, as well in determining the pattern size and configuration. The patterns were about 4 acres in size and arranged in an elongated inverted 9–spot (Figure 6.3). The injection well was located down-structure to compensate for the movement of air up-structure. The patterns were elongated up-structure to provide for optimum sweep efficiency in the patterns. Five patterns were developed due east of Cities' original fireflood project. The reservoir and fluid characteristics are shown in Table 6.5.

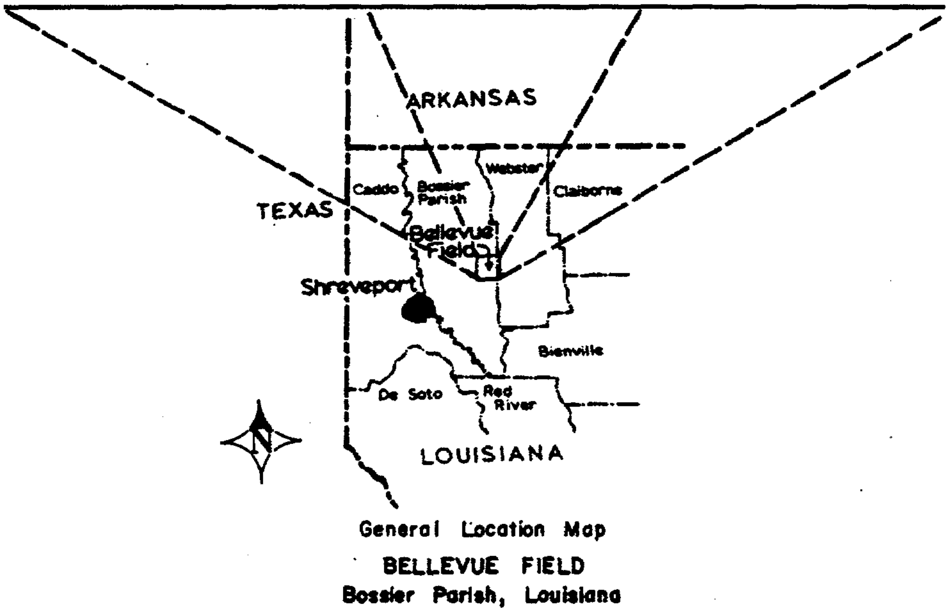

FIGURE 6.2 — Location Map of Bodcau Fireflood

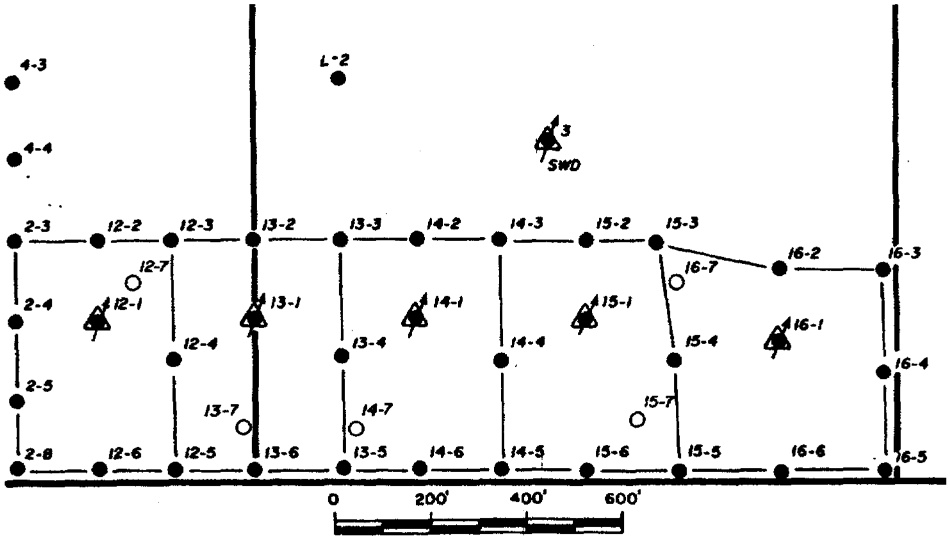

FIGURE 6.3 — Project Pattern Map of Bodcau Fireflood Project

TABLE 6.5 — Reservoir And Fluid Characteristics of Nacatoch Sand, Bodcau Lease, Bellevue Field, Bossier Parish, LA[8]

Depth, ft.	450
Project size, acres	19
Avg. pay thickness, ft.	54
Average porosity, %	33.9
Average permeability, mD	700
Water saturation, % PV	27.4
Oil saturation, %PV	72.6
Oil Satn. at the start of fireflood, STB/ac-ft.	1,909
Reservoir pressure, psig	40
Reservoir temperature, °F	75
Oil gravity, °API	19
Oil viscosity at reservoir temperature, cP	676
Dip angle, degree	4.5

Following extensive laboratory combustion tube experiments, the five injectors were ignited using electric heaters in August and September of 1976. During the first six months of operation, air was injected down the casing for the dry burn phase. After the injection rates stabilized at their maximum, the injectors were reperforated in the top 10–12 feet to allow water injection into the upper section of the Nacatoch sand simultaneously with air injection into the base of the zone. A limestone interval provided partial separation of the two injected fluids. The purpose of water injection was to improve vertical sweep efficiency by forcing the combustion to expand farther out in the lower section of the reservoir before rising to the top, thereby heating a large volume of the reservoir.

During the combustion phase, the producing wells experienced hot gas breakthrough or even burnout as combustion front approached the producers. When this occurred, the wells became impossible to operate due to sand production or tubing leaks resulting from the blowtorch effect of hot gases on the tubing. When a producing well became difficult to operate, the tubing was pulled, and the depths of the markings on the tubing were noted as an indication of the interval through which the sand laden hot gasses were flowing. The producing interval was squeeze cemented and only the sections not causing the well problems were reopened for production. This process was repeated several times during the combustion phase.

In spite of considerable care in design and operation, an explosion occurred in the air compression/injection system, destroying the distribution lines and severely damaging one compressor. Buildup of a lubricant film on the inside walls of the air injection line was determined as being the cause of the explosion. The distribution lines were repaired and put back into service within 36 hours, and preventive actions such as periodic washing of the air distribution system with 5% nitrox solution (mixture of sodium hydroxide and sodium nitrite) and careful checks of lubricants on discharge valves and cylinders for buildup during maintenance, were taken to prevent future explosions,

Air injection was terminated in late 1980 after 50% of the pattern volume was burned and heat scavenging water injection was initiated. Because of the gravity segregation effects, much of the heated oil remained in the lower portion of the thicker pay after the termination of air injection. This heated oil was displaced and recovered by the heat scavenging water.

During the six years of operation (duration of the DOE contract), the project produced 667,609 bbl of oil, compared with 700,000 bbl predicted. It was anticipated that the project would ultimately produce more than the predicted 700,000 bbl of oil, if the economics permitted it. Whether this was the case is not known, because no project-related production data were released since the expiration of the DOE contract in 1982. The project was terminated in 1990.

The project paid out and yielded attractive economics under the economic climate in which it was conducted. During the DOE contract period the actual expenditures were $8.79 million compared to the initial estimated expenditure of $8.23 million. Additional work beyond the initial scope of work for the project, including drilling nine additional producing wells and four postburn core wells and also repairing the damaged compressor, added to the unplanned costs.

Project Performance Analysis

The project was carefully designed (which cannot be over-emphasized) and well operated. Many of the operating problems were predicted and backup provided. Due to the extremely low reservoir pressure (40 psig), it became necessary to operate the producing wells at minimum possible bottomhole pressure to maximize pattern oil recovery. This operating procedure required that a static liquid level be maintained below the producing formation at all times. This was accomplished by setting subsurface pumps at a total depth and keeping the well continually pumped off. This was also necessary to minimize sand production. The operator installed a gas collection system to control the venting of hot produced gases and maintain the bottomhole pressure at the desired value. The extreme downhole temperature and the velocity of the gas caused condensed water to float inside the casing just above the high temperature zone. This resulted in pressure buildup and fluid production stoppage. The problem was solved by periodic cycling of vented gas from zero to maximum flow. This cycling allowed the condensed water to drop to the bottom of the well, where it was removed by the subsurface pump, reducing bottomhole pressure and also partially cooling the hot section. Hardened and honed pump barrels were utilized to minimize pump erosion due to sand production. Pressurized heaters treaters were used to break emulsions and lower bottom sediment and water (BS&W). Coke buildup in the casing/tubing annulus was minimized by periodic cleaning. In spite of a well-planned operation, an explosion occurred in the air injection system, destroying the distribution lines and severely damaging one of the three main compressors. The explosion was attributed to the buildup of a lubricant film on the inside walls of the air injection lines.

In spite of all the efforts to minimize sanding problems, sand production and the handling of hot combustion gases remained the major operating problems during project life. Of the eight original producing wells, only the one farthest from the injector did not require remedial work. Remedial cement squeeze jobs were performed in producers at frequent intervals to shut off perforations at which hot combustion gases carrying sand eroded the perforations. Remedial work at wells along the north line of the project area became so frequent and difficult that these wells were shut off and not returned to producing status until long after termination of air injection in October 1980.

To better evaluate the performance of the simultaneous air and water combustion process, four wells were drilled, cored and logged. Results of the program indicated extensive burning outside of the pattern area. Based on the interpretation of the core and log results, Cities Services arrived at the following conclusions:

1. The geological structure played a significant role. Air preferentially migrated up structure while water moved down, causing variations in the situ combustion process ranging from dry to quenched combustion at various positions.
2. Several hard lime streaks kept the injected fluids separated behind the leading edge of the waterflood. Ahead of the water, they did not impede the migration of air to the very top of the zone.
3. Residual oil saturation in the burned intervals was zero, indicating a highly efficient process.
4. Significant reductions in oil saturation down-dip of the injector, in intervals above the hard lime streak, was an indication of quenched combustion or hot waterflood. Based on the analysis of clay alterations, quenched combustion was surmised.
5. The simultaneous air and water injection process with partial vertical separation is not well suited to reservoirs with appreciable structure when applied in a pattern type development.

In summary, the Bodcau in-situ combustion project was both technically and economically successful, paying out quickly, and provided an attractive return on the invested capital. The capture efficiency, however, was low. Though 72% of the oil in place was displaced, only 42% was captured. Extensive migration of oil outside the lease line occurred as a result of excessive air injection. The operator should be commended for having devoted considerable effort to the design and operation of the project and for thoroughly documenting the project operations. The project performance indicates that very little was left to chance, and that virtually all difficulties were foreseen and every effort made to deal with them.

Since the oil recovery was close to the forecasted level and the project costs were close to the projected amount, it is clear that the operator fulfilled the set objective and demonstrated that a carefully designed and well-engineered combustion project can overcome technical obstacles and will result in economic success.

General Observations

On the basis of published information, and the unpublished results of some of the tests, firefloods may be divided into several classifications. The combustion reaction was essentially the same regardless of the reservoir configuration or the method of application, but the manner in which it was used could be considerably different. Firefloods can be divided into the following types or classes. In each of these classes there is at least one example of a technical success and in some there are many examples.

A. Complete Liquid Displacement
  1) Non-pattern or single injection well.
    Miga, Venezuela — Gulf
    Hankamer, Texas — Gulf
    Delhi, Louisiana — Sun Oil

  2) Pattern or multiple injection wells.
    Government Wells, Texas — Mobil
    Trix Liz, Texas — Sun
    Gloriana, Texas — Sun
    Fry Unit, Illinois — Marathon

B. Gravity Segregated Displacement and Multiwell Stimulation
    Moco Lease, California — Mobil
    Newport Beach, California — General Crude (now Mobil)
    Battrum, Canada — Mobil
    Bellridge, California — Mobil

C. Specialty Applications
  1) Air-water fireflooding — wet combustion — COFCAW.
    Sloss, Nebraska — Amoco
    Athabaska — Amoco
    Bodcau — Cities

2) Waterflood following a fireflood.
Bellevue, Louisiana — Getty
North Tisdale, Wyoming — Continental

3) Heat Wave.
Delaware Childers — Sinclair

4) Reverse combustion.
Kentucky — Gulf
Bellamy, Missouri — Phillips

5) Tar Sands.
Kyrock — Gulf
Athabasca — Amoco, Texaco
Mobil — Sun

6) Oxygen on Emricned air fireflood.
Forest Hills, Texas — Greencotton Oil
Esperson Dome, Texas — Mobil

An explanation of the different uses for combustion were probably in order. As has been described earlier a fireflood moves through a sand packed and oil saturated tube or an oil reservoir and does several things. The oxygen in the air reacts with the fuel that has been deposited on the sand and creates a temperature ranging from 500–1000°F. No liquids can remain in the rock that is being gas driven at this temperature so all of the liquids move out except for a small portion of the oil which is essentially solidified by the high temperature and gas drive and remains behind as fuel. The liquids and vapors are driven ahead by the gas drive and eventually condense as the cold formation ahead of the firefront cools the fluids. The air volumes required to support the combustion process are tremendous. For example, at Miga the air-oil ratio is 11,000 cu ft/bbl. The pressure at the firefront is 2,200 psia and the estimated temperature is 800°F; therefore, about 30 reservoir barrels of gas are flowing through the combustion zone for every barrel of oil that is flowing. The main function of the air is to furnish oxygen for the combustion reaction but the flue gas that is generated also serves other functions. It helps vaporize and move oil and water ahead of the combustion zone and at the producing wells it provides gas lift for the oil and water. A fireflood therefore most closely resembles a cycling project in a gas condensate reservoir where dry gas is supplied continuously from an outside source.

The volume of gas involved greatly outweighs the oil and water. Literally, for every barrel (300 lb) of oil produced there is also a barrel of water (350 lb) and in the case of Miga there is also 900 lb of air injected and approximately 900 lb of flue gas produced. Therefore, approximately three pounds of flue gas are produced for each pound of oil that is produces.

Back to the task of explaining the difference in uses of fireflooding. If one had a circular reservoir with an infinite number of producing wells around the perimeter so as to form a ditch and an injection well at the center, one could fireflood the reservoir and collect all of the oil that was displaced which would be about 75–85% of the oil originally in place. This would be ideal but it is also non-existent, so we have to take what does exist and do the best we can with it. Complete liquid displacement or type A requires that sufficient producing wells exist to produce all of the oil and water that is being displaced by the combustion front and all of the flue gas that is being generated. Once the flue gas has passed through the firefront it is free to move about the reservoir in the same manner as free natural gas would move, i.e., gravity segregate and occupy only the top fraction of the reservoir, move updip and form a secondary gas cap, etc. However, before the air moves through the combustion zone it performs as if the air and combustion zone had a 1:1 mobility ratio. The movement of the combustion zone is controlled mainly by the fuel that is deposited and the heat that is conducted forward through the rock; therefore, it is not affected to any great degree by changes in permeability, liquid saturations, porosity, etc. If these changes become extreme to the extent of fractures or impermeable barriers, the shape of the combustion zone will obviously be influenced. The path the hot fluids take ahead of the combustion zone will also have an influence, but since at field rates most of the heat is carried forward by conduction through the rock, the heat carried forward by the fluids is less significant. Inadequate injection rates may also allow gravity segregation to take place between the air and the fluids being displaced. In reservoirs of moderate thickness the gravity override can probably be avoided by using adequate air injection rates. In thick reservoirs it may be impossible to avoid.

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CHAPTER 7 — AIR COMPRESSION PLANT

Introduction

The role of an air compression plant in an ISC project is to economically and continuously provide clean, dry, high-pressure air at the required rate to support and sustain combustion, while meeting environmental and safety requirements. A compression plant consists essentially of one or more compressors with a power source (driver), control system, intake air filter, inter and after coolers, separators, filters, dryers, fuel and lube oil storage tanks, interconnections piping, exhaust emission control equipment, and a distribution system to carry air to injection wells.

A schematic of a typical air compression plant for an in-situ combustion project is shown in Figure 7.1. The air compressor is the heart of the compressed air system and the selection of proper compressor system is critical to a trouble free operation. Compressors vary widely in design or type, each with a fixed set of operating characteristics. It is the duty of the project engineer to best specify the compressor type to the project need. Air compressor is an expensive and rather a complicated piece of equipment to specify, purchase, operate and maintain. To achieve the expected performance, care must be exercised in selecting equipment, laying out and installing it correctly, and then maintaining the system in good working order.

The intent of this chapter is to provide guidance to the ISC project engineer or operator in the selection, purchase, operation and maintenance of air compressors and related equipment.

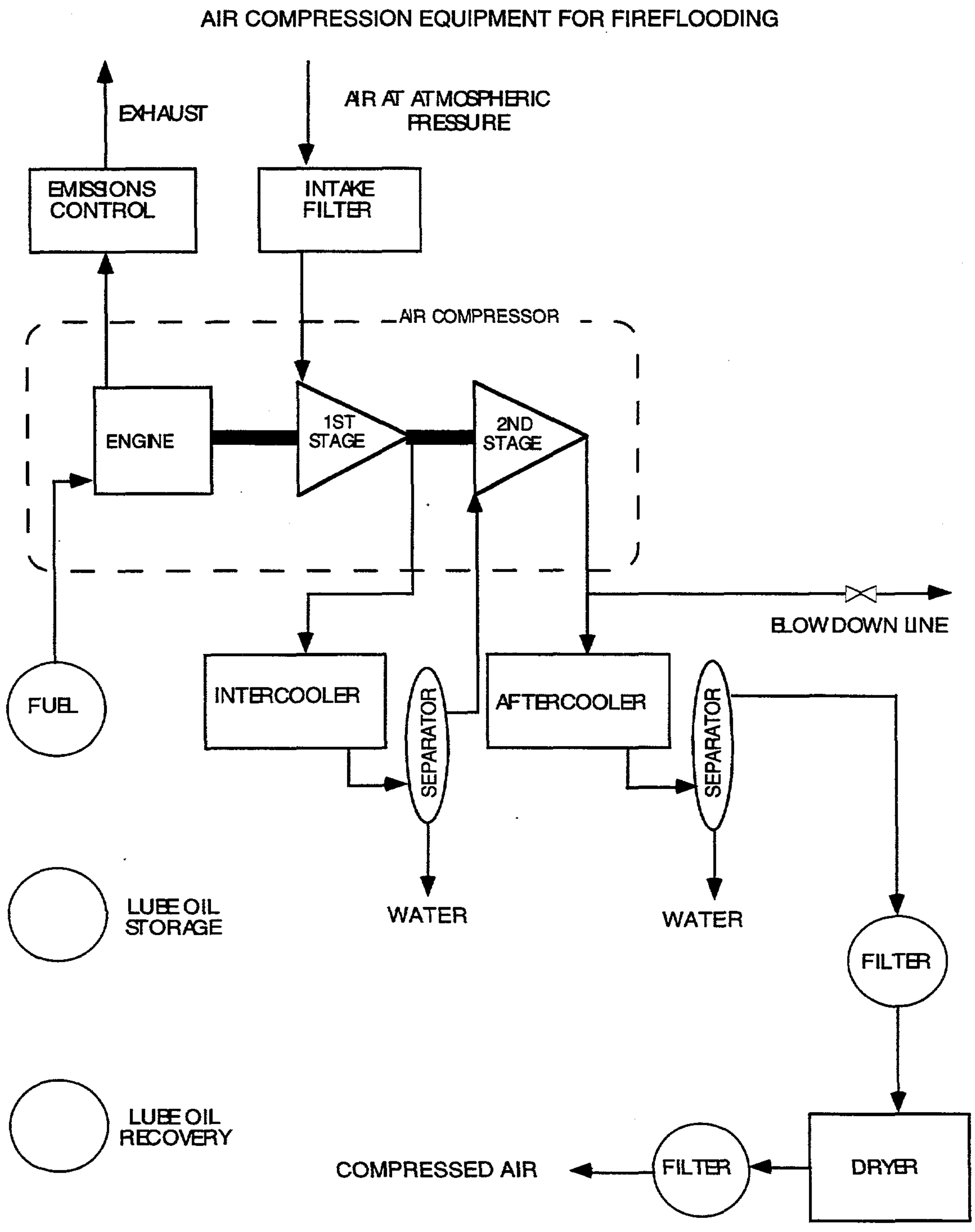


FIGURE 7.1 — Air Compression Equipment for Fireflooding

Some of the topics addressed in this chapter include:

- Compressor types and their characteristics.
- Basic thermodynamic relationships applied to air compressor.
- Compressor specification and selection criteria.
- Compressor performance characteristics.
- Compressor operational problems and maintenance issues.
- Lubrication and drive requirements.
- Other air compression plant equipment and their functions.
- Compressed air distribution system.
- Case history of oil field experience with air compressors.

This chapter also includes numerous charts and a step by step procedure for compressor sizing.

Compressor Types

The compressor is a mechanical device utilized to raise the pressure of a compressible fluid such as air. While compressors are manufactured in a variety of types, sizes and physical configurations, they all utilize one of the two basic mechanical methods to compress gas:

1. Reducing its volume.
2. Increasing its velocity and subsequently converting the velocity (kinetic) energy into pressure energy.

Compressors of the first category are referred to as the **intermittent flow** machines and those based on second technique are classified as the **continuous flow** devices.

Machines using the intermittent compression mode are also referred to as positive displacement compressors, of which there are two distinct types: reciprocating and rotary. Continuous flow machines are also subdivided into two basic groups: dynamic and thermal. The principal types of compressors are shown in figure 7.2. Not all types of compressors are made in all pressure- volume ranges. The typical operation ranges of various types of compressors are shown in Figure 7.3.

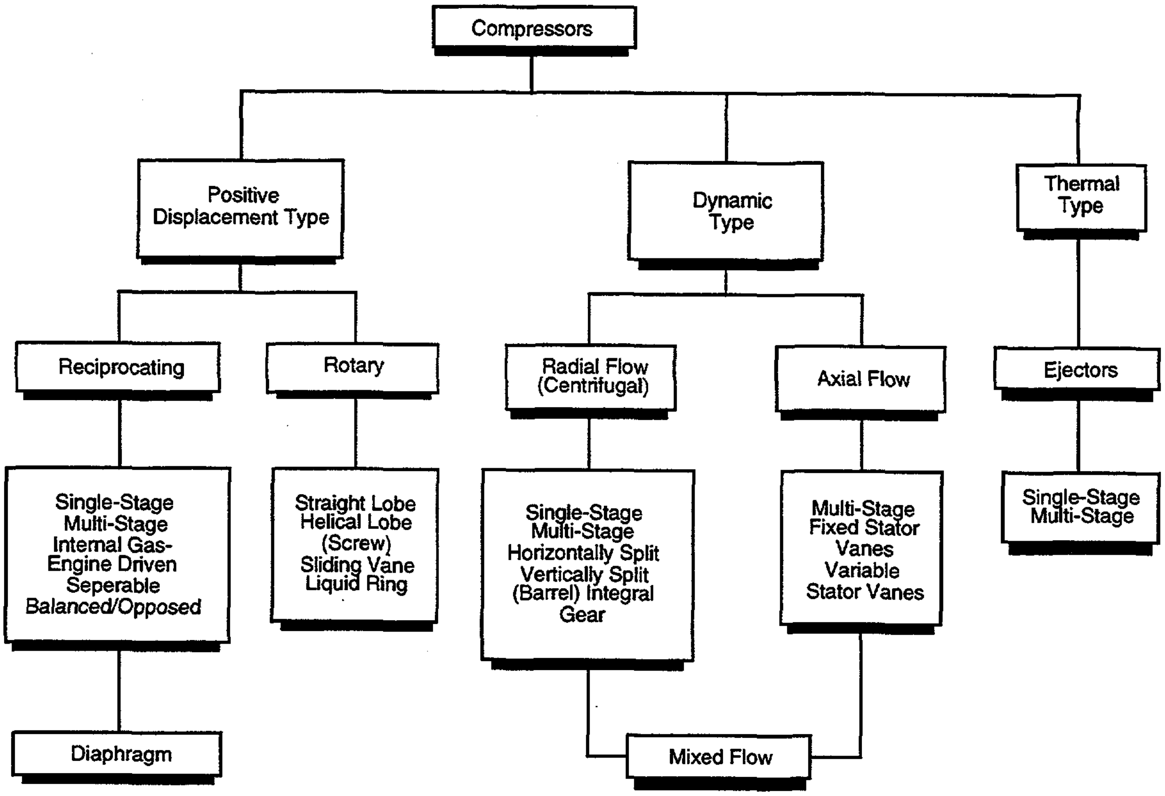


FIGURE 7.2 — Principle Compressor Types

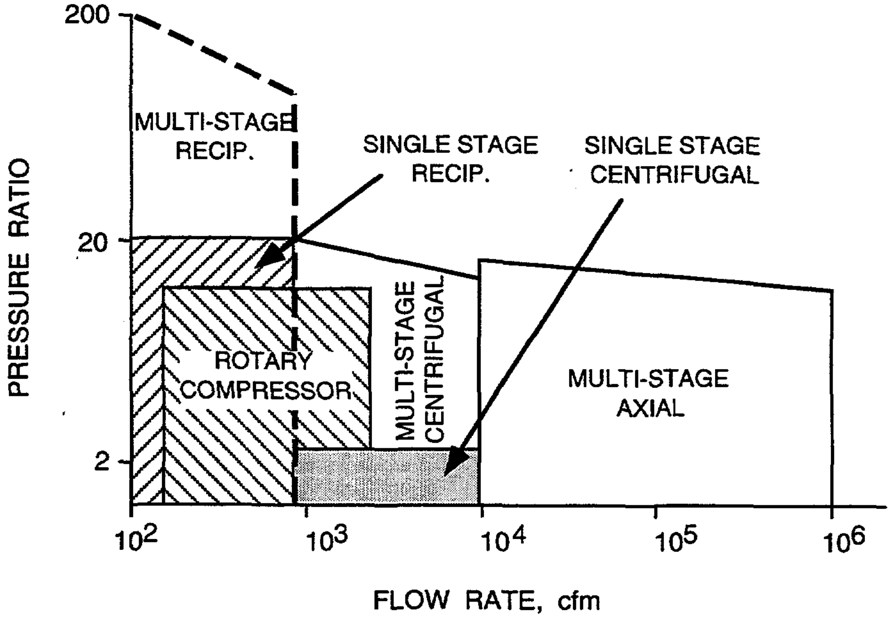


FIGURE 7.3 — Typical Application Ranges of Compressor Types

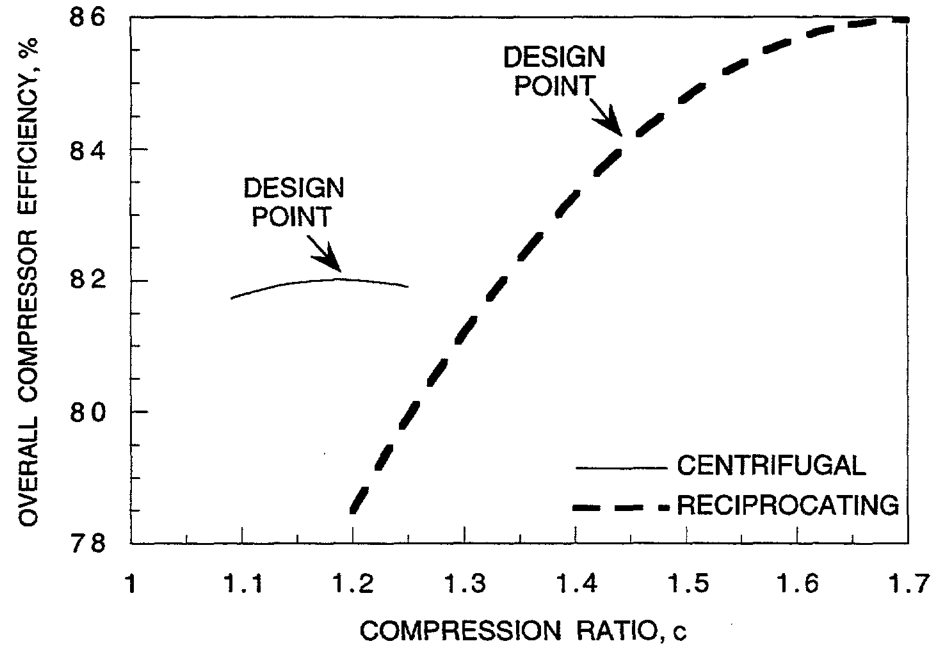


FIGURE 7.4 — Comparison of Centrifugal and Reciprocating Compressor Efficiencies

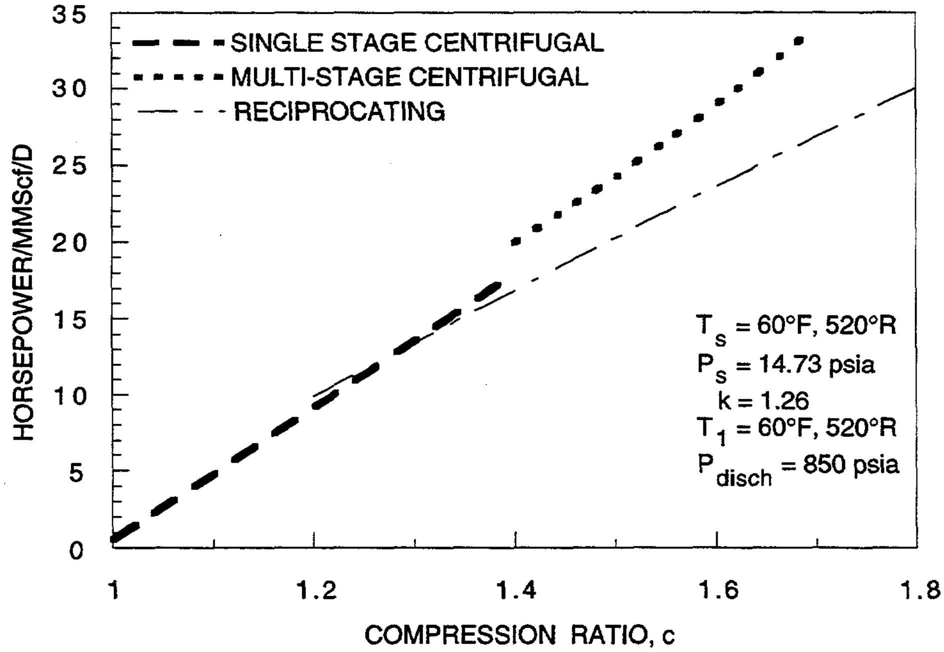


FIGURE 7.5 — Compressor Power Requirements at Various Compression Ratios

The principal compressor types used in ISC projects are either reciprocating or centrifugal. In addition in many projects rotary screw compressors are used as auxiliary units either to boost the discharge pressure of the main unit or to serve as the first stages of a larger reciprocating system. In at least two projects, reciprocating compressors are used as the upper stages of a centrifugal system to achieve the desired discharge pressure. Table 7.1 presents the type of compressors employed in some past and current U.S. in-situ combustion projects. This table indicates that the installation most often found in the field is the gas engine driven multistage reciprocating compressor.

TABLE 7.1 — Compressor Types Employed in the U.S. ISC Projects

Project and Duration	Compressor Type and Manufacturer	Rate and Pressure	Drivers
Mobil Oil Company Moco-T Lease Project, CA (1961-1992)	12 Stage (8000 BHP) Cooper – Bessemer Centrifugal Compressor.	27 MMScf/d at 675 Psig	Gas Turbine (8000 HP). Later replaced by Synchronous motor.
	First (1961) installation was a 350 HP (angle type) Ingersol Rand Reciprocating Compressor.	2.5 MMScf/d at 600 Psig	Natural gas fired integrated engine.
Amoco Production Co. Sloss Field, Nebraska COFCAW Project (1965-1971)	Clark Brothers 6 Stage Horizontally Opposed Double Acting Reciprocating Compressor.	6.7 MMScf/d at 4125 Psig	Natural gas fired integrated engine (2900 HP)
Getty Oil Co. Bellvue, LA Fireflood (1963-1988)	Four, 3 Stage Horizontally Opposed Ingersol-Rand Reciprocating Compressors with air cooled intercoolers.	2.5 MMScf/d each at 125 Psig	Turbo charged Gas Engine (1000 HP)
	Three, 6 Stage, Ingersol-Rand Centrifugal Compressors	20 MMScf/d each at 125 Psig	3500 HP, 300 rpm Synchronous Motor.
Sun Oil Co. May Libby Field, Delhi, LA Combustion Project (1960-1972)	Four, 3 Stage Ajax Horizontally Opposed Double Acting Reciprocating Compressors.	Each compressor is rated for 1.3 MMScf/d at 1000 Psig and 230 BHP	300 HP Turbo charged gas Engine

TABLE 7.1 (cont.) — Compressor Types Employed in the U.S. ISC Projects

Project and Duration	Compressor Type and Manufacturer	Rate and Pressure	Drivers
Cities Service Co. Bodcau Lease, Shreveport, La In-situ combustion project (1971-1990)	Compressor # 1 3-Stage Ingersol Rand Model 4 RDS-3 Reciprocating Compressor with Water cooled inter cooler	3.18 MMScf/d at 315 Psig and 742 BHP at 800 rpm.	Originally driven by a 1000 HP 'Waukesha' Natural Gas Engine. Later replaced by a 1000 HP, 900 rpm General Electric Induction Motor.
	Compressor # 2 3-Stage Ingersol Rand Model 4 RDS-3 Reciprocating Compressor with Water cooled inter cooler.	5.74 MMScf/d at 315 Psig and 1170 BHP at 885 rpm	1250 HP General Electric Induction Motor running at 900 rpm.
	Compressor # 3 3-Stage Ingersol Rand Model 4 HHE-3-VG Reciprocating Compressor with Water cooled inter cooler	12 MMScf/d at 280 Psig and 2800 BHP at 300 rpm	3000 HP General Electric Synchronous motor running at 327 rpm.
Gulf Oil Co (Chevron) Cotton Valley Field, Heidelberg, MS Combustion Project (1971-1992)	3 Clark Bros. Reciprocating Compressors. One 6-Stage Unit and Two 5-Stage Units. Each 5-stage unit was equipped at the down stream end with a single stage 'Sullair' oil flooded Rotary Screw Compressor to boost the pressure from 3000 to 5000 psi.	6.2 MMScf/d total capacity at 5000 psig. 1.2 MMScf/d at 5000 psig 2.5 MMScf/d each at 3000 psig. Booster screw compressor rated at 2.5 MMScf/d with a pressure ratio of 1.67	2500 HP natural gas fired engine

TABLE 7.1 (cont.) — Compressor Types Employed in the U.S. ISC Projects

Project and Duration	Compressor Type and Manufacturer	Rate and Pressure	Drivers
Texaco Caddo Pine Island, La, Harrell Fee Lease In-situ combustion project (1980-1983)	One 2-stage Reciprocating Compressor. One Single Stage Integrated Reciprocating Compressor	1 MMScf/d at 900 psig. 300 MScf/d at 600 psig	First Stage: 50 HP 440 V 3- Phase Induction Motor. Second Stage: 300 HP 440 V 3-Phase Induction Motor 230 HP Integrated Gas Engine
Monterey Resources (now part of Texaco) Midway Sunset Fireflood (1982-	Ingersol Rand CENTAC II Centrifugal Compressor with a Reciprocating Booster Compressor at the upper stage.	5 MMScf/d at 250 Psig	1500 HP Synchronous motor
Koch Exploration (Continental Resources) Buffalo Red River Unit Air Injection Project, S. Dakota (1979-	Centrifugal Compressor for first four stages (Cooper W. Superior) Reciprocating Compressor for last 3 stages (W. Superior Model W 74)	13 MMScf/d at 250 Psig and 3600 rpm 13 MMScf/d at 5000 Psig	3000 HP Induction Motor 3000 HP Synchronous Motor.
U.S. Dept. of Energy Naval Petroleum Reserve #3 (NPR-3) Tea Pot Dome Field Fireflood Casper, Wyoming	5 Stage Horizontally Opposed Double Acting Ingersol Rand Reciprocating Compressor with water cooled intercoolers.	3.2 MMScf/d at 800 Psig.	Turbo charged Waukesha Gas Engine (2900 HP)
Koch Exploration (Continental Resources) Medicine Pole Hills Unit (MPHU), Bowman County, N. Dakota Air Injection Project	7-Stage W. Superior Model MW 68 Reciprocating Compressor with water cooled intercoolers (2 units)	5.2 MMScf/d at 5000 Psig	Turbo charged gas engine (2650 HP)

TABLE 7.1 (cont.) — Compressor Types Employed in the U.S. ISC Projects

Project and Duration	Compressor Type and Manufacturer	Rate and Pressure	Drivers
Amoco Production Co. West Hackberry, La Air Injection Project (1994 -	One 'Atlas Copco' Model ZR-6, 2-stage Oil-less Screw Compressor	4.2 MMScf/d at 100 psig	'Waukesha' Model 5108 GL 'Lean Burn 'gas engine
	One 'Ariel' Model JGK- 4 Four Stage Reciprocating Compressor with Water cooled intercooler	4.2 MMScf/d at 4300 Psig	'Waukesha' Model 9390 GL 'Lean Burn' gas engine.
TOTAL Minatome Corporation 'Horse Creek' Field Air Injection Project, Bowman County, N. Dakota (1996-	Two 8 Throw / 7 Stage Reciprocating Compressor with Water cooled intercoolers (2 units)	5.0 MMScf/d each at 5000 Psig	Turbo charged integral gas engine (2650 BHP at 900 rpm)

Before presenting the details of the principal compressor types employed in ISC projects, a discussion on the relative merits of these compressors and the reasons for the popularity of reciprocating compressors in ISC projects are in order.

Relative Comparison of Various Compressor Types

Proper compressor selection for ISC service is very difficult and several factors must be taken into consideration before finalizing the selection. These include peak project air requirements, desired injection pressure, initial cost, power requirements, operation and maintenance cost etc. For small pilot or experimental projects, where air requirements are small, skid mounted, packaged reciprocating compressors are preferred because they are less expensive to purchase and operate. In a large operation, the choice is not that obvious. For many operations, both reciprocating and centrifugal compressors can meet the flow and pressure requirements: Both these compressors have advantages and disadvantages for a particular application and must be taken into consideration during the selection process.

Advantages and Disadvantages of a Centrifugal Compressor

The advantages of a centrifugal compressor over a reciprocating machine are:

- Lower installed initial cost where pressure and volume conditions are satisfied.
- Lower operating and maintenance expenses (shut down required only once every three years). The operating and maintenance cost of a centrifugal is approximately one-third of an equivalent, reciprocating machine.
- Greater volume through put per unit of floor space occupie.
- Smaller foundation requirements.
- Greater continuity of service and dependability
- Higher compression efficiency at compression ratios less than 1.25 (see Figure 7.4). The compression efficiency is the ratio of theoretical work to actual work required to compress a given quantity of gas.
- Minimal operational attention requirement when operated within the design envelope.
- Adaptability to high speed, low maintenance cost drivers.

The principal disadvantages of using a centrifugal compressor in an ISC project are:

- They are very unstable at low flow rates.
- Because they are dynamic, the flow is much more sensitive to operating environments, requiring a more sophisticated control system.
- External maintenance is mandatory; only the manufacturer could trouble shoot and repair the compressor.
- If major mechanical failure of compressor internals (rotor) occurs, due to unstable operation, it will take longer to repair or overhaul a centrifugal unit (than a reciprocating one) unless a complete spare rotor is available.
- Carrying a spare rotor, though ensure lower downtime, can increase the compressor installed cost by about 50%.
- Require more skilled manpower to maintain and operate due to relatively narrow range of stable operating regime.

Advantages and Disadvantages of a Reciprocating Compressor

The advantages of a reciprocating compressor over a centrifugal machine are:

- Greater flexibility in capacity (throughput) and pressure range.
- Superior compression efficiency at compression ratios above 1.3. This advantage increases dramatically as the compression ratio increases (Figure 7.4.)
- Requires less power to compress a unit volume of gas at compression ratio of above 1.3 (Figure 7.5).
- Less susceptibility to changes in operating conditions.
- Capacity (output volume) can be easily be varied to meet the demand by using appropriate capacity controls.
- Can deliver air at any pressure up to the limit of its mechanical strength and drive capability.
- Require less skilled manpower to operate, since the machine is less sensitive to variation in the operating environment.
- Routine maintenance can be done on site by operator's personnel.
- Major mechanical problems probably will not arise. If major problems do arise, it is less expensive to repair.
- More forgiving if routine maintenance is deficient.
- Operating environments has minimal effect on output.

The disadvantages of using a reciprocating compressor are:

- Lower capacity.
- Higher initial installed costs.
- Foundation requirements are much more massive than that for an equivalent centrifugal machine.
- Has more and heavier moving parts and, therefore, lower mechanical efficiencies than centrifugal compressors.

- Require more careful design of the discharge piping system (piping between compressor and intercooler and at the compressor outlet) to avoid vibration and pulsation. Centrifugal do not have this problem.
- Require higher maintenance (shutdown and overhaul required once every 9 months) due to large number of moving parts and corresponding wear.
- Higher lubrication and cooling costs compared to other compressor types.

Advantages and Disadvantages of Rotary Screw Compressors

Rotary screw compressors has following advantages over reciprocating and centrifugal compressors:

- Simpler design and wide capacity range.
- Can develop 7.3 times the head of a centrifugal compressor operating at the same speed.
- Has performance characteristics and flexibility comparable to a reciprocating compressor.
- It has compression efficiencies comparable to centrifugal compressors.
- Operation and maintenance costs compare favorably with the centrifugal compressors which are about one third the cost of maintaining reciprocating machines.
- Lighter in weight than the reciprocating machines and does not exhibit the shaking forces of the reciprocating compressor, thus making the foundation requirements less stringent.
- Flooded screw compressors can realize pressure ratios (ratio of discharge pressure to intake pressure) as high as 21 to 1, making it an ideal machine to boost the discharge pressure of the centrifugal.

Disadvantages:

- Overall efficiency (70%) is less than the reciprocating or centrifugal machine and decreases with increase in compression ratios.
- Has much higher internal fluid leakage losses than the centrifugal or reciprocating machines and this impedes its attractiveness as a mainstream compressor. Higher fluid leakage losses also prevent the machine from realizing higher compression ratios.
- Typical flooded single stage screw compressors are restricted to 4 to1 compression ratio.

- Oil flooded compressors require a more expensive lube oil recovery system to minimize loss.
- Require much higher horsepower per unit of compression ratio.
- Screw compressors are noisier to operate.

Reasons for the Popularity of Reciprocators in ISC Operation

Despite its lower capital, operation, and maintenance costs compared to the reciprocators, centrifugal compressors have not found widespread acceptance among most ISC operators. Following are some of the reasons for this situation.

1. In-situ combustion operations generally involves significant amount of compression and the service require considerable flexibility in operating pressure and throughput. Typically at the start of an ISC operation, the injection pressures are higher than the project's average injection pressure and the injection rates are well below the average. Once ignited and the combustion front began to move away from the injector, the injection pressure drops and the injection rate increases. The reciprocating compressors best provide this operating condition flexibility. Reciprocating compressors are the only compressor types whose capacity and pressure may be varied in accordance with the requirements, without sacrificing the efficiency.
2. Most ISC projects implemented in the U.S. in the 1950s and 1960s were either small pilot or experimental projects. The volume of air required in these projects were relatively small (often much less than and outside the practical limits of most centrifugal compressors). Though specially designed centrifugal compressors can handle such low volumes, they are not cost effective compared to reciprocators of similar throughput. This preclude the use of centrifugal compressor in such application. The centrifugal compressor has been applied in the approximate range of 1,000 scf/min to 150,000 scf/min (14.4 MM scf/d to 216 MM scf/d). Below 6MM scf/d flow rate the operation of centrifugal compressors becomes unstable, leading to mechanical failure of the machine.
3. Availability of natural gas in most field location and the suitability of natural gas fueled gas engines as drivers for the reciprocators (centrifugal are high speed machines and require either gas turbines on electrical motors as drivers) also can be cited as a reason for the popularity of reciprocating compressors in ISC services.
4. Other reasons for the widespread use of reciprocating compressors in ISC projects include: familiarity and ease of repair on site, less skilled manpower requirements to operate and maintain, less costly down time due to ready availability of spares, low power requirements and superior compression efficiency compared to centrifugal.

5. Given its widespread usage and satisfactory performance in the past ISC projects, most operators tend to stick with the tradition and unwilling to consider other compressor types for ISC operations.

Basic Terms and Definitions of Compressor Terminology

An engineer or operator in charge of selecting or specifying compressors for an in-situ combustion project must have a good understanding of various compressor related terms. This is needed to avoid confusion and to prevent miscommunication with vendor.

In this section an attempt is made to explain selected terms specific to compressor related calculations. These terms apply to all compressors regardless of type.

- *Suction Pressure*: This term refer to the air (gas) pressure existing on the inlet or suction, side of the compressor. This is expressed in pound force per square inch (lb_f/iN^2) gauge (psig) or lb_f/iN^2 absolute (psia). The exact point of measurement of suction pressure is important in the final sizing and selection of the compressor.
- *Discharge Pressure*: The air (gas) pressure existing at the discharge or outlet end of the compressor. This is also expressed in units of psig on psia. As with suction pressure the exact point of measurement is important in the final sizing and selection of the compressor.
- *Compression Ratio*: It is the quotient obtained from dividing absolute discharge pressure by the absolute suction pressure. It is usually applied to a single stage of compression, but may be applied to a complete multi stage, compressor as well.
- *Capacity*: It is the quantity (volume) of air (gas) actually delivered when operating between specified suction and discharge pressure. In the compressor literature, it is expressed in various units. These include: cubic feet per minute (cfm), inlet cubic feet per minute (icfm), actual cubic feet per minute (acfm). Standard cubic feet per minute (scfm), millions standard cubic feet per day (MMscf/d), and millions cubic feet per day (MMcfd).

All these units expresses the volume delivered at certain conditions of pressure, temperature gas composition and a definition of these units is in order.

Cubic feet per minute (cfm): It is the volume rate per minute measured at the specified or known inlet condition (usually ambient) of pressure and temperature. The pressure usually the barometric pressure expressed in psig and the temperature is the prevailing air temperature. It is best to specify the pressure and temperature at which the volume is to be expressed.

Actual cubic feet per minute (acfm): This term originated in the chemical process industry and expresses the volume at process condition. Like 'cfm', it is the intake volume rate per minute expressed at the prevailing compressor room pressure and temperature conditions. Often in compressor literature the term 'cfm and 'acfm' are used interchangeably.

Inlet cubic feet per minute (icfm): Same as 'cfm' and refer to the volume at the prevailing suction conditions.

Standard cubic feet per minute (scfm): 'scfm' means 'cfm' at standard condition. However, standard vary and some care is necessary. In the United States, the usual standard is 14.696 psia and 6°F. In Europe, the usual standard is 1atm and 0°C. The U.S. natural gas industry adopted 14.4 psia and prevailing inlet temperature (usually 65°F or 70°F) as its standard. Hence the engineer must specify the standard conditions to the compressor vendor.

Million cu. ft. per day (MMcfd): It is the daily output capacity of the compressor at the specified (standard) inlet condition. It is not the same for all people. Like 'scfm', its definition depends upon the standard adopted. In the natural gas pipeline industry where this term is most frequently used, it is refer to the volume at 14.4 psia and inlet temperature.

Million standard cubic feet per day (MMscf/d): It is the daily output capacity of the compressor, measured at 14.7 psia pressure and 60°F. This term is commonly used in the oil field arena and adopted by ISC operators to express the compressor capacity. Again, the engineer is advised to specify the standard conditions, so as to leave no doubt in the compressor vendor's mind.

Horsepower: refer to the time rate of work required to compress and deliver a given quantity of gas (air) in accordance with a specified process. The total required horsepower is a function of capacity, compression ratio and compressor efficiency. Like volume, the compressor literature refers to several different horsepower and an explanation is in order.

Theoretical Horsepower: is the work theoretically required to compress and deliver a gas at the desired discharge pressure in accordance with a specified thermodynamic process.

Gas Horsepower: (GHP) is the actual work required to compress and deliver a given quantity of gas. This includes all losses (thermodynamic, leakage and fluid friction) except mechanical losses.

Indicated Horsepower (IHP) is the horsepower obtained from an indicator card of a reciprocating compressor. It is the same as the gas horsepower.

Break Horsepower: (BHP): It is the total power input required by the compressor to compress and deliver a given quantity of gas. This includes gas horsepower and all mechanical losses. It is also sometime referred to as the shaft horsepower. It is also the power developed and delivered at the compressor shaft by the prime mover.

Peak Horsepower (PHP): It is the maximum power required by a given compressor when operating at a: (1) constant discharge pressure with variable suction (intake) pressure or (2) constant suction pressure with variable discharge pressure.

Basic Relationships

This section discusses briefly some basic thermodynamics and mathematical relationships necessary to determine the size of a compressor and the power required to compress a given volume of air. To keep the discussion simple, no attempt is made to derive various gas compression equations. Only the final expression is presented. For a detailed discussion on the thermodynamic fundamentals and the equations derivation, the reader is referred to other publications.

Principles of Compression

Pressure, temperature, and volume are the three variables that influence the status of a gas. A change of one variable affects either or both of the other variables.

The relationship between pressure (P), volume (V) and temperature (T) is expressed by the ideal gas law.

$$PV/T = Constant = R \tag{7.1}$$

Where

'R' is the universal gas constant and its value depends upon the units chosen for 'P', 'V' and 'T'.

When

P is in lbf /iN$_2$ abs

V is in cu. ft./ lb. mole

and T is in °R (°F + 460), the value of R is 10.729

Similarly ‘R’ has a value of 1545 when ‘P’ is in lbs/sq.ft., V is in cu. ft./ lb. mole and T is in °R.

All gases deviate from ideal gas laws to some extent. It is therefore, necessary that this deviation from ideality be accounted for in compressor calculations to prevent compressor and driver sizes from being greatly in error. This deviation from ideality is accounted for by multiplying the right hand side of Equation (7.1) by the gas deviation factor (or compressibility factor) Z.

Thus the real gas law that applies to all gases can be written as

$$PV = ZRT \tag{7.2}$$

The value of Z depends upon the system pressure, temperature and type of gas.

Another important gas property is the specific heat ratio ‘k’. This ratio is given by

$$k = {}^{C_P}\!\!\diagup_{C_V} = \frac{C_P}{C_p - 1.986} \tag{7.3}$$

Where

C_V= specific heat at constant volume, Btu / lb_{m} - mole - °F

CP = specific heat at constant pressure, Btu / lb_m - mole – °F

In compressor calculation, the compressor capacity is a volumetric value based on flowing conditions of pressure, temperature, and relative humidity (if moisture is present). The flow units are given as inlet cubic feet per minute (icfm) or actual cubic feet per minute (acfm). In oil field, the flow value is stated as standard cubic feet per minute (scfm). Unfortunately, the definition of standard condition is not universal. The ASME standard uses 68°F and 14.7 Psia at 36% relative humidity. The API standard is 60°F and 14.7 Psia. The natural gas industry uses 14.4 Psia and 60°F as its standard. To avoid confusion, it is always advisable to check the reference condition whenever the scf abbreviation is encountered. In the SI unit, there is only one set of reference conditions, 101.325 kPa and 15°C as established by the international standard ISO 5024. The recalculation of volumes from one set of standard conditions to another is rather straight forward and can be accomplished using Equation (7.2) as follows.

Given the volume occupied by dry air at 60°F temperature and 14.7 Psia pressure as 100 cubic feet. What is the corresponding volume at (a) 14.7 Psia and 68°F and (b) 14.4 Psia and 60°F. Gas deviation factor Z=1.0 at atmospheric pressure.

Solution:

P_1= 14.7 Psia

V_1=100 cu. Ft.

T_1= 60°F+ 460 =520°R

Z_1=1.0

P_2= 14.7 Psia

T_2= 68°F+ 460 =528°R

V_2= ?

Z_2= 1.0

From Equation (7.2)

$$P_1V_1 \Big/ T_1Z_1 = P_2V_2 \Big/ T_2Z_2$$

Hence

$$V_2 = \frac{P_1V_1}{T_1Z_1} \times \frac{T_2Z_2}{P_2}$$

Substituting the corresponding values

$$V_2 = \frac{14.7 \times 100.0}{520 \times 1.0} \times \frac{528 \times 1.0}{14.7}$$

$$= 101.54\ CubicFeet$$

Similarly for the conditions (b), the corresponding volume is 102.1 cubic feet.

Compression Cycles

There are three compression cycles or thermodynamic processes available to an engineer to carry out the work of compression. These are:

1. Isothermal compression.
2. Adiabatic compression.
3. Polytropic compression. Only isothermal and adiabatic compression are pure basic thermodynamic cycles.

The polytropic process is a modification of adiabatic compression involving an efficiency to more nearly represent actual condition and as such is not a true basic cycle. Although, true isothermal and adiabatic compressions are not achievable in the practical types of compressors, nevertheless, they are useful as a basis for compressor calculations.

The PV diagram depicting these three compression cycles are shown schematically in Figure 7.6. When a gas is compressed heat is generated. The manner in which this heat of compression is dealt with distinguishes the compression cycles from one another. Isothermal compression occurs when the temperature of the gas being compressed is held constant. This requires continuous removal of the heat of compression. This compression is described by the formula.

$$P_1V_1 = P_2V_2 = \text{constant} \qquad (7.4)$$

Adiabatic compression: also known as the *isentropic* (constant entropy) compression is obtained when no heat is added to, or removed from the gas during compression. This process is reversible when no friction exists. For an ideal gas the compression follows the formula:

Where k is the ratio of specific heat = C_P / C_V and

$$P_1V_1^k = P_2V_2^k \qquad (7.5)$$

$$\frac{T_2}{T_1} = \left(\frac{P_2}{P_1}\right)^{\frac{k-1}{k}} \qquad (7.6)$$

$$= (R_c)^{\frac{k-1}{k}} \qquad (7.7)$$

Where Rc = compression ratio = ratio of discharge pressure to inlet pressure and the subscripts 1 and 2 in Equation (7.7) denote inlet and discharge conditions.

For a real gas, the adiabatic compression follows the formulation

$$P_1V_1^{\gamma} = P_2V_2^{\gamma} \tag{7.8}$$

And

$$\frac{T_2}{T_1} = \left(\frac{P_2}{P_1}\right)^{\frac{\gamma-1}{\gamma}} = (R_c)^{\frac{\gamma-1}{\gamma}} \tag{7.9}$$

Where 2 = isentropic exponent for a real gas

For a compression ratio, Rc < 2.0, 2 is approximately equal to 'k' for most real gases.

Though adiabatic compression is never exactly obtained in practice nevertheless, it is closely approached with most reciprocators and used as the basis for these compressor design.

Polytropic compression cycle is used as the basis for centrifugal compressor design and follow the relation

$$PV^n = \text{constant} \tag{7.10}$$

When Equation (7.10) is expressed between the initial (1) and final (2) conditions we have

$$P_1V_1^{n} = P_2V_2^{n} \tag{7.11}$$

Where n = polytropic exponent and

$$n *1 \text{ or } n * k \tag{7.12}$$

Expressing Equation (7.11) in terms of temperature and pressure we have

$$\frac{T_2}{T_1} = \left(\frac{P_2}{P_1}\right)^{\frac{n-1}{n}} \tag{7.13}$$

The value of 'n' is experimentally determined for a given machine and may be lower or higher than the adiabatic exponent 'k'. In reciprocating and internally cooled centrifugal compressors, 'n' is usually less than 'k'. In un-cooled centrifuge, 'n' is usually higher than 'k' due to internal gas friction.

Thermodynamically, the adiabatic process is reversible, while the polytropic process is irreversible. For real gases, below a compression ratio of 2, the polytropic exponent 'n' for the gas can be calculated from the following relation

$$\frac{n-1}{n} = \frac{k-1}{k}\left(\frac{1}{n_p}\right) \tag{7.14}$$

Where np is the polytropic compression efficiency. 'n' can also be calculated if the inlet (suction) and discharge pressure and temperature are known. The following formula may be used.

$$\frac{T_d}{T_s} = \left(\frac{P_d}{P_s}\right)^{\frac{n-1}{n}} = R_c^{\frac{n-1}{n}} \tag{7.15}$$

$$\eta_a = \frac{\left(\frac{P_d}{P_s}\right)^{\left(\frac{k-1}{k}\right)} - 1}{\left(\frac{P_d}{P_s}\right)^{\frac{1}{\eta_p}\left(\frac{k-1}{k}\right)} - 1} \tag{7.16}$$

The adiabatic compression efficiency η_a is defined in terms of the polytropic efficiency η_p by the following

In the above equations, the subscript 'd' and 's' refer to the discharge and suction conditions respectively.

Polytropic efficiency η_p can be obtained from (7.14) by rewriting the equation as

$$\eta_p = \frac{\left(\frac{k-1}{k}\right)}{\left(\frac{n-1}{n}\right)} \tag{7.17}$$

Theoretical Horsepower

Theoretical work (horsepower) is the heart of the compressor design and the engineer must have some basic understanding

Adiabatic Compression

For reversible adiabatic (isentropic) compression of an ideal gas, the theoretical horsepower requirement is given by

$$HP_T = \frac{0.0642Q}{m}\left[\left(\frac{P_d}{P_s}\right)^m - 1\right]\left(\frac{T_s}{520}\right)(Z_m) \qquad (7.18)$$

Where:

Q= gas flow rate in standard cubic feet per minute (14.7 Psia and 60°F)

P_s, P_d = absolute pressure at suction and discharge, respectively, Psia

m = k-1/k

k= C_P/C_V (molal specific heat ratio)

units of C_P and C_V are in Btu/lb-mole °F

T_s = absolute temperature at suction, °R

$Z_m = (Z_s + Z_d) / 2$ = mean compressibility factor

Z_s= compressibility factor at suction

Z_d= compressibility factor at discharge

Although Equation (7.18) is derived based on ideal gas with a constant specific heat, it is equally valid for real gases provided the specific heat variation is not large. Several efficiencies are defined in order to apply Equation (7.18) to real world compressors. These efficiencies are defined as follows:

η_a = adiabatic efficiency:

It is defined theoretical isentropic horsepower (Eqn 7.18) divided by the actual or gas horse power (GHP) delivered to the gas

$$= HP_T / GHP \qquad (7.19)$$

η_m= mechanical efficiency:

It is the fraction of the driver break horsepower (BHP), actually transmitted to the gas. (This allows for mechanical losses) Thus

$$\eta_m = \text{GHP BHP} \qquad (7.20)$$

η_{ao} = overall adiabatic efficiency:

It is the ratio of the theoretical adiabatic horsepower developed per stage of compression divided by driver break horsepower.

$$\eta_{ao} = HP_T \quad BHP = *_a * *_m \qquad (7.21)$$

Hence BHP = HP_T / $*_{ao}$

$$= \frac{0.0642Q}{m}\left[\left(\frac{P_d}{P_s}\right)^m - 1\right]\left(\frac{T_s}{520}\right)(Z_m)\left(\frac{1}{\eta_{ao}}\right) \qquad (7.22)$$

P_d, P_s = absolute pressure at discharge and suction, Psia

T_s = absolute temperature at suction, °R

The adiabatic head Ha represents the isentropic energy supplied to compress a gas in ft.- lb_f lb_m

The adiabatic head is calculated from the following relation which applies to one stage of compression.

$$H_a = \left(\frac{RT_s}{M}\right)\left(\frac{1}{m}\right)\left[\left(\frac{P_d}{P_s}\right)^m - 1\right](Z_m) \qquad (7.23)$$

Where

M = gas molecular weight

R = gas constant = 1545 ft. lbs/ lbm

Since work is force times distance or in this case, weight times head, the compressor horsepower (GHP on BHP) is related to the adiabatic head by the following:

$$\text{GHP} = \frac{w\,H_a}{33{,}000\,\eta_a} \tag{7.24}$$

$$\text{BHP} = \frac{w\,H_a}{33{,}000\,\eta_{ao}}$$

where

$$w = \text{mass flow rate of gas in } \text{lb}_m / \text{min} \tag{7.25}$$

For a single stage of compression, neglecting any changes in potential or kinetic energy, the temperature change from inlet to outlet, can be obtained from the first law of thermodynamics (energy balance) as

$$\Delta t = t_d - t_s = \frac{6.33\left(2.547\,\text{BHP} - L\right)}{Q\,C_p} \tag{7.26}$$

Where

t_s = suction temperature, °F

t_d = discharge temperature, °F

Q = gas flow rate, Scf / min

L = total heat lost to the surroundings or to the cooling water in Btu/ hr. 'L' also includes the heat lost to heat transfer (cooling) jackets, lubricating oils, etc. But it does not include any heat transferred to compressor intercoolers or aftercoolers.

Equations (7.22) through (7.26) must be applied separately to each stage in a multistage system.

Polytropic Compression

A polytropic compression follows the Equation (7.10) (PV^n = constant). The exponent 'n' in Equation (7.10) is a constant that depends on gas properties, amount of cooling supplied to the compressor and energy losses due to friction and irreversibility.

The basic horsepower equations are identical to those for a reversible adiabatic compression (Equation 7.18) except that the isentropic exponent 'k' is replaced by the polytropic exponent 'n' and the adiabatic efficiency η_a by polytropic efficiency η_p.

Thus the power equations for a one stage polytropic compression are

$$= \frac{0.0642Q}{m'}\left[\left(\frac{P_{discharge}}{P_{suction}}\right)^{m'} - 1\right]\left(\frac{T_{suction}}{520}\right)(Z_m)\left(\frac{1}{\eta_p}\right) \tag{7.27}$$

Where

$$m' = \left(\frac{n-1}{n}\right)$$

The polytropic efficiency η_p is defined by Equation (7.17)

The equation for polytropic head H_p is analogous to that for adiabatic head (Equation 7.23)

Thus

$$H_p = \left(\frac{RT_{suction}}{M}\right)\left(\frac{1}{m'}\right)\left[\left(\frac{P_{discharge}}{P_{suction}}\right)^{m'} - 1\right]\left(\frac{T_{suction}}{520}\right)(Z_m) \tag{7.28}$$

The outlet and inlet temperature for polytropic compression are related by the expression given by Equation (7.13) where

T_2 = discharge temperature, °R

T_1 = suction temperature, °R

As in the case of adiabatic compression, the polytropic formulas must be applied separately to each stage in a multistage system.

For a given speed and inlet capacity, the centrifugal (or axial) compressor develop a constant polytropic head (in ft.-lbf / lbm) regardless of the *nature of the gas*, its inlet temperature or whether it is cooled or not during compression. The polytropic head, theoretically remains the same, regardless of whether the gas compressed is CO_2 (gravity = 1.528) or air (gravity = 1.0) or natural gas.

Although the polytropic head developed by a dynamic machine (such as the centrifugal compressor) at a given speed and capacity remains constant regardless of the gas, the pressure rise generated is *not*. The pressure rise vary approximately linearly with the density of the gas. Thus a centrifugal compressor operating at a given speed will compress a given inlet volume of CO_2 to a greater pressure, than the same inlet volume of air. This fact must be kept in mind while selecting a compressor for in-situ combustion service, because oil field compressor vendors often rate the compressor for natural gas, than for air. In such cases, the compressor discharge pressure, when used for air compression, is likely to be lower than that quoted by the vendor.

Isothermal Compression

The theoretical horsepower for a reversible isothermal compression is given by the expression

$$\mathrm{HP_T} = \frac{QTZ_m}{8110} \ln \left(\frac{P_d}{P_s}\right) \tag{7.29}$$

Where

$\ln \left(\frac{P_d}{P_s}\right)$ is the natural logrithm of compression ratio

Equation 7.29 assumes that the heat of compression is fully removed by cooling. In practice, this is not feasible and the actual power developed is less than the theoretical power predicted by Equation 7.29.

The performance of a real world compressor can be evaluated by the following:

$$\mathrm{GHP} = \frac{HP_T}{\eta_t} \tag{7.30}$$

$$\text{and BHP} = \frac{HP_T}{\eta_{ao}} \tag{7.31}$$

Where

η_t = isothermal efficiency

η_{ao} = overall isothermal efficiency

$= \eta_t \times \eta_m$

η_m = mechanical efficiency

Once the break horsepower for a single stage of compression is calculated, the discharge temperature can be determined by Equation (7.26)

Reciprocating Compressor

Introduction

The reciprocating compressor is probably the best known and the most widely used compressor type in the oil patch. More than 80% of all the compressor systems in use in the oil field are reciprocators. Its widespread popularity among oil field operators can be attributed its superior compression efficiency and greater flexibility in capacity and pressure range at a lower power cost. Reciprocating compressors had been employed in the oil field since the early 1900 when the practice of reservoir pressure maintenance through well head gas re-injection began (J.O. Lewis, 1917).

Oil field reciprocating compressors vary in size from small 5 horsepower units to larger power units for several thousand horsepower. Majority of oil field reciprocating compressors are moderate horsepower, heavy duty packaged units, and direct connected to a gas engine driver. These units are usually designed to meet the minimum requirements of the API specification 11P (SPEC 11P) developed to meet the oil and gas fields need for a compact, semi-portable, well balanced, skid mounted compressor.

The packaged reciprocating compressors are adequate for light to medium duty services such the compression of well head gas for discharge into trunk lines, gas lift operations, reservoir pressure maintenance activities and pilot gas injection EOR processes such as the in-situ combustion and flue gas flood. In large EOR projects such as the commercial scale in-situ combustion, CO_2 and hydrocarbon floods, large multistage reciprocating compressors with interstage coolers are employed.

Irrespective of the project size an operator or the engineer in charge of specifying and purchasing compressors for an in-situ combustion project must have a good understanding of the specific characteristics for different compressor types and the many factors that must be considered in the compressor selection process. These issues are not only essential to the proper formulation of the compressor specification sheets for vendor quotation, but also to the selection of right type of compressor for the intended service.

In the following pages various facets of reciprocating compressors are reviewed. Detail description of the compressor components and their design features are beyond the scope of this work and not presented. A brief overview of major components of the reciprocating compressor is, however, presented to aid in the development of compressor specification sheets.

Description

As mentioned earlier, a reciprocating compressor is a positive displacement machine that utilize the motion of a piston in a cylinder to compress the gas. The basic construction of a reciprocating compressor is depicted in Figure 7.7. It consists of a frame (housing) to which are attached the necessary compressor cylinders and driver, plus the necessary auxiliaries such as intercoolers (where required), interconnecting gas piping, cooling water jacket piping etc.

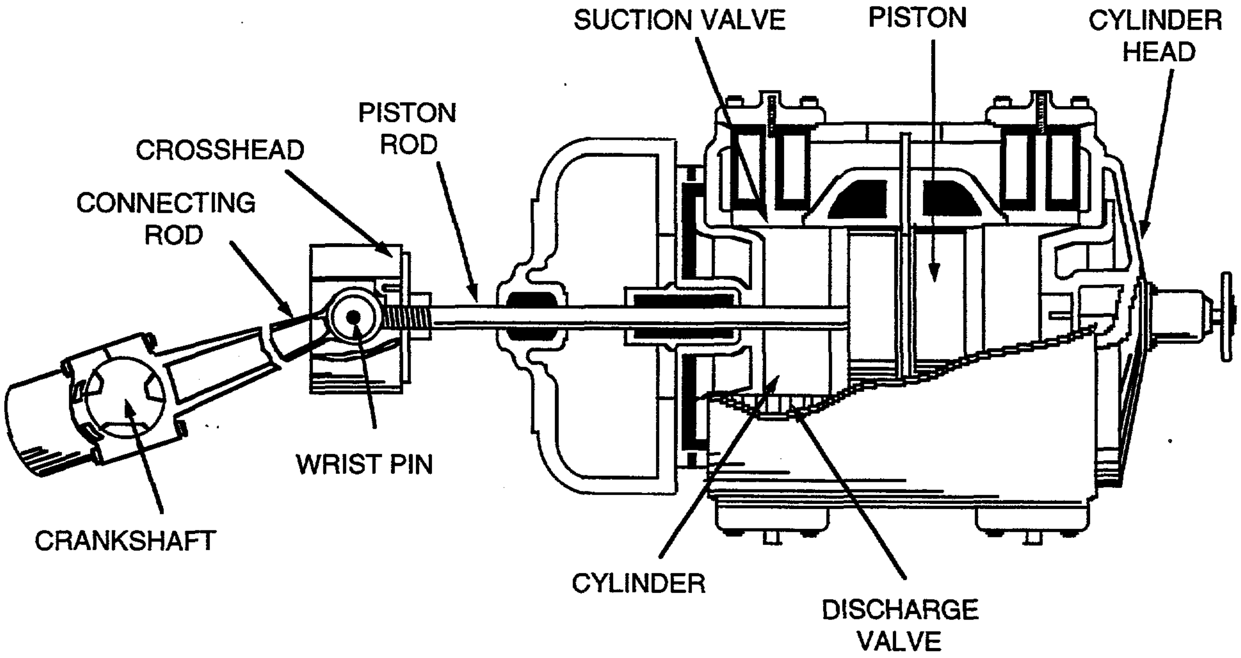


FIGURE 7.7 — Basic Construction of Reciprocating Compressor

Each cylinder assembly of a reciprocating compressor consist of a piston, cylinder, cylinder heads, suction and discharge valves, and the parts necessary to convert rotary motion of the driver to reciprocating motion of the compressor piston (connecting rod, crosshead, crosshead pins, and piston rod)

A reciprocating compressor is said to be *single–acting* if the compression occurs only on one end of the piston. In a *double-acting* compressor, compression takes place on both side of the piston. Almost all of the compressors employed in the oil field are double-acting. In these compressors, the gas (air) is compressed alternatively on each end of the piston. Because of the cylinder area occupied by the piston rod, the available area for compression on the crank end (piston rod side) is less than on the head end of the piston.

The reciprocating compressor uses automatic spring loaded valves to admit the gas into and out of the cylinder. These valves open only when the proper differential pressure exists across the valve. The inlet valve opens when the pressure inside the cylinder is slightly below the intake pressure. Discharge valve open when the pressure in the cylinder is slightly above the discharge pressure. The discharge valve closes once the pressure in the cylinder drops below the discharge line pressure, thus preventing flow reversal.

All reciprocating compressors have a space between the end of the piston and the cylinder head. The volume formed by this space plus the volume formed by the valve cavities is called the fixed clearance. This clearance, plus any variable clearance (addition or subtraction of clearance volume through the use of clearance pockets), constitutes the total clearance volume.

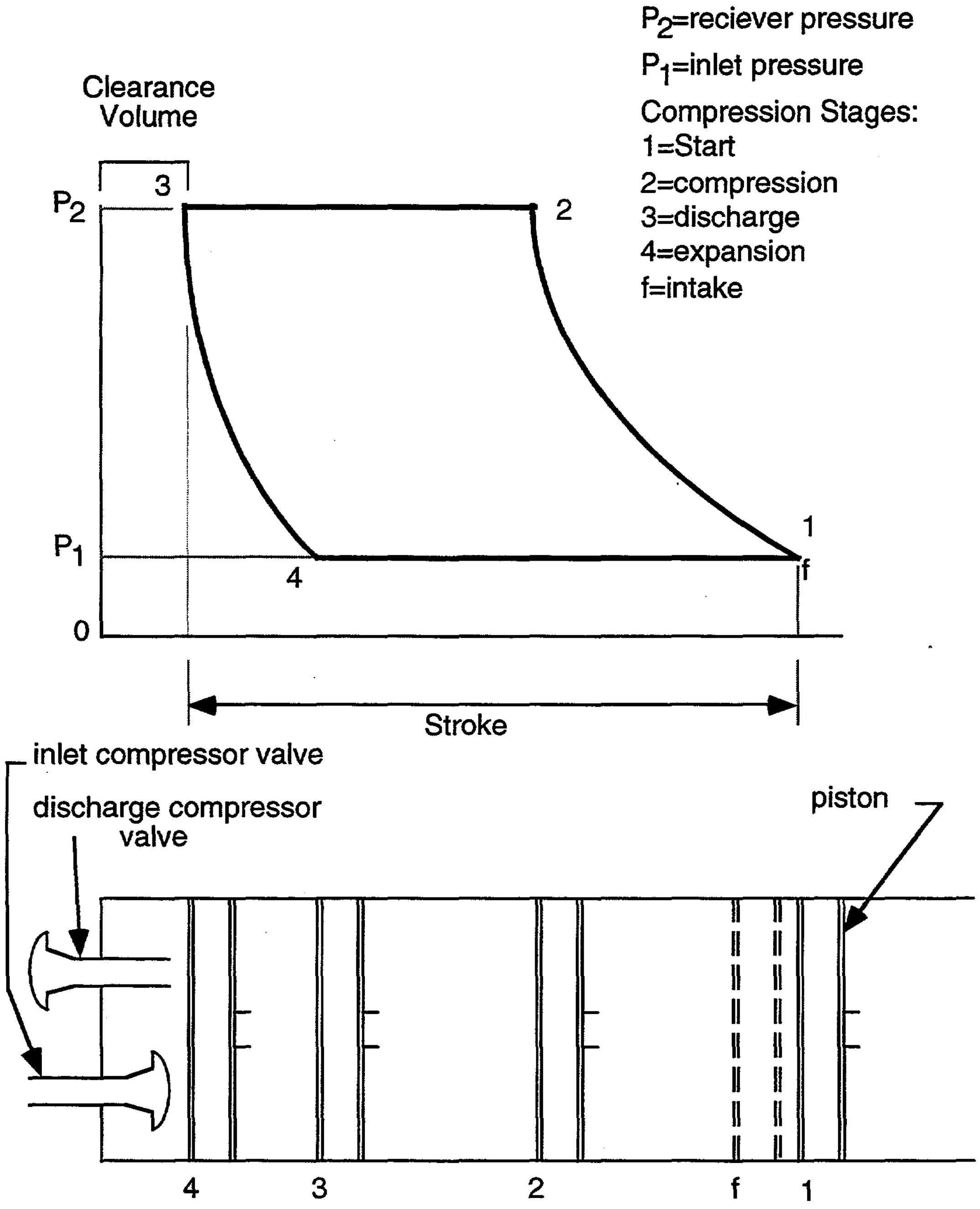


FIGURE 7.8 — Diagram Illustrating Ideal Reciprocating Compressor Cycle

Figure 7.8 shows the ideal basic cycle of a reciprocating compressor on a pressure volume (PV) diagram. The events during this cycle are as follows.

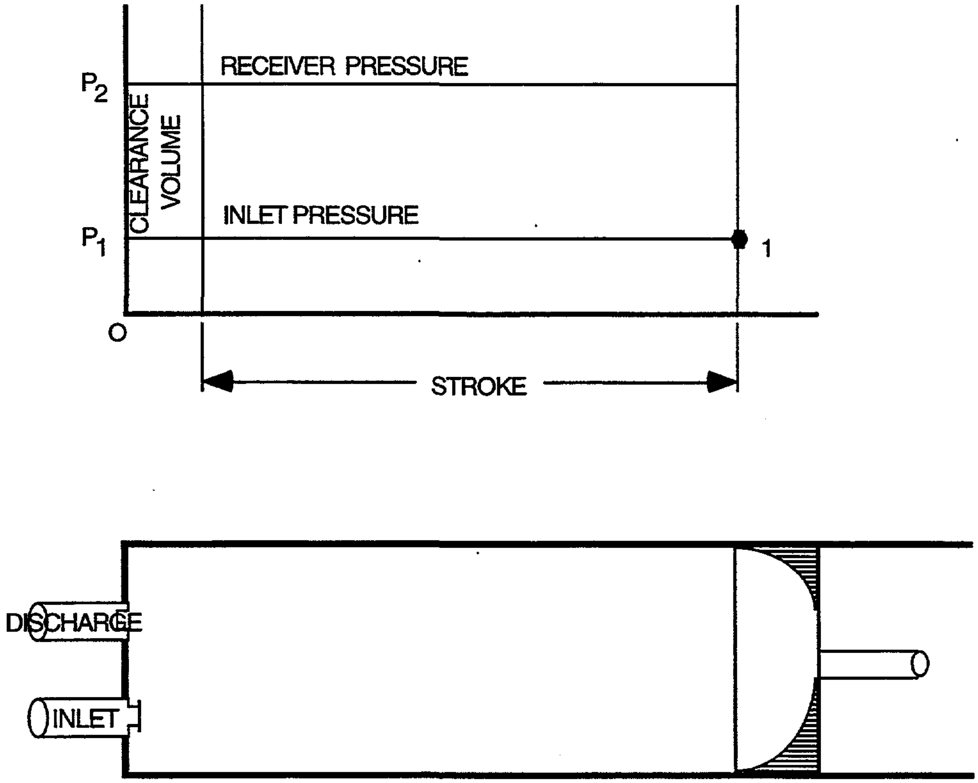


FIGURE 7.8A — Intake

- Figure 7.8A, shows the basic element with the cylinder full of atmospheric air. On the theoretical PV diagram, point 1 is the start of compression. Both valves are closed.

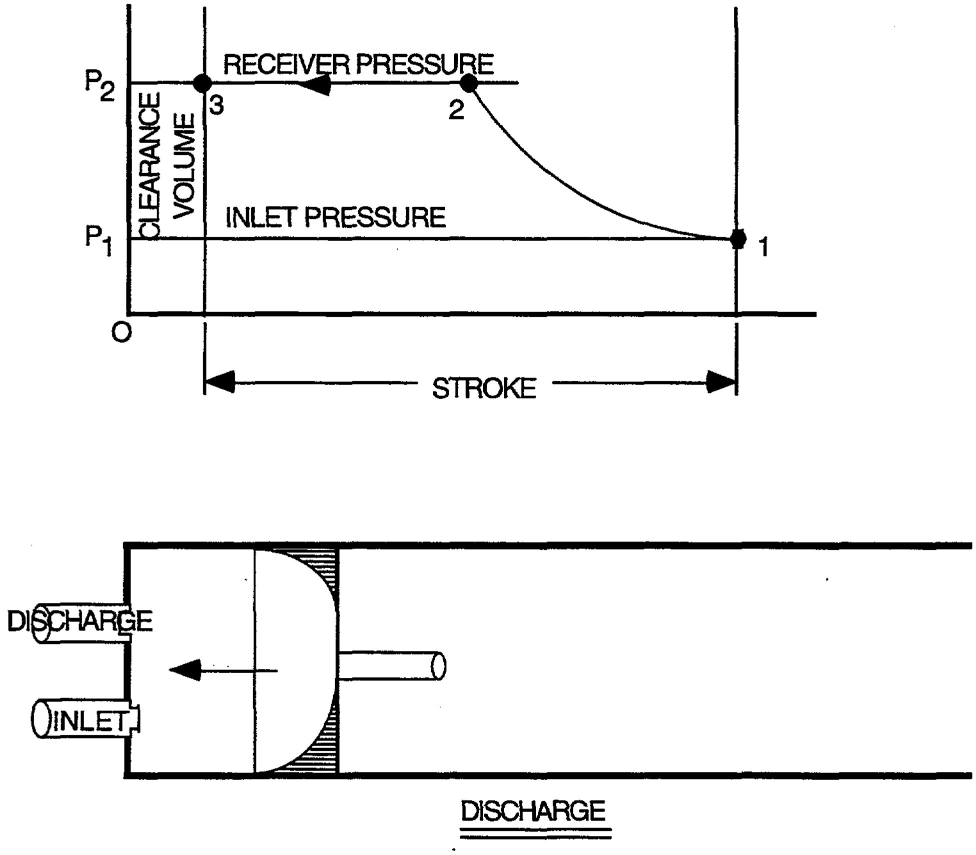


FIGURE 7.8B — Compression

- Figure 7.8B shows the compression stroke. Here the piston moved to the left, thus reducing the original volume of air with an accompanying rise in pressure. With the suction and discharge valves closed, the piston moves from point 1 to point 2 and the air is compressed isentropically (no heat transferred in or out of the air, and no frictional losses) until the pressure in the cylinder reaches the discharge pressure.

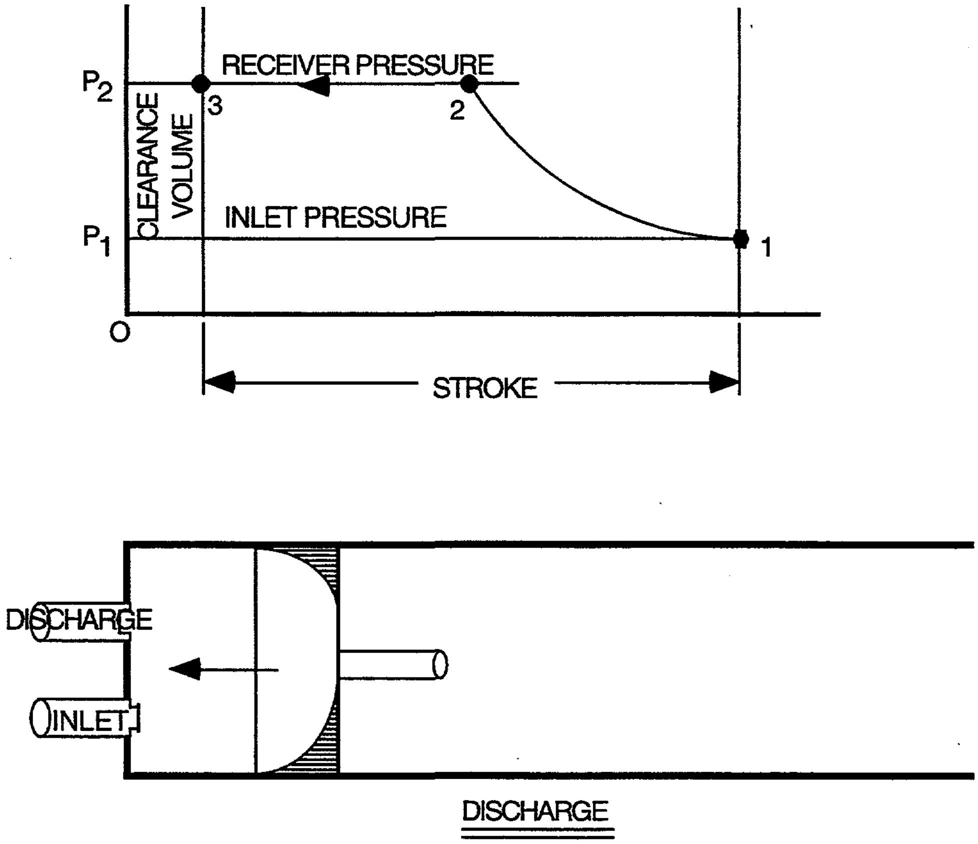


FIGURE 7.8C — Discharge

- Figure 7.8C shows the discharge stroke. At a point just beyond point 2, the discharge valve opens and remains open until the piston reaches the end of the stroke at point 3. The compressed air flows out through the discharge valve into the discharge line.

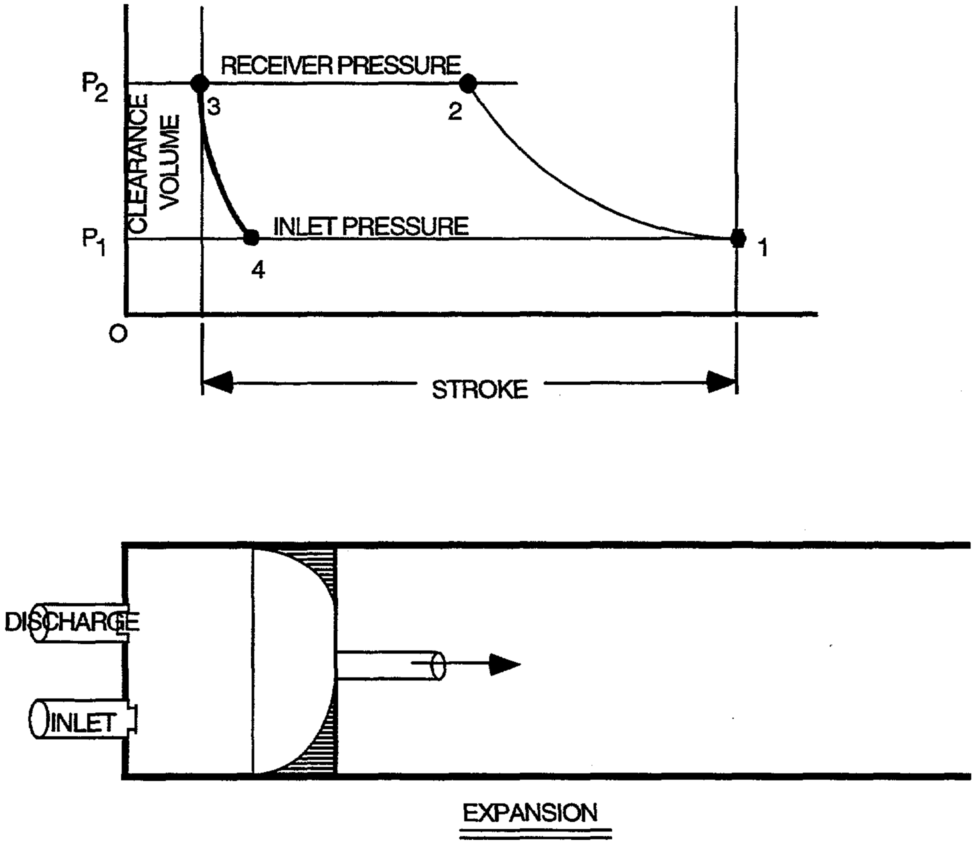


FIGURE 7.8D — Expansion

- Figure 7.8D shows the expansion stroke.When the piston reaches point 3, the discharge valve closes; leaving the clearance space filled with air at discharge pressure.During the expansion stroke, both the inlet and discharge valves remain closed and the trapped air in the clearance space expands isentropically from discharge pressure at point 3 to point 4, at which point the pressure drops below the inlet pressure. During this cycle the piston moves to the right.

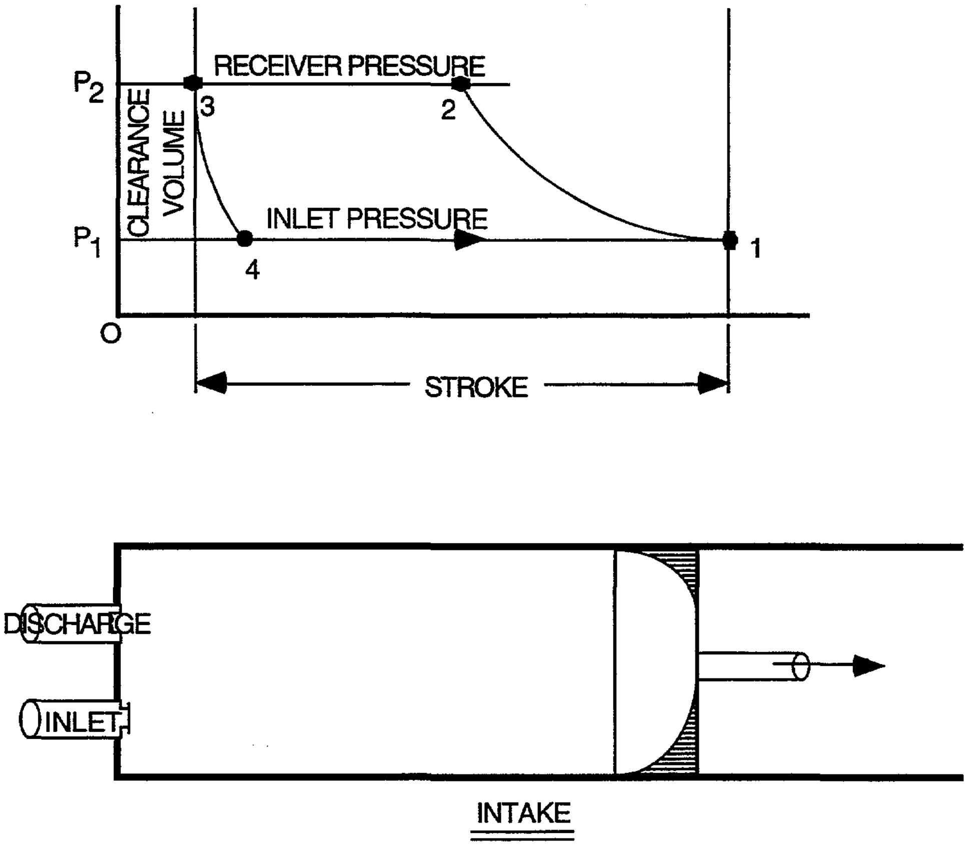


FIGURE 7.8E — Suction

- Figure 7.8E shows the intake or suction stroke. At point 4, the inlet valve opens and the air flows into the cylinder as the piston moves from point 4 to point 1. At point 1 on the PV diagram, the inlet valve closes and the cycle repeats on the next revolution of the crank.

Reciprocating Compressor Performance

To determine the quantity of air that a specific compressor can compress and discharge, the *displacement*, *volumetric efficiency*, and *cylinder capacity* must be known.

Displacement of a compressor is the actual volume displaced by the piston and is normally expressed in cubic feet per minute, or ft. ^{3}/min. It is a function of the area of the piston face, the length of the stroke, and the number of strokes per unit time. Most compressor manufacturers publish data listing displacement at full compressor speed for each size (bore, stroke, rod size) cylinder that is manufactured.

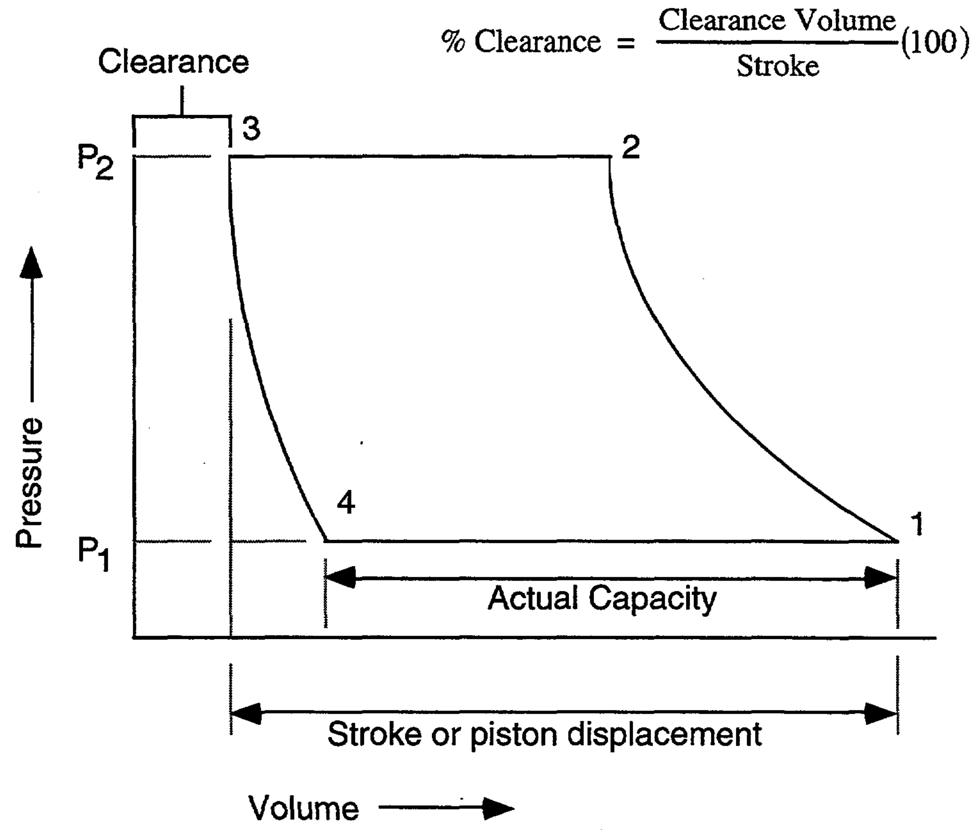


FIGURE 7.9 — P-V Diagram Showing Clearance Volume

Clearance volume is the volume remaining in the compressor cylinder at the end of a discharge stroke (Figure 7.9). The clearance volume is usually set by the compressor manufacturer and is set to match the specified compressor cylinder capacity.

Compressor cylinder capacity is the intake volume of air expressed in cubic feet per unit time at suction conditions of temperature and pressure. This volume is calculated as the piston displacement (expressed in ft. ^{3}/min.) multiplied by the volumetric efficiency.

Volumetric efficiency in a reciprocating compressor is the ratio of actual cylinder capacity to piston displacement, stated as a percentage. Volumetric efficiency is a function of clearance volume, compression ratio, and the ratio of specific heat 'k'. The theoretical volumetric efficiency may be calculated as follows:

$$E_v = 100 - C\left[(R_c)^{\frac{1}{k}} - 1\right] \qquad (7.32)$$

Where:

E_v = volumetric efficiency expressed as a percentage

C = cylinder clearance expressed as a percentage of cylinder volume

R_c = the ratio of compression

$$= \left(\frac{\text{discharge pressure, psia}}{\text{suction pressure, psia}}\right)$$

k = ratio of specific heat capacities at average cylinder temperature.

Equation (7.32) is based on ideal PV diagram, and does not take into account factors that affect the volumetric efficiency under actual operating conditions. The actual volumetric efficiency is always lower than that calculated from Equation (7.32) due to the neglect of factors such as the inlet gas preheating, pressure drop across the valves, internal leakage, gas friction, etc. A more practical formula used by compressor manufacturers to calculate actual volumetric efficiency is given by:

$$E_v = 96 - L - C\left[(R_c)^{\frac{1}{k}}\left(\frac{Z_s}{Z_d}\right) - 1\right] \qquad (7.33)$$

Where:

Z_s, Z_d = gas compressibility factors at suction and discharge respectively.

= C an arbitrary adjustment factor to account for losses due to inlet preheating, pressure drop across the valves etc.

L = factor to account for internal leakage losses

Most compressor manufacturers provide charts to calculate the volumetric efficiency. Figure 7.10 is one such chart for a gas having a ‘k’ value of 1.4.

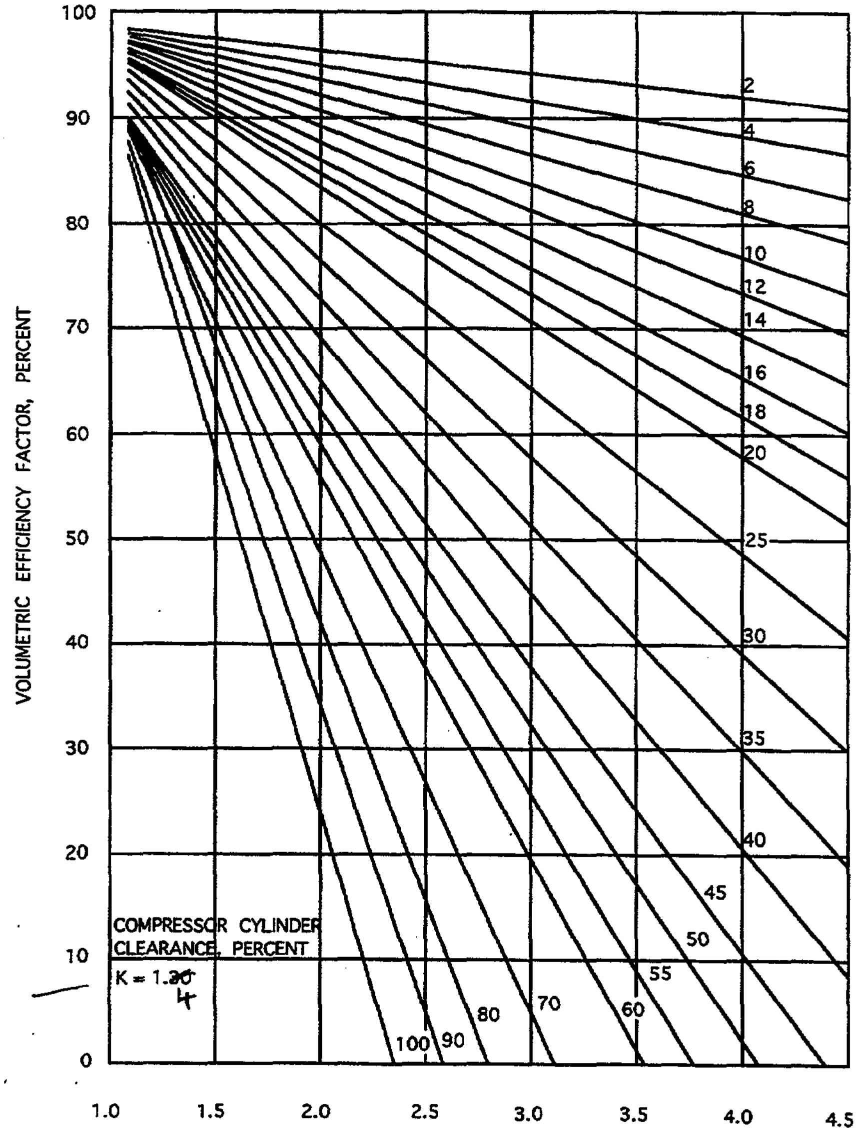


FIGURE 7.10 — Typical Compression Ratio vs Volumetric Efficiency Curves for a Reciprocating Compressor (Reproduced with Permission from Compressed Air and Gas Data Book)

Discharge Temperature

Gas temperature increase as gas is compressed. Since air support combustion, the oil vapors present in the cylinder can ignite and explode if the cylinder temperature is too high. Further, at elevated temperature the lubricating oil may breakdown and prone to carbonization. Also the life of the cylinder packers is shortened by the dual requirement to seal both high pressure and high temperature. Hence the cylinder discharge temperature of an air compressor must be limited to a safe value.

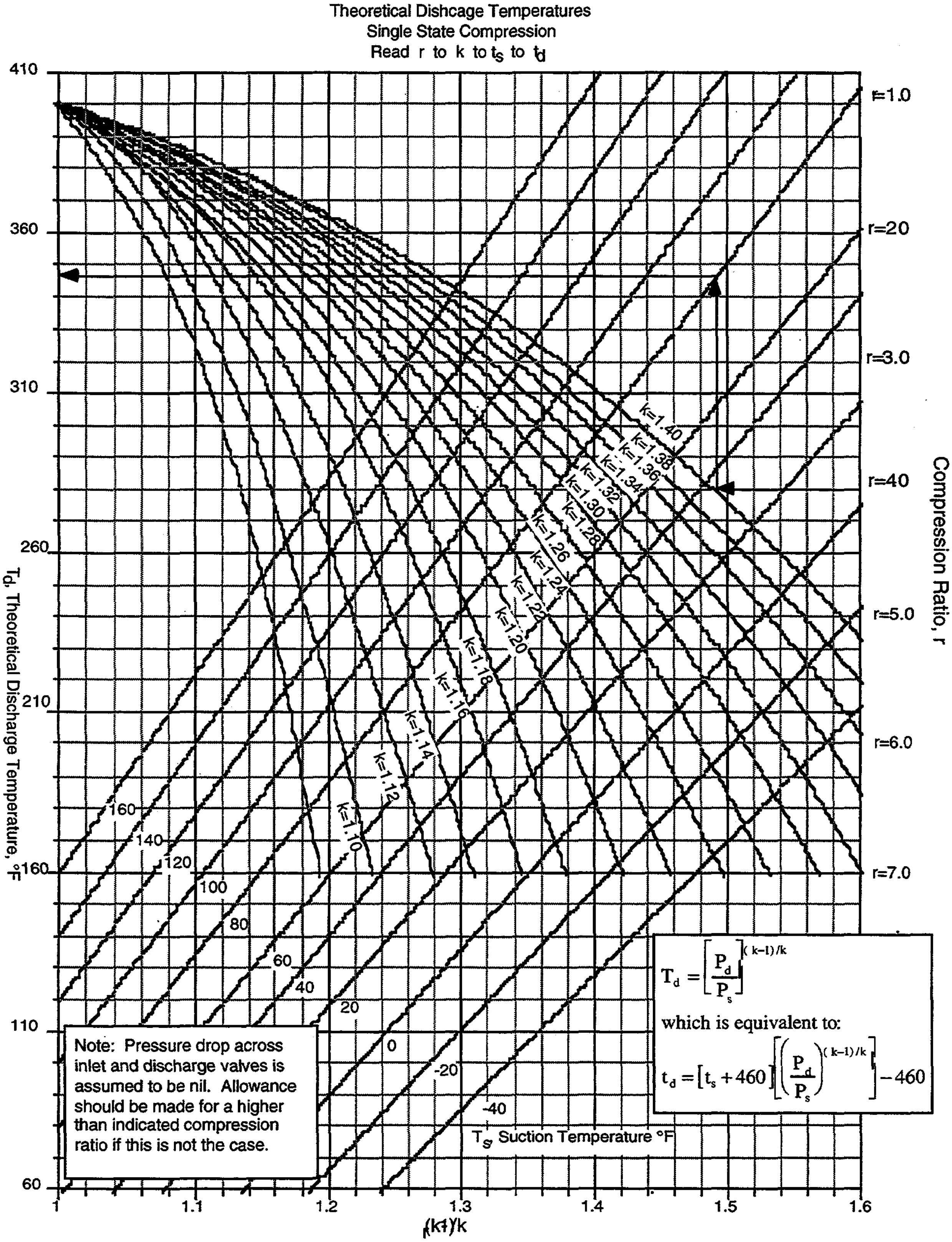
The temperature of the gas discharged from the cylinder is calculated from Equation (7.7) as:

$$T_d = T_s \left(R_c\right)^{\frac{k-1}{k}} \qquad (7.34)$$

Where:

T_d = absolute discharge temperature, °R or K

T_s = absolute suction temperature, °R or K



Theoretical Dishcage Temperatures
Single State Compression
Read r to k to t_s to t_d

$$T_d = \left[\frac{P_d}{P_s}\right]^{(k-1)/k}$$

which is equivalent to:

$$t_d = [t_s + 460]\left[\left(\frac{P_d}{P_s}\right)^{(k-1)/k}\right] - 460$$

Note: Pressure drop across inlet and discharge valves is assumed to be nil. Allowance should be made for a higher than indicated compression ratio if this is not the case.

FIGURE 7.11 — Chart to Estimate Theoretical Discharge Temperature from a Cylinder (Reproduced with Permission from Compressed Air and Gas Data Book)

Figure 7.11 is a chart that can be used to solve Equation 7.34. The discharge temperature determined from either Equation 7.34 or from figure 7.11 is the theoretical value. Since the Equation 7.34 neglect the heat from friction, irreversibility effects etc., the discharge temperature obtained from the chart or equation is always lower than the measured value. Discharge temperature is often controlled by circulating water through cylinder jacket. For a water cooled reciprocating compressor operating at a volumetric efficiency greater than 20%, the value calculated from Equation 7.34 is close to the actual value.

To reduce carbonization of the lubricating oil and the danger of fires when compressing air, it is desirable to maintain discharge temperatures below 250°F.

Multi Staging

As pointed out in the previous section the maximum permissible compression ratio across the cylinder is limited by the desirable cylinder discharge temperature. Further, a high compression ratio will mean a low volumetric efficiency and require a larger cylinder to produce the same capacity. For this reason multi staging is used in reciprocating compressors.

If R_{co} is the overall compression ratio then for 'n' stages the compression ratio per stage is given by:

$$R_{cn} = \sqrt[n]{R_{co}} \tag{7.35}$$

Where R_{cn} is the compression ratio for each stage.

For example:

Three stage: $R_{cn} = \sqrt[3]{R_{co}}$

Two stage: $R_{cn} = \sqrt[2]{R_{co}}$

The per stage compression ratio obtained from Equation (7.35) is a theoretical value and does not account for the pressure losses between stages. However, it is a useful first approximation for estimating the required number of stages. The actual interstage pressures are defined by the compressor manufacturer, who will take into account the intercooler and aftercooler pressure drops. Many compressor vendors recommend that the per stage compression ratio be kept 4 or less when compressing air.

Compressor Horsepower Estimation

The total horsepower required to compress the air from the inlet pressure to the desired final discharge pressure determines the compressor size and drive requirement. This is needed to prepare the compressor inquiry data sheet. Gas processors Association recommend the use of Equation (7.36) to obtain a quick and reasonable estimate of compressor horsepower.

$$\text{BHP} = (20) \times (\text{ratio per stage}) \times (\text{No. of stages}) \times (\text{MMcfd}) \times (F) \qquad (7.36)$$

Where:

MMcfd = Compressor capacity referred to 14.4 psia and suction temperature

F = An allowance for interstage pressure drop

Use 1.0 for single stage compression

Use 1.08 for two-stage compression

Use 1.10 for three-stage compression

Curves are available which permit easy estimation of approximate compression horsepower requirements. Figure 7.12 is typical of these curves. The horsepower required is determined by entering the x-axis at the total compression ratio and going vertically to the appropriate curve, and then horizontally to the y-axis to determine the break horsepower requirement per MMcfd.

Horsepower obtained using Equation (7.36) or Figure 7.12 are based on average values and more accurate values are needed for accurate sizing of the compressor. Detailed compressor horsepower calculations can be made using the BHP/ MMcfd curves (Figures 7.13 through 7.16). These curves published by compressor manufacturers provide net horsepower and include mechanical efficiency and other losses. The proper use of these charts should provide the user with reasonably correct horsepower requirements for inquiry.

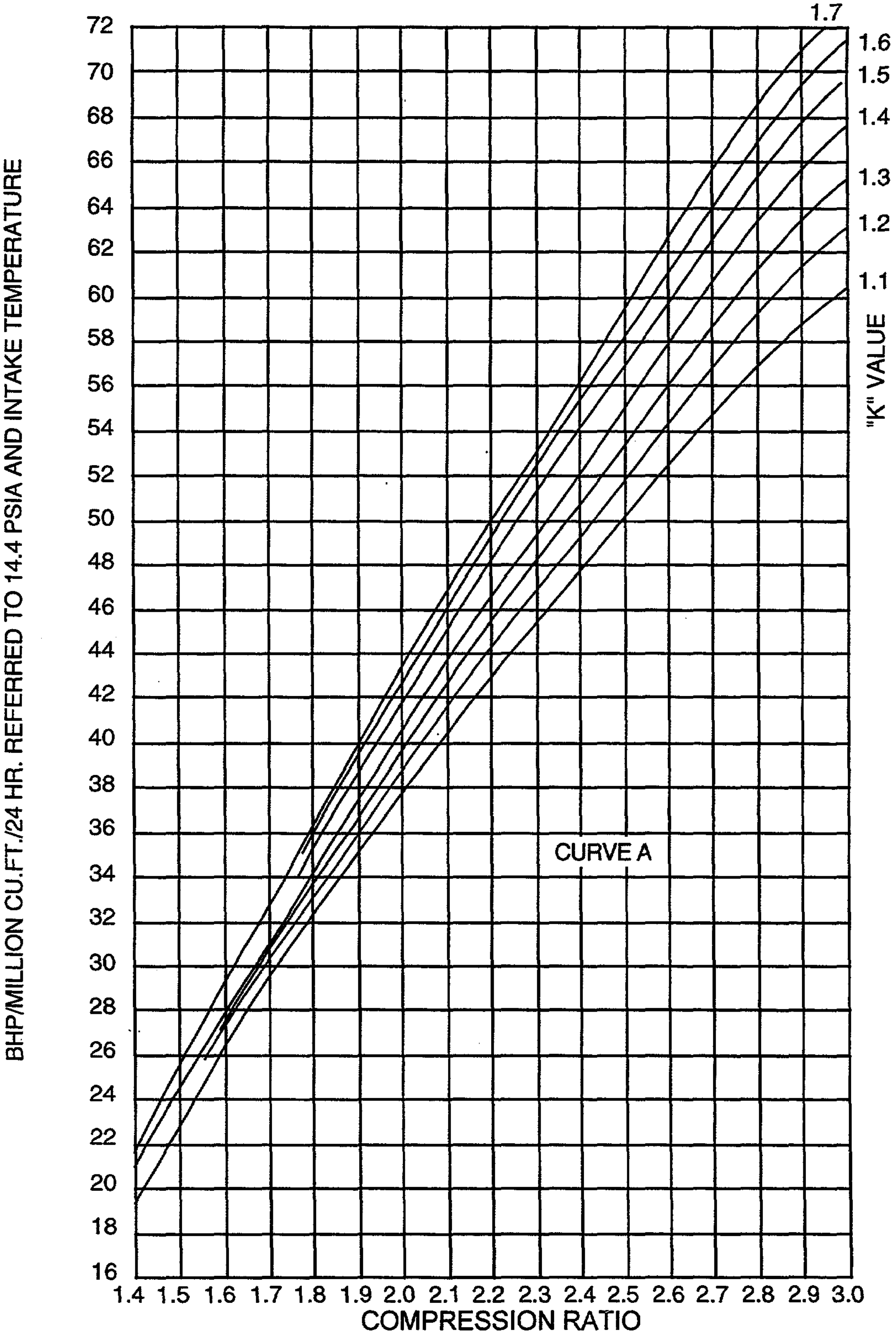


FIGURE 7.12 — Horsepower Curves for Reciprocating Compressor for Different 'K' (Compression Ratio ≥ 3) (Loomis, 1980)

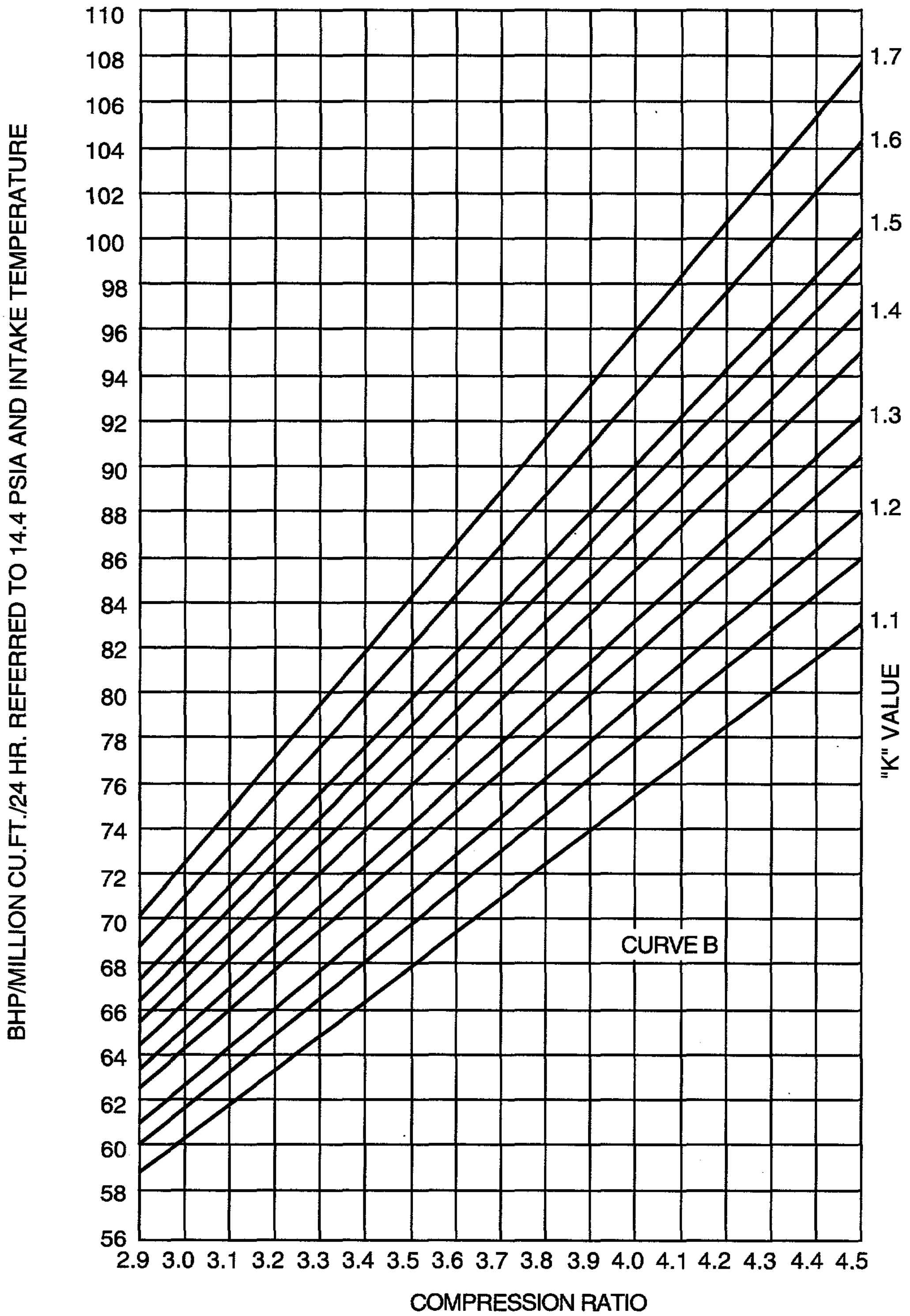


FIGURE 7.13 — Horsepower Curves for Reciprocating Compressor (Compression Ratio 2.9 to 4.5) (Loomis, 1980)

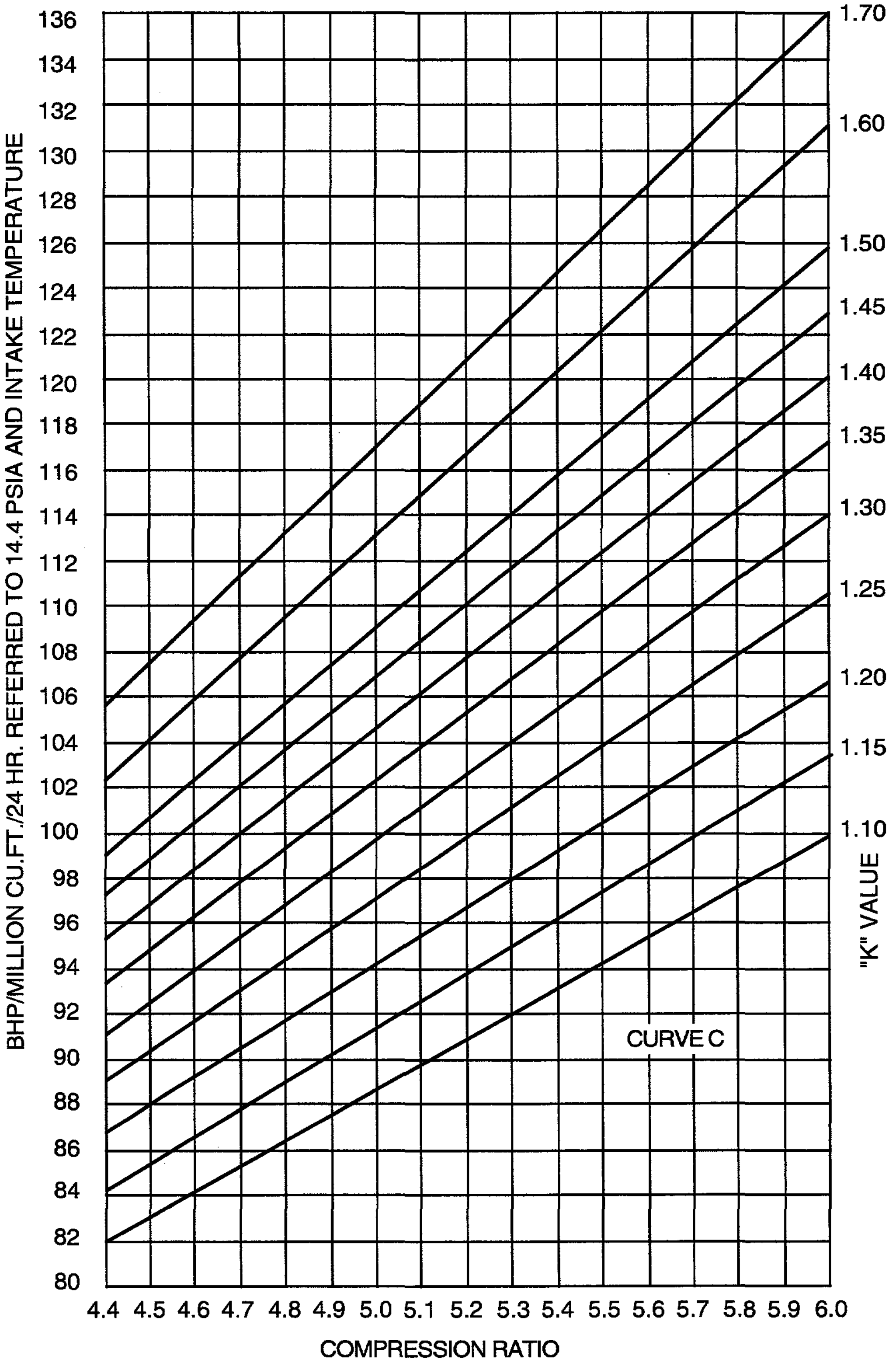


FIGURE 7.14 — Horsepower Curves for Reciprocating Compressor (Compression Ratio 4.4 to 6.0) (Loomis, 1980)

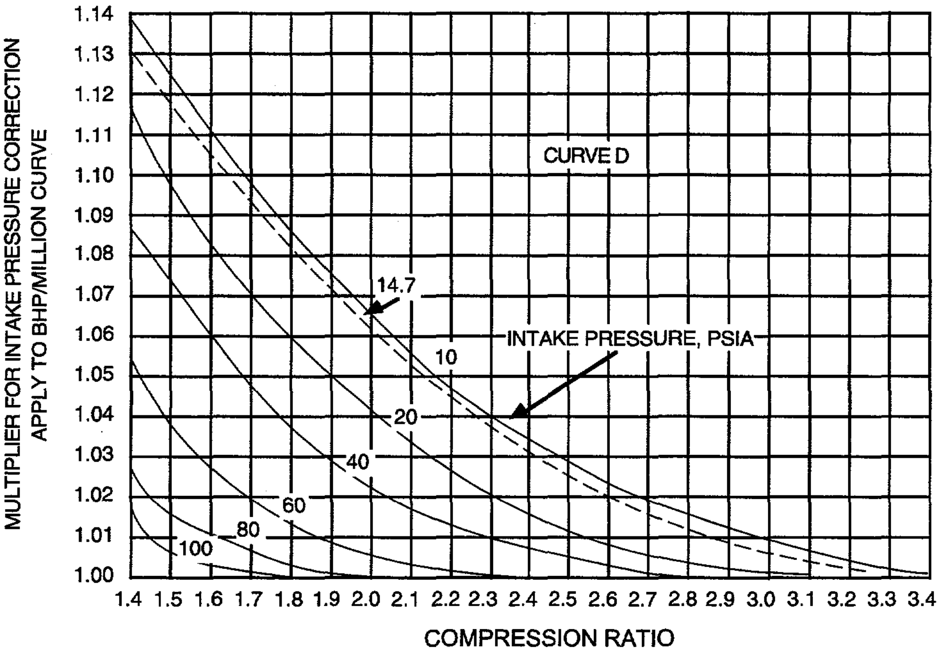


FIGURE 7.15 — Correction Factor Curves for Low Intake Pressure (Loomis, 1980)

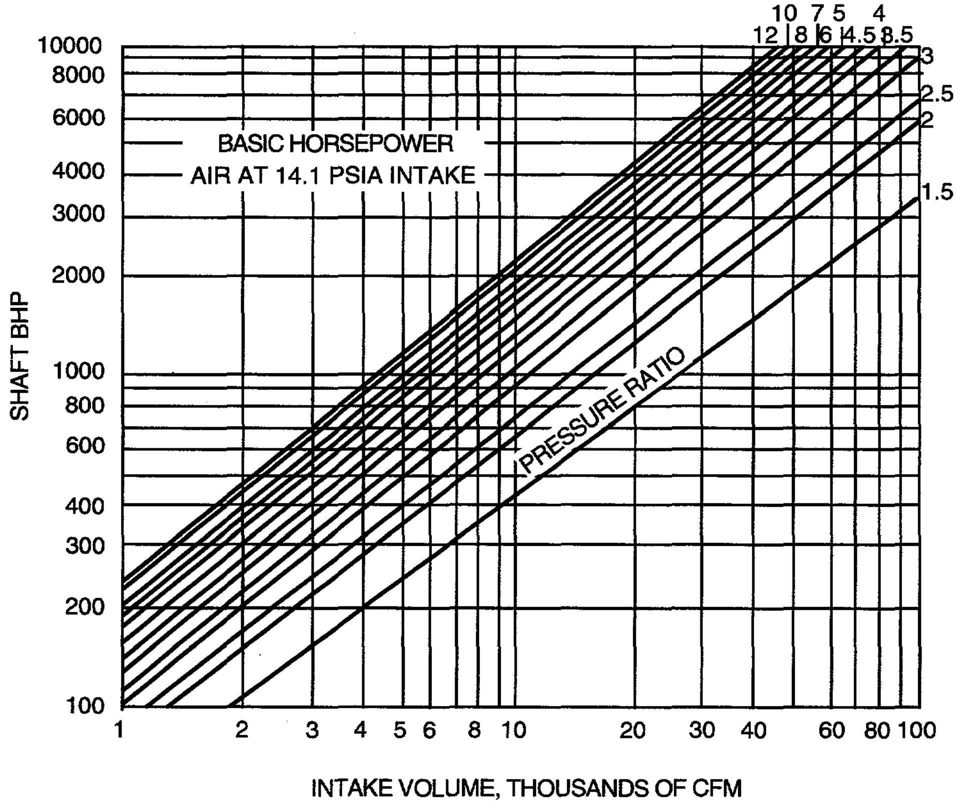


FIGURE 7.16 — Reciprocating Compressor — Shaft Horsepower Estimation Curves (Loomis, 1980)

Note that Q in these charts are in MMcfd at prevailing suction temperature and 14.4 psia rather than at 14.7 psia and 60°F (scf) the standard used in oil field.

The above horsepower charts provide the power requirement per stage. When using the horsepower charts, each stage of compression must be calculated separately and the totals added together to obtain the total brake horsepower requirement. Volume to be handled at each stage must be corrected to the actual temperature and moisture content at the inlet to that stage.

When multi stages are used, allowance must be made for interstage pressure drop. Inter-stage pressures may be obtained as follows:

1. Obtain the overall compression ratio R_{co}.
2. Calculate the ratio per stage (R_{cn}) by taking the n^{th} root of overall compression ratio where 'n' is the number of compression stages.
3. Multiply R_{cn} by the absolute intake pressure of the stage being considered.

This procedure should give the absolute discharge pressure of a stage and the calculated intake pressure to the next stage. The calculated upper stage intake pressure is then corrected for intercooler pressure drop by reducing the pressure by 3–5 psi.

The per stage horsepower for compression is then calculated using Figures 7.13 through 7.16 and Equation 7.37

Where:

$$\text{BHP} = \left(\frac{BHP}{MMcfd}\right)\left(\frac{14.7}{14.4}\right)\left(\frac{T_s}{520}\right)(Z_{avg})\left(\frac{MMScf}{d}\right) \tag{7.37}$$

is read from Figures 7.13 through 7.16

14.7 = Standard pressure base, psia

14.4 = pressure base, psia for Figures 7.13 through 7.16

T_s = suction temperature, °R

MMScf/d = Millions of standard cubic feet of air (rate per day) measured the standard condition of 14.7 psia pressure and 60°F (520°F).

$$Z_{avg} = \left(\frac{Z_s + Z_{14.7}}{2}\right)$$

The horsepower requirement for multistage compression is decreased by intercooling between stages. If intercooling is not employed, the heat of compression in the first stage will increase the volume to be compressed in the second stage with the resultant increase in horsepower requirement. The horsepower required by the second stage is in direct proportion to the absolute inlet temperature of the first stage. Hence, the second stage horsepower requirement will be equal to the first stage horsepower multiplied by the ratio of temperature increase across the first stage. The temperature ratio may be expressed by (see Equation 7.34):

$$c^{\frac{k}{k-1}} \tag{7.38}$$

Where: c = compression ratio per stage

k = ratio of specific heat

The second stage horsepower may be determined from the following expression, in which subscript 1 refers to the first stage and subscript 2 to the second stage.

$$\left(\frac{BHP}{MMcfd}\right)_2 = \left(\frac{BHP}{MMcfd}\right)_1 \times (c_1)^{\frac{k-1}{k}} \tag{7.39}$$

If intercooling is used, the total horsepower required is roughly equal to the horsepower requirement of the first stage multiplied by the number of stages. This assume that the inlet temperature and compression ratio per stage is the same for all stages.

Reciprocating Air Compressor for ISC services

Both packaged and process type reciprocating compressors are used in ISC projects.

Packaged Compressors

Packaged type compressors probably account for the majority of installed units in the past U.S. ISC projects. The vast majority of past U.S. ISC projects were small pilots, implemented by smaller operators with limited technical man power resources. A packaged system is ideally suited for such situation, because it offers a completely factory engineered and tested system, ready to install at the site. This relieve the operator or his technical staff from the need for the sizing and specification of compressor and its auxiliaries.

A packaged compressor may be defined as a system that include all the components necessary to provide a controlled compressed air source. Though, there is no industry definition of what is included in a package, API Spec. 11P recommend that such a system be include compressor, driver (engine or motor), compressor cooling system, exhaust silencer, emission control equipment, inlet air filter, scrubbers, control panel, piping, pulsation bottle, etc., all mounted and aligned on a skid as an operable unit with a minimum of field construction. The skid must be designed to withstand the loading and the moves from one job site to the next. The ideal and most desirable package for the operator is one in which only the required utilities of power and cooling water are brought to the package, with the end product being clean dry air.

Packaged type compressor for oil field service are generally offered in sizes ranging from a minimum of approximately 300–7,000 BHP. Discharge pressure range from 125 psig to up to about several thousands psig. These systems are ideal for projects where the injection volume and pressure are moderate.

Process Compressors

Process compressor systems are similar in configuration to the packaged system, but are designed for permanent installation. The process compressor system include only the compressor, driver, power transmission equipment and basic control system. Procurement of all the other necessary components such as the lubricating system, instrumentation, inter and after coolers, pulsation suppression system, piping, emission control equipment etc. is the responsibility of the purchaser. The compressor vendor is responsible for the satisfactory performance of the secondary equipment only if he supplies them. Otherwise, the compressor vendor is responsible only for the proper performance of compressor train which includes compressor, driver, power transmission components and the associated equipment. In the event the auxiliary equipment are purchased from other sources, the purchaser should coordinate these purchases with the compressor vendor to ensure smooth integration of components and for realizing low maintenance, trouble free operation under the specified service condition.

Process type air compressor is a heavy duty low to moderate speed (300–600 rpm) machine designed for a minimum service life of 20 years and at the minimum 3 yeas of uninterrupted operation. Process type compressors are best suited for use in large scale commercial air injection projects whose volume throughput and injection pressures are high. All the commercial air injection projects in the U.S. utilize process type compressor in their operation.

Reciprocating Compression Selection

Proper selection of a compressor for a particular application involves preparing specifications from which the manufacturers will quote their equipment. The specifications must include certain minimum design data, such as description of equipment sought (reciprocating or centrifugal compressor), capacity, discharge pressure and temperature, type of prime mover, and other required options. The preparation procedure of a specification sheet for the purchase of a reciprocating compressor is outlined briefly in the following.

1. Establish the inlet and discharge conditions and compression ratio.
2. Decide whether the compressor is to have one, two, or more stages of compression. The ratio of compression permissible in one stage is usually limited by the discharge temperature. A sufficient number of stages, with cooling between them, must be used to prevent the discharge temperature from exceeding the practical limit. As a first approximation, the temperature of the air discharged from a cylinder (stage) can be estimated from the Equation 7.34. When multistage operation is involved; equal ratios of compression per stage are commonly used. For three-stage compression, the compression ration per stage is approximately equal to the cube root of the total compression ratio.
3. Establish the required capacity in standard cubic feet/day and convert it to the actual volumetric quantity of air at the inlet condition of the respective stages on a per minute basis (cubic feet per minute, cfm). The desired capacity rate must be explicit and the conditions of pressure and temperature at which it is measured must be given.
4. Establish the horsepower requirements. For the purpose generalized charts provided by the compressor manufacturer (Figures 7.12 through 7.16) can be used. The total required compressor horsepower (sum of the horsepower per stage) determines the required frame size. A frame can be considered as a platform to which the necessary compressor cylinders, driv-

ers, and the auxiliaries such as intercoolers, interconnecting piping, valves, etc., are mounted.

5. Determine the approximate compressor cylinder sizes. The required capacity of each has already been established (Step 3). From appropriate charts or formulas, the volumetric efficiency of each stage of compression must be established to calculate cylinder size.
6. Now check the frame loadings to be sure that all are within the design limits established for the selected frame. If all are too high, a heavier frame must be used.
7. Assuming the frame requirements have been met, the selection so far as stroke, speed, number of stages and sizes of cylinders is now complete. Now recalculate the horsepower requirements more accurately. Table 7.2 depicts a typical reciprocating compressor inquiry form recommended by compressed air institute. It maybe used as a guide to the information that should be submitted with an inquiry about a new reciprocating air compressor.

TABLE 7.2 — Reciprocating Compressor Inquiry Sheet

( ) Any Customer Written Specifications Yes______ No_____ (If "yes," attach specification).

( ) Description of Application:

( ) Duty Cycle_____hrs/day. Average continuous operating time______minutes

( ) Gas Handled________Clean______________Contaminated with_________

Dry____ Wet_____

( ) Gas Analysis: (If available give mol. wt., compressibility factor)

(for air, $N_2 = 0.79$, $0_2 = 0.21$)

( ) Any comments on previous experience or preference as to materials in piston rings, piston rod, cylinder liners, type stuffing box, type packing, valve material?

( ) Barometer_____psia or Altitude_____ft. above sea level

( ) Intake pressure________psig Intake Temp._______ °F Rel. Humidity_______%

Possible variation of intake pressure from_____psig to _____psig

( ) Disch. Press______psig. Possible variation from______psig to______psig

( ) Capacity required______cfm, cfh, cfd measured at_____ psig at_____°F dry or sat.

Acceptable variation of capacity from__________cfm to______________cfm

( ) Regulation required to control from_____intake pressure_____discharge pressure

( ) Automatic start and stop Cut-in____psig Cut-out_____psig

( ) Constant speed control Cut-in____psig Cut-out_____psig

( ) Type of Drive ____

( ) Electrical Conditions ___________________ Steam Conditions______________

( ) Type of Mounting ____

( ) Location of Unit: outdoors or indoors; hot or cold ambient; ventilated or non- ventilated space.

( ) Cooling Water: Temp______°F. Clean_______Dirty________Salt Water______

Fresh Water___________ Corrosive?__________

( ) Special accessories required:

Filter_____Aftercooler______Receiver_____Type Starter______ Belt Guards______

( ) Other pertient information not covered above:

( ) Number of units required__________ Shipment needed_______________________

( ) Only estimating information needed by_____________________________________

( ) Firm quotation needed by____

Centrifugal Compressors

Centrifugal compressors are machines in which air is compressed by the mechanical action of rotating vanes or impellers imparting velocity and pressure to the air. In a centrifugal compressor the flow is in a radial direction. The following is adopted from the "Compressed Air and Gas Handbook" with permission from the Compressed Air and Gas Institute, Cleveland, Ohio.

Definitions

The following definitions will be helpful in understanding the construction and application of centrifugal-type compressors:

Base plate is a metal structure on which the compressor is mounted and after the driver as well.

Capacity is the rated maximum flow through a compressor at its rated inlet and outlet temperature, pressure and humidity. Capacity is often taken to mean the volume flow at standard inlet temperature, pressure and humidity.

Casing is the pressure-containing stationary element that encloses the rotor and associated internal components, and it includes integral inlet and discharge connections (nozzles).

Diaphragm is a stationary element between the stages of a multistage centrifugal compressor. It may include guide vanes for directing the air or gas to the impeller of the succeeding stage. In conjunction with an adjacent diaphragm, it forms the diffuser surrounding the impeller.

Diaphragm cooling is a method of removing heat from the air or gas by circulation of a coolant in passages built into the diaphragm.

Diffuser is a stationary passage surrounding an impeller in which velocity pressure imparted to the flowing medium by the impeller is converted into static pressure.

Efficiency any reference to the efficiency of a dynamic-type compressor must be accompanied by a qualifying statement that identifies the efficiency under consideration. (See Sec. 7) for definitions of adiabatic, polytropic, etc.)

Flange connection (inlet or discharge) is a means of connecting the casing to the inlet or discharge piping by means of bolted rims (flanges).

Guide vane is a stationary element that may be adjustable and that directs the flowing medium to the inlet of an impeller.

Impeller is the part of the rotating element that imparts energy to the following medium by means of centrifugal force. It consists of a number of blades mounted so as to rotate with the shaft. Impellers may be classified as follows:

a. *Open face* without enclosing cover, may be cast in one piece, milled from a solid forging, or built up from castings, forgings, or plates.

b. *Closed type* with enclosing cover and hub disk, which may be cast in one piece or built up from castings, forgings, or plates. Blades may be attached to the enclosing cover and hub disk with separate rivets, with machined integral with the blades or by welding.

Impellers are further classified with respect to blade form, as follows:

a. *Radial bladed*, having straight blades extending radially.

b. *Backward bladed*, having straight or curved blades installed at an angle to the radius and away from the direction of rotation.

Inducer is a curved inlet section on an impeller.

Multicasing compressor. When two or more compressors are driven by a single motor or turbine, the combined unit is called a multicasing compressor or compressor train.

Performance curve is a plot of expected operating characteristics (e.g., discharge pressure versus inlet volume flow, or shaft horsepower versus inlet volume flow; see Figure 7.18)

Rotor is the rotating element and is composed of the impeller or impellers and shaft and may include shaft sleeves, thrust bearing collar, and a thrust balancing device.

Seals are devices used between rotating and stationary parts to separate and minimize leakage between areas of unequal pressures. Basic types include clearance-type metallic labyrinths: single and multiple, injection-type labyrinths, eductor-type labyrinths, or a combination. Dry contact seals include carbon ring and synthetic materials such as Teflon. Liquid-injection types use water or oil seals.

Shaft is that part of the rotating element on which the rotating parts are mounted and by means of which energy is transmitted from the prime mover.

Shaft sleeves are devices that may be used to position the impeller or to protect the shaft.

Single-stage centrifugal compressors are machines having only one impeller. They may be classified as follows:

a. Single-flow.

b. Double-flow.

Stability or percentage stability is 100 minus the surge limit at rated discharge pressure, where the surge limit is expressed in percentage of rated capacity.

Surge limit (pulsation point) is the volume flow below which partial or complete cyclic flow reversal occurs, resulting in unstable aerodynamic operation.

Thrust balancing device (balance piston or drum) is the part of the rotating element that serves to counteract any inherent axial thrust developed by the impeller.

Centrifugal Compressor Characteristics

Compression of gas by means of a reciprocating compressors is easily pictured and is generally well understood by engineers and operators. The capacity of such a unit at constant speed is essentially constant, and the discharge pressure is that required to meet the load conditions.

A centrifugal compressor, on the other hand, develops its pressure within itself, independent of the load, but the load determines the flow to be handled. This is a generalized statement, of course, limited by the physical size of the unit and the size of the driver.

Both of the preceding statements are made on the assumption of constant speed and no controlling devices. On both centrifugal and reciprocating compressors, it is possible either to vary the speed or to provide integral regulatory means so that any desired pressure or flow requirement may be met, providing it is within the limits of the compressor and its driver.

In its simplest form, a centrifugal compressor is a single-stage, single-flow unit with the impeller overhung on a motor. This single-flow unit consists of the inlet nozzle, the impeller, the diffuser, the volute, and the driver. The passage of gas through the unit follows the order above. The gas enters the unit through the inlet nozzle, which is so proportioned that it permits the gas to enter the impeller with a minimum of shock or turbulence. The impeller receives the gas from the inlet nozzle and dynamically compresses it. The impeller also sets the gas in motion and gives it a velocity somewhat less than the tip speed of the impeller.

The diffuser surrounds the impeller and serves to gradually reduce the velocity of the gas leaving the impeller and to convert the velocity energy to a higher pressure level. A volute casing surrounds the diffuser and serves to collect the gas to further reduce the velocity of the gas and to recover additional velocity energy.

The maximum discharge pressure that may be obtained from a single-stage unit is limited by the stresses permissible in the impeller. Where the requirement for pressure exceeds that obtainable from a single-stage compressor, it is possible to build a centrifugal compressor with two or more impellers. This requires a return passage to take the gas leaving each diffuser and deliver it to the inlet of each succeeding stage.

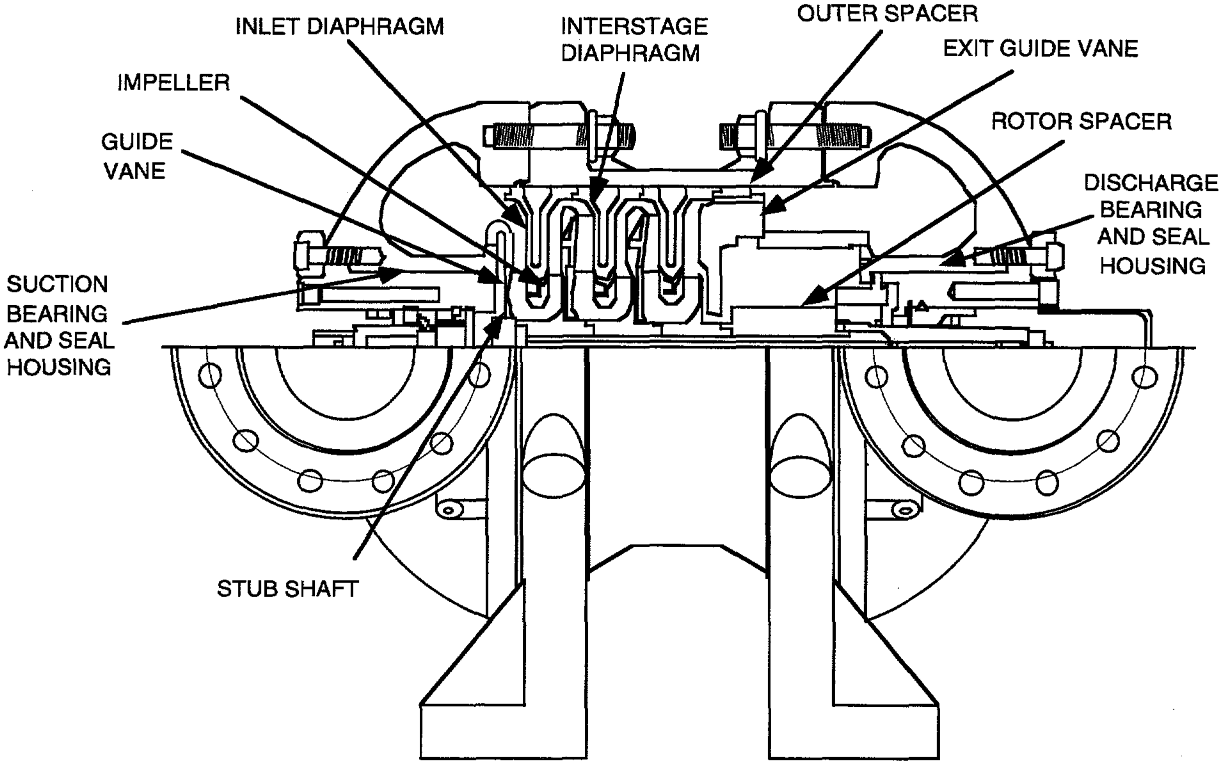


FIGURE 7.17— Cutaway of a Centrifugal Compressor

In a typical multistage centrifugal compressor (Figure 7.17) the compression is accomplished by multiple impellers that act in series and are mounted on the same shaft. Flow of gas between stages is guided by the interstage diaphragms from the discharge of one impeller into the inlet of the next impeller. Sealing between stages is done by the labyrinth rings, which impose restriction on the flow between impellers at the shaft, at the impeller eye, and at the balancing drum.

Operating Characteristics

Demand Load

Regardless of the actual service to which a centrifugal unit may be applied, the general nature of the demand load may be divided into three classifications as follows:

1. Frictional resistance.
2. Constant head or pressure.
3. A combination of constant head or pressure plus frictional resistance.

The frictional resistance load is that which would be typically encountered in ISC application. It is the pressure necessary to overcome the frictional resistance of flow through piping or associated equipment.

The fixed-head or pressure load is that which is required to overcome a controlled back pressure.

A third type of load, which is a combination of the above, is by far the most common. Virtually all loads are to a certain degree a combination. An example of this type of load is that of ISC prospect for which the majority of the pressure requirement is to overcome frictional resistance, but in addition, some is required to maintain a pressure at the sand face to prevent back flow.

In Figure 7.18, the three types of loads are shown graphically. Curve CD represents the purely frictional load, curve AB represents the fixed head, and curve AE represents the combination.

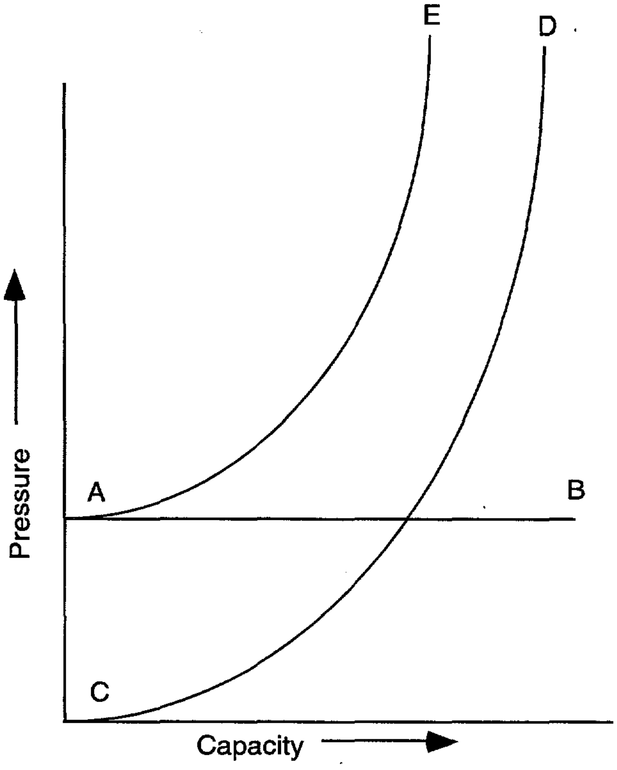


FIGURE 7.18 — Typical Curves, Illustrating Three Types of Centrifugal Compressor Loading (Rollins, 1989)

Application to Load

As previously mentioned, a reciprocating compressor is essentially a constant-flow, variable-pressure unit. This is shown in Figure 7.19 line JK. Actually, because of the decrease in volumetric efficiency at increasing pressures, the reciprocating compressor will have a sloping characteristic, shown by line JL. A centrifugal compressor is essentially a variable-flow, constant-pressure unit as indicated by the line FM. Because of internal losses, the compressor characteristic is not a straight line but is similar to line FG.

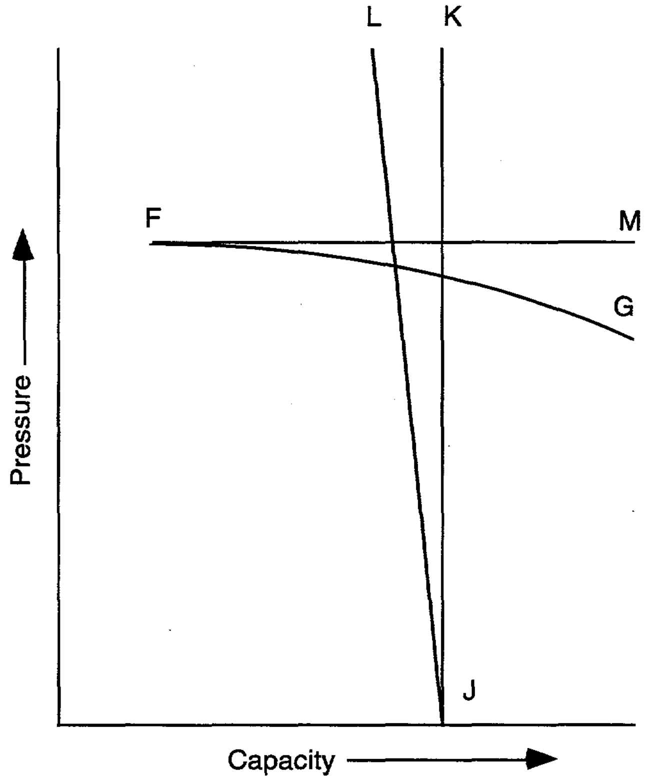


FIGURE 7.19 — Performance Characteristics of Centrifugal vs Reciprocating Compressor (Rollins, 1989)

It would be possible to select a centrifugal or a reciprocating compressor for the same flow and pressure as indicated by point H, and the characteristic curves are shown in Figure 7.20 as FG for the centrifugal and as LJ for the reciprocating units.

To explain the application of a centrifugal unit to any given service, the performance curve, shown by line FG, is superimposed on a demand or load curve, AE. With this combination of compressor and load, the capacity handled will fall at the intersection of the two curves at point H. This is only point at which the compressor will operate at that given demand requirement.

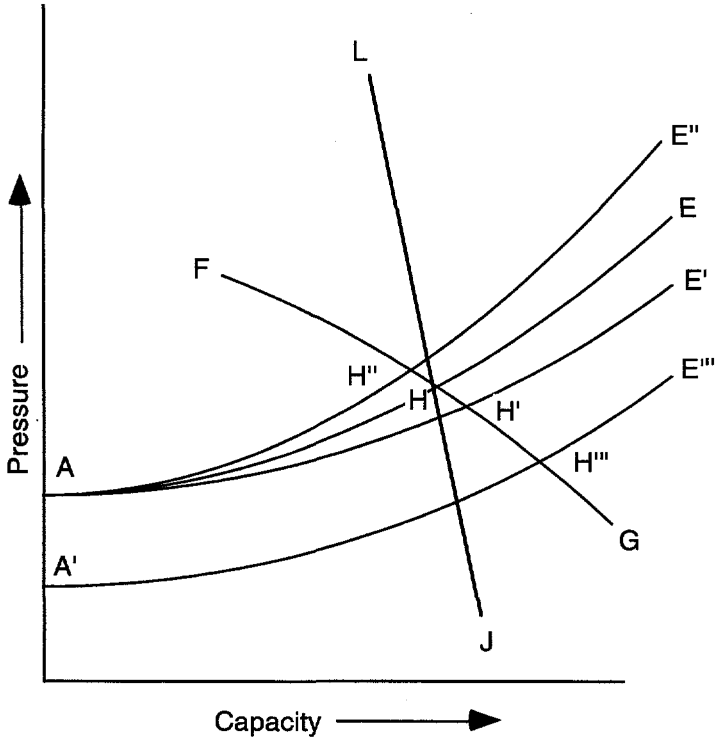


FIGURE 7.20 — Characteristic Curves of a Centrifugal Compressor and a Reciprocating Compressor, Superposed Upon Demand-Load Curves (Rollins, 1989)

For many applications, the demand curve will change, and this may result from varying the frictional resistance. This is shown by lines AE' and AE", in which case the flow handled by the compressor is at the intersection of these two curves, or point H".

Controlling Pressure or Capacity

The use of a valve as a means of controlling pressure or flow at any given value is the simplest form of control. It is not efficient, however, since this artificially created resistance represents an irrecoverable loss of power. A more efficient way to control the unit for any given pressure or flow is to vary the speed. This creates a family of curves like those shown in Figure 7.21 by curves FG, F'G', F"G", and so on. By varying the speed, it is possible to set the intersection of the compressor characteristic and the demand curve to any given required pressure or flow within the operating limits of the compressor and driver.

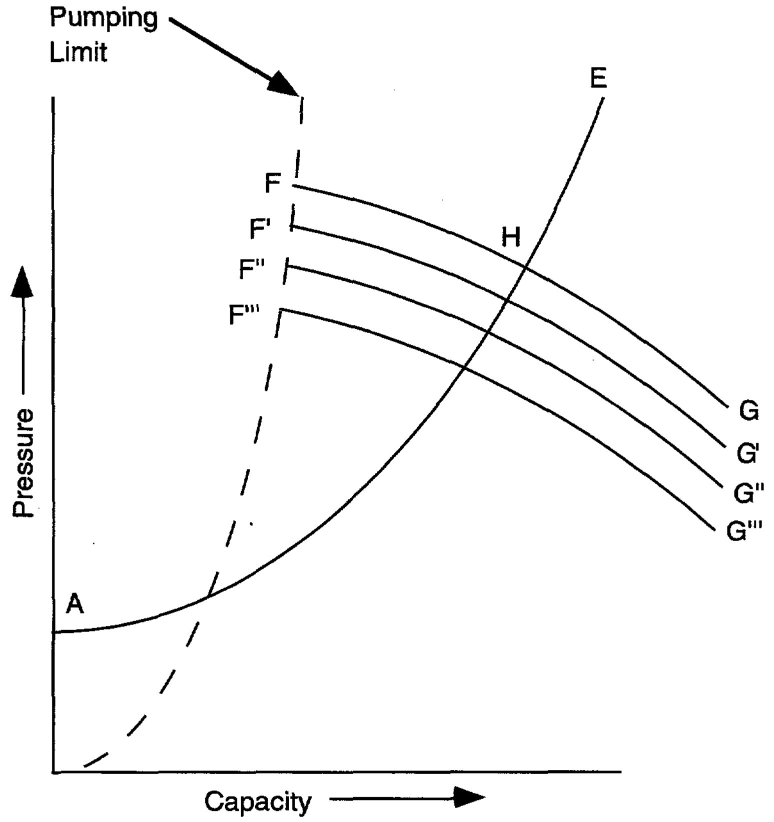


FIGURE 7.21 — Characteristic Curves of a Centrifugal Compressor at Variable Speed, Superposed Upon Demand-Load Curves (Rollins, 1989)

The method of controlling the compressor characteristics, therefore, depends on the type of driver. For steam-turbine drive, the normal method of control would be vary the speed, permitting efficient operation and a wide range of control. In the case of motor drive, the picture becomes more involved, since the most commonly used motors are essentially constant-speed drivers. For motor drive, the following control possibilities may be considered:

1. Synchronous motor or squirrel-cage induction motor:
    - Speed variation may be obtained by using hydraulic coupling between the motor and the compressor.
    - Speed variation may be obtained by using an electric coupling between the motor and the compressor.

- Pressure or flow variation may be obtained by means of a butterfly valve or equivalent installed near the compressor inlet or near the compressor discharge, preferably the former.
- Pressure or flow variation may be obtained by adjusting the characteristic curve of a centrifugal compressor by use of adjustable inlet guide vanes or adjustable diffuser vanes.
- Static-type, variable-frequency control for variable-speed start for limited kVA inrush requirements with synchronous motor drive two-pole motors.

2. Wound-rotor induction motor: Speed variation may be obtained by varying the resistance in the rotor or secondary circuit using either a liquid rheostat or a step resistance (rarely used).

Briefly, a centrifugal compressor can be operated to meet a given pressure and flow requirement by varying either the demand curve or the compressor characteristic curve so that the intersection of these curves will be at the required point.

Selection of Unit

The preceding study of the effect of inlet conditions on the characteristic of a compressor emphasizes two points in connection with its proper application. They are:

1. The importance of investigating the operating conditions to be sure that the compressor is large enough to meet the job requirements.
2. The necessity of a means of controlling the centrifugal compressor when variations in the operating conditions are such that a pressure would be developed in excess of the actual requirements.

The following information is necessary to ensure obtaining a centrifugal unit that will be physically capable of meeting the requirements under the most adverse operating conditions. Also, a knowledge of the range of these conditions is needed to ensure that a driver of sufficient size is furnished. Attention is called to Table 7.3 which shows a typical centrifugal inquiry form.

1. Minimum inlet pressure.
2. Maximum inlet temperature.
3. Maximum molecular weight.
4. Maximum k value.

5. Maximum discharge pressure.
6. Maximum inlet capacity.
7. Maximum moisture content.
8. Supercompressibility factor at inlet and discharge.
9. Gas characteristics (e.g., analysis, corrosiveness, dirt content).

In selecting a machine for a given application, the preceding characteristics must be carefully considered. The practical lower limit of capacity for which either compressor may be designed is determined by the specific requirements. In connection with low-capacity units, consideration must also be given to an economic comparison with reciprocating and rotary compressors capable of doing the same job, including cost and installation. In some instances, it may be economical to use a centrifugal compressor for a portion of the required pressure range, followed by a reciprocating or rotary compressor for the remainder of the pressure range.

Since the size of the required compressor and the horsepower of the driver are direct functions of inlet capacity, extreme care must be exercised in establishing actual inlet capacity. Standard capacity (scfm) is frequently used in specifications and, since there are several standards in common use, it is necessary to establish the particular standard involved. Air has been frequently specified at 14.7 psia (1.013 bars), 60°F (15.5°C) and dry. For all applications, the standard capacity must be corrected to the actual inlet pressure, inlet temperature, and moisture content to arrive at actual inlet capacity. In consideration of accepted metric equivalents, the CAGI (Compressed Air and Gas Institute) Standards Committee has settled on 14.5 psia (1 bar), 68°F (20°C) and dry as a standard.

Approximate Selections Limitations

Although the following rule-of-thumb approach will vary among compressor manufacturers, a brief survey of the following points will serve to guide the selection of the type of compressor and, in some cases, will eliminate centrifugal units from consideration where conditions make it inherently not suited.

There is no define minimum inlet capacity. However, single-stage and multistage compressors have not been built for inlet capacities lower than 250 cfm (425 cmh).

Numerous commercial centrifugal compressors are in service at discharge pressures up to 25,000 psig (172 bars). For other applications, centrifugal compressors have been built for discharge pressures up to about 10,000 psig (690 bars).

There are frequent applications involving an inlet capacity within the practical limits of a centrifugal compressor, but because of the high pressure ratio, the inlet capacity to the last stage may be so low as to preclude the use of a centrifugal compressor.

Because of thermal stresses and problems of alignment, a limit of 450°F (232°C) is normally set as the maximum discharge temperature at design pressure and capacity for centrifugal compressors of standard design using standard materials.

Where discharge temperatures must exceed this value, special designs and materials are used. Centrifugal compressors have been built for discharge temperatures up to about 1000°F (538°C). In cases where the pressure ratio would result in a discharge temperature in excess of 450°F (232°C) and where this temperature is neither required nor desired, several alternatives may be used:

1. Multisection compressors with external coolers between sections of the same compressor.
2. Multicasing compressors with external cooler between compressors. If necessary, each compressor in the multicasing arrangement may be a multisection compressor.
3. Internal cooling of the compressor as with injection of a coolant such as water or a condensed vapor into the gas stream in the diffuser sections of the compressor, or indirectly as with coolers mounted within the compressor casing or external to the compressor.

TABLE 7.3 — Centrifugal Compressor Inquiry Sheet

Compressor Data						
	Normal	**Maximum**	**Minimum**			
1. Inlet flow*				**Gas analysis % volume**		
2. Mass flow				**Constituent**	**Guar.**	**Alt.**
3. Molecular weight						
4. Average compressibility ($Z_{ave)}$)						
5. Average K (C_p / C_v)						
6. Relative humidity %						
7. Barometer						
8. Inlet temperature						
9. Inlet pressure						
10. Discharge temperature						
11. Discharge pressure						
12. Speed required						
13. Power required (all losses included)						
14. Side load: Flow						
Pressure						
Temperature						
15. Indicate guarantee point						

* If inlet flow is listed SCFM (standard conditions) indicate conditions under which flow was measured, i.e.

Temperature _____ ; Pressure _____% R.H.

TABLE 7.3 (cont.) — Centrifugal Compressor Inquiry Sheet

Electric Motor Data	
Site data: Area: Class_____ Group ____ Div _____ Nonhazardous Unusual conditions Dust Fumes Altitude ________ Ambient temperature ________	Enclosure type: TEFC TEWAC Weather protected TEIEF (using_____gas) Force ventilated Open-drip proof Open Exp. Proof; Class ______ Group _______
Motor Type: Squirrel Synchronous (Brushless Slip ring) Wound rotor Direct current ___________	**Basic Data:** _____ Volts _____ Phase ______ Hertz Nameplate power _____ Service Factor ______ Synchronous rmp _________ Insulation class ______ Type ________ Temperature rise ____°C above ____°C by ____
Starting: Full voltage Reduced voltage Loaded Unloaded Voltage dip______%	

Sizing Consideration

Centrifugal air compressors normally are specified on the basis of required air flow volume. However, there are several ways to calculate volume, and serious problems can result unless both user and manufacturer use the same method. At the very least, the user can have trouble comparing bids from competing manufacturers. At worst, he may choose the wrong compressor.

These problems can be avoided by specifying capacity in terms of the actual inlet conditions and by understanding how compressor capacity is affected by variable ambient conditions, such as inlet pressure, temperature, and relative humidity. Also, factors such as cooling-water temperature and motor load must be considered before a compressor and its drive motor can be sized.

The main item that must be specified is inlet air volume. Standard cubic feet per minute (scfm) is the common unit of measure for compressor inlet capacity; however, several definitions of this unit exist. One definition of scfm fixes the variable at 14.7 psia (1.013 bars), 60°F (15.5°C), and 0% relative humidity. Another, adopted by the ASME, specific scfm at 14.7 psia (1.013 bars), 60°F (15.5°C), and 36% relative humidity. A third (metric) definition specifics a standard (or normal) cubic meter of air at 1 atmosphere, 32°F (0°C), and 0% relative humidity.

To avoid the confusion caused by these variable standards, some users have adopted a simpler unit that expresses inlet volume in terms of the actual inlet pressure, temperature, and humidity. This inlet cubic feet per minute (icfm) indicates the actual volume entering the first stage of a multistage compressor at the expected operating conditions. This volume, in turn, determines the impeller design, nozzle diameter, and casing size that provides the most efficient operation.

Inlet pressure is determined by taking the barometric pressure and subtracting a reasonable loss for the inlet air filter and piping. A typical value for filter and piping loss is 0.3 psig (0.02 bar).

The need to determine inlet pressure at the compressor flange accurately is particularly critical in high-altitude installations. Because barometric pressure varies with altitude, a change in altitude of more than a few hundred feet can greatly reduce compressor capacity. Often, the lost capacity can be restored by using larger-diameter impellers, but occasionally a different-sized compressor must be used.

The other variables that influence compressor capacity, temperature, and relative humidity of the inlet air must be considered over the range of conditions expected in service. Air volume is lowest at the highest expected operating temperature, and vice versa. Therefore, the impellers must be designed to deliver the required flow at the highest temperature expected. This guideline also applies to the temperature of the cooling water, which controls the temperature of the air delivered to the stage following an intercooler.

Relative humidity also affects the useful volume of air available at the compressor inlet. The higher the humidity, the less is the effective air volume available: thus the impellers must be sized for the highest humidity expected.

Importance of Air Density and Volume Flow

Volume flow does not tell very much because the weight of air in each cubic foot depends on the temperature and pressure of the air. In other words, the weight flow is related to the density of the air as well as the volume flow. The following formula relates weight flow to volume flow:

$$W = Q\rho \tag{7.40}$$

where W = weight flow, lb/min

Q = volume flow at the given air density, cfm

ρ = weight density, lb/ft.^{3}

Air density (weight of a cubic foot of air) is inversely proportional to its absolute temperature. Thus, the higher the temperature, the less weight flow in each cubic foot. The weight flow delivered in summer is less than in winter. Therefore, the specification for a compressor should provide for the required weight flow to be delivered on a hot summer day. A slightly larger compressor will be required if air temperature is 90°F (32°C) rather than 68°F (20°C). If the manufacturer's rating (based on air at 68°F or 20°C) is accepted, the compressor will not deliver the same weight of air per minute at 90°F (32°C).

Another reason that the volume flow by itself must be qualified is that air density also depends directly on air pressure. Because atmospheric air pressure depends on altitude, a compressor installed at a higher elevation (above sea level) gets less weight of air in each cubic foot of intake air than the same compressor installed at sea level. This change in weight flow due to differences in barometric pressure can be significant. For example, because of the lower atmospheric pressure, a compressor in Kansas City will deliver nearly 5% less air than the same compressor installed in Miami.

For dry air, the relationship of density to temperature and pressure is

$$\rho = \frac{144P}{RT} \tag{7.41}$$

where P = absolute air pressure, psia

R = gas constant of dry air

T = absolute air temperature, °R

However, barometric pressure is not the only factor that affects inlet pressure. The effects of air filter, inlet valve, and piping leading to the compressor should also be considered. And because these components cause significant pressure drop, a cubic foot of air measured just ahead of the compressor flange will contain less air by weight than a cubic foot measured ahead of the filter. Then the density of air entering a compressor becomes

$$\rho = \frac{144(P_b - \Delta P)}{R_m T} \tag{7.42}$$

where P_b = absolute barometric air pressure, psia

Δ_p = volume flow at the given air density, cfm

R_m = gas constant of air mixture (i.e., with water vapor)

Density of moist air at various temperature can be estimated from Figure 7.22.

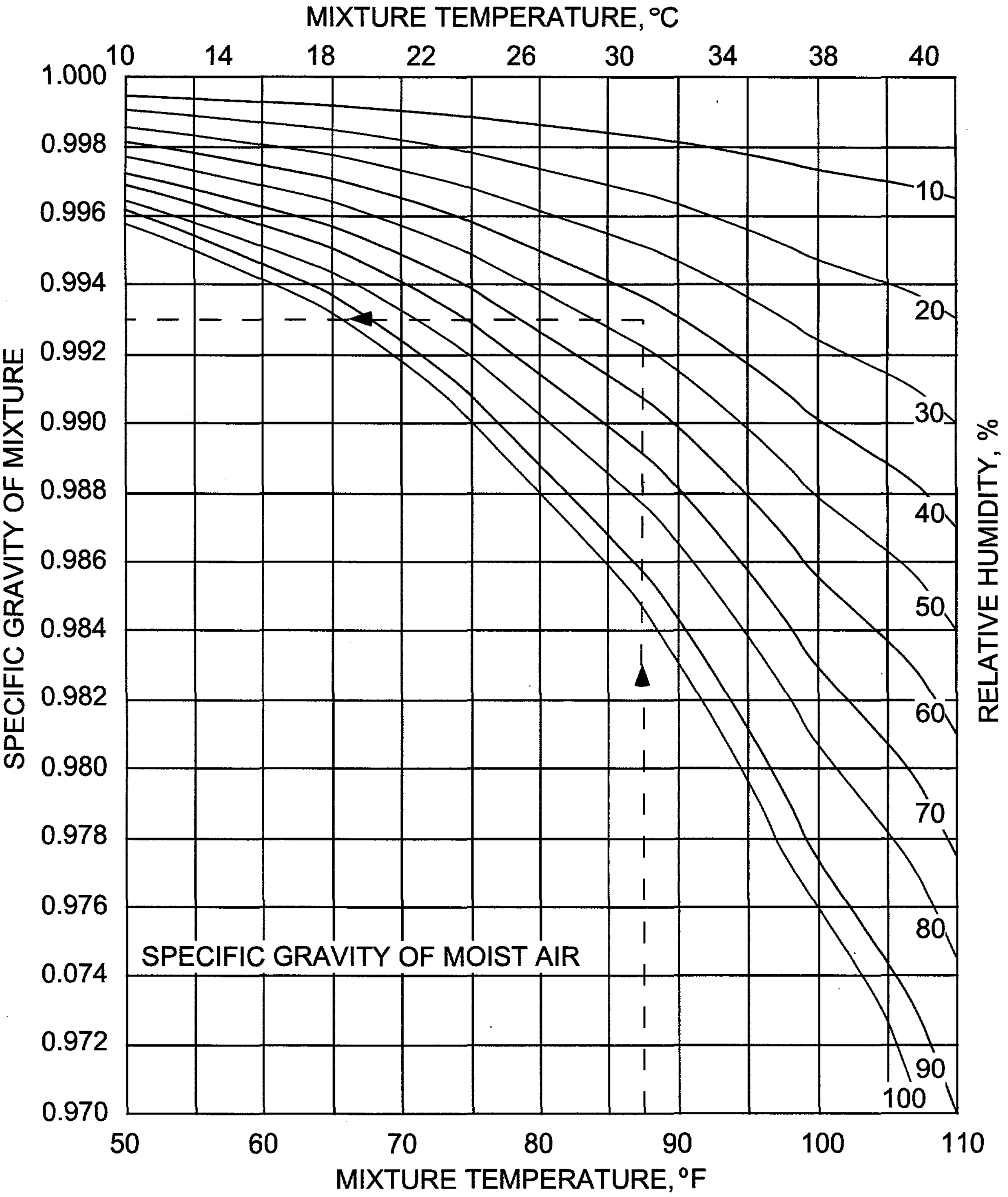


FIGURE 7.22 — Density of Moist Air as Function of Temperature (After Rollins, 1985)

Humidity

Another variable that often causes confusion in sizing an air compressor is humidity. Atmospheric air always contains water vapor. As a result, the compressor takes in a mixture of air and water vapor. This affects compressor operation and performance because the higher the pressure of the air, the less water vapor it can hold. And what it can no longer hold condenses in the intercoolers and aftercooler and is drained as water. So, once again, the weight of the cubic foot in is not the same as the weight out. The compressor must be sized slightly larger to allow for the water vapor loss, which, although it is part of the inlet flow, is not part of the delivered weight flow.

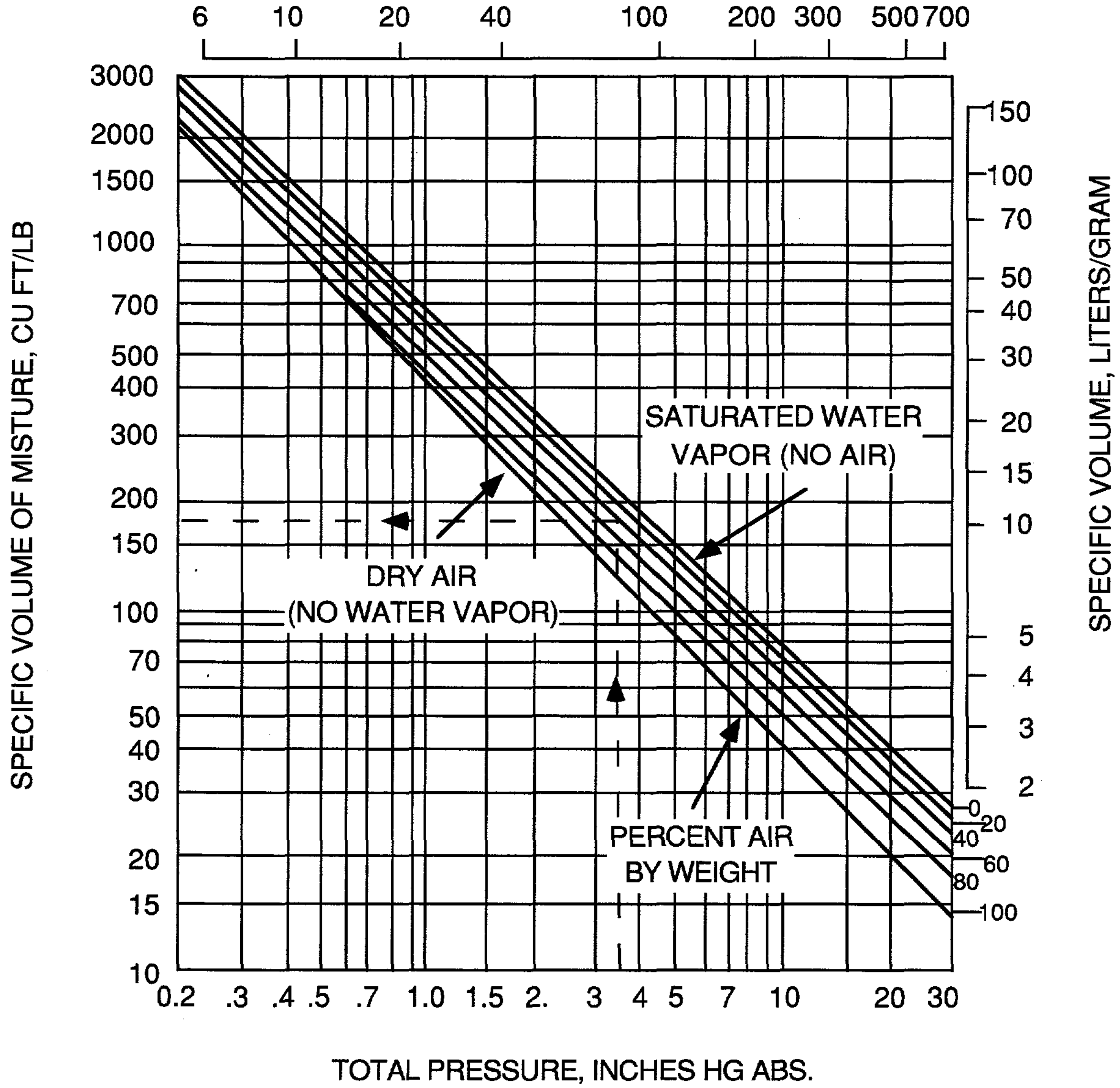


FIGURE 7.23 — Specific Volume of Saturated Air-Water Vapor Moistures at Saturation Temperature and Dry Air at 70°F (21.1°C) (After Rollins, 1985)

A portion of the inlet volume is attributable to water vapor. This depends on the relative humidity of the intake air (See Figure 7.23).

Specify Ambient Conditions

In order to be sure to have enough air, the compressor buyer must be careful in specifying ambient conditions. These should tend toward the minimal conditions, that is, high air temperature, normal barometric pressure, and high humidity. This does not mean that the specification should be based on the maximum air temperature on record. The result would be an unnecessarily large compressor.

A related item to be considered in selecting a compressor of the correct capacity is cooling-water temperature, since most air compressors are intercooled. Water temperature has much the same effect as air temperature. This is easy to understand because the water cools the air before it enters the next compression stage. The warmer the cooling water, the warmer the air, and the less dense it will be. Therefore, water temperature should be specified at the highest anticipated temperature; otherwise, the compressor will deliver less air than expected. When cooling-water temperature is lower than specified, water flow can be reduced.

Centrifugal Air Compressor Characteristic

Centrifugal air compressor performance can be represented by a characteristic curve of discharge pressure versus flow. This is a continuously rising curve from right to left (Figure 7.24). The effect of environment on performance requires understanding of two phenomena associated with this curve: choke (stonewall) and surge.

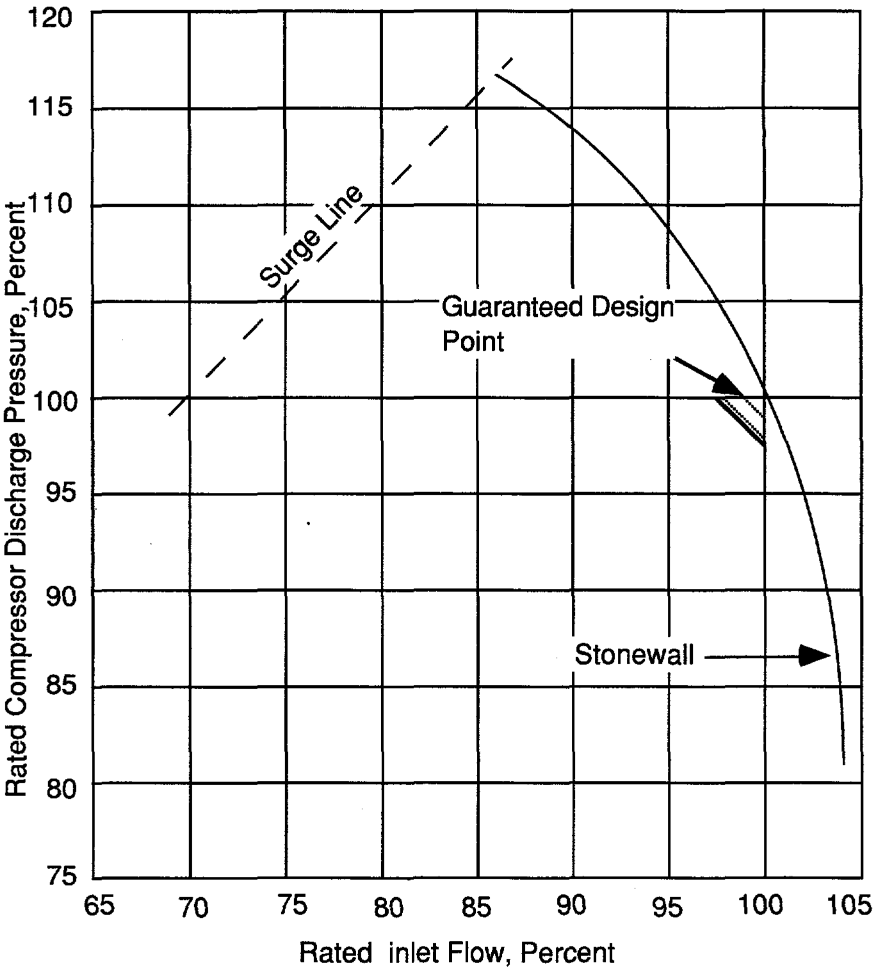


FIGURE 7.24 — Centrifugal Compressor Characteristic Curve

When the compressed-air system pressure decreases, a centrifugal compressor delivers an increased volume of air. As the system pressure continues to decrease, the air delivery from the compressor continues to increase until the air velocity somewhere in the compressor reaches the speed of sound. At this point, the flow is said to be *choked* because further reduction in system pressure does not result in additional air delivery by the compressor.

On the other hand, the maximum discharge pressure of the centrifugal compressor is a function of the intersection of the surge line and the sloping performance curve. When the compressed-air system pressure increases, the compressor furnishes less air as higher pressures are encountered until the system resistance is matched. This relationship may continue until the compressor is unable to maintain a steady flow of air into the system.

When the compressor cannot maintain a steady flow of air, backflow from the system through the compressor occurs until a momentary equilibrium is established between the compressor and the system. This backflow is commonly referred to as *surge*. This phenomenon is roughly equivalent to the stalled condition of an airfoil. Under this condition, compressor operation moves from surge to some point below the operating point shown on the performance curve. When the compressor continues to operate against sustained excessive system pressure, compressor operation moves up the curve and surge occurs again.

Neither of these conditions is desirable and both should be avoided. Control systems that allow the compressor to function without reaching the choked or surge condition must be based on prevailing environmental conditions. It is, therefore, helpful to examine individual environmental factors that can affect compressor performance.

Characteristic centrifugal compressor performance curves (Figure 7.24) rise from right to left, showing a reduction in delivery at increasing pressures. Stable operation occurs on the portion of the curve that lies between the design point and the surge line.

Weight or Volume Flow

The compressed-air system is in reality a vessel that stores energy in the compressed air, energy that can be transferred to the formation. When a portion of this stored energy is withdrawn from the system, it must be replenished by the compressor.

The performance of the compressed-air system is measured by the pressure of the air in the system. Air pressure for a steady air usage and relatively constant system temperature depends on the weight of the air in the system. Boyle's law states that, for a constant gas temperature,

$$p_1 v_1 = p_2 v_2 \tag{7.43}$$

where v = specific volume, ft.^{3}/lb

Therefore, $$\frac{P_1 V_1}{W_1} = \frac{P_2 V_2}{W_2} \tag{7.44}$$

where V_1 = total volume

w = total weight

The compressed-air system volume is constant, so

$$V_1 = V_2 \tag{7.45}$$

Therefore, assuming no change in temperature or relative humidity,

$$\frac{P_1}{W_1} = \frac{P_2}{W_2} \tag{7.46}$$

or

$$P_2 = \frac{P_1 W_2}{W_1} \tag{7.47}$$

As air is withdrawn from the compressed-air system, the weight of the air (if not replaced) and the air pressure decrease. The performance of the compressed-air system therefore depends on the weight of the air delivered by the compressor. Because each centrifugal compressor has a fixed volume design capacity, in cubic feet per minute or cubic meters per hour, the weight flow capacity is determined by the pressure temperature and relative humidity of the air entering the compressor.

The compressor characteristics curve and work input are related to flow as a function determined by physical geometry, blade angle, speed of rotation, molecular weight of gas, and other factors to a minor degree. Once this characteristic has been established for a compressor, it can be affected by inlet air temperature, inlet air pressure, and cooling-water temperature.

Effect of Inlet Air Temperature

The relationships (Equation 7.7) can be used to explore the effects of inlet air temperature. Aerodynamic work input to a centrifugal compressor is proportional to polytopic head and weight flow of air to which the head is imparted. Polytropic head is measured in foot-pounds (work) per pound of air or, more simply, as feet of head. Power is then obtained by multiplying head times total weight flow and considering mechanical losses and efficiency. The polytropic head is obtained from Equation 7.28.

For a fixed geometry and constant speed, air compressor head per stage is constant. The only variables are the inlet temperature and the pressure ratio. Therefore, if inlet pressure is constant and inlet temperature is increased, discharge pressure must necessarily drop to maintain the equality. Conversely, when inlet temperature decreased, discharge pressure must increase.

Inlet air temperature also affects the weight flow through all types of compressors:

$$W = \frac{Q\rho}{RT} = \text{constant} \times \frac{\rho}{T} = \text{constant} \times \rho \qquad (7.48)$$

where W = weight flow, lb/min

Q = volume flow rate, cfm

ρ = weight density, lb/ft.^{3}

Weight flow through a centrifugal compressor is proportional to inlet volume and inlet pressure and indirectly proportional to inlet air temperature. Because P1/RT1 is weight density, another way of stating this relationship is that weight flow is proportional to density. As inlet temperature decreases weight flow through the compressor increases, and vice versa, although volume flow remains constant.

Often the compressor manufacturer states the capacity for a standard air temperature, which may be as low as 60°F (15.5°C). Then, when the compressor operates with 90°F (32°C) inlet air, for example, the weight flow is reduced by the ratio of the absolute temperatures:

$$\frac{60 + 460}{90 + 460} = 0.945 \qquad (7.49)$$

For a fixed air usage, the compressed-air system pressure is reduced by the ratio of the weight flows or 5.5%, other factors remaining unchanged. In SI units, capacity stated in terms of a standard temperature of 68°F (20°C) with an actual inlet temperature of 86°F (30°C) would mean a weight reduction of

$$\frac{20 + 273}{30 + 273} = 0.967 \qquad (7.50)$$

Proper performance of the compressed-air system requires that the compressor rating be guaranteed for the summertime air inlet temperature or that a weight flow rating be guaranteed at the same conditions.

The effect of wintertime air temperature on air density must also be considered. A compressor rated for 90°F (32°C) summertime inlet air temperature, for example, will have a 17% higher weight flow when operating with a 10°F (-12°C) wintertime inlet air temperature:

$$\frac{W_2}{W_1} = \frac{90+460}{10+460} = 1.17 \qquad (7.51)$$

This increased weight flow will not impair the pressure performance of the compressed-air system because the resultant increase in pressure can be relieved through a relief valve or through more frequent cycling of the compressor. But this increase weight flow will increase the cost of compressing the air because of the increased power required:

$$P = C_1 \text{ x } W \qquad (7.52)$$

where: P is the power required. Therefore, for this example, the power required by the compressor will increase 17%. Alternative expressions for power are

$$P = C_2 \times \frac{P}{t}$$

and where C_1, P_2, C_2, and C_3 are constants,

or $P = C_3 \text{ x } W$

Figure 7.25 shows the effect of inlet air temperature. Increasing temperature means decreasing flow and power requirement, and decreasing temperature means increasing flow and power requirement. The implications to the buyer are twofold. First, the compressor must be rated at a sufficiently high temperature so that the plant does not run short of air on a hot day--perhaps not the highest temperature of the year, but a mean temperature based on a reasonable confidence level. Second, controls must be provided to prevent the compressor from drawing excessive additional power when the air is cooler.

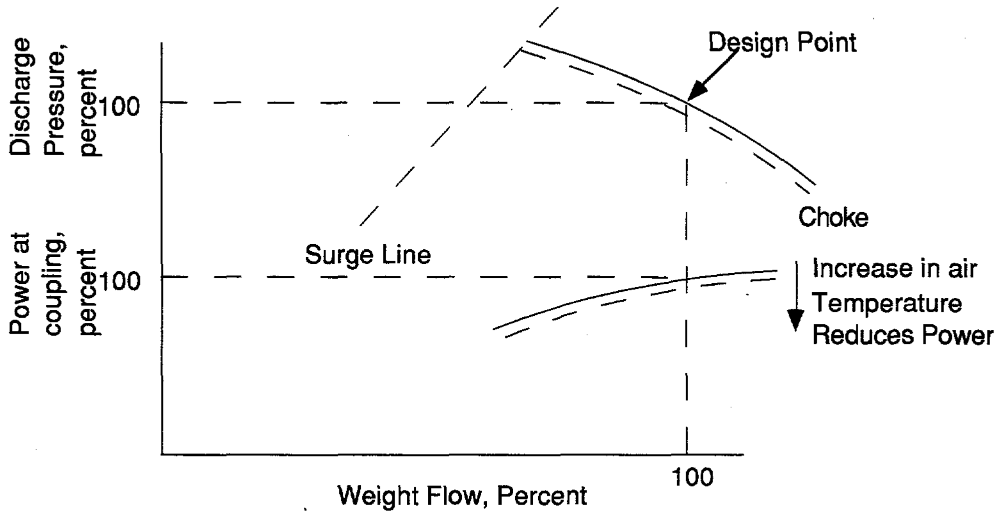


FIGURE 7.25 — Effect of Inlet Air Temperature on Flow and Power in a Centrifugal Compressor (Courtesy Compressed Air Institute, 1989)

Effect of Inlet Air Pressure

A change in the inlet pressure does not affect the established pressured ratio, but the discharge pressure varies directly with changes in the inlet pressure (Figure 7.26). Reducing the inlet pressure also reduces the weight flow through a compressor, but the volume flow remains the same. Because weight flow is reduced, the power requirement is also lower.

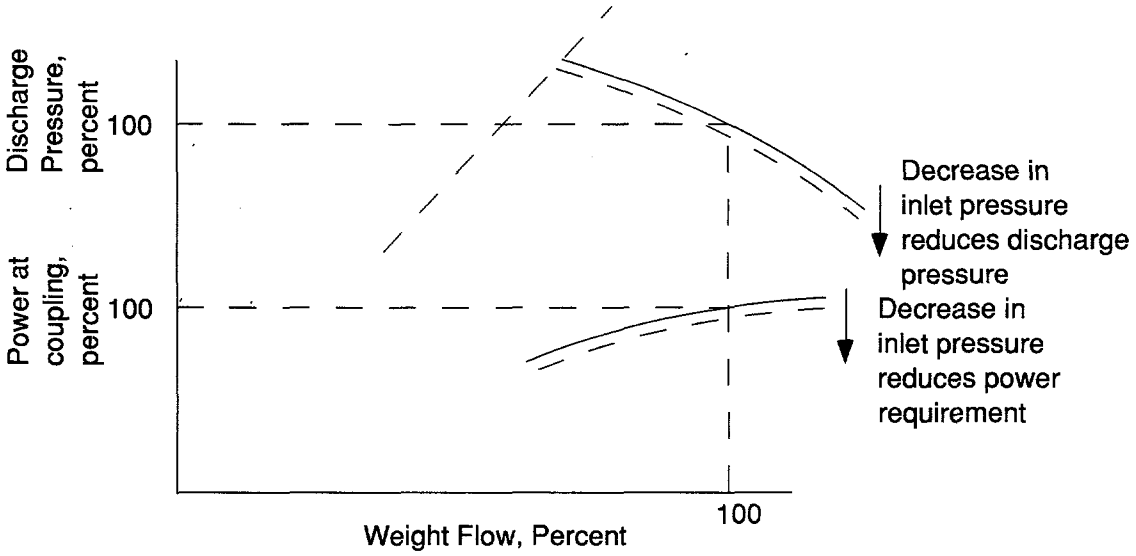


FIGURE 7.26 — Inlet Pressure Effects on Centrifugal Compressor Performance

If a given discharge pressure is required, a higher pressure ratio is required when the inlet pressure is lower, which, in turn, causes a higher work input. This factor should be considered when the compressor operates at high elevations.

Under normal operating conditions, the daily change in inlet air pressure is relatively small, except when the inlet air filter becomes dirty and needs cleaning.

Effect of Cooling-Water Temperature

First-stage performance is not affected by cooling-water temperature. However, all successive stages undergo a change in performance similar to that related to air temperature (Figure 7.27). Changes in cooling-water temperatures directly affect the temperature of the air entering the second and third or any later stages.

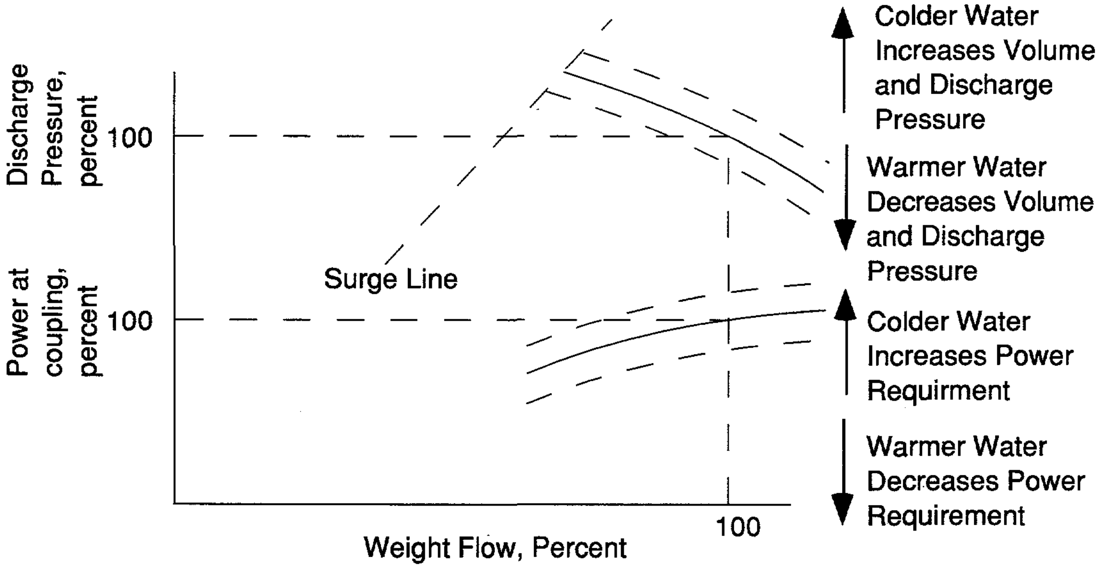


FIGURE 7.27 — Effect of Cooling Water Temperature on the Centrifugal Compression Performance

A reduction in cooling-water temperature increases the discharge pressure, weight flow, and the power consumption. Conversely, a higher cooling-water temperature decreases the discharge pressure, weight flow, and power consumption.

Most significant are the combined effects of simultaneous changes in water and air temperatures because in most plants they tend to increase or decrease together. On a summer day, higher air and water temperatures are normal, whether the water comes from cooling towers, a public supply, a river or the sea, although changes in air temperatures are more extreme than changes in water temperature because of the moderating effect of heat storage capacity in water. The combined effect of higher air and water temperatures is to depress the compressor characteristic, resulting in lower discharge pressure, lower weight flow, and lower power consumption. Colder temperatures increase weight flow and power requirements. This discussion is related to an uncontrolled compressor. It also describes what happens to an installed compressor selected for rated ambient conditons at a give site.

Designing the Compressed Air System

Air compression plant for an in-situ combustion project (See Figure 7.1) it consists essentially of one or more compressors, drivers, air intake filter, aftercooler and separators, air dryer, interconnecting piping, and a distribution systems to carry the compresses air to the injection wells. For illustration, the compressor in Figure 7.1 is shown as a two-stage compressor.

Air at atmospheric pressure is filtered before entering the system to remove dirt that would harm the compressor. After each stage of compression the resulting heat is removed in the coolers, followed by removal of condensed water in the separator. The compressed air is given a final filtering to remove any material that might block the formation. Remaining water vapor is removed in a final dryer, and then, if a dry bed dryer was used, the air is filtered once more. The blowdown line provides for pressure release when the compressors are shut down. The fuel source shown in the Figure 7.1 could be natural gas line, an electric line, or diesel fuel storage tank. In most areas, environmental regulations may require the treatment of engine exhaust (if natural gas or diesel fueled engine is used to drive the compressor) to remove NO_x and other pollutants. The compressor and the engine use fire-resistant lubricants, which are stored on site.

The most important consideration in the design of compressed air system for fireflood project is the availability of some air for the project at all times. This is very important for a number of reasons:

1. When air injection stops, in most cases there is a small backflow into the injection well. In unconsolidated formations, this means sand-fill in the injection well and costly workover.
2. In thick formations, without maintaining the pressure gradient from injection, vertical drainage may resaturate the burned zone. This resaturated rock must be burned again before the burning front can proceed. This increases the overall air requirement for the project.
3. With back-flow of combustion gases there is always a possibility of an explosive mixture entering the injection well. These combustible gases can detonate when air injection is resumed.

Therefore, consideration should be given to the use of smaller multiple units in the project. If multiple units are used this will ensure the availability of some air all the time. Economics is the main reason why many operators shy away from the use of multiple units in ISC projects.

There are many and equally important considerations in designing a compressed air system for in-situ combustion services. These include:

1. Establishing the peak and average air demand and injection pressure.
2. Selection of compressor and prime movers.
3. Whether package compressors or individual components will be used.
4. Locating the compressors.
5. Selection of control devices.
6. Selection of ancillary equipment.
7. Compressed air distribution system piping.
8. Lubricating oil requirement.

A brief discussion of each of these consideration follows.

Establishing Injection Rate and Pressure

In the design of the compressed air system for in-situ combustion operation the major governing factors are the daily peak air injection rates and pressure required to conduct the field operation. This is needed for determining of the compressor plant capacity and the compressor type to be used. In dry combustion operation air need to be supplied at a rate commensurate with the desired rate of advancement of the burning front. For a given fuel concentration, higher the injection rate farther the combustion front will advance and faster the oil will be produced. Hence a combustion project is usually designed based on maximum possible air rate that will be used on a constant basis during most of the burning operation. The compressor must be sized not only to meet the peak air requirements, but be flexible enough to accommodate a reduction in capacity due to changes in operating conditions.

Estimation of peak and average injection pressure is also very important because together with the daily output they influence the type of compressor to be used. As noted previously, typically at the start of a combustion project the injection pressures are higher than the project's average injection pressure. The injection pressure drops once the combustion front move away from the injector. This requires operating pressure flexibility. Compressor should be selected to provide the peak pressure output with some margin to cover possible changes in conditions.

Selection of Compressor and Prime Movers

Ideally a compressor considered for ISC service is required to satisfy the following criteria: (Barnett et al., 1965)

- Must operate largely unattended with minimum of operator attention.
- Must lend itself to outdoor installation with minimum of weather protection required in more severe climates.
- Must have the ability to operate over a wide range of capacity and pressure.
- Must have the ability to operate over a wide range of volumetric efficiency.
- Must have the ability to deliver the desired volume without loss of efficiency.

Selection of compressors for a specific fireflood project must consider all conditions anticipated through the life of the project. Three primary elements that determine the type of compressor to be used in a project are:

1. The performance (operating pressure and discharge volume) flexibility required.
2. Dependability of service (compressor must have a high degree of operating reliability with plant availability to be 90% or better).
3. The energy (fuel or power) requirement.

These three items usually overshadow the first cost making it a distance fourth. Large projects requiring large volumes of air at moderate pressure (less than 2,000 psi) tend to use centrifugal compressors. Their flow capacity ranges from 5–144 MMscfd and can provide long periods of relatively maintenance free operation.

Multistage reciprocating compressors are generally used in projects requiring high injection pressure (greater than 2,000 psi). These compressors can have discharge pressures to 8,000 psi and are normally limited to 7 MMscfd although larger units are available. In smaller projects where air requirements are small use of skid mounted packaged reciprocating compressor systems are recommended because they are less expensive to purchase and operate. If both centrifugal and reciprocating compressors can meet the flow and pressure requirements of a project it is suggested that an individual assessment of the advantages and disadvantages of each type as they related to user's needs be made prior to selection.

Another type of positive displacement air compressor used in some fireflood projects is the rotary air compressor. Rotary compressors are low pressure, low capacity machines; their output ranges from 0.5–2 MMscfd with discharge pressure usually limited to less than 200 psi. In large fireflood projects they are generally employed as a pre-compression unit to compress air from atmospheric pressure to 200 psi and to eliminate stages from a reciprocating unit.

The prime mover or driver of a compressor is the main power source that provides the energy to drive the compressor. It requires proper selection and matching to the compressor to ensure satisfactory compressor operation. The selection of the type of prime mover for a compressor should be based on technical and economic consideration.

The technical consideration should include the following items:

1. Service requirements of the compressor (in-situ combustion compressor must operate continuously 24 hours a day, 7 days a week, the year around, and the driver should be selected with this in mind)
2. Availability of electricity and other fuel sources.
3. Site conditions.
4. Compatibility of driver and compressor.

Economic consideration should include the following cost items:

1. Driver's first cost.
2. Fuel consumption or power cost.
3. Maintenance cost.
4. Installation cost (especially when comparing natural gas driven engine versus an electric motor).
5. Environmental consideration.

It is preferable to have the compressor vendor furnish the compressor, the driver and accessories so that all elements are properly coordinated and assume responsibility for the complete package.

In in-situ combustion operation, low-speed natural gas engine is often the prime mover of choice. Since engine manufacturers rate their engines for maximum, intermittent, or continuous service care should be exercised when selecting a gas engine driver to be certain that the horsepower ratings meets the required service. Since the recent federal and state air pollution regulations are very restrictive with regard to engine emissions, it is advisable to review the emission characteristics of the engine prior to purchase. Low emission engines or catalytic converters are two potential solutions to exhaust emission requirements.

If gas is not readily available at the site or gas engines cannot be used due to environmental consideration, electric motors may be used to drive the compressors at higher cost, but with less maintenance expense. Electric motors do not have emission problems. Electric drive reciprocating compressors are constant speed machines and hence no rate adjustment is possible by speed control such as is possible with a natural gas engine drive. There are three basic types of motors available that apply to oil field compressors. These are induction motors, synchronous motors, and dc motors. Proper motor selection is a very critical decision and involves several key factors. Some of these included:

1. A proper motor-to-compressor speed match.
2. Voltage and frequency match.
3. Speed and torque requirements for starting and operation,
4. Current restrictions.
5. Desired motor efficiency.
6. Ambient temperature at job site, etc.

It is important to evaluate energy costs over the project life because it is the major part of the operational expense.

Package or Process Compressors

Many combustion projects are undertaken to investigate the technical and economic viability of the process in a given field and as such do not require the large elaborate compressor installations found in large fireflood projects or gas transmission projects. Minimal initial investments and lower operating expenses over the life of the project are the general requirements of such projects. Smaller projects are also generally undertaken by organizations with limited technical manpower resources.

Smaller combustion projects requiring moderate volumes of air should consider installing packaged air compressors. These factory-engineered plants are highly popular in oil field operation because they are less expensive to purchase (or leased) and install, have a high degree of reliability and are easily relocatable. Operating and maintenance expense, excluding fuel are also lower than the process type units found in larger projects. Since these systems are offered as a ready to install operable unit with a minimum of field construction, they relieve the operator or his technical staff from the need for the sizing and specification of compressor and its auxiliaries.

The ideal and most desirable package for the operator is one in which only the required utilities of power and cooling water brought to the package, with the end product being clean dry air.

Process compressor systems found in larger projects are similar in configuration to the packaged system, but are designed for permanent installation. Unlike the packaged unit which include all the components necessary to provide a controlled compressed air source the process system include only the compressor, power transmission equipment and basic control system. Procurement of all the other necessary components such as the lubricating system, instrumentation, piping, emission control equipment, etc., is the responsibility of the purchaser. Process compressor systems are designed for high volume, high pressure unattended operations and have a high degree of reliability, with plant availability to 95% or better. The system is designed to be highly flexible and capable of automatically adjusting to changing pressure and volume requirements inherent in combustion projects.

Process type compressor systems require high initial investment and are more expensive to operate and maintain than packaged units. In larger projects their use is justified due to their reliability, operational flexibility and low unit compression and maintenance cost.

Locating the Compressor Station

In selecting the site for compressor station location, items to be considered include its convenience for inspection and maintenance by technicans working on the lease, proximity to the water supply, its nearness to lease road, surface topography, and in some cases the distance to the near est electric powerlines. If feasible, the station must be located near the center of the lease to minimize the length of the injection well piping network. In hilly country, the compressor station should be located at highest possible elevation to allow adequate drainage in bad weather. The selected site should allow for maximum exposure to prevailing winds in warm climates, but shelter the station in cold areas. The compressor station must be located at sufficient distance from other facilities to minimize potential noise problems or damage due to explosion.

Control and Safety Systems

The typically oil field compressor has a basic protection and monitoring control system. These include sensors to monitor process pressures, temperature, and vibration levels of major components. Since reliable operation of the air compressor is critical to the success of combustion project, consideration should be given to equip the compressed air system with a highly dependable automatic warning and shutdown system.

A chief reason for employing an automatic warning and shutdown system is to free maintenance personnel for duties other than monitoring compressors. The first cost of the system depends upon the type and the degree of sophistication sought. Automatic warning and shutdown systems are available from the simplest, designed to shut compressor down when temperature or pressure becomes too high, without any indicating device, to the most sophisticated systems containing visual displays to indicate both impending danger warning points and the exact cause of shutdown for more serious conditons.

Since the first cost of the system depend upon the degree of sophistication sought, the question of how much sophistication is warranted for a given machine is often raised. There is no simple answer to this question. A trouble free air injection plant operation is vital to the economics well being of a combustion project. Economic failure of many past combustion projects can readily be traced to explosions and costly repair of air compression-distribution system. Hence in a combustion project the importance of a highly dependable surveillance system cannot be overemphasized. The first cost of a surveillance system should be balanced against the potential loss of revenue in the event of a compressor shut down.

Ancillary Equipment

Ancillary equipment such as the air filters, air dryers, compressor lubrication system, interstage coolers, interstage scrubber, etc., are vital to the trouble free operation of a air compression plant and care must be exercised in their specification and selection. Completely pre-engineered units in addition to the basic compressor and driver usually include all the basic ancillary equipment from the air filter to the aftercooler, to exhaust silencer.

Compressor vendor often offers a customized packaged ancillary system for his compressor. It is recommended that the operator give serious consideration to purchase the system from the vendor.

In any event, it is suggested that compressor vendor's service be utilized during the ancillary equipment selection process.

Compressed Air Piping

For compressors to be functional, it must be connected to the system with piping. Since the user is responsible for sizing and furnishing the compressor suction and discharge piping system, he must at least have a rudimentary understanding of the compressor inlet and outlet piping requirements. The inlet and outlet piping requirements are somewhat different for the reciprocating and centrifugal compressors and these are briefly addresses in this section.

A clean, cool, dry air supply is essential to the satisfactory operation of a compressor. The air inlet must always be located far enough from prime mover exhaust pipe (if a fossil fuel engine is used as the drive) to ensure that air will be free from dust, dirt, or moisture and contamination by exhaust gases.

The inlet piping should be as short and direct as possible, with long-radius elbows where bends are necessary. If the inlet pipe is extremely long, a larger size should be used. A good inlet piping system should be self-supporting. The compressor should not be subject to the pipe strain associated with long runs of heavy pipe.

Inlet and Discharge Piping Requirements for Reciprocating Compressors:

Since steady flow does not exist in either the inlet or discharge of a reciprocating compressor cylinder, compressor piping should not be sized based on pressure drop under steady flow conditions. Sizing based on constant airflow from the compressor will result in the selection of pipe size, which are too small. If the pipe leading to and from a compressor cylinder are too small the pressure drop through lines will decrease the capacity of the compressor cylinder and increase the power required to compress a unit volume of air.

Due to the cyclic intake of air into the compressor cylinder, the air inlet flow to a reciprocating air compressor will be pulsating flow and cause inlet and discharge pipe to pulsate. Uncontrolled piping pulsation can affect compressor performance, and even cause piping failure. If the pulses generated by the cylinder are in step with the natural frequency of the air column within the pipe, the pulse amplitudes will peak and the system is said to be resonant. Resonance within the pipe can cause undue pressure losses, reduced capacity, after-cooler tube leakage and valve breakage. The best method to avoid resonance is through proper piping design and avoiding lengths that can cause pipe to resonate. Most compressor manufacturers can provide, at an extra charge, an optimum piping arrangement that avoid or minimize piping pulsation.

The piping between the compressor and aftercooler separator, and the discharge manifold constitute the discharge piping. As with inlet piping, certain discharge pipe lengths must be avoided to prevent resonance. Compressor manufacturers can provide this design information. The hot discharge line should not be allowed to come in contact with flammable materials such as wood. Any gaskets in the discharge piping should be of oil-proof, noncombustible material.

Pipelines through which hot air passes should be kept clean to avoid initiating combustion of accumulated dirt and oil. Discharge piping should be connected to the compressor with flanged fittings to permit removal of the cylinder at any time without disturbing the piping. Provision must be provided to allow the expansion of discharge pipe carrying hot air. All discharge pipes should be suitably anchored to minimize vibration, which results from the pulsating discharge of the compressor.

Piping Requirements for Centrifugal Compressors

For centrifugal compressors, the air piping should be arranged so as to permit uniform air velocity over the entire areas of the compressor inlet. This can be achieved by running suitable length of straight pipe just ahead of the compressor inlet. The inlet piping should preferably approach the compressor axially to avoid crowding the inlet air to one side of the first stage impeller.

Compressed Air Distribution System Piping

The compressed air distribution systems piping is one of the most important elements of a fireflood air injection plant. The air from the compressor is distributed to various injection wells through a system of pipelines, which are either buried or supported close to the ground level. Normally a carbon steel pipe with no internal coating is used for the air injection lines. In many projects, however, internally coated piping is being used to avoid corrosion. Since any pressure loss between the compressor and the injection well is an unrecoverable loss, and can impact the overall project performance careful planning is necessary to minimize pressure losses. The following general guidelines are suggested toward the design of air injection distribution system.

1. The air injection distribution line must be designed for a working pressure preferably 25% greater than the maximum expected wellhead injection pressure.

2. Pipe sizes should be large enough that the pressure drop between the compressor outlet manifold and the injection well head will not exceed 5 psi per 100 feet of pipe. Pressure drops must be determined based on maximum airflow rates through individual piping section. Pressure drops through valve, fitting, etc., should be pegged at 5 psi total for each expansion section.
3. Air injection lines from the manifold to injection wells should contain flow control valves and meters to control the flow of air to each injection well. In cold climates, these lines should be buried to minimize heat losses and to prevent any moisture from freezing and plugging the line.
4. A positive air flux must be maintained at all time from the compressor to the formation to achieve high level of safety.

Lubricating Oil Requirements for Air Compressors

Compressors are lubricated to prevent wear and to seal clearance around pistons, valves, and rotor elements. Both mineral and synthetic oils are used to lubricate air compressors. Since mineral oil based lubricants began to breakdown and deposit carbon about 325°F and can cause explosion, lubricant oils have to be completely excluded from the air stream. During normal operation of the air compressors, some lubricant is always carried into the air discharge lines as a suspended mist. Since oil filtering equipment suitable for high-pressure air injection systems is sophisticated and expensive, use of mineral oil in air compression system is not recommended. Fires and explosions can only occur when both fuel and oxygen are mixed in the proper proportions in the presence of an ignition source possessing sufficient energy to ignite the combustible vapors. Early day fireflood explosions in compressor and distribution systems is often attributed to the use of mineral oil based lubricants in compressor cylinder and the presence of an oxygen enriched atmosphere in the piping.

Synthetic lubricants do not readily breakdown and have the advantages of lower volatility and flammability when compared to conventional mineral oil based lubricants. Synthetic lubricants employed in the fireflood projects are designed to provide high temperature stability and long term lubrication with minimal deposit than conventional mineral oils.

A characteristic of compressed air system is that the auto-ignition temperature of air/fuel mixtures is decreased as air pressure increases. The auto-ignition temperature is reduced even further when the air stream contains rust particles, which act as a catalyst promoting the oxidation of the lubricant. Whereas the auto-ignition temperature of Andersol 500 (a widely used synthetic lubricant in fireflood projects) in air is 770°F at 0 psig, it drops to 615°F at 200 psig air pressure and to 515°F at 2,000 psig air pressure. Despite the substantial drop in the auto-ignition temperature of the synthetic lubricant, the normal temperature of the discharged compressed air (350°F) is substantially lower than the depressed auto-ignition temperature of the lubricant at elevated pressure. The auto-ignition temperature is lowered even further if rust particles are present in the air stream. It is the responsibility of the operator to keep the air stream free of contamination to reduce the risk of explosion.

Since synthetic lubricant tend to swell many types of packing and gasket elastomers, it is necessary to make certain that packings and gaskets are made of a material not affected by the synthetic lubricant. It is recommended that the operator consult lubricant vendors before selecting a lubricant for the compressor.

Explosion in Air Compression Plant

Although explosions in compressed air systems have happened in the past and are uncommon in present day operation, they continue to happen. No in-situ combustion project should be undertaken without first conducting a careful study of potential hazards and a preventive maintenance program to eliminate or reduce the possibility of such explosions must be undertaken. A brief of description of an in-situ combustion project air system explosion and the corrective actions taken by the operator to prevent any future explosion is presented in the following (Hardin, 1981)

Operating under a U.S. Department of Energy Contract, Cities Service Oil Company conducted a cost-shared commercial scale demonstration in-situ combustion project in the Bodcau Fee lease of the Bellevue Nacatoch Reservoir near Shreveport, Louisiana. This 19–acre, 5–pattern project was started in July 1976 and terminated in 1982 (See Chapter 6 for more information on this project).

This project was carefully designed and operated in an expert manner and was an economic success. The operator employed three reciprocating compressors to supply air to the project. The compressor cylinders were lubricated with synthetic lubricant to minimize explosion hazards. In spite of considerable care in design and operation of the air compression plant, an explosion occurred in the air compression/injection system.

Analysis of the explosion indicated that the explosion have resulted from the auto-ignition of lubricant carried over from the cylinders of the #2 compressor. The lubricant which had been accumulating in the low spots of compressor #2 cylinder discharge valves was carried over in the air stream into #3 compressor cylinders. As the lubricant passed through the #3 compressor's cylinder discharge valves, the air turbulence transformed the liquid lubricant into a finely divided oil mist. This mist formed an air/fuel mixture, which was within the flammable range for the lubricant. The mixture was ignited at the #3 compressor discharge valve by the heat of oxidation resulting from the swiftly moving oxygen enriched airflow. The ignition caused a low order explosion and the resulting shock wave was sufficient to propagate a larger oil film detonation, which then traveled throughout the air discharge piping system.

In order to prevent similar problems in the future, the operator adopted the following preventive program.

1. Periodic washing of the air distribution system with 5% (by weight) solution of sodium hydroxide and sodium nitrate, with frequent checks of possible lubricant collection points made between washes. The chemical wash was designed to destroy any oxidized residues in the lines.
2. Careful checks for buildup of carbonaceous residues on discharge valves and cylinders during routine maintenance.
3. Settings of high temperature shut down switches were lowered to activate at 300°F and discharge pressure held at minimum levels.
4. Elimination of mineral oil as cylinder lubricant in all air compressors.

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CHAPTER 8 — IGNITION

Introduction

A fireflood operation is initiated by igniting the formation. If the formation fails to ignite or ignition could not be sustained for an extended period of time the project may not be successful. Many past firefloods especially in heavy oil reservoirs have failed an account of poor ignition attempt. Hence ignition is one of the critical aspects of combustion recovery. The ignition is generally initiated by supplying large amounts of heat, sufficient to elevate the formation temperature around the injection well to a value higher than the crude's ignition temperature. Once this temperature is reached, in the presence of an oxidant, usually air, ignition is achieved. A sharp increase in the sand-face temperature at constant air injection and heat input rates is indicative of ignition. Typical values for ignition temperature range from 250°–500°F.

Several different techniques are employed in the field to achieve ignition. These techniques can be divided into two categories, spontaneous and artificial. If the reservoir temperature is high enough and the formation contain sufficiently reactive crude than it can be auto ignited after a period of air injection without the need for any artificial ignition device. Alternatively, the formation can be ignited using one or more of the many artificial techniques developed for this purpose such as the electrical downhole heaters, gas fired downhole burners, catalytic heaters, hot fluid injection and chemical means.

This chapter briefly review the various techniques and devices employed in the field to initiate ignition in the field. The equipment details and operation procedure for the gas fired burners and electrical heaters, the two widely used ignition devices in fireflood operation is also presented. For additional information, the reader is directed to an in-depth review report on ignition by Shallcross (1989). This DOE publication review the various ignition techniques and devices appeared in the patent literature including their unique features, limitation and reliability.

Spontaneous Ignition

Crude oils oxidizes (low temperature oxidation reaction) when exposed to air and releases heat. If the heat release rate is rapid enough to overcome heat losses, ignition can occur spontaneously, without the need for an external source of heat. The time required to elevate the formation to the crude's ignition temperature depend upon the crude reactivity and initial reservoir temperature. In general, higher the initial reservoir temperature lesser is the time required to reach the ignition temperature. The oils that are more reactive often generate larger quantities of heat and thus can heat their surroundings more rapidly and reduce the time required to achieve self ignition. Since heat loss rates to the over and underburden zones are greater in thinner than in thicker reservoirs spontaneous ignitions are more likely in deeper thicker reservoirs containing moderately reactive crudes.

An estimate of the time required (measured from the start of air injection) to achieve spontaneous ignition can be made from the following modified expression (Prats, 1982) of Tadema and Weijdema (1979), if it can be assumed that all the heat of reaction is consumed in heating the formation and the heat losses to the surrounding are negligible.

$$t_{ign} = \frac{(2.04 \times 10^{-7}) \left(\rho C\right)^{*} T_0^{2} \left[1 + 2T_0 \frac{R}{E}\right] \exp\left(\frac{E}{RT_0}\right)}{A\, \phi\, S_o \rho_o\, \Delta H \left(P_{O_2}\right)^{n} \left(\frac{E}{R}\right)} \qquad (8.1)$$

where:

t_{ign} = ignition time, day

$(\rho C)^*$ = equivalent heat capacity per unit volume of the porous medium, Btu ft^{-3} F^{-1}

T_0 = initial reservoir temperature, °R (°F +460)

R = universal gas constant, (1.9869 Btu/lb-mole °R)

E = activation energy, Btu/lb-mole

ϕ = porosity, fraction

S_o = oil saturation, fraction

ρ_o = oil density, lbm/ft.^{3}

ΔH = heat of low temperature oxidation of the crude, Btu/scf of oxygen reacted
($\cong$ 100 Btu/scf oxygen)

A = oil's low temperature oxidation reaction pre exponential factor, sec^{-1} atm^{-n}

P_{O2} = partial pressure of oxygen, atm

n = reaction order with respect to oxygen

From the above expression it is readily apparent that the time necessary to achieve ignition decreases as the reservoir temperature (T_0) or crude reactivity increases (smaller 'E' or larger 'A'). The effect of increasing oxygen partial pressure (higher reservoir pressure) is also to shorten the autoignition time.

Equation (8.1) is very sensitive to temperature. Even an error of 1°F in the estimation of reservoir temperature would result in an error of several percent in the estimated ignition time as indicated by the following hypothetical example.

Example:

Estimate the spontaneous ignition time assuming the reservoir temperature to be 90 and 91°F and the following data.

Air injection pressure	350 psig
Heat of oxidation	110 Btu/Scf
Porosity	0.34
Oil saturation	0.62
Oil density	59.8 $\text{lb}_m/\text{ft.}^3$
Reservoir heat capacity	39 Btu/ft.^{3} °F
n	0.6
A	3090 sec^{-1} atm$^{-0.6}$
E/R	16,000°R

Case 1: t = 90°F

$T_0 = 460 + 90 = 550°R$

$P_{O2} = 0.21 \times (350 + 14.7)/14.7 = 5.21$ atm.

From Eq. 8.1,

$t_{ign} = \{(2.04 \times 10^{-7})(39)(550)^2 \times [1 + 2(550)/16{,}000](4.31 \times 10^{12})\}$

$\div [(0.34)(0.62)(59.8)(110)(3090)(16000)(5.21)^{0.6}]$

= 60 days

similarly for t = 91°F

$T_0 = 91 + 460 = 561°R$

$t_{ign} = \{(2.04 \times 10^{-7})(39)(561)^2 \times [1 + 2(561)/16{,}000]\ (4.084 \times 10^{12})\}$

$\div [(0.34)(0.62)(59.8)(110)(3090)(16000)(5.21)^{0.6}]$

= 57 days

Thus a 1°F difference in the reservoir temperature result in 5% error in the estimated ignition time.

Since Equation (8.1) neglects the heat losses, the self ignition time computed using the above expression is always shorter than would be expected in the field. However, the ignition time computed using this simple expression does give an indication whether it is feasible to achieve autoignition in a reasonable amount of time. If, for example, the calculated autoignition time is only a few hours or days, than spontaneous ignition is economically feasible and should be considered. On the other hand, a calculated ignition time of months or years points to the need for techniques that can lower the ignition time greatly. A knowledge of the oxidation characteristics of the crude in presence of the reservoir rock is useful in ascertaining whether it is feasible to autoignite the oil in reasonable time.

Burger (1976), using a numerical simulator, investigated the effect of heat transfer (in the direction of flow) and flow geometry on ignition time and concluded that unless initial reservoir temperature is very low, Equation (8.1) yield an acceptable value for ignition time. Burger's calculated ignition times are only a few percent greater than those given by Equation (8.1) except for low temperature reservoirs, where the differences are as much as 100%.

Spontaneous ignition has been utilized to initiate fireflood in many fields. Spontaneous ignition can often be achieved with in a reasonable time in formations deeper than 4,000 ft. due to high reservoir pressure and temperatures. For example, in the Medicine Pole Hills Unit, N. Dakota and the Buffalo Red River Unit, S. Dakota in-situ combustion projects, ignition occurred in as little as five hours due to high initial reservoir temperature (230°F) (Miller, 1995). It also appears that in many shallow California reservoirs autoignition can be achieved in a matter of weeks due to high reservoir temperature (> 100°F) and presence of fairly reactivity crude.

Though, the initial oxidation rate and consequent heat generation rate are highest in the immediate vicinity of injector, autoignition does not occurs near the well. This is because the injected air transfers heat away from the well, and consequently ignition occurs at a point some distance away from the injector. This distance increases with the air flow rate. Since the region between the ignition point and the injector is saturated with oil and oxygen, after ignition the burning front moves backwards toward the injector, prior to moving in the direction of air flow. During this backburning period temperature around the injector can rise to a very high value and damage the well casing if the free oil entering the hole (backflow) is allowed to present in the hole. Injection well damage can be minimized or prevented by exposing a limited section of pay to air through selective perforation of cemented completions. Also, by maintaining a high enough air injection rate and by ensuring that no interruption of air flow occurs, backflow of reservoir fluids in to the wellbore can avoided, thus minimizing the chances of wellbore damage.

A rapid auto-oxidation, especially in heavy oil reservoirs is desirable to minimize the formation of low temperature oxidation products. Low temperature oxidation tend to promote the formation of unstable peroxides and buildup of coke near the wellbore. When autoignition does occur, the backburn can ignite the coke and the resulting high temperature can damage the downhole tubulars.

Artificial Ignition

As noted previously autoignition cannot be achieved in reasonable time in low temperature reservoirs or in reservoirs containing low reactivity crudes. Ignition in such reservoirs can be achieved by heating the oil-bearing formation to the oil's ignition temperature. Several artificial ignition techniques are available for this purpose. These include: downhole electric heaters, gas-fired downhole burners, catalytic heaters, hot fluid injection technique, chemical methods, and fluid pack methods.

The electrical heater, gas burner and hot fluid (steam) injection are the most widely used artificial ignition methods and are described in detail in the following sections. The other less popular techniques are only briefly dealt with. For a more completed discussion of these lesser used techniques the reader is referred to the DOE's report on in-situ combustion ignition devices (Shellcross, 1989).

The amount of heat needed to initiate ignition depends upon the heating rate and on the ignition temperature of the crude. Though these conditions vary considerably from one field to another rough estimates can be made using empirical correlations. As a first approximation, the energy which must be supplied to rise the temperature of unit thickness of the formation (Q/h) at a distance 'r' from the well from the reservoir temperature T_r to ignition temperature T_{ign} is given by (Burger, 1985):

$$\frac{Q}{h} = \pi \left[r^2 - r_w^2 \right] (\rho C)_r \left[T_{ign} - T_r \right] \qquad (8.2)$$

where:

r = heated radius, ft.

r_w = wellbore radius, ft.

$(\rho C)r$ = volumetric heat capacity of the formation, Btu ft.$^{-3}$ °F^{-1}

T_r = initial reservoir temperature, °F

T_{ign} = ignition temperature, °F

Assuming $r = 3$ft., $r_w = 0.5$ft., $(\rho C)_r = 31.3$ Btu/ft.^{3} °F and $(T_{ign} - T_r) = 360$°F one obtains

$Q/h \cong 310{,}000$ Btu/ft.

Equation (8.2) assumes no heat losses due to either conduction or convection. In reality, this is not true and often more heat need to be supplied to initiate ignition. The energy input in the reported projects vary from a low of 0.5 MM Btu to 3.5 MM Btu per foot of formation. Often in excess of a million Btu of heat per foot of formation are needed to ignite a thick (>15 ft.) reservoir containing heavy oil (15°API or less). More heat must be supplied to initiate ignition in thinner reservoirs or reservoir containing lighter oils.

Gas Fired Burners

Historically gas fired burners are the most widely used device to initiate ignition in a fireflood project. The heat required to ignite the formation is generated downhole by burning a combustible mixture of air and hydrocarbon gas such as the natural gas or propane in a specially designed combustion chamber (burner) housed inside a heat shield. The heat shield is a stainless steel cylindrical vessel (pipe) lined with a refractory material and serve to protect the casing and downhole tubulars goods from direct exposure to the high combustion temperature.

The principal advantages of employing gas burners in combustion projects are:

1. Ready availability of natural gas in most fields.
2. Good temperature control.
3. No depth or pressure limitation.

It has been used successfully to ignite formations at depths as shallow as 100 ft. and as deep as 6,200 ft. and pressures to 3,500 psi. Reported air injection rates during ignition vary an order of magnitude from 100 Mscf/D to 960 Mscf/D.

A downhole burner system requires an independent means of introducing fuel and air to the bottom of the hole for combustion, means to initiate the fire at the burner, and surface metering and control equipment for the fuel and air streams. Stoichiometric mixtures of air and fuel often result in combustion temperatures (of the order of 1200–2000°F), far in excess of that required to ignite the formation and are destructive to downhole equipment and materials. For these reasons, a secondary supply of air is utilized in burner assembly to reduce effluent temperature and to minimize possible well damage.

A variety of downhole burner system have been patented in the U.S. since the early 1950s (Shallcross, 1989) and a few are described in the petroleum engineering literature (DePriester et al., 1963; Brandt et al., 1965; Smith, 1967; Crevolin, 1984). These designs differs in mechanical details, configuration utilized to supply fuel gas and air to the combustion chamber, the method employed to ignite the air-fuel mixture and the technique followed to reduce the effluent temperature.

One design (Smith, 1967) employ a single tube string other than the casing to supply fuel and air to the burner. In this arrangement, the fuel is supplied down the inner string, and air is forced down the annular area. The air is split into two streams (primary and secondary) at the entrance to the burner chamber. With this arrangement, the ratio of primary to secondary air is fixed once the burner is run into the hole. The effluent gas temperature is reduced by mixing with the secondary air prior to injection into the formation

In an alternate configuration (DePriester et al., 1963; Brandt, 1965), the fuel gas and the air are introduce into the combustion chamber through two parallel tubings. The secondary air is injected down the casing tubing annulus. While this arrangement permit the easy adjustment of the primary air-fuel ratio and the ratio of primary air to secondary air at the surface, they are more cumbersome to work with due to the difficulty of simultaneous lowering and raising of two parallel strings within the well.

As pointed out previously, the combustion of air-fuel mixture often result in temperatures much higher than that needed for ignition and must be cooled prior to transferring the heat to the formation. This is accomplished either directly or indirectly. In the indirect scheme the combustion gases are cooled by transferring some of the heat of combustion to a secondary stream of air flowing around outside of the combustion chamber and heat shield. In the direct method the combustion gases are cooled by mixing it with the secondary air to a final temperature of 550–900°F. In the design that transfer the heat of combustion indirectly to the secondary air, the exhaust gases are vented to the surface (Brandt, 1965). The relatively cool air-effluent gas mix or the heated air is then discharged over a fairly limited section of the pay to initiate and sustain the combustion.

In a typical downhole installation system, a tubing string with a pump seat at the bottom is first lowered into the cased ignition well. The seat is positioned few feet above the top of the perforation, so that it is away from the heat generated by combustion within the formation. The burner is then lowered inside the tubing string on a second, smaller tubing, until it rests on the seat. The fuel gas is then supplied down the inner tubing, while the air is forced down the annulus between the two strings. A number of small conduits in the burner just above the combustion chamber allow the air to flow into the ignition chamber and mix with the fuel gas. The air-fuel mixture is ignited by some means such as by the use of a spark plug or chemical compound. The secondary air that is injected down the casing annulus serves a number of useful roles. Firstly, the air cools the burner unit as it flows around it and helps to control the temperature within the well. More importantly, it is this supply of air that is used to oxidize the oil within the formation. Finally, a constant flow of air into the casing annulus prevents the hot combustion gases from flowing back up the well instead of into the formation. Most burners in use today incorporate thermocouples into the design to monitor the temperatures in the well, in the combustion chamber, and around the ignition system.

Oil-bearing formation often do not ignite on the first attempt and must be reignited. Further, for a variety of reasons, the combustion front dies before it is well established. Hence it is important that the downhole burner system be equipped with a reusable ignition device so that it can be reignited if necessary without the need for having to pull the burner from the hole.

Gas fired burners are ignited using an electrical ignition device or by chemical means.

Electrical igniters include spark plugs, glow plugs and resistance heaters. Several igniter designs have appeared in the patent literature over the years and are described by Shallcross (1989). Prior to 1965 electrical igniters were built into the burner as an integral component and hence are not reusable due to damage incurred during the ignition of the gases. To overcome this drawback, the later igniters were designed to operate as a stand alone battery or generator powered unit. The unit is lowered to the burner on a wireline within the fuel gas tubing string. When in place, the spark gap electrodes or the resistance heaters protrude into the burner's combustion chamber where they may ignite the gases.

To ignite the burner, the igniter is lowered into place, guided by the location stops. When the igniter is in place, tension on the wireline and the weight of the batteries bears down on a pressure switch located in the mid-section of the unit. The shifted weight closes the electrical circuit and the electrodes spark across the gap. Once ignition is achieved, the igniter is withdrawn from the burner. In an alternate design, the igniter electric circuit incorporate a bimetallic element that permit the electrical igniter to operate only when it is cool. Thus, once the fuel gas has been ignited and the igniter is hot, the spark plug or resistance wire will not operate. Thus, should the burner flame is put out, this design permit the automatic reignition by the igniter once the bimetallic element has cooled sufficiently.

A major disadvantage of using electrical ignition system is that its heat generating capacity is limited and as such it may fail to ignite the gas if the amount of gas reaching the igniter is excessive. Further, since power losses increases with depth, electrical igniters cannot be employed in deeper wells. Also operational problems such as the electrical shorts, poor connections, heater element burnout etc. can preclude the satisfactory functioning of these igniters.

Burner gases can also be ignited chemically using pyrophoric chemicals.such as the calcium phosphide, triethylborane (TEB), silane and disilane. Linseed oil containing catalysts such as cobalt naphtheneate and dimethyl aniline have also been used as igniter. The chemical ignition system is extremely easy to use and is the preferred choice of many operators. Most operators prefer TEB over other pyrophoric chemicals because it does not react with water or hydrocarbons, and ignites in the presence of air at temperatures above -4°F.

In the chemical ignition method a sealed cup containing a pyrophoric material (that spontaneously ignite in the presence of oxygen) is placed into the tubing string supplying fuel gas to the burner and lowered on a wireline to the gas fired burner. The cup is allowed to open and expose the pyrophoric material to air only when it is within the burner's combustion chamber. The pyrophoric material upon contact with the oxygen in the air ignites and this heat of combustion then ignite the combustible gas mixtures. The cup is then withdrawn completely from the well or left 15–40 feet above the burner to be used to reignite the burner if necessary.

Safety must be of major concern in the use of chemical ignition method. Pyrophoric chemicals are extreamly reactive in the presence of oxygen and care must be exercised to avoid exposing it to air when handling these chemicals at the surface. Technicians must be properly trained in the safe handling of these chemicals to avoid personal injury. Further steps must be taken prevent contact between the pyrophoric material and air outside of the combustion chamber in the downhole to prevent damage to casing and downhole equipments.

Description and Operation of a Popular Gas Fired Ignition System

Ignition operation is a complex and non-trivial task and certain procedures must be followed to ignite the formation successfully. A variety of gas fired ignition system is employed in the oil field and the operating procedures vary the system. Nevertheless, with all the system the injection well must satisfy the following conditions prior to the installation of the burner:

- The well must be in good mechanical condition (no casing leaks; wellhead and casing have satisfactory pressure rating, etc.)
- The tubing must have been drifted and found free of obstructions.
- Both the well casing and tubing must be thoroughly cleaned and free of any hydrocarbon residue.

A schematic of a popular downhole burner ignition system is shown in Figure 9.1. This system developed and patented by the Gulf Research & Development Company (now Chevron) and used widely under licence by the petroleum industry includes surface equipment for installing the burner and for supplying metered quantities of air and fuel, the thermocouple-fuel tubing and the burner assembly.

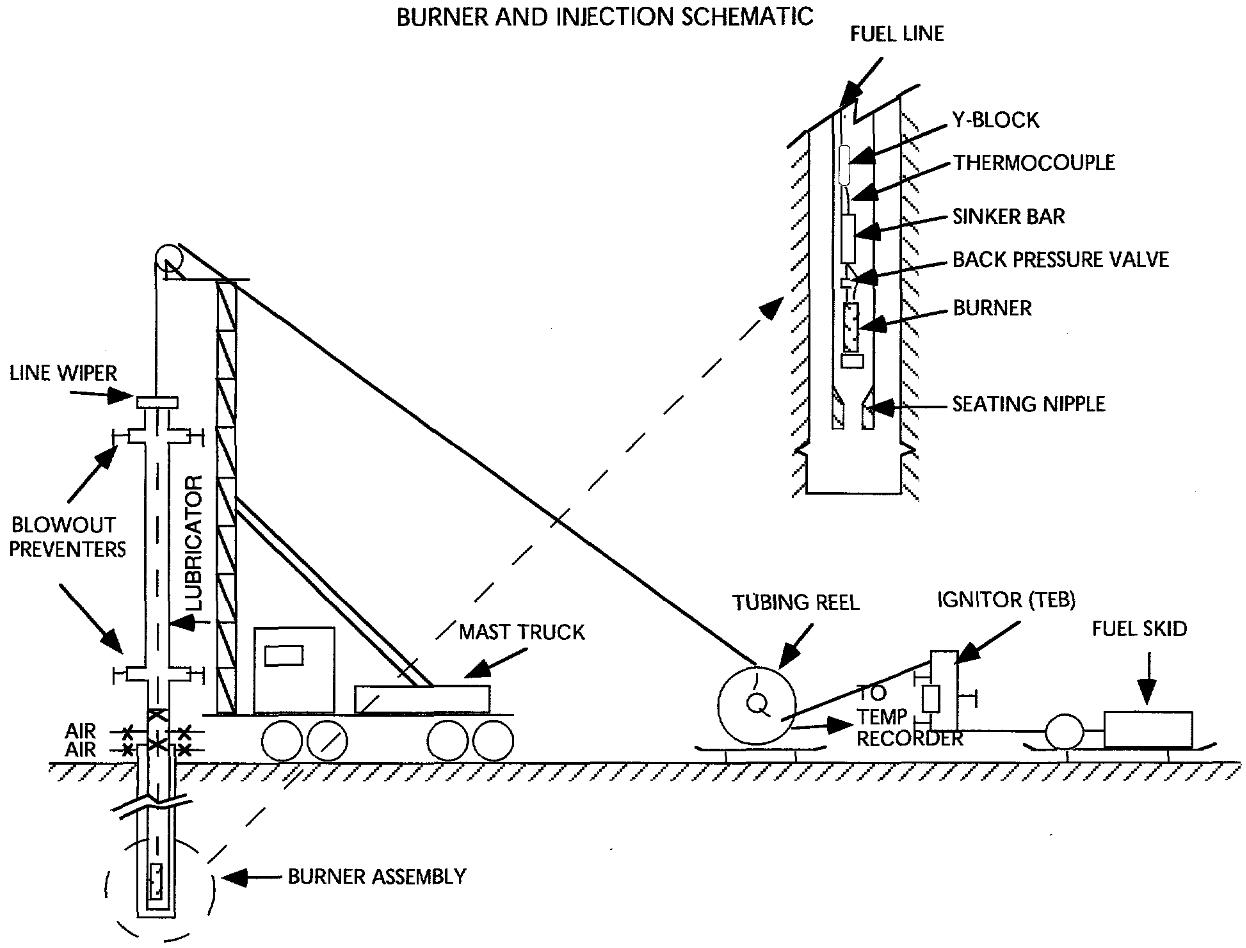

FIGURE 8.1 — In-Situ Combustion Ignition System

The basic burner assembly (Figure 8.1) consists of a burner and burner stop, fuel check valve, Y-block, and thermocouple. A sinker bar also is incorporated in the complete burner assembly. The assembly is designed for use inside tubing with a minimum internal diameter of 2 and 3/8 inches.

The basic surface equipment also shown in Figure 8.1 includes a simple wellhead lubricator hookup and a mast and hoist for installing the burner. In addition the surface facility include air and fuel supply, metering facilities, and temperature recording and safety control instruments.

An air compressor with sufficient capacity (usually in the range of 0.5-4 MMScf/d) and capable of uninterrupted operations at pressures up to 1 psi per foot of depth is utilized to supply air. The air is supplied to the tubing and casing through a parallel set of control valves and orifice meter runs, thereby permitting the control and measurement of the air flow into the tubing and casing.

A metering pump is utilized to supply metered quantity of fuel to the burner. Although the burner can burn any liquid paraffin hydrocarbon more volatile than, gasoline, propane is generally the preferred fuel owing to its wide availability and low cost.

A downhole temperature limit switch is utilized to ensure safe operation of the burner. This switch automatically stops the fuel injection to the burner in the event an excessive temperature develops owing to air supply failure, wellbore fire, etc.

Additional informations on the system can be found in the article by Smith (1967), who described the system in considerable detail. Here we describe the step by step procedure for the installation and operation of the burner.

1. Install and pressure-test all injection lines (at 1–1/2 times the operating pressure).
2. Install fuel tubing and fuel injection system.
3. Install temperature measuring and control devices.
4. Install crown sheave on mast truck.
5. Assemble the lubricators with the blowout preventer open and line wiper packing removed. The lubricator is rested on the ground.
6. Assemble the burner with an appropriate sinker bar weight and thermocouple.
7. String the fuel tubing with Y-block connections to the burner assembly.
8. Insert the burner assembly through the line wiper and into the lubricator.
9. Fuel line is filled with propane and the check valve operation tested. The fuel line is pressure tested to 1,000 psig.
10. Install lubricator and the burner on the wellhead; no tension and sharp bending of the fuel tubing is permitted during the installation (i.e., the assembly should not be raised by the fuel tubing).
11. Raise the burner assembly from the top of the gate valve by one foot.
12. Assemble the line wiper packing hand-tight.
13. All tubing head valves are opened slowly.
14. Remove all the handles.
15. Lower the burner assembly inside the well tubing to the burner seat.

16. The blowout preventer and line wiper are firmly tightened.
17. Recheck fuel line pressure and check valve operation. The pressure should approximate the casing pressure, plus 350 psig, less the weight of the column of propane in the fuel tubing.
18. Recheck temperature recorder and air flow meter readout. The recorder should read bottomhole temperature.
19. Discontinue fuel pumping.
20. The fuel metering pump is adjusted to the proper rate to produce a predetermined burner exhaust temperature.
21. Install TEB container on the fuel bypass manifold.
22. All fuel lines leading to the TEB container are purged with propane before tightening.
23. Activate the fuel pump to raise the fuel line pressure to the proper value.
24. Open the upper valve of the TEB container slowly.
25. When the pressure of the TEB container reaches the fuel tubing pressure, open the lower valve of the TEB container. The fuel bypass valve is then closed.
26. When the TEB enters the air stream, an abrupt temperature increase will be noted on the temperature recorder.
27. Burner operation is usually carried out for a period of 3–5 days to ignite most formations.

Electrical Ignition

Many operators prefer electrical igniters over gas fired igniters due to their relatively simple operations and low cost. The major advantages of electrical igniters include: (1) ease of operation; (2) excellent temperature and heat input rate control; (3) flexibility in changing heater location to permit the exposure of all parts of the formation to the ignition temperature; and (4) flexibility over the duration of heater operation to ensure formation ignition (if feasible). Further unlike the gas burner (see section 8.3.1 1) the electrical ignition system does not require elaborate surface and downhole facilities and tools to install the igniter downhole and initiate ignition.

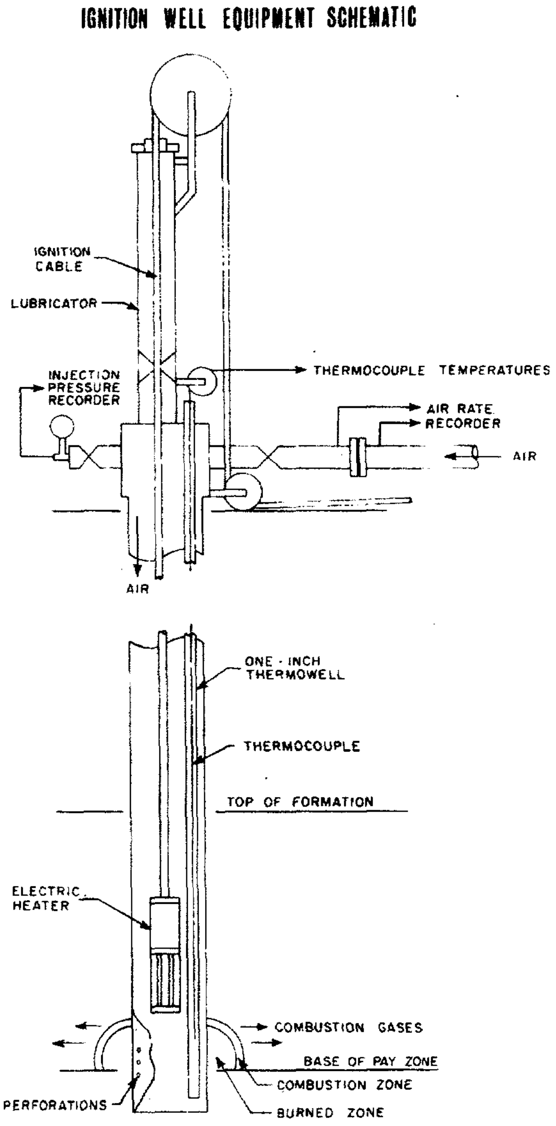

FIGURE 8.2 — Schematic of an Electrical Ignition System for Fireflood Injection Well

While electrical igniters are safer and easier to control than downhole burners they cannot be deployed in deeper wells owing to excessive line power losses. A significant portion of the power supplied at the wellhead can be dissipated as heat within the cable due to the cable's electrical resistance. The amount of electrical power lost depends upon the cable material chosen, the cable diameter, the depth of operation, the line voltage, and whether the power is supplied by single- or three-phase transmission.

Basically, the electrical ignition systems consist of:

- An electrical cable of suitable length.
- A high-pressure lubricator.
- A source of electric power.
- An air-injection system.
- The electric heater.

Power supply for the ignition system generally is rated for 220, 440, or 880 volts AC. Electric power can be supplied by portable generator units or from normal field power sources through suitable transformers. Downhole ignition systems are designed for a specific voltage and power phase. Load requirements range between 20 and 40 kw. The power supply must not only be compatible with the heater design, but also it must be capable of the maximum load delivery. Schematic of an electrical ignition system for fireflood is shown in Figure 8.2.

Two general types of electrical downhole heaters are in use for ignition services. In the simpler and most common design, a series of "nichrome" elements coiled on ceramic cores and enclosed in a stainless steel case constitute the heater. This heater is lowered into the well on an armored cable. The cable not only bears the weight of the heater, but also supplies the electric power and may carry signals from any thermocouples present. The heater elements are designed to operate continuously at 1500°F. The electrical resistance wires inside the housing is insulated with magnesium oxide. Air is injected down the well and the heat is imparted to the air as it passes around and along the electric elements. In the second design, the heater is made up of a number of commercial alloy steel-sheathed heating elements connected to a suitable head arrangement and mounted on the end of a tubing string. The end of the string incorporates baffles and jackets so that air must pass over the heated section several times before passing into the well. Often times the combination of conductors, electrical insulation, and armor makes the size of the cable rather large and makes it difficult to lower the heater into the well under high pressure.

Proper operation of the igniter is indicated by current and voltage measurements. Heater temperature is controlled by varying the power to the heater — either by adjusting the voltage, or by a simple on-off control of the heating cycle. Temperatures may also be controlled by proper adjustment of the air-injection rate.

Hot-Fluid Injection and Chemical Ignition

In shallow formations containing sufficiently reactive crude, ignition can be achieved by injecting surface-heated fluids such as steam. This technique is more applicable to cases where the oil is sufficiently reactive but low reservoir temperatures prolong the ignition time to such an extent that autoignition is not achieved. Autoignition can be achieved in reasonable time by raising the formation temperature by hot-fluid injection. Once a significant volume of the formation has been heated to ignition temperature, the injection of heated fluid is terminated and normal air injection is begun.

The formation temperature can also be elevated above the ignition temperature by inducing and controlling an exothermic reaction within the wellbore or formation proper. Difficulties involved in chemical ignition include hazards associated with the handling of chemicals and the problem of proper placement of the chemicals to ensure satisfactory ignition.

In a typical chemical ignition method, a quantity of autoignitable fluid such as tung oil or linseed oil is injected into the formation around the ignition well. The fluid is then pushed away from the immediate vicinity of the well by a slug of another fluid such as diesel oil. An oxygen-containing gas (such as air) is then injected into the formation, and the autoignitable fluid (the tung oil or linseed oil) ignites. The heat generated within the formation is sufficient to ignite the crude. The purpose of the injection of the second fluid is to push away from the wellbore the highly reactive autoignitable fluid so that the injection well is not subjected to the severe temperature. To accomplish this, the second fluid must be less reactive and miscible with the autoignitable fluid. Light crude oil, kerosene, or diesel oil can all be used as the displacing fluid.

Detecting Ignition

Since the cost of injecting air is substantial, it is important to ascertain early during the operation whether ignition has been achieved. This knowledge is important because it can prevent unnecessary incurring of expenses for igniter operation if the formation fails to ignite in a reasonable time.

In artificial ignition methods, temperature measurements and gas analyses are useful in detecting ignition. In electrical ignition, thermocouples are installed within the heater. Temperature traverses during heater "off" periods can indicate formation-face temperature. When the heater is being operated opposite the formation face, a rapid rise in temperature at constant heat input rate is often construed as evidence of ignition. Gas analyses at surrounding producers also can provide an indication of ignition. In many instances, gas breakthrough to offset producers occurs within a matter of days after initiation of air injection. Initially, the oxygen content of the produced gas streams may be higher but subsequently drops, indicating ignition. The produced gas may also contain CO and CO_2.

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CHAPTER 9 — IN-SITU COMBUSTION WELL DESIGN, COMPLETION, AND PRODUCTION PRACTICES

Introduction

Since potential explosive situation can develop rapidly in in-situ combustion projects due to the presence of hydrocarbons in compressors (lubricants), air injection lines, air injector, etc., safety is of prime concern in fireflood operations. Design and engineering of fireflood surface and subsurface system are more involved and require careful planning and monitoring.

In this chapter, the fireflood injection and production well design and completion procedures are detailed. Fireflood operational problems and project monitoring techniques are also discussed.

Well Completion Practices

The design of fireflood well completions requires special consideration of several troublesome factors that are amplified by the fireflood process, which include high temperature, corrosion environment and proper selection of corrosion-resistant materials, preparation of the injection well for safe injection of air by assuring that the surface equipment and downhole pipe are absolutely free of hydrocarbons, and sand and clay control. Figures 9.1 and 9.2 show schematics of typical injection and production wells, respectively.

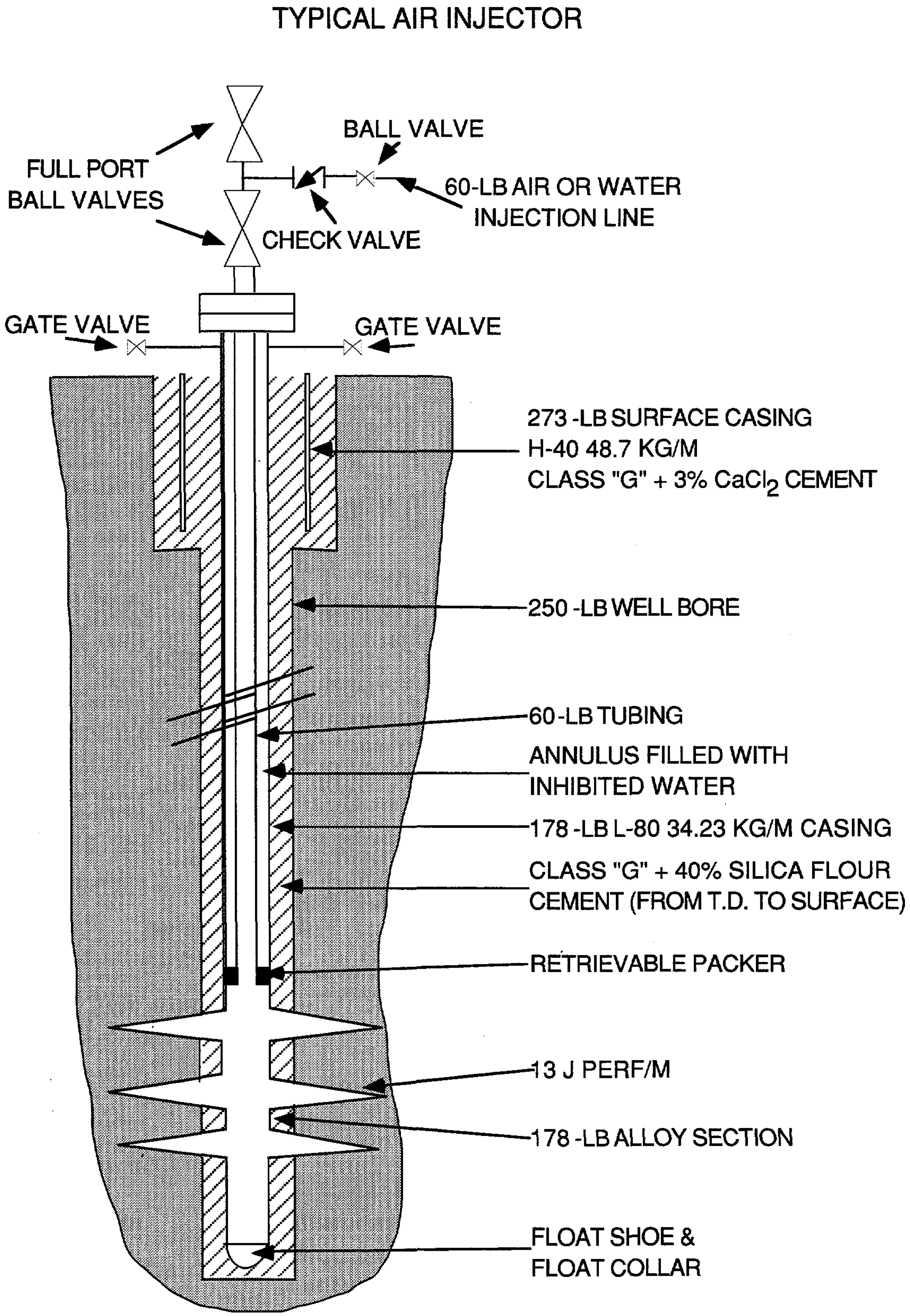

FIGURE 9.1 — Schematic of a Typical Fireflood Injection Well

TYPICAL PRODUCING WELL COMPLETION

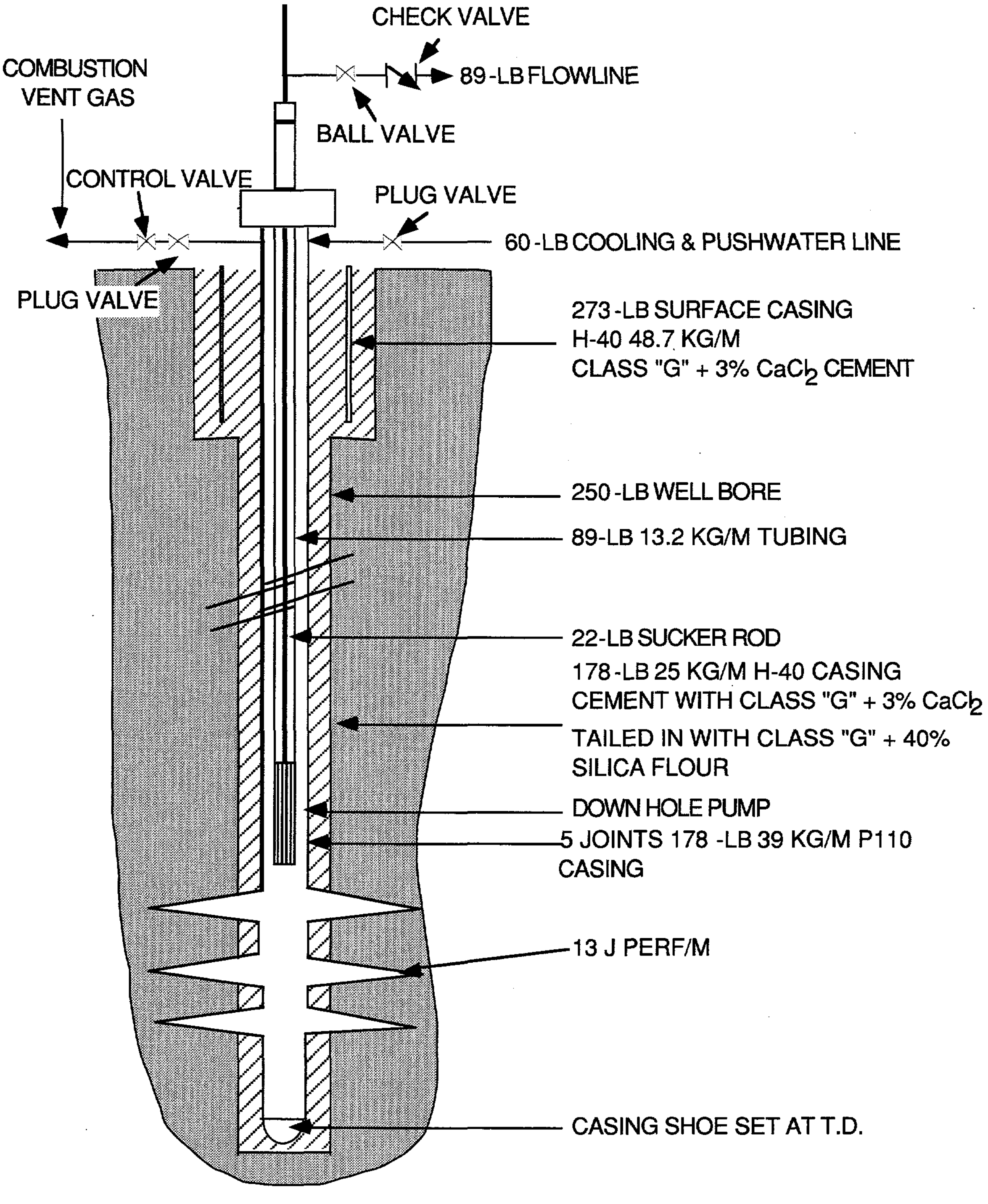

FIGURE 9.2 — Schematic of a Typical Fireflood Producer

With regard to safe air injection, the following general precautions are always applicable:

1. No hydrocarbons are permitted to enter the injection wells at any time.
2. All lubricants used on downhole equipment should be synthetic or non-hydrocarbon type, such as Fyrquel-base grease.
3. All equipment, tools, lines, etc., should be cleaned and hydrocarbon-free.
4. All tubing, work string and injection string should be cleaned and hydrocarbon-free.
5. Personnel of all levels should be informed of the importance of preventing hydrocarbons from entering the well.

Movement of sand particles into the wellbore from semi-consolidated to unconsolidated sand as fluid is produced can be and generally is a production problem in most fireflood producers. The sand production mechanism can be extremely complex and is influenced by all completion operations ranging from first bit penetration to the start of production or injection. The problems of sand control in thermal recovery wells are especially troublesome because of high production rates of reservoir fluids as a result of the high volume of fluid injected in these processes. The greatest single problem of any enhanced recovery process is that of making lasting, high-productivity well completions which are resistant to erosion and corrosion at elevated temperatures.

The remainder of this Section describes and recommends certain drilling and well completion projects currently used in industry which may have application in most fireflood produce. Also included is a list of screening tests which should be performed prior to any completion to ensure its success.

Drilling and Well Preparation

Successful preparation of a well for sand control requires that each well completion procedure be designed and executed properly. Any failures in drilling, underreaming, casing, cementing, perforating, or the use of completion or workover fluids could be detrimental to well productivity.

Drilling Fluids

Both productivity and injectivity can be adversely affected by washouts through the production interval and by reduction in permeability due to fresh water invasion into the formation which causes swelling of water sensitive clays. Drilling fluids, therefore, have to be inhibited against clay hydration, generally with 1–10% brine or KCl solutions and/or other clay stabilizing compounds, such as hydroxy-aluminum.

Cementing

Poor cementing techniques could cause channeling and may contribute to excessive water or gas production in certain wells. Formation damage from cement particle invasion into the production zone could be a severe problem in certain enhanced recovery wells. For this reason open hole completions or a cement "puddling" technique designed to minimize column height or head while cementing casing through the production zone is sometimes recommended. In some areas casing can be set through and cemented with high silica flour cement. For an open hole completion operation, the well is drilled to gauge to the top of the producing formation and then cemented in accordance with the best available cementing practices; i.e., the cement should possess low-fluid loss, and the casing string should be centralized, equipped with scratchers, and rotated or reciprocated during the cementing operation. A high-silica flour cement is recommended for all zones experiencing high temperature.

During the cement "puddling" operation, cement with proper water loss and setting time additives is spotted in open hole through the production interval while pumping through the drill string equipped with scratchers. The drill string is rotated and withdrawn slowly through the production zone during the cementing operation to remove, or scratch mud cake from the side of the wellbore and to prevent the formation of pockets of mud in the cement. After the cement has been "puddled in," the drill string is removed from the well; centralized casing is run to the top of the cement pool and then slowly through the cement to the bottom of the well; and the cement is then permitted to set prior to perforating.

Perforating

Jet perforating is a piercing and pulverizing process that creates a flow path through the casing, cement sheath, and into the formation. However, cement, cooper, lead and carbon from the jet charge can penetrate and mix with crushed formation material, sometimes causing significant perforation damage and restricted productivity and injectivity.

Perforations should be gravel packed with properly sized sand to prevent the "tunnel" from being filled with formation fines when the well is placed on production. If gravel is not sized properly, sand will enter the perforated area, become trapped in the gravel, and cause a prohibitively high pressure drop across the perforations.

Completion fluids across the interval at the time of casing perforating should be free of solids because they can be driven into the perforation by the force of the charge. Perforation debris removal methods include underbalance, backflow, perforation washing, acid stimulation, and swabbing. Underbalance, backflow, and perforation washing, for the most part, are effective remedial measures, but are not always 100% successful. Acid stimulation under certain conditions could be responsible for reduced permeability and compressive strength of the formation, sometimes resulting in abnormal production decline shortly after treatment. Swabbing is undesirable in soft formations because of excessive sand removal and the uncertainty that all perforations have been properly cleaned.

Well Completion and Workover Fluids

Colloids, brine, and bridging solids impart effective fluid loss control, excellent suspension properties, and low friction loss to well completion and workover fluids. These colloids generally consist of calcium lignosulfonate, hydroxyethyl cellulose and other polymers. In addition, special fluids, such as oil base, inverted emulsion and chalk emulsion systems, have been used successfully to protect sensitive clay bearing formations from fresh water. The chalk emulsion is actually a water-in-oil emulsion containing acid soluble bridging and weighting materials which have been stabilized by finely divided acid soluble chalk solids.

Stable performed foam has replaced mud, oil, and water as a circulating medium in well completion and remedial operations in many shallow, low pressure reservoirs of California. The foam with a density as low as 0.3 ppg is performed at the surface to a consistency of aerosol shaving cream by blending detergent, fresh or salt water, compressed air or gas, and sometimes other special additives such as surfactants. The foam has been used in California wells to core the completion interval, stabilize severe sanding and shale sloughing problems, retrieve open hole liners, recomplete old, low pressure wells by drilling in new liners, and recover sanded-up equipment and cement liners in lost circulation zones. Advantages include low hydrostatic head, elimination of formation damage, high carrying capacity for cuttings removal, low circulation pressures, and simple installation.

Open Hole Completion

The main advantage of open hole completion is the increased productivity over that of perforated completions. For example, theoretically it would require four perfect 1/2-in. diameter holes per foot, penetrating the casing, cement sheath, and 8 in. of the formation to equal open hole productivity. In addition, these openings in unconsolidated sand must be held open by gravel or by chemical consolidation of the surrounding formation.

Only those sand control methods believed to have possible application in open hole completions will be discussed in the following. A unique sand and clay control method designed especially for high-temperature, low pH fireflood producers incorporating cased hole completions will also be discussed.

Screens

Slotted liners, wire wrapped screens and pre-packs, have been used effectively in certain areas to control sand production. However, it is not recommended that the well be permitted to create its own pack around a screen placed across the producing interval. This procedure will generally result in a disturbance of the formation, possibly causing excessive fine sand production or plugging before the screen or pack stabilizes. All screens, therefore, should be used in conjunction with gravel packs to retain gravel packing material which, in turn, supports the formation sand.

The all-welded wrapped-on-pipe screen has the highest flow capacity. Wire and pipe are normally 304 stainless steel, but for extremely corrosive atmospheres special alloys of Inconel and Incoloy are available, such as Iconel 625 and Incoly 825. Some laboratory corrosion tests have shown that Inconel 625 has a better high temperature corrosion and oxidation resistance than Incoloy 825. A schematic of a recommended completion for a fireflood production well is shown in Figure 9.2

A slot or wire width opening of two times the 10 percentile diameter of the formation sand has been proved effective in certain areas containing sand with broad size distribution. In areas with relatively uniform sand size, slots equal to the 10–15 percentile formation sand diameter have been used satisfactorily. The self-cleaning, keystone type slot or wire opening is recommended under that of parallel sided slots in which particles 1/2 the slot width tend to wedge and plug.

Pre-packs are designed to bridge fine formation sands without the need for gravel packing. They are fabricated with an outer cylinder of either unconsolidated or resin-consolidated sand which is supported by a slotted mandrel. Since pre-packs necessarily must be somewhat smaller than the wellbore into which they are positioned, the formation may subsequently shift and cause productivity impairment.

Pre-packs may plug when:

1. The formation contains large quantities of clay.
2. Asphaltenes or paraffins are precipitated by viscous, low gravity crude oils.
3. Emulsions are formed.
4. Carbonate or sulfate scale is deposited.

They offer the following advantages:

1. Large surface area for filtering.
2. Compatible with most well fluids.
3. High permeability (50–100 darcys).
4. High compressive strength (5,000 psi at 150°F).
5. Can be run on a wire line or tubing.
6. Withstand temperatures to 500°F.

To reduce the chances of formation movement around the pre-pack and the risk of plugging with formation fines or clay, this device should be used in conjunction with underreaming and conventional or consolidated sandpacks.

Open Hole Gravel Packing

Open hole gravel packs should provide higher productivity than inside gravel packs because restrictive casing perforations are eliminated and the underreamed wellbore improves radial flow into the well. Open hole gravel packing in stratas of clay and shale are preferred over other completion techniques since the gravel should prevent migration of the shale or clay to the screen and sealing it off.

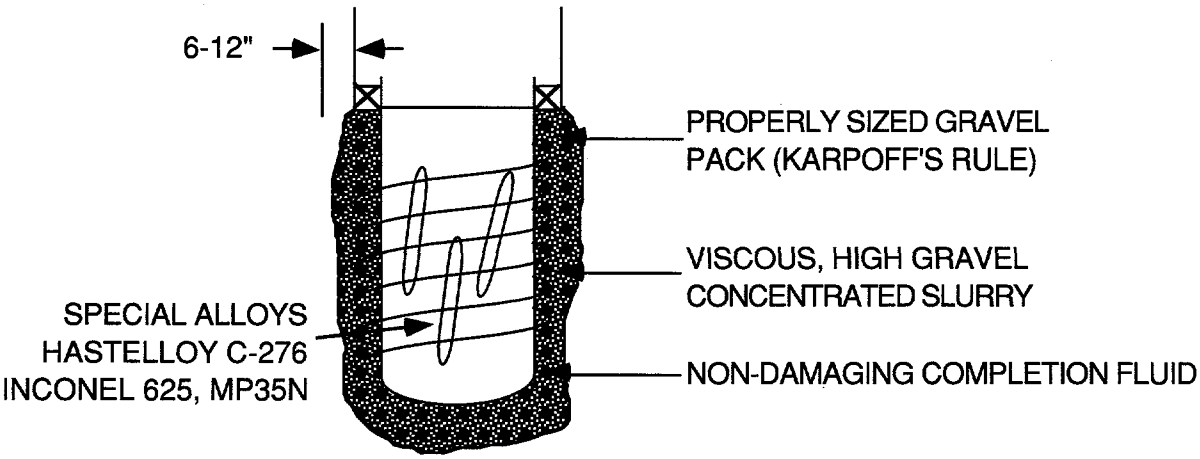

FIGURE 9.3 — Schematic of Open Hole Gravel Packing for Sand Control in Producer

Gravel packing (Figure 9.3) consists of underreaming the wellbore 6–12 inches larger than the casing diameter; running and hanging the wire wrapped liners; packing with gravel using a viscous, high gravel concentrated (15 lb/gal) slurry at low circulation rates to prevent intermixing of the sandpack with formation sand; washing to remove gravel bridges; and then repacking, if necessary. During the foregoing operations, a nondamaging completion fluid should be used as suggested earlier. Also, pre-flushes of clay stabilizing material should be used prior to both underreaming and gravel packing and will be discussed later. In addition, the hole should be enlarged slowly to prevent corkscrewing, a caliper log should always be run in the underreamed hole to determine if sloughing has occurred, and debris should be removed from the well prior to running the liner.

The ratio of gravel size to formation sand size should be estimated from Karpoff's rule which states that gravel size should range from 5–10 times the 50 percentile or median formation sand diameter. Sand movement should be properly restrained under these conditions since the gravel pore openings, theoretically, are properly sized relative to the sand particle diameter.

Effectiveness of gravel packs can sometimes be determined by radioactive tracer methods. Gravel packs in open hole injection wells sometimes tend to slump soon after the start of injection, and logging may indicate that repacking is required.

Consolidated Pack

The consolidated pack (Figure 9.4) is a slurry consisting of a carrier fluid, resin (or other type of bonding agent), coupling agent, sand, and catalyst, which is blended at the surface and pumped behind a liner or in open hole where the resin or bonding agent is permitted to cure. This process is designed to achieve gravel packing and sand consolidation in a single injection step. If a liner is used, any consolidated material remaining in the wellbore is simply drilled out. In most open hole completions, no liner is used and the consolidated pack is redrilled through the entire producing zone with a regular bit. All the same rules and precautions associated with conventional open hole gravel packing and drilling apply to this particular technique.

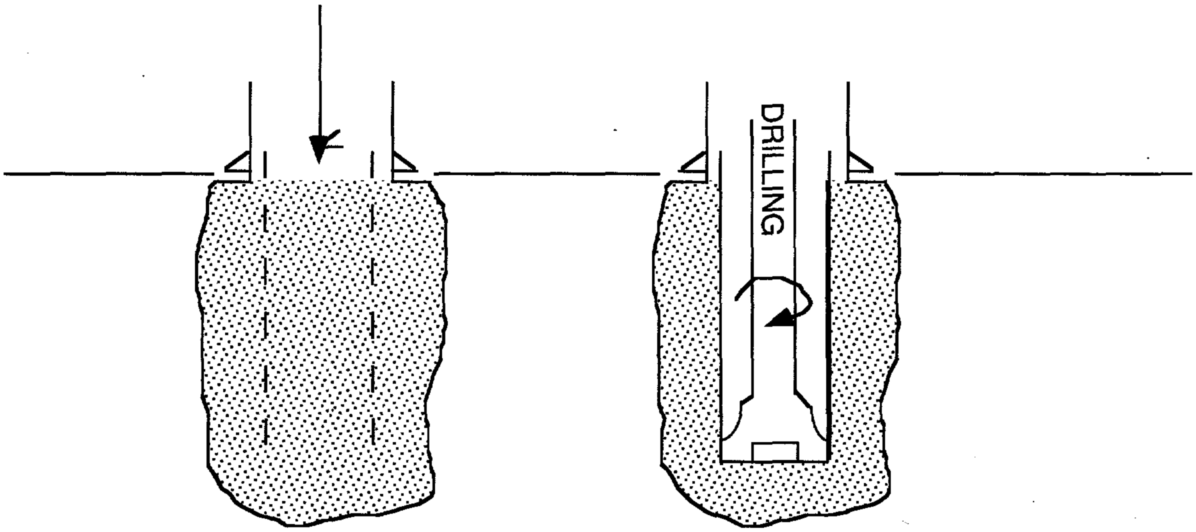

FIGURE 9.4 — Sand Control (Slotted Liners and Wire Wrapped Screens)

The main advantage of the consolidated pack treatment is that consolidation of the sand is assured in all areas where the sand laden slurry can be pressure packed. The pack possesses excellent strength (5,000 psi) and permeability (60 darcys) and is stable in most well environments up to 500°F. The process works well with clay bearing formations, and excess resin can be used to consolidate a portion of the formation behind the pack to stabilize both sand and clay when a special clay stabilizing compound, such as Halliburton's Claylok or Claysta, is injected ahead of the resin.

Cased Hole Completion

Cased hole completions in fireflooding generally are recommended only for injection wells although they may be used for producers under certain circumstances. If it is found that open hole completion cannot be satisfactorily performed, or is not desired for some reason, then setting the casing with the best cementing technology along with the best well completion, perforating, gravel packing and/or chemical sand consolidation methods available should be implemented.

In unconsolidated formations, the sand immediately behind the perforation must be stabilized, as previously discussed, either with a sandpack or with chemical or artificial consolidate. Another technique is to gravel pack a wire wrapped liner inside and across the perforated interval of the long string of casing. One such method of chemical consolidation designed for high temperature, low pH atmosphere is discussed below.

Solder Glass Sand Consolidate Treatment

The solder glass method for sand consolidation is patented by Gulf (new Chevron) and uses a devitrified glass to bind together sand particles. The consolidated mass possesses high internal strength and resistance to hot gases, hot water, steam, acidic environment, and high temperature. The consolidated formation also retains permeability and compressive strength when subjected to a variety of well production and stimulation conditions. For a fireflood or steamflood reservoir with sand production problems, it is a promising technique to control sand production.

In addition to sand control, the solder glass method of sand consolidation promotes a certain amount of production stimulation which is unrelated to oil viscosity. Increased production can be achieved through a decrease of wellbore damage caused by clay swelling and emulsion blocking. Formation permeability in dirty sands is increased by shrinkage and permanent dehydration of clays during a pre-burn period prior to the sand consolidation treatment.

The treatment consists of three main steps:

1. An eight-hour period of air injection at 1200°F to burn the sand clean and to shrink and clays present.
2. Injection of solder glass cementing solution.
3. A 14–hour period of air injection at 800–1200°F to melt and devitrify the cementing material.

The well selected for this treatment should be one in which the zone to be treated is ±50 feet from a gas cap or aquifer and has an initial gas saturation greater than 10%. To maximize control over the process, a single point entry is mandatory in the well to be treated. Although not a preferred method if the selected well has been previously completed, it is necessary to squeeze-cement the existing perforations with a low-water loss, heat-resistant cement and recomplete in the same zone with a single perforation. If the well has produced a large amount of sand, it may also be desirable to repack the formation with clean sand.

If more than one perforation is desired in any zone, each perforation must be isolated and treated individually; i.e., start from the bottom of the production zone and back-fill the well with sand to a depth of at least 2 feet above each previously treated perforation before perforating and treating in a higher plane.

The air rate to be used is determined by the flow rate of air required to sufficiently cool the burner but not to exceed a flow to cause flame-out. Optimum air requirements for any given bottom-hole pressure are based on a burner slot actual velocity of 14 ft./sec. The downhole burner used in this treatment was discussed in Chapter 8. A tentative program for the solder glass sand consolidation method follows:

1. Install suitable 3,000 psi W.P. wellhead on casing. Pressure test casing to 3,000 psi with fresh water.
2. Run open-ended 2-7/8-in. O.D. EUE tubing, equipped with a casing scraper, to plug-back depth and reverse-circulate well with 10 bbl diesel fuel, followed by 2.0% caustic and 1% detergent solution, until returns are clean. Displace cleaning solution with fresh water, or 4% KCl solution, or clay-stabilizing solution, if required.
3. Pull tubing and perforate casing with one hole using a suitable jet shot (5/8–3/4 in. hole and 9–11 in. penetration) at a depth to be determined from the electric log. Perforating to be done under clean and filtered fluid; maintain pressure differential from wellbore into formation at all times, if sand is loosely consolidated.

4. Run 2-7/8 in. O.D. EUE tubing with a burner stop on bottom to a depth 5 ft. above the perforation. Install Christmas tree.
5. Install and pressure-test to 3,000 psi all injection lines and Christmas tree. Install the mast, lubricator burner assembly, fuel tubing hoist, and the fuel injection system.
6. Unload water from hole to a tank or pit by circulating air down the casing and up the tubing. Maintain surface casing pressure 200 psi above the reservoir pressure. When all fluid has been displaced from annulus, the remainder of fluid in tubing may be displaced into formation.
7. When essentially all of the water has been displaced from the tubing, continue injecting air down tubing and casing. Increase the injection pressure gradually until the desired injection rates are obtained in both tubing and casing. Casing rate should be only 10% of total injection rate.
8. Lower the downhole burner to the seat. Adjust the tubing and casing air rates and ignite the burner at a fuel rate such that the temperature of the gas entering the formation is at 1,200°F to clean the sand to be treated.
9. After eight hours of operation at 1200°F, pull burner out of seat and continue cold air injection for one hour. Pull burner out of hole into lubricator.
10. Inject 15 bbl of fresh water, followed by 10 bbl of 0.5% caustic solution, down the casing to further cool the formation while injecting all air into tubing. Then displace fluids into formation with air down both tubing and casing.
11. When the cooling liquids have been displaced into the formation, direct all air into tubing and inject 5 bbl of cementing chemicals (solder glass). Resume air injection down casing to displace the cementing material into the formation.
12. Lower the downhole burner to the seat. Adjust the air and fuel rates such that, after burner ignition, the temperature of the gas entering the formation is 800°F.
13. Increase the burner exhaust temperature at a rate of 50°F/hr to 1200°F.
14. After 8 hours of operation at 1200°F, shut off the burner and retrieve the burner assembly from the tubing.
15. Continue cold air injection for one hour. Inject 25 bbl of fresh water to cool the wellbore and formation.
16. Stop air injection.

17. Slowly inject water down the casing and bleed the casing and tubing to a tank until there is no oxygen produced.
18. When the produced gas has no oxygen content, stop water injection. Put well on production by producing the tubing to a separator.

Clay Stabilization

Serious reductions in permeability of the formation can occur when clay minerals restrict flow by either expanding to fill the pore volume or dispersing and lodging in restrictions. The expanding force acting on clays is caused by the affinity of exchangeable interlayer cations and surfaces for fresh water. The inherent negative charge on almost all clay minerals is neutralized by adsorption of cations, producing a positive surface charge with a negative inner charge. These clay particles with an electric double layer repel each other, and, thus disperse.

Chemicals are now available which stabilize many water-sensitive formations. One such compound, a positively charged hydroxy-aluminum ion which is prepared in the field by reacting aluminum chloride and sodium hydroxide in a high shear device, is absorbed and polymerized on the negatively charged clay mineral surface to form a stabilizing network that prevents further migration. This chemical, Claylok, a trademark of Chevron, has been successfully used to improve permeability following acid treatments, stabilize formation fines, desensitize clay bearing formations prior to steam injection, and reduce formation damage during perforating and gravel packing. Most field brines and fresh water will not remove the treatment, but mixtures having pH values below 4 or above 9 will damage its effectiveness.

Halliburton has a process that uses an organic, oil-soluble chemical, trade name SFD–3, to shrink water-swollen clays and then surround them with a hard furan-type resin which increases permeability and stabilizes clay in some dirty formations. A new Halliburton product, Claysta, is organic in nature and stabilizes clay in a similar fashion as Claylok, but has the added advantage that it is stable to subsequent acid or caustic treatments.

It appears that these clay stabilizing compounds have a possible application in open hole as well as in cased hole completions. Injection of these chemicals prior to underreaming and gravel packing may eliminate or significantly reduce formation damage caused by clay swelling. Incorporating these inhibitive chemicals into the gravel pack slurry, drilling fluid and/or other completion fluids may also prove to be advantageous. All possibilities should be evaluated in the laboratory before implementation.

Well treatments for some typical situations are described:

A. Case 1

Assumptions

1. Well has not been previously steamed
2. Sand production problem
3. Formation sensitive to fresh water

General Procedure

1. Bail out and clean up well.
2. Run injectivity test with filtered (1 micron) 2% KCl solution. Adequate injectivity should be approximately 2 bbl/min at no more than 300 psi surface pressure.
3. Run CBL, Δt and/or spinner survey with 2% KCl solution.
4. If formation is not taking fluid uniformly, acidize with 100 gal/ft.* 15% HCl, followed by 200 gal/ft. mud acide,** followed by 100 gal/ft. 3% HCl, and then followed by 600 gal/ft. 1% filtered KCl solution (spacer between acid and hydroxy aluminum).
5. Inject 5 bbl/ft. hydroxy aluminum.***
6. Run spinner survey or profile to determine if all perforations are taking solution.
7. Overflush with 5 bbl/ft. filtered 1% KCl solution.
8. Install injection well wellhead or pumping well wellhead and pumping unit.
9. Shut-in well and age 24–48 hours.
10. Start steam injection in injection well or place production well on production.

* Per foot of perforated interval.

** Mud acid consists of 12% HCl + 3% HF + 0.3% inhibitor + 0.3% surfactant + 0.3% iron sequesterant + 0.3% anti-sludging agent (Dowell products).

*** Injected Claylok should be 0.3 Molar and, therefore, must be diluted 20–fold with 1% KCl water. *Always add 1% KCl to concentrate.*

B. Case 2

Assumptions

1. Well has not been previously steamed.
2. Sand production problems.
3. Formation sensitive to fresh water.

General Procedure

1. Bail out and clean up well, and acidize, if necessary (Steps 1–4 in Case 1).
2. If well is perforated, shoot additional perforations (8 shots per foot) under 2% KCl solution.
3. Install gravel pack in hydroxy aluminum while keeping well full with hydroxy aluminum.

   Pack fluid should incorporate hydroxy aluminum, or 2% KCl solution when possible.
4. If open hole, remove old liner, install new liner, and gravel pack in hydroxy aluminum.
5. Run steps 5–9 in Case 1.

C. **Case 3**

Assumptions

1. Well has not been previously steamed.
2. Sand production problems.
3. Clay and sand migration are problems.
4. Formation sensitive to fresh water.

General Procedure

1. Bail out and clean up well.
2. Cool well with filtered (1 micron) 2% KCl solution until temperature of formation around wellbore is less than 200°F.* Twenty-five barrels of cooling water per perforation is usually a sufficient quantity for cooling.

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* Temperatures greater than 200°F will cause aluminum chloride to precipitate in formation.

Screening

Certain preliminary tests should be run in the laboratory to determine which completion technique is most likely to be successful. The following is an outline of proposed tests which should be run for the purpose of designing the best or optimum well completion:

1. Permeability, porosity and water sensitivity.
2. Clay content and types of clays present, if any.
3. Grain size distribution — to be used for the proper selection of slotted liner size and/or conventional or consolidated grain size.
4. Effect of steam condensate — permeability before and after injection.
5. Fluid penetration studies — determine depth of fluid penetration in core and resultant damage from conventional mud, extremely low water loss mud, invert emulsion, chalk emulsion, and fluids containing bridging material of calcium carbonate, oil soluble resins, and HEC.
6. Degree of clay or fine sand migration in core samples during fluid or steam injection.
7. Effectiveness of clay stabilizing compounds, such as Claylok, Claysta, and SFD–3–furan resin combination, in native cores.
8. Compatibility of clay stabilizing compounds in presence of and as a part of well completion fluids.
9. Chemical consolidation and compressive strength of consolidated native cores and compare with clean sand chemical consolidation.
10. Design and run combustion tube and autoclave corrosion tests* in a more severely corrosive, erosive, oxidizing, and elevated temperature environment than has been run in the past. In this manner, the best material available for any given fireflood well completion can be selected along with other auxiliary techniques which may be required to lengthen the useful life of downhole equipment; i.e., downhole cooling, corrosion and oxidation inhibitors, special coatings, etc.

Suggested Drilling and Well Completion Procedures

The following outline of general drilling and completion procedures is recommended for air injection and producing wells. These procedures are meant only to be a guide for the engineer in designing such well completions.

Air Injection Well (Figure 9.1)

1. Drill the well with "best" low-water loss drilling mud using current drilling practices for that area.
2. Run 2–4 joints (depending on thickness of reservoir) special alloy pipe; i.e., Inconel or Incoloy Series, on bottom of casing and set the casing with a high-silica flour cement, using centralizers and scratchers, while rotating or reciprocating the casing to remove mud cake and pockets of mud from annulus during the cementing operation. A synthetic lubricant should always be used on threads while making up casing.
3. Plug back well with 20–40 mesh sand and cement plug or standard bridge plug to depth 1–2 feet below intended perforation.
4. Install BOP. Pressure test casing to 3,000 psi with fresh water.
5. Run neutron, gamma ray, CCL, and other desired well surveys.
6. Run open-ended 2-7/8 in. O.D. EUE tubing,* equipped with casing scraper, to plug-back and reverse-circulate well with 10 bbl diesel fuel followed by 2% caustic and 1% detergent solution until returns are clean. Displace cleaning solution with fresh water followed by 5% Nitrox** solution. Circulate 1–2 well volumes. Displace 5% Nitrox solution with filtered 0.2% Nitrox solution.
7. Pull tubing and perforate special alloy casing with one hole using suitable jet shot (3/4-in. diam. hole and 9–11 in. penetration) at a depth determined from electric log. To prevent flowback of sand in unconsolidated regions, perforating should be done with pressure differential from wellbore into formation. After perforating, keep hole full of 0.2% Nitrox solution.
8. Run injectivity and pressure fall-off tests with 0.2% Nitrox solution. Injectivity should be at least 1 BPM at pressure less than fracture pressure. Pressure fall-off should be at least 500 psi/min.
9. If injectivity test is unsatisfactory, either reperforate at same depth or clean up existing perforation with mud acid. Before reperforating or using mud acid, however, tag bottom to make certain there is no sand fill. Repeat injectivity and pressure fall-off tests.

10. Repeat Steps g to i until adequate injectivity and fall-off are attained.
11. Run 2–7/8 in. O.D. EUE tubing with burner stop, pup joint(s), crossover, packer, and telescoping union (Figure 9.1). Space out and set packer to have burner seat at 5 feet above perforation. Packer should be set in special alloy casing no closer than 25 feet from perforation.
12. Remove BOP and install wellhead.
13. Purge all surface lines and equipment with 5% and 0.2% Nitrox solution. Install and pressure test to 3,000 psi all injection lines and Christmas tree.
14. Close well in and observe pressure decline. A pressure fall-off rate of 4 times the stabilized time (4 x 30 minutes) indicates adequate injectivity with minimum formation damage.
15. Commence injecting air at 2–3 MMscfd and continue for 3 days.
16. Install the mast, lubricator, burner assembly, fuel tubing hoist, and fuel injection systems.
17. After 3 days, reduce air injection rate to 1 MMscfd for one day.
18. Lower the downhole burner to the seat. Adjust the air and fuel rates such that after burner ignition the temperature of the gas entering the formation is 800°F.
19. Lower the downhole burner to the seat. Adjust the air and fuel rates such that after burner ignition the temperature of the gas entering the formation is 800°F.
20. Air injection will continue over the life of the project at various increased rates, depending on the size of the fireflood.

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* Again, always use synthetic grease while making up tubing.

** Nitrox consists of 2 parts Sodium Nitrite and 1 part Sodium Hydroxide

Production Well (Figure 9.2)

1. For liner type completions, drill to the top of the producing formation with standard drilling mud using current drilling practices for that area. For "set through" completions, skip Steps a, c, and e.
2. Set the casing with standard low-water loss cement, using centralizers and scratchers, while rotating or reciprocating the casing to remove mud cake and pockets of mud from annulus during the cementing operation. The bottom two joints of casing are fabricated from special alloy material.
3. Drill through the production sand with the "best" completion fluid as determined from laboratory screening tests. Clay stabilizing agents should be incorporated into the completion fluid, if needed.
4. If required, inject clay stabilizer through entire production interval.
5. Underream formation 6–12 in. using "best" completion fluid to circulate out cuttings.
6. Run caliper log and other desired logs with "best" completion fluid.
7. Run properly designed prepacked liner or wire wrapped perforated pipe and perform tailored gravel pack or consolidation pack with clay stabilized completion fluid.
8. Perform properly tailored open hole consolidation pack with clay stabilized completion fluid. Permit bonding agent to cure sufficiently, and drill through with standard bit, using best completion fluid. A slotted liner used only to properly guide the bit could be incorporated into this process.
9. Lower tubing to bottom and reverse circulate clean with 5% KCl solution; POH with tubing.
10. Set retrievable bridge plug, install steam quality expansion type casing head, install BOP, and recover bridge plug. In place of expansion type casing head, a telescoping union or expansion joint could be run above packer if packer is used. If no packer is used, no expansion joints are required; i.e., downhole cooling may be required during production of hot well fluids.
11. Run 2-7/8 in. O.D. tubing, packer (if required), 2 joints special alloy tubing, expansion joint (if required), and seating nipple.
12. If packer is used, space out to set packer inside special alloy casing at least 20 feet above pay zone, gravel pack, or consolidated pack. If no packer is used, position bottom of tubing at top of pay. Tubing should be lined with straight phenolic coating. All materials below

packer and including packer should be fabricated from special alloy material. If no packer is used, the bottom eight joints of tubing should be special alloy.

13. If packer is used, displace annulus fluid with salt water containing 80–100 ppm cobalt catalyzed sodium sulfide oxygen scavenger and Tretolite KW12 or Visco 938 film coating chemical at 1/2% by volume.
14. Set packer, remove BOP and install wellhead.
15. Run rods and pump with coupon rack on bottom.
16. Test well. When it is evident that well will flow, recover rods, pump and coupon rack.
17. Set coupon rack in seating nipple and swab well if necessary.
18. After well has cleaned up and stabilizes, conduct static BHP and BHT surveys.

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* Properly designed for high-temperature corrosion resistance.

Preservation of Hot Production Wells

During the fireflood process, the combustion zone is propagated through the reservoir by burning a portion of the oil, with the remainder of the oil and connate water moving ahead towards the producing well. Water and oil are vaporized near the combustion zone and transported to cooler regions in the formation ahead of the combustion front where they condense. The temperature decreases ahead of the combustion front and levels off at between 200°–600°F at the steam plateau, ahead of which is located still another zone of warm fluids. The combustion zone moves through the reservoir at a speed which is a function of both the air rate and the amount of oil burned and travels at a speed less than the advance of the steam plateau. At the time of steam breakthrough in the production wells, model studies have shown that about 17% of the reservoir has been burned and about 50% of the original-oil-in-place has been produced.

Relatively high temperatures after steam breakthrough can accelerate corrosion and/or failure of downhole equipment and cause premature shutdown or loss of production wells. Significant additional oil recovery can be obtained from hot wells with the implementation of downhole cooling in conjunction with proper material selection.

Estimated cooling water requirements, as a function of oil production rate and formation flowing oil temperature are shown in Figure 9.5.

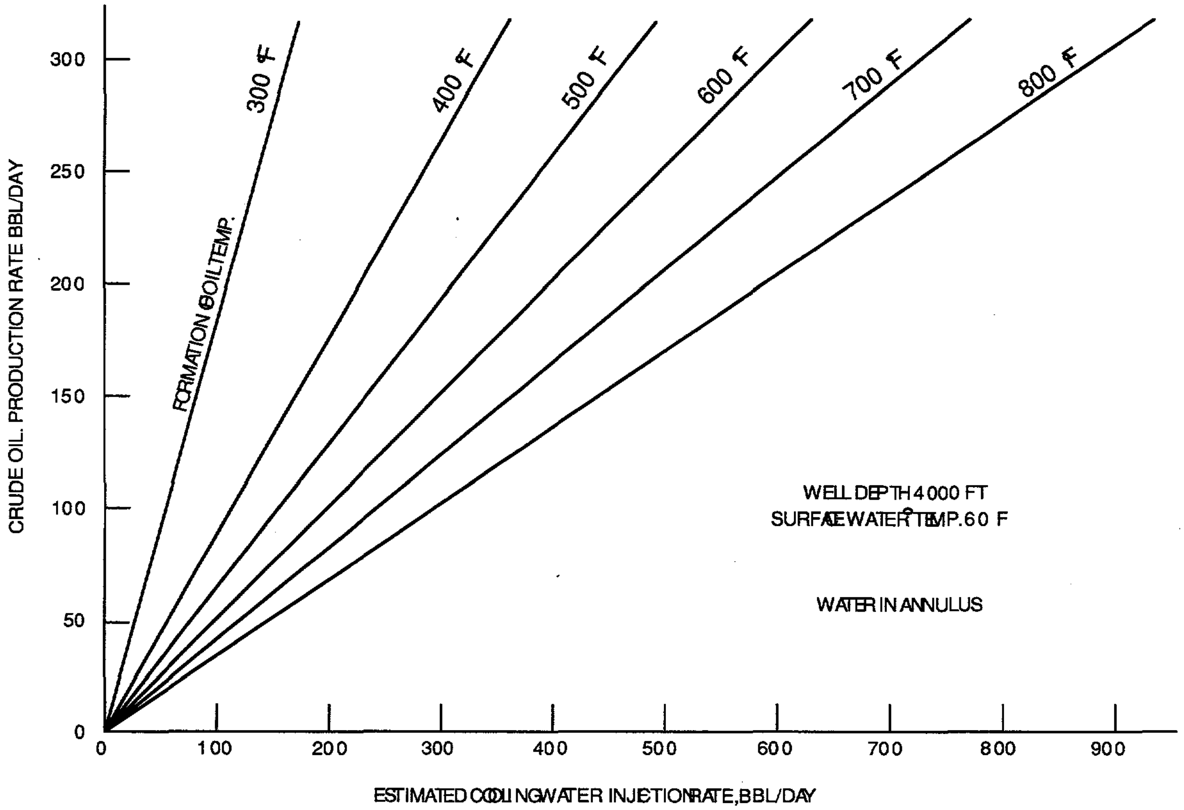

FIGURE 9.5 — Estimated Cooling Water Requirements for Fireflood Production Wells to Maintain Bottom Hole Temperature at 250°F

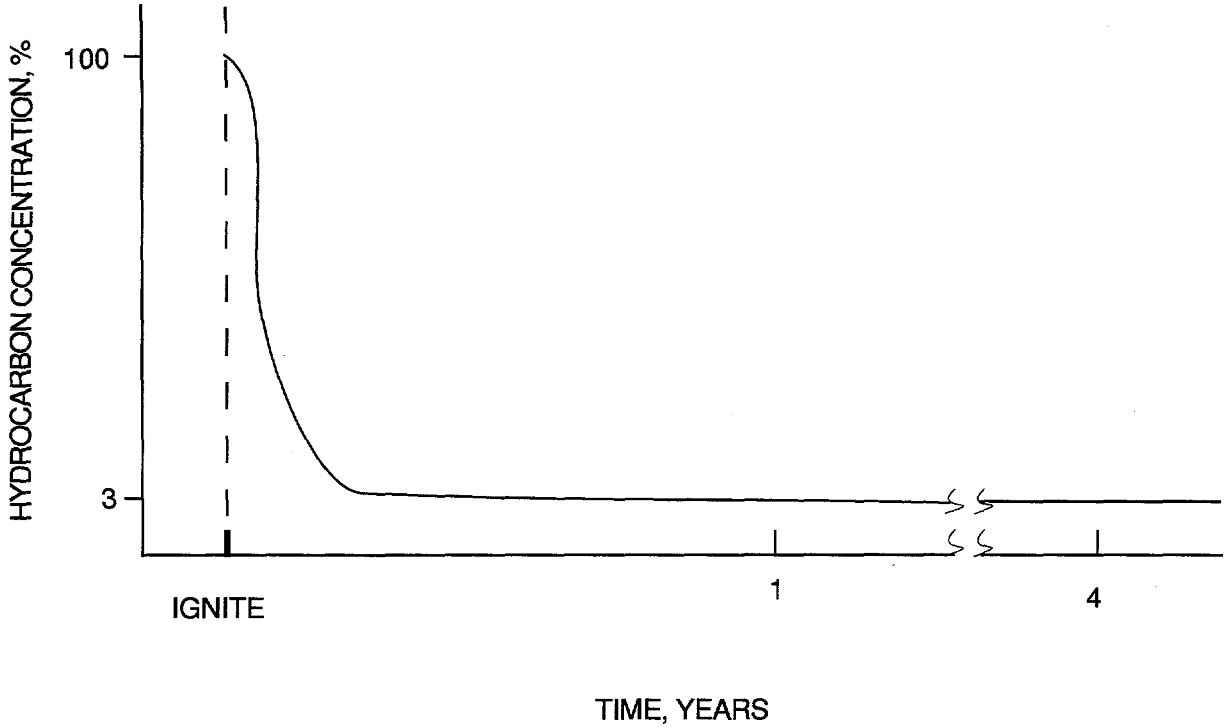

FIGURE 9.6 — Trend for Hydrocarbon Emissions from a Fireflood

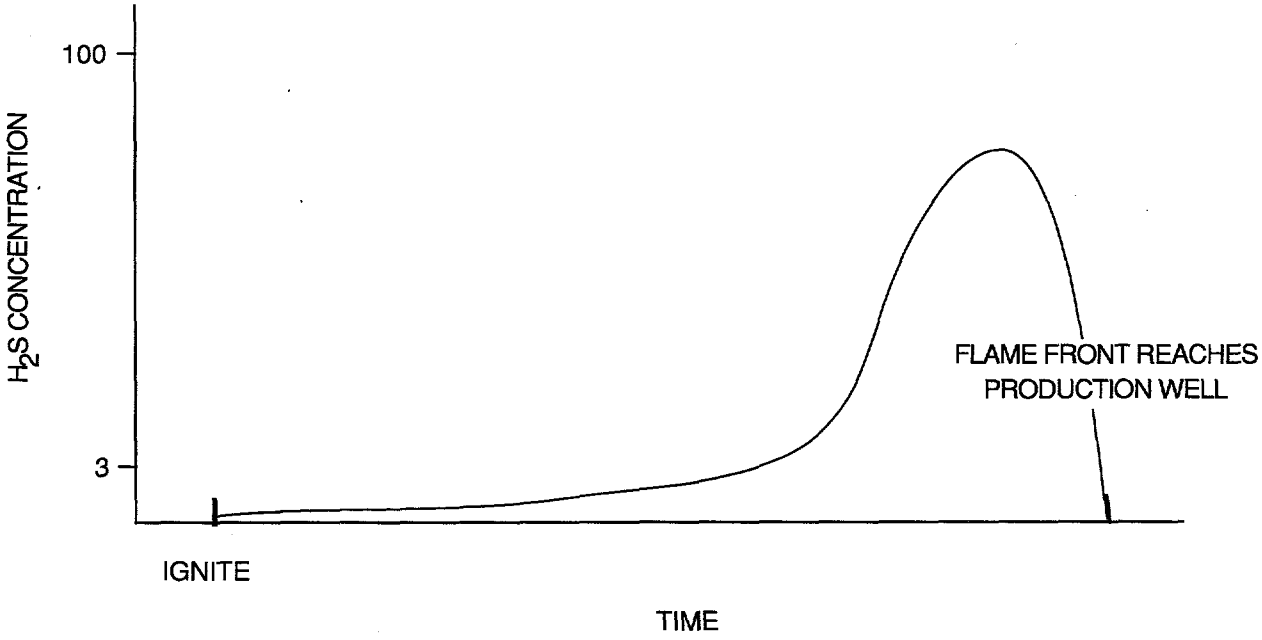

FIGURE 9.7 — Trend for H_2S Emissions from a Fireflood

Operational Problems

Each fireflood is unique and the operational problems encountered are very much project dependent. These were discussed in detail in Chapter six. The most common problem plaguing many combustion projects include sand production, corrosion, emulsion, well failures, compressor failures, and explosion. These and other operational problems are discussed under individual projects in Chapter six.

Project Monitoring

Various measurements and checks must be made and recorded to ensure proper operation of a fireflood. Measurements required to monitor the process are: injected and produced fluid measurements produced gas analysis, downhole temperature measurement and flowline temperature measurements. A typical monitoring program used in the Cities Service-DOE Bodcau fireflood follows (Chu, 1982)

1. Combustion gases from producing wells were tested monthly for volumes and content. The volumes were determined for material balance calculations. The content of the gas indicated the efficiency of combustion and whether the combustion front had reached the producer.
2. Producing wells were tested twice a month for oil and water production rates.
3. Flow line temperatures were checked daily for indications of thermal stimulation or downhole problems. The volume of quench water used at the producers was based on observed flowline temperature as well as gas production rate.
4. Downhole temperature measurements at the observation wells were utilized to calculate the size of the burned zone and location of the burn front.

Waste Gas and Other Fluid Disposal

Introduction

Consideration of environmental impact is an important part of planning a fireflood clearly; a fireflood can produce large amounts of pollutants by way of the flue gas and from the air compression and oil handling equipment. This will have a major impact on project design in terms of equipment selection, operating procedures, and cost.

This section offers an introduction to the pollution control methods applicable to a fireflood project. Topics covered include:

1. Disposal of waste liquids.
2. Description and behavior of gas pollutants.
3. Design considerations for flare stacks, incinerators, and scrubbers.

Waste Liquid and Their Disposal

The water produced from a fireflood is generally similar to the water obtained from primary production. In that case standard oil field water disposal procedures are applicable, and this waste may be combined water from primary production. Two exceptions are noteworthy:

1. The water may contain dissolved H_2S. If so, special handling procedures will be required to assure operator safety.
2. The water will contain dissolved CO_2, which may warrant special equipment to avoid corrosion.

Some pollutant removal system, such as scrubbers, will produce toxic liquid wastes requiring special handling. These wastes may contain caustic, mixtures of $(HCO_3)^-$, $(CO_3)^{--}$, $(SO_3)^{--}$, $(SO_4)^{--}$, salts, or special solvents. The most common means of disposal are:

1. Hire a contract disposal service.
2. Blend with a large amount of production water and inject into a water disposal zone.
3. Store in evaporation pits followed by contract or land-fill disposal of accumulated solids.

Since EPA and local pollution disposal regulations depends upon the toxicity and nature of the pollutant and often changes, it is advisable to consult the local and state pollution control authorities prior to formulating a disposal plan.

Waste Gases

General

The possible waste gases released from a fireflood operation and their sources are listed in Table 9.3. All of these pollutants would *not* be produced from a fireflood at the same time. Their occurrence depends on the flue gas composition, the operation of the fireflood, and the equipment used for the project. Although flue gas is the key source of pollutants, pollution control equipment can also release pollutants as process by-products or through system inefficiency. The typical amounts are estimates based on the most probable behavior of a fireflood producing 8 MMscf/d of flue gas and requiring 2,535 kW (3400 hp) for air injection. Engine exhaust emissions are based on EPA guidelines and on data obtained for a 746 kW (1,000 hp) turbo charged reciprocating engine burning natural gas at a rate of 97.3 scf/min. Emissions from scrubber systems are based on 90–95% removal efficiency.

TABLE 9.3 — Pollutants Produced by a Fireflood Project

Pollutant	Sources	Conc. Range	Typical Amount
Hydrocarbons	Flue Gas (Flare)	1-5%	200,000 Scf/d
	Crude Oil Storage	0-3%	9 Scf/bbl oil (estimate)
	Engine Exhaust	0.3-0.6%	14,400 Scf/d
H_2S	Flue Gas (Flare)	0-1%	1,600 Scf/d
	H_2S Scrubber	0-0.1%	80 Scf/d
SO_2	Incinerator Exhaust	0-0.06%	1700 Scf/d
	SO_2 Scrubber	0-0.06%	80 Scf/d
CO	Flue Gas (Flare)	0-3%	16,000 Scf/d
	Incinerator Exhaust		32,000 Scf/d
	Flame	0-0.5%	10,000 Scf/d
	Catalytic (Excess Air)	0-0.5%	30,000 Scf/d
	Catalytic (Substoichiometric	0-0.6%	32,000 Scf/d
	Engine Exhaust	0.04-0.38%	4,200 Scf/d
NO_x	Engine Exhaust	2,100 – 2,800 ppm	13,200 Scf/d
	Incinerator		
	Flame	10 – 300 ppm	600 Scf/d
	Catalytic	< 10 ppm	60 Scf/d
Odor (from miscellaneous S-gases and hydrocarbons)	Flue Gas (Flare)	< 50 ppm	200 Scf/d

Flue Gas

The hydrocarbon composition of flue gas changes with time according to the trend illustrated in Figure 9.6. Actual times will depend on the operation of the fireflood.

The first flue gas produced is the natural gas in the reservoir. As CO_2 from combustion and nitrogen from injected air sweep through the reservoir the hydrocarbons in the flue gas become diluted until, after some months, their concentration reaches about 3% with a heating value of 50–80 Btu/Scf. Larger concentration changes can occur on account of shutting in production wells, changing flue gas production rates, or changing air injection rates.

Depending on the reservoir, flue gas can contain H_2S and trace amounts of other sulfur gases such as COS, CS_2, mercaptans, and disulfides. The concentration of H_2S in flue gas can be expected to follow the trend shown in Figure 9.7.

Since H_2S is highly soluble in most crude oils, the concentration in flue gas will be very low initially. When the crude oil becomes saturated with H_2S, the concentration in the flue gas will increase dramatically. This generally occurs when the flame front is near the production well.

Flue gas typically contain 0.2 ± 0.1% of CO. Larger concentrations may be indications of incomplete combustion resulting from air breakthrough or an excessive air injection rate.

Most flue gases have a burnt gas odor resulting from trace amounts of sulfur gases and higher hydrocarbons. If the odor of the flue gas is highly obnoxious, gas treatment may be required to eliminate a public nuisance.

Pollution Control Equipment

General

Table 9.4 summarizes the different pollution control systems suitable for a fireflood project and their recommended applications. The following paragraphs describe the operation, and design alternatives for these systems.

TABLE 9.4 — Application of Pollution Control Systems to a Fireflood Project

Equipment	Gas Treated	Pollutant Removed	Method	Suggested Application
Flare Stack	Flue gas	None	Vent to atmosphere	Flue gas meets air quality regulations
Flare Stack with Flame Burner	Flue gas	H/C $^{(1)}$, CO$^{(1)}$, S-gases$^{(1,2)}$	Burn	Flue gas with enough H/C to support combustion (>200 Btu/Scf)
Thermal Incinerator	Flue gas	H/C, CO, S-gases$^{(2)}$	Burn	Flue gas not suitable for a flare with burner or a catalytic incinerator (heat value > 85 Btu/Scf but < 200 Btu/Scf)
Catalytic Incinerator (Excess Air)	Flue Gas	H/C, Co, S-gases$^{(2)}$	Burn	Flue gas with heat value < 200 Btu/Scf
Catalytic Incinerator (Substoichiometric)	Flue Gas	H/C, CO$^{(3)}$, S-gases$^{(2)}$	Burn	Flue gas with heat value < 85 Btu/Scf
H_2S Scrubber	Flue gas	$H_2S^{(4)}$	Chemical Reaction	Flue gas containing H_2S but acceptable amounts of other S gases
SO_2 Scrubber	Incinerator Exhaust	$SO_2^{(4)}$	Chemical Reaction	When H_2S removed from flue gas is inadequate or impractical
1. Removal Efficiency may be poor 2. S-gases are converted to SO_2 3. May increase amount of CO for flue gas with heat values > 70 Btu/Scf 4. Typical removal efficiency is 90–95%.				

Flare Stack

The most common means of flue gas disposal has been through a flare stack. The simplest and lowest cost system available.

A flare stack may consist of:

1. A pipe which vents directly to the atmosphere.
2. A pipe that releases gas inside a vented tank for mist containment.
3. A pipe outfitted with a flame burner.

Combustion of Low Heat Value Waste Gases

To burn a waste gas containing a very low concentration of combustibles, some assistance is required. This is accomplished by two methods in incinerators:

1. Oxidation in thermal incinerators is accomplished by long residence time exposure to excess air at high temperatures. A conventionally fueled flame burner and the long residence provide the necessary heat energy time results from slow flow through a long insulated flow section.
2. Catalytic incinerators use a combustion catalyst to reduce the activation energy required for hydrocarbon oxidation.

Similar to thermal incinerators, combustion efficiency increases with increased residence time over the catalyst and increased operating temperature.

Thermal Incinerators

A thermal incinerator consists of a flame burner, a fan, a long refractory-lined flow section, and an exhaust stack.

Heat recovery equipment can also be included. This may be worth considering at installations where heat treaters, buildings, steam generators, or other energy users are near enough to make energy recovery economical.

The major disadvantage of all thermal incinerators is the cost of fuel for the flame burner. Some designs offset this somewhat by using the heat released from burning the pollutants to supplement flame heat. Even so, the cost of fuel can be significant and should be considered carefully when purchasing such a unit. Thermal incinerators are most suitable for flue gases having heat values between 85 and 200 Btu/Scf.

Catalytic Incinerators

A catalytic incinerator uses flameless combustion on a combustion catalyst to destroy gas pollutants. Such units are more expensive than thermal incinerators, but they offer much lower operating costs because no supplemental fuel is required for operation. The major components of a catalytic incinerator are: the catalyst beds, a heat exchanger, air blowers, a preheat burner, and the stack. The preheat burner is used only for start-ups to heat the flue gas, and in turn the S1 catalyst to a temperature above the ignition temperature for the waste gas. Most flue gases will ignite at 350–450°F. Once the first stage exhaust temperature is high enough to assure self-sustaining operation, the burner is shutoff. A flame shield is recommended to prevent direct flame contact with the S1 catalyst. The air mixer shown after the heat exchanger is recommended to assure good fuel and air mixing.

Combustion in a catalytic incinerator is controlled by the amount of air added to the waste gas before each catalyst bed. Two types of operation are possible. The first involves substoichiometric (fuel rich) combustion in both stages. This is especially suitable for flue gases having heat values less than 85 Btu/Scf. In this mode enough air is added to burn 25 Btu/Scf per stage or about 50 Btu/Scf of the total flue gas heat value resulting in a final exhaust temperature of about 1600°F. Any excess heat value will exit the system as unburned hydrocarbons in the exhaust. Fortunately catalytic combustion follows the standard combustion hierarchy where larger molecular weight compounds are preferentially burned. Thus, the unburned hydrocarbons are mostly methane, which is an acceptable emission. The second mode of operation involves substoichiometric combustion in the first stage and excess air combustion in the last stage. This extends the upper limit of burnable flue gas heat value and it provides for complete combustion. Suggested applications would be waste gases having heat values less than 200 Btu/Scf. or projects requiring complete removal of the pollutants in flue gas.

Scrubbers

Scrubbers remove gaseous pollutants by contact with a solution that will react with the pollutants and thereby absorb them. Scrubbers can also be designed for particulate removal, but this is not necessary for the particulate free gases produced by a fireflood. In a fireflood application scrubbers would be used to remove H_2S from the flue gas or SO_2 from the exhaust of a system which burns flue gas. Generally, removal of H_2S should be preferable because smaller gas volumes and gas at lower temperature are involved. However, incineration of the flue gas followed by SO_2 scrubbing of the exhaust may be required for flue gases containing large amounts of miscellaneous sulfur gases not removable by an H_2S scrubber. Removal efficiencies are typically 90–95% for both types of scrubbing.

Caustic scrubbing is the most common means of removing H_2S from a waste gas such as fireflood flue gas.

There are many reactions that will effectively remove SO_2. The most common are:

1. Carbonate ($CaCO_3$, Na_2CO_3, $NaHCO_3$, $MgCO_3$)
2. Alkali ($NaOH$, $Ca(OH)_2$, $Mg(OH)_2$)
3. Oxide (CaO, MgO)

Scrubbing with NaOh is probably the most suitable for the size system required for typical fireflood projects. It is highly efficient and generally allows for a smaller, simpler scrubbing system. The other approaches have merit for very large scrubbing systems or for locations where the scrubbing agent is available at very low cost. Two alternatives to caustic scrubbing are noteworthy: dry scrubbing and scrubbing with oil field produced water. Dry scrubbing involves flashing a concentrated solution of $NaHCO_3$ and Na_2CO_3 in the scrubber followed by filtration of the effluent to remove particulate solids. Production water may be usable for SO_2 scrubbing if it contains large amounts of carbonates and bicarbonates.

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CHAPTER 10 — OXYGEN / ENRICHED AIR FIREFLOOD

Introduction

Use of pure oxygen or oxygen enriched air instead of air as injectant in in-situ combustion process has several advantages and has been practiced since the early 1980s. Greenwich Oil Corporation was the first operator (Hvizdos et al., 1982) to successfully employ oxygen-enriched air in a combustion project. Laboratory and field studies with pure oxygen or oxygen enriched air have suggested that the performance of an in-situ combustion process can significantly be improved over that of conventional air injection. Oxygen or enriched air combustion projects increase the percentage of oxygen being injected to greater than 21%. In heavy oil reservoirs, use of enriched air often enhances the high temperature oxidation reactions and improves recovery. The use of oxygen or oxygen enriched air in fireflood to improve performance was first suggested by Ramey (1954). He pointed out that use of enriched air in fireflood could provide the desired oxygen flux at lower injection rate and pressure. Oxygen fireflooding could minimize many operational problems encountered in the traditional air fireflooding such as the high gas vent rate, tubular erosion, excessive sand production, etc., increase oil productivity and improve the economics.

Although, specific advantages of oxygen/enriched air fireflooding have been demonstrated in the laboratory, and practiced in the field since the 1980, the process is still considered as an unproven emerging technology. Assuming that field is amenable to oxygen fireflood, the decision to implement the process in the reservoir will depend primarily on economic, safety and materials compatibility considerations (Shahani and Gunardson, 1994).

This chapter presents an overview of various issues associated with the oxygen/enriched air fireflood and discusses the performance of an oxygen fireflood.

Potential Advantages and Disadvantages of Oxygen/Enriched Air Fireflooding

A major advantage of using oxygen or oxygen enriched air in a fireflood is that the volume of gas necessary to move the combustion front at a given velocity is about one-fifth that required for air injection (Garon et al., 1986). Use of enriched air permit higher oxygen injection rates at a given injection pressure than is possible with normal air. This often translates to accelerated oil production due to faster propagation of the combustion front through the reservoir. In addition use of pure oxygen or oxygen enriched air in fireflood will result in a significant reduction in the volume of produced gas and generates a high CO_2 concentration in the exhaust gas.

Moore et al. (1984) and Garon et al. (1986) list following as the major advantages of using enriched air in firefloods:

1. Under conditions of elevated pressure and high oxygen flow rate, oxygen is cheaper than air (Howard, 1982).
2. Surface facilities for small scale (pilot operations) are relatively simple and should present less severe operating problems than are normally experienced with conventional air injection operations.
3. Lower injection rate resulting from the use of enriched air could make some tight reservoirs amenable to fireflooding that otherwise would not be suitable and could enable larger well spacings to be used.
4. In enriched air fireflooding, the concentration of CO_2 in the produced gas could be in excess of 90% (Persico et al., 1983), and, consequently, the partial pressure of CO_2 would be much higher. Since the solubility of CO_2 in crude oil increases with pressure, high concentration of CO_2 can result in miscible displacement of the crude oil.
5. In heavy, viscous oil reservoirs, swelling and viscosity effects associated with CO_2 solubility in the oil will contribute to accelerated oil recovery. The extent of the benefits due to CO_2 will depend to a large degree on the extent of reservoir contacted by the carbon dioxide.
6. Oxygen enriched air combustion projects often exhibit better combustion efficiency than the normal air provided the oil display non zero order reaction rate with respect to oxygen partial pressure (Moore et al., 1984).
7. In oxygen firefloods, spontaneous ignition can occur much more quickly due to greater reaction rates.

8. The fuel availability and the oxygen requirements per unit volume of reservoir are generally lower in enriched air firefloods than the normal air projects. Moore et al. (1984) attribute this to lower gas partial pressure that result in higher steam bank temperature and quality.
9. The use of oxygen or oxygen enriched air as injectant in firefloods could result in improved sweep efficiency. The reasons for this improvement are: (a) improved mobility ratios resulting from the increased solubility of CO_2 in the crude, and (b) improved stability resulting from a lowering of produced to injected gas ratios.
10. The use of oxygen instead of air can lower the produced gas-oil ratios by a factor of about five and would result in higher oil production. The benefits of lower produced gas-liquid ratios are: improved bottom hole pump performance, lower pollution control costs, less expensive gas handling equipment, and lower sand production due to lower gas velocities at the perforations.
11. Oxygen fireflood can alleviate some of the more common operational problems associate with the normal air injection projects such as the poor injectivity, ignition failures, sand migration, erosion, gas leakage to other sand, emulsion, corrosion and explosion hazards. Problems associated with the reservoir heterogeneities and anisotropices, however, can only be resolved through field tests in specific reservoirs.

The use of oxygen or oxygen enriched air as injectant in firefloods offer many advantages, the process also posses many disadvantages. The inherent disadvantages associated with the process are as follows:

1. Safety must be the prime concern when considering the use of pure oxygen or even enriched air for oil recovery. In oxygen service everything is fuel. Conventional oil field carbon steel tubing and casing will burn in an oxygen rich environment when subjected to an ignition source. The use of oxygen in systems contaminated with hydrocarbons can be particularly dangerous. Great care must be taken to analyze potential problems, which might occur, and to eliminate all hazardous situations. Velocities in the wellhead and tubing must be constraint to prevent creation of sparks due to impingement. Though, field experience with oxygen fireflooding is limited, pure oxygen can be injected into an oil reservoir as demonstrated by the success of Forest Hill oxygen fireflood operation.
2. The amount of oxygen stored behind the combustion front is much greater in oxygen fireflood than in normal air injection fireflood. The fraction of the injected oxygen retained behind the combustion front will increase significantly with increasing operating pressure.

The volume of oxygen stored behind the front, however, can be lowered by co-injecting water with oxygen or by injecting oxygen and water alternatively.

3. Corrosion in oxygen fireflood operation is likely to be more severe than in air fireflood due to the elevated concentrations of oxygen and CO_2 in the vent gas.
4. The operation of a pilot test conducted to ascertain the suitability of a reservoir for oxygen fireflood is often more expensive than the normal air fireflood. This is because the oxygen fireflood pilot is usually performed with expensive liquid oxygen delivered by tanker trucks. The additional costs incurred to ensure a safe and hazard-free operation, also increase the cost of operation.

Proper design and careful operation can overcome the disadvantages listed above. The oxygen supply industry has considerable experience in the safe handling of large quantities of oxygen and in the specification of materials of construction for the intended service.

Economics of Oxygen Fireflood

Supply Option

Once fireflooding has been identified as the preferred technique there is the question of whether to use air or oxygen. Though enriched air offers much greater flexibility than normal air and likely to produce better performance, the decision whether to use air or oxygen (or oxygen enriched air) as injectant should be based on economics. A comprehensive economic analysis of air versus oxygen should include both the cost of supplying oxygen to a fireflood project as well its effect on the overall fireflood performance. Such an assessment should include the economic benefits of faster production, wider well spacings, lower gas to oil ratios, and produced gas handling and disposal costs (Shahani and Gunardson, 1994).

There are three options for supplying oxygen to a fireflood project. In the first option (Figure 10.1), liquid is trucked from a supplier's air separation plant and stored on the site in vacuum insulated cryogenic tanks. These tanks normally would hold a week's supply of oxygen. The liquid is pumped from the tanks to a vaporizer at the required pressure and then vaporized and stored until needed. In the adsorption processes (Figure 10.2), air is passed through a vessel containing adsorbent (an inorganic crystalline material known as a zeolite molecular sieve), that selectively adsorbed nitrogen and carbon dioxide molecules from air on its surface and let the oxygen passes through. The gaseous oxygen with about 90% purity (entirely satisfactory for fireflood applications) at low pressure is then compressed to the injection pressure. In the third option (Figure 10.3) a cryogenic air separation plant is employed to separate oxygen from other constituents of the air. Cryogenic separation is the most energy efficient and lowest cost method to produce large volumes of oxygen for a large commercial scale oxygen fireflood. Selection of the oxygen supply mode depends on the conditions of the field project including the project life expectancy and the injection rates. In Table 10.1 the various oxygen supply options are compared (Drnevich and Thompson, 1982). Oxygen supply vendors, in general own and operate these facilities.

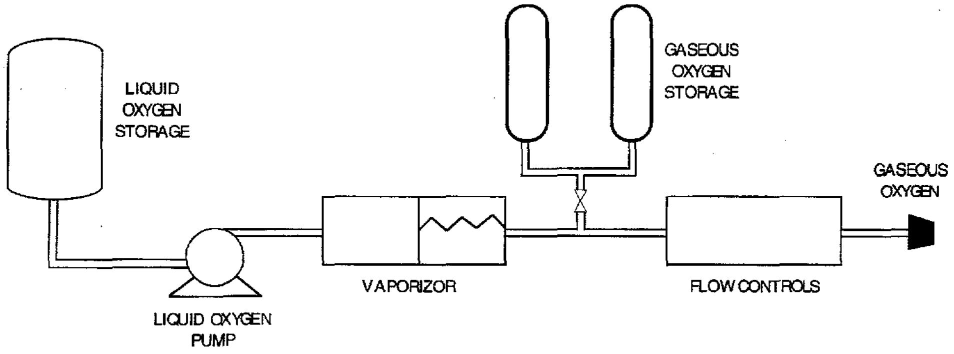

FIGURE 10.1 — Schematic of a Liquid Oxygen Vaporization Systems for Oxygen Fireflood (After Henningson and Duckett, 1984)

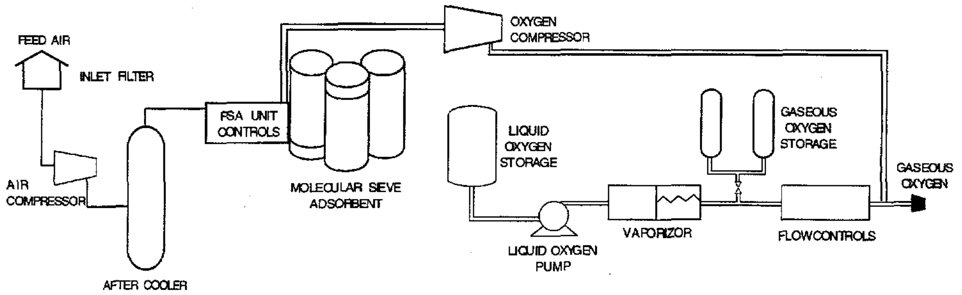

FIGURE 10.2 — Schematic Absorption (Pressure Swing) Air Separation System (After Henningson and Duckett, 1984)

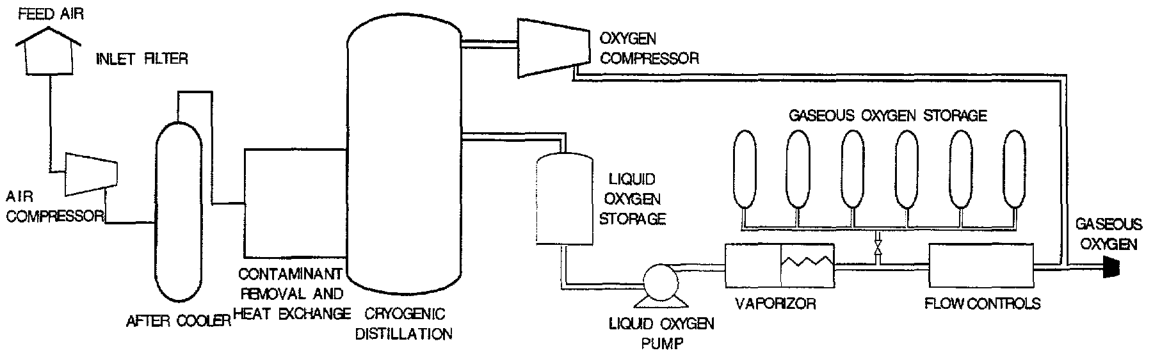

FIGURE 10.3 — Schematic of Cryogenic Air Separation Plant (After Henningson and Duckett, 1984)

TABLE 10.1 — Oxygen Supply Option

	Trucked Liquid	Adsorption Plant	Cryogenic Plant
Operating life (yr.)	<5	>5	>10
Capacity (MMscf)	0.2-2	0.2-1.4	0.2-50+
Capital cost	Low	Medium	High
Operating cost	High	Medium	Low
Lead time (months)	9	14-16	18-22
Purity (%)	~100	90-95	95-100
Cost ($/Mscf)	3.0-5.0	2.5-4.0	1.2-3.0

The oxygen supply companies with extensive experience with use of oxygen for fireflood include:

1. Air Products and Chemicals Inc., Allentown, Pennsylvania.
2. Canadian Liquid Air Ltd., Calgary, Canada.
3. Union Carbide Industrial Gases Inc., Tonawanda, New York.

These companies can provide support to operators in the design of oxygen injection facilities, well completion design, and train field personnel in the safe handling of oxygen and in the selection of oxygen compatible materials.

Economics

Many factors affect the economics of oxygen fireflood. The factor, which has the greatest effect on the commercial scale operation, is the cost of oxygen compared with the cost of air. To inject oxygen into a well it is necessary to compress the gas to an elevated pressure. A given volume of oxygen can be compressed to the desired pressure using a smaller compressor at lower compression cost, than the air containing the same volume of oxygen. This advantage in capital investment and operating cost for compression, however, is offset by the cost of producing pure oxygen. The oxygen production cost is a strong function of the plant size and decreases as the capacity of air separation plant increases due to economic of scale. The larger the quantity of oxygen the lower is its unit cost. Therefore, the difference in cost between supplying oxygen or air at elevated pressure is a function of the quantity of gas supplied and the pressure at which it is delivered. The cost of oxygen is only slightly affected by the desired purity. The cost of producing 80% purity oxygen is only about 5% lower than the cost of producing 99% purity oxygen (Hvizdos, 1978).

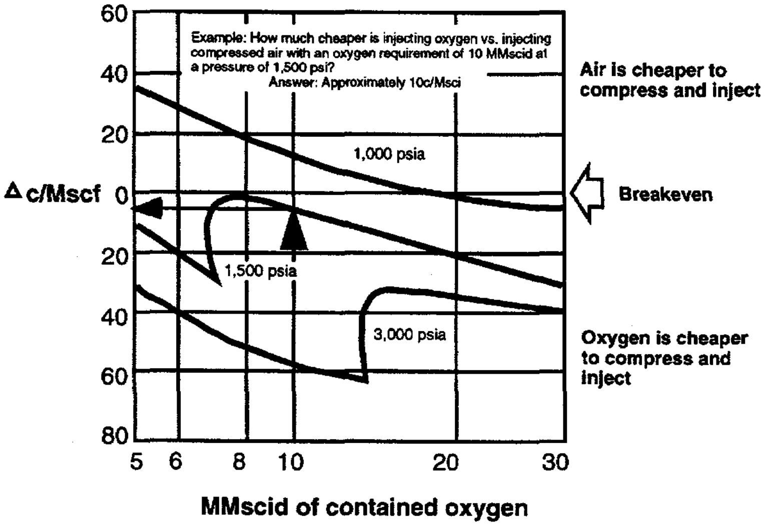

FIGURE 10.4 — Differential Cost for Oxygen Compared to Air (After Shahani and Grunardson, 1994)

Injection of pure oxygen can be cheaper than the equivalent amount of oxygen in air at elevated pressure. Hvizdos et al. (1983) showed that oxygen could be less expensive than air at high pressures and high flow rates. In Figure 10.4 the difference in cost between supplying oxygen or air at elevated pressure for a range of quantities and delivery pressure is depicted (Shahani and Gunardson, 1994). In this plot the quantity of contained oxygen is shown on the x-axis. The differential cost between compressing oxygen and air in cents per thousand cubic feet of contained oxygen is shown on the y-axis. This differential cost takes into account the capital and operating cost of the compressor(s) as well as the cost of producing the specified quantity of 99.5% purity oxygen over the economic life of the project. The economic life of the project is assumed to be 15 years. Both the power cost and the rate of return on investment are also assumed to be same for both the systems. The analysis shown for three different deliveries pressures. The discontinuity in the curves for 100 psia and 3,000 psia are a result of switching from a combination of reciprocating and centrifugal compressors at lower flow rates to reciprocating compressors at higher rates.

The economic analysis depicted in Figure 10.4 was performed 15 years ago, by Hvizdos (1983) based on cryogenic air separation. Since then, advances have been made to cryogenic air separation technology, which has further reduced the cost of producing pure oxygen. Incorporating these advances into analysis will more likely further improve the economics of oxygen fireflood. Recent developments in adsorption and membrane separation based oxygen production technologies have made them competitive with the cryogenic technology and can play an important part in making small-scale oxygen fireflood projects economically attractive.

For small experimental projects, the cheapest source of supply would probably be oxygen delivered to the site as liquid oxygen and vaporized as needed. The current price of liquid oxygen delivered to the site range from $110–$140 per ton depending upon the delivery distance from the liquid oxygen plant. Since most commercial projects will require large volumes of oxygen, it may be best to erect an on site oxygen plant. The best way to supply oxygen for a commercial size project is very complex and the service of an oxygen supplier must be enlisted to arrive at the best plan.

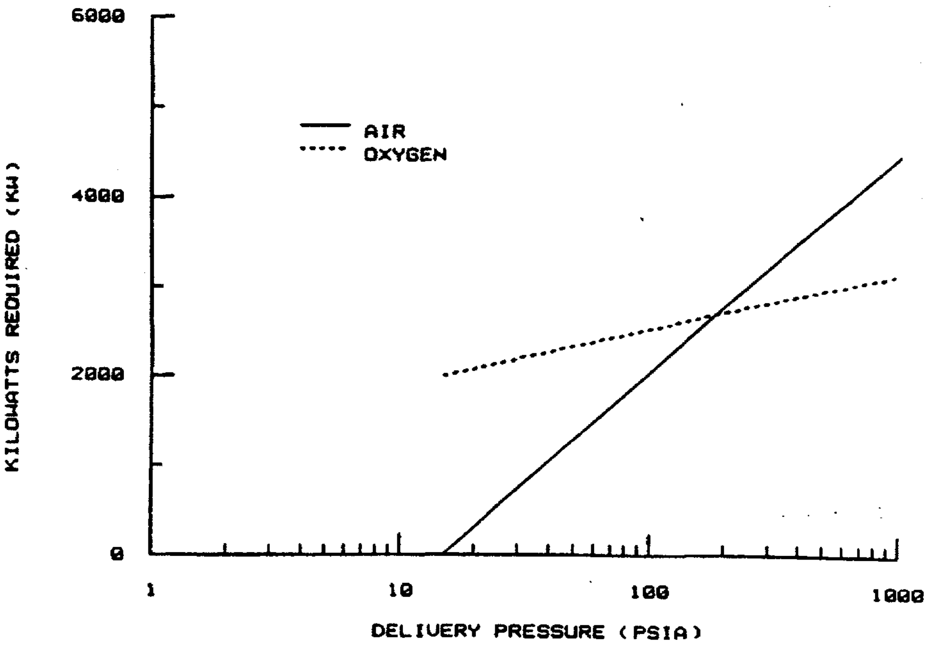

FIGURE 10.5 — Breakeven Analysis on Delivery of 4MMscf/D Oxygen (After Hvizdos et al., 1983)

Pete et al. (1988) prepared economic projections to compare oxygen with air injection for the production of heavy oil in Texas. This analysis indicate that when the project's oxygen requirements are greater than 4 MMscf/d and the injection pressure is greater than 180 psi, use of pure oxygen is more cost effective than air (see Figure 10.5).

Laboratory Studies

Combustion tubes are the principal physical models used by most organizations to evaluate and compare the combustion performance of oxygen/enriched air versus normal air and to obtain design parameters for oxygen/enriched air flooding. Combustion tubes are linear models and cannot provide information on sweep efficiency. Three dimensional scaled model experiments of fireflooding and numerical simulation can provide useful information on fireflood sweep efficiency and one such study (Garon et al., 1984) has been reported in the literature. This section summarize the results of selected laboratory oxygen/enriched air studies

Pusch (1977) carried out the earliest reported tube tests using oxygen*. Results of the combustion tube tests carried out by Moss and Cady (1982) using oxygen indicated that the peak temperatures and oxygen utilization were almost identical for both air and oxygen. This study also indicated the oxygen requirement was 35 and 20% higher than the equivalent air in dry and wet combustion.

* This study was the first to document the importance of safety in using oxygen in a hydrocarbon environment.

A more comprehensive study by Hansel et al. (1984) with a range of oxygen concentration (from 21–95%) and light oil (31°API) indicated only very small differences between runs with regard to fuel consumption, apparent hydrogen-carbon ratio of fuel, combustion temperature, and oxygen utilization. Shahani and Hansel carried out further work on light (32°API), medium (21–23°API), and heavy (13°API) crude oils at oxygen concentration from 21–95%. These studies indicated that the combustion characteristics tend to improve with oxygen additions, and that the chief benefit of oxygen enrichment in light and medium gravity oils was that the combustion could be maintained for conditions at which the use of air was unsatisfactory. They also found that for heavy oils, the fuel availability was significantly reduced at high oxygen concentrations, and higher oxygen concentration tends to improve oil recovery.

Results of the enriched air combustion tube studies carried out by Cady and Satchwell (1985) showed that an increase in the oxygen concentration led to a decrease in the fuel deposition and an increase in the $CO/(CO+CO_2)$ ratio. Oxygen combustion tube studies carried out by Garon and Wygal (1974), however, indicated no significant change in fuel deposition with a change in the injected oxygen concentration.

Results of the combustion tube experiments performed by Moore and his co-workers at the University of Calgary, Canada (1987) suggest that the degree of oxygen enrichment of the air can affect the burn performance. Their tube tests performed on Athabasca oil sand core indicates that the overall oxygen and fuel requirements are a linear function of total operating pressure. They surmised that because of the direct effect of total pressure and total gas injection flux on oxygen storage, the oxygen flux at the burn front is likely to be lower for enriched air combustion than for normal air combustion. Moore (1987) also observed significant oxygen storage in the unswept region downstream of the main combustion zone.

Results of oxygen enriched air combustion tube studies by Petit (1987) on heavy (15.8°API) and light (25.7°API) oils indicated that irrespective of the system pressure oxygen requirements are higher at the front of the combustion front than for normal air combustion. The oxygen requirements are slightly higher for heavier oil than for the lighter oil.

Enriched air wet combustion tube studies by Venkatesan et al. (1990) indicate that the fuel consumption and oxygen requirements generally decrease with increasing water — oxygen (WO_2) ratio and remain constant during the transition from normal wet to super wet combustion.

Three dimensional scaled model tests by Garon et al. (1984) indicate no improvement in the sweep efficiency with oxygen injection.

Safety Consideration

General

Beyond the economic and process issues, safety is a prime issue in oxygen fireflood. Oxygen, especially at high pressure, is more hazardous than air. Many metals including the conventional oil field carbon steel tubing and casing will burn in high-pressure oxygen enriched environment (common to most oxygen firefloods), if ignited. In the fireflood process all three components of uncontrolled combustion — namely, oxidant, fuel and a potential source of ignition are present. Hence special precautions must be taken in the operation of an oxygen or enriched air fireflood. Technical cooperation between the operator and the oxygen supplier is a must to ensure safe operation of the oxygen/enriched air fireflood. Service of the oxygen supplier must be enlisted in the development of operating procedures for the safe operation of oxygen injection system and in the design of injection wells, and production wells.

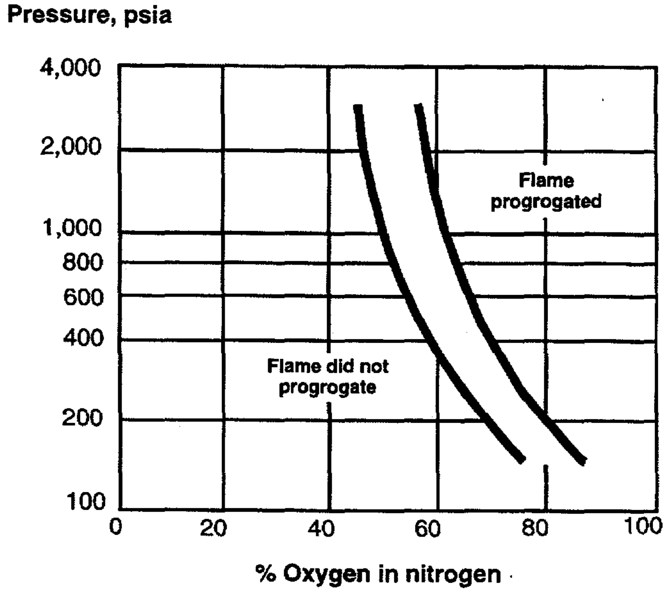

FIGURE 10.6 — Propagation in Carbon Steel Pipe as Function of Oxygen Concentration and Pressure (After Shahani and Grundardson, 1994)

In an oxygen rich environment, the combustibility of metals depends on the oxygen concentration, initial pressure, temperature, geometry, heat sink potential, and direction of burn (Shahani and Gunardson, 1994). Flame propagation in carbon steel is a strong function of the oxygen concentration and pressure. Laboratory tests indicate that at a given pressure, carbon steel tube would continue to burn upon ignition, provided the oxygen concentration exceeds a critical value. Below this critical value the tube will not burn. In Figure 10.6 the propagation of the flame in carbon steel pipe is mapped as a function of the pressure and initial oxygen concentration (Merington, 1983). In oxygen injection well, flame propagation can be controlled or eliminated by incorporating firebreak sections in the tubing and casing. The firebreak is a length of casing or tubing section that is made from metals whose melting point is well below their ignition point and hence do not burn in oxygen. Nickel- and copper-based alloys are the materials of choice for firebreak in oxygen fireflood application. The use of firebreak in oxygen fireflood is very cost effective since it eliminate the need for expensive fire resistance materials in large quantities.

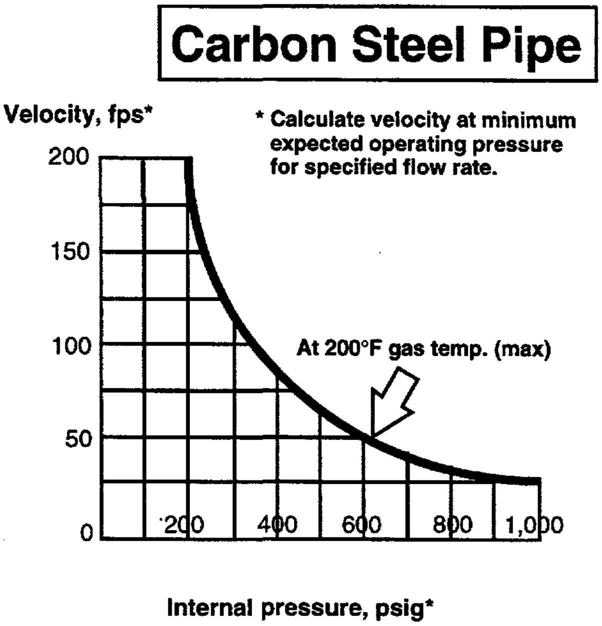

FIGURE 10.7 — Maximum Permissible Oxygen Velocity in Carbon Steel Pipes (After Shahani and Grundardson, 1994)

Ignition may occur if the velocity of oxygen in the piping system is such that it led to generation of spark due to particulate impacting metal surface. The maximum velocity of oxygen in the piping system must always below a certain threshold value. The threshold value is a function of the prevailing temperature and pressure. Figure 10.7 shows the effect of internal pressure on the maximum velocity for straight runs of carbon steel pipe (Merington, 1983). For bends and elbows, the maximum allowable velocity should be reduced by 50%.

Injection Well

In oxygen fireflood, the greatest safety concerns are at the injection well. Design of the wellhead and wellbore, including injection tubulars, packers, ignition equipment, burners, chokes, and support equipment is governed by the same velocity and material constraints outlined in the previous section. Tubing and casing need not be made of exotic metals provided rigid adherence to velocity threshold is maintained. The injector should be initially cleaned using Nitrox solution to minimize presence of hydrocarbons. A packer must be installed to maintain the casing-tubular annulus oil free. Packer seals gaskets, valve packing and thread lubricants must be made of oxygen compatible material such as the Teflon.

Injection tubing must be free of rust or other loose particles, which can create spark by impingement upon other surfaces. Injected gases must also be free of such particles. Use of premium thread designs which eliminate internal gaps between connecting collars is recommended to avoid disrupting oxygen flow and to prevent dirt, oil, and other particles from lodging during cleaning operations (Merington, 1983). Premium connection tubulars should be cleaned and redoped with Teflon sealant.

The well should be equipped with bottomhole temperature monitoring equipment and purging facility. If the temperatures exceed predetermined limits then the well should be purged with nitrogen or quenched with clean water. As mentioned earlier, the oxygen injection well completion design should incorporate a firebreak section in the casing and tubing to prevent upward migration of a metal burn should one occur.

An overbalance injection pressure should be maintained at all times to prevent backflow. If the primary injection system shuts down for any reason, a backup system must be available.

Oxygen enriched operations should always be start with nitrogen diluted synthetic air; then gradually increase oxygen concentration over a period of few weeks to reduce potential for high temperatures near injection well-bores (Duncan and Khallad, 1996). If oxygen injection is to be terminated for an extended period, Duncan (1996) recommend that an oxygen compatible wireline blanking plug be installed in a downhole profile. The tubing must be flushed with water or nitrogen prior to installing the plug. The slickline unit must be cleaned and relubricated with synthetic oil.

Producing Well

Completion of producers for oxygen fireflood application is no different from those normal air fireflood producers. In oxygen fireflood increased corrosion can be expected at producing well due to the presence of higher concentration of CO_2 in the vent gas. Consideration should also be given to possibility of the presence of flammable concentrations of oxygen and hydrocarbons in vent gases at the producers. At atmospheric pressure oxygen and natural gas form an explosive mixture if the oxygen level exceeds 12.1% by volume and the natural gas concentration exceeds 5% by volume. At higher pressures, the oxygen — natural gas mixture can explode at lower oxygen concentration. For instance, at 500 psig the required oxygen concentration is reduced to 9%. Hence the oxygen concentration in the produced gas must be measured frequently (preferably twice a day) and corrective action taken to avoid a potential explosive situation. Production wells should be shut-in upon detection of high oxygen levels, and pressures kept low to minimize damage in the event of an explosion.

If the well is shut in due to high oxygen level in vent gases and if it become necessary to vent the annulus gases, then special precaution must be taken. The venting valves must be blanketed with nitrogen prior to opening and the impinging velocities must be limited to avoid creating sparks. During shut-in it is advisable to circulate the wells with inhibiting fluids and avoid taking acoustic fluid level measurements.

Oxygen Distribution Lines

The delivery of pure oxygen to the wellhead is not much different from piping oxygen to a reactor in the chemical process industry. By adopting existing technology and safety procedures oxygen can be safely delivered to the wellhead. The pipeline system must be sized to satisfy for both allowable pressure drop and velocity constraints. Elbows, tees, valves, orifices, and other pipeline components must be sized based on the velocity constraint. Fairfield (1985) recommended that in the design of oxygen delivery system for fireflood consideration be given to the following:

- Since impingement of loose particles on other surfaces can be a potential ignition source, maintain oxygen velocities at low values.
- Keep the oxygen delivery system free of any hydrocarbon and other potential flammable material.
- Lubricate thread, seals with an oxygen inert lubricant.
- Where conditions warrant, incorporate firebreaks fabricated out of special metal such as copper, monel, and inconel.
- Avoid any abrupt changes in direction of oxygen flow path.
- Avoid conditions that can result in rapid compression of gases during the valve opening and closing operation.

Field Projects

Currently no oxygen fireflood is in operation. At least 10 oxygen/enriched air firefloods were known to have been in operation in North America during the 1980s. These include 4 in the USA and 6 in Canada. The U.S. Oxygen Fireflood include: Greenwich Oil's Forest Hills field fireflood in Texas, Arco's Holt sand unit oxygen fireflood in Montague county, Texas, Mobil's Esperson Dome Oxygen fireflood, Liberty County, Texas, U.S. DOE's Teapot Dome field fireflood in Natarona County, Wyoming.

The Canadian fireflood include: Husky Oil's Golden Lake Waseca fireflood in Saskatchewan, DOME Petroleum's Lindberg fireflood in Alberta, BP Canada's Marguerite Lake fireflood in Alberta, Gulf Canada's Pelican Lake project in Alberta, Petro Canada's Kinsella B fireflood in Alberta, and Canadian Occidental's Morgan Area fireflood in Alberta.

Fairfield (1985) has presented the salient features of these operations. In the following the operational history of Greenwich Oil's fireflood is presented to document the design, implementation and operation aspects of a commercially successful oxygen fireflood pilot.

Forest Hill Oxygen Fireflood

Project History

The Forest Hill Field is located in Wood County Texas, near the town of Quitman. The formation is the Harris sand, Eagleford in age. The field is three miles long (northeast-southwest direction) and two and one-half miles wide. The crude in the Harris formation is a low gravity (10°API), high viscosity, asphaltic sour crude. The field was discovered in 1954 and by 1964, 26 wells were drilled and completed. Field development was curtailed in 1966 due to low crude prices and a rapid decline in production. From 1966–72 attempts were made to implement various improved recover processes, but proved unsuccessful.

Greenwich Oil acquired the field in 1974 and initiated an air fireflooding in the field. Neco air injection wells were drilled and air injection was started in 1976. Reservoir response to air injection was noted in early 1977. By the end of 1978, five air injectors were in operation. Between 1978 and 1980, 38 new producing wells were drilled. In 1978, Greenwich began planning for an oxygen fireflood field test. In 1980, following a two-year laboratory effort, Greenwich initiated a single pattern oxygen fireflood. Oxygen enriched air was injected into an existing air injection well beginning January 1980 and terminated in 1982. This two year field test was the first known successful oxygen fireflood in the world and demonstrated that high concentration of oxygen could be safely be injected into an oil reservoir.

80% purity oxygen was injected into injection well at an average rate of 250,000 scf/d at an injection pressure of about 2,200 psig over a two-year period. A total of 0.22 MMM scf of 80% oxygen was injected into the formation at an oxygen cost of $6.6/bbl (1980 dollars). The wells in the oxygen pattern showed a 55% increase in oil production over those in the air injection patterns. The oil production increased from 10,200 bbl/month (average air injection pattern production) to 15230 bbl/month an increase of 5,030 bbl

The oxygen fireflood test was terminated in January 1982 due to falling oil price. Following the termination of oxygen injection, Greenwich started injecting water in March 1982, to recoup the heat generated in the reservoir during the fireflood and to maintain reservoir pressure. The oxygen fireflood project results were very favorable and Greenwich planned on resuming oxygen injection in 1985, but later abandoned the plan due to oil price collapse.

Project Description

The Forest Hill oxygen fireflood operating facilities were divided into two sets of subsystems: injection, and production. The components of these subsystems are described in the following sections. The properties of the test reservoir site is shown in Table 10.2

TABLE 10.2 — Forest Hill Oxygen Fireflood Reservoir and Fluid Properties

Description	Value
Formation	Harris Sand
Depth (ft.)	4,800
Avg. Porosity (%)	27.7
Avg. Permeability (md)	626
Water Saturation (% PV)	36
Original Oil in Place (bbl /ac-ft.)	1,362
Reservoir Volume (ac-ft.)	28,568
Formation Volume Factor	1.01
Oil Gravity (°API)	10
Oil Viscosity (cp)	1,002 @ 18°F
Reservoir Temperature (°F)	185
Asphaltene Content (wt.%)	31

Injection Subsystems

The major components of the system include:

- Injection Gas supply system.
- Flow control skids.
- Injection pipelines.
- Injection wells and wellhead area.

Injection Gas Supply System

The injection gas supply system consists of an air compression/cleanup system, a liquid O_2–N_2 supply/blending system, and a gaseous O_2 supply system. Compressed air is supplied to the liquid O_2–N_2 supply/blending system where it is cleaned, dried, and mixed with oxygen to provide a blend up injection gas with oxygen purities ranging from 21–90 mole percent. A sidestream of clean air is mixed with oxygen from the liquid supply system to provide a stream of 0.9 mole fraction oxygen. Nitrogen for purging is supplied from liquid nitrogen storage, pumping, and vaporization facility. Oxygen is supplied from a liquid oxygen tank. All three products (N_2, blend up gas, and 90% O_2) are supplied to separate manifolds at a pressure of 3,000 psig.

The injection gas supply system is owned and operated by the oxygen supplier. The injection gas supply system sports a safety system to prevent uncontrolled oxygen release in case of a line break downstream. Also, gaseous nitrogen is stored at an elevated pressure to be made available for line and well purging during power outage. Plant emergency trip stations are incorporated into the system to allow manual shutdown of the system in an emergency.

Flow Control Skid

The function of the flow control skid is to provide the capability for taking blend gas (21≠90% O_2), oxygen, and nitrogen from the supply system headers and distribute the required gas or blend to individual wells. Each skid is designed to service six or seven injection well.

Individual mass flow meters are utilized to provide a measurement of the volume of gas injected into individual well. The operating flow range for each well is 0–45,000 scf/hr. A selection knob is included in each skid to allow the operator to set the oxygen purity during the blend up phase. Feedback from the injection gas supply system is provided by an oxygen purity read-out.

For personal protection, valves and indicators (gas flow, line pressure, manifold temperature, pressure drop across the strainer, N_2 purge flow) are mounted on panels which shield the operator from the piping valve system. Similarly, instrumentation, which may need calibration (pressure, flow and temperature transmitters), is also installed on the front of the panel. Features are provided to maintain gas flow for well protection in emergency situations and protect against overpressurization. The skids are designed for 3,550 psig, and are protected by relief valves set at 3,300 psig.

The flow control skids are also designed to interrupt the flow of oxygen in case of a line break downstream and to provide for automatic line and well purge during a power failure or activating of a plant emergency trip station at the injection gas supply system.

Injection Pipelines

The injection pipelines carry nitrogen, air, air-oxygen blends, and oxygen from the flow control skid to the wellhead area of each injection well. The lines are welded and run underground.

Each pipeline consists of 2.375" O.D x 0.218" wall externally coated carbon steel carrier pipe and terminated at each end with a 1" schedule 80 monel tie-in piece topped with an insulating connector. For safety, all carbon steel piping is buried at a minimum depth of four feet. Bright yellow marker posts bearing pipeline signs identify the pipeline route. These posts are located directly over the pipeline and each can be seen easily from the next.

Pipelines are equipped with cathodic protection to monitor corrosion. Cathodic protection consists of magnesium anodes located at intervals not exceeding 1,000 feet along the pipeline. For each anode location, there is a test station, which consists of a junction box on top of one of the yellow marker posts. The insulating connectors at each end of each oxygen pipeline are parts of the cathodic protection scheme and are protected by Kirk cells from internal arcing during lighting strikes.

The pipelines are all made of welded construction, are hydrotested, and then cleaned for oxygen service. Relief valves mounted on the flow control skid are utilized to prevent the pipeline from over-pressure.

High pressures and high oxygen concentrations pose potential combustion risks to the pipeline system. Careful pipeline cleaning, gas velocity limitations, proper equipment and material selection, and monitoring of the oxygen supply can limit the risk of pipeline contamination and subsequent reaction with oxygen.

Injection Wells and Wellhead Area

The wellhead area subsystem is an above ground arrangement of piping, valves, and controls that connects the injection piping to the Christmas tree. Nitrogen, air, air-oxygen blends, and oxygen are carried through the wellhead area piping and valves into the injection well.

All wellhead equipment uses conventional technology with provisions for oxygen compatibility, resulting in high reliability and control. Safety systems are fail-safe with no electrical power required for operation. There are no unusual safety or operating problems imposed by temporary equipment failure, curtailment of oxygen supply, or power interruptions, so long as pressure is maintained on the wellhead. The gas supply system equipment redundancy and backup system and injection well design ensure this.

The wellhead area controls basically consist of:

- A check valve to prevent injection gas back-flow from the well and minimize fluid back-flow from the formation into the bottomhole area.
- Pneumatic pressure sensors which isolate the well in case of either a loss of nitrogen pressure in the annulus or a loss of feed gas pressure to the injection well.
- Pressure transmitters which allow monitoring of the annulus and the injection gas pressure.
- A nitrogen pumper connection which allows purging of the wellhead and well with nitrogen in case of a gas supply interruption or a well workover.

Production Subsystem

The production subsystem include:

- Production wells.
- Diluent oil distribution.
- Produced oil handling.
- Produced gas handling.
- Waste water disposal.

Diluent oil is distributed to each well and is blended downhole with the viscous crude to facilitate pumping. The oil produced from each well is collected and transported to the treatment system.

Produced oil, first processed in a gas oil separator to remove entrained gas, flows to a heater-treater where the oil-water emulsion is broken and the water is removed. The water is pumped to wastewater storage tanks prior to final disposal using well injection. The treated oil is pumped to storage tanks prior to sale. Produced gas collected from the field and from the oil treatment system is passed through a gas-oil separator prior to final processing in a gas incinerator. A flare is provided for start-up and as backup to the incinerator. Waste heat, recovered from the incinerator flue gas, is used to reheat the oil feed to the heater-treater.

Production Wells

The production wells employ dual-string completions with downhole gas separation. Diluent oil flows down one string and produced liquids, with a small amount of entrained gas, are pumped up the other tubing string. Most of the produced gas flows up the annulus. The gas production rate is controlled at the wellhead to prevent blowout of downstream equipment and to influence oil production rates.

Diluent Oil Distribution

Diluent oil, which enables production of the highly viscous crude, is distributed to each well through an underground pipeline network. A 40°API gravity crude is used as the diluent. The diluent oil is pumped from the storage at about 600 psig into the pipeline network. The pressure drops to about 300 psig at the wellhead.

Since the pipeline is underground, the effects of an energy release due to pipeline breakage would be mitigated. The piping is fitted with flow control valves so that a section of leaking or blocked pipe can be isolated. If sufficient surface observable oil leakage is noticed, special soil samples are collected to define the components of the oil leakage and verify whether the oil is similar to production oil or the diluent oil. This may or may not be of importance from an environmental perspective and will depend upon whether the two oils are hazardous or have different hazardous classification.

Produced Oil Handling

The produced oil handling system collect and treat the produced oil to meet sales specifications. This system consists of pipelines, test stations, tank batteries, and sales tanks.

Produced fluid flow through an underground piping network under the wellhead pressure of approximately 100 psig. The tank line leading to each battery is 4" in diameter. A separate gas gathering system is utilized to gather vent gas.

On a regular basis, production from each well is diverted to a test station to measure the production rates of oil, gas, and water from individual well. Produced fluids first pass through the test separator to remove gases, which then are fed to the gas-gathering pipeline. The liquids flow to the test vessel. The total liquid production is calculated by determining the change in liquid level over time. A sample is taken to determine the water content of the liquid. Testing is usually is carried out over an 8–24 hour period.

Produced fluid flow into a gas-oil separator, from which the gas flows into the gas gathering system. The separated liquids are warmed in preheaters before being introduced to the heater-treaters. Flue gases warm the heating medium from the incinerator.

The warmed oil flows into a heater-treater, where additional heat is added via a firetube burning natural gas. T configuration of vessel internals promotes the breaking of emulsions. Chemicals may be added to further reduce the surface tension of water droplets and promote their coalescence. Separated gas taken from the top of the heater-treater flows to the gas gathering system. The water collects at the bottom of the vessel where it is drawn off. Treated crude is drawn from the side. A weighted float determines the level of the oil-water interface.

Treated crude flows to a sales tank for storage. Each tank is 18 feet in diameter and can hold 500 bbls of liquid. Since the highly viscous crude has very low vapor pressure, vapor recovery from the storage is not required.

Crude is transferred from the storage tanks to the sales tanks via a LACT unit, which meters and analyzes the oil. The oil is first pumped through the BS&W monitor. If the water content is too high, the "bad oil" is diverted back to a spare sales tank for reprocessing through the heater-treater. If the oil is within specifications, it passes through a precise liquid flow meter, which corrects volume measurements for temperature and pressures. The LACT unit also collects time-composited samples of the oil, which are analyzed later.

Treated crude that has met sales specifications is stored in the sales tanks pending custody transfer. From the tanks, the oil is pumped through a LACT unit into tank trucks. This second LACT unit records the exact amount of oil for which payment is made.

Produced Gas Handling System

The produced gas (off-gas) is gathered in a pipeline network, and treated by incineration to eliminate hydrocarbon pollutants from the vented stream. This system consists of produced gas gathering and produced gas treating.

A pipeline system carries the produced gases to the gas processing facility. The major gas source is the produced gas from the production wells. Gas overheads from the heater-treaters and various tanks also contribute to the gas stream. Gas pressure at the wellhead is regulated to about 18 psig. so gas entering the pipeline downstream can do so under its own pressure. A gas-oil separator, or "knock-out vessel" allows entrained or condensed liquids to settle out of the gas stream. The liquids are routed to the heater-treater feed stream.

The gas stream is monitored for composition changes, which could lead to corrosive or flammable conditions. Multiple pipelines with interconnections provide flexibility, while "fail-safe" controls, safety valves, check valves and metering equipment limit the effect of pipeline problems and act as environmental controls to prevent hydrocarbon venting. The pipeline is a low-pressure system and underground line leakage is unlikely during normal operation.

Produced gases consist mainly of carbon dioxide and nitrogen with low levels of carbon monoxide, hydrogen, and C1–C6 hydrocarbons. Hydrogen sulfide and sulfur dioxide are generally present in very low quantities (5–10 ppmv); so sulfur control is not required. The hydrocarbon, hydrogen sulfide and carbon monoxide content of the produced gas are oxidized in a gas incinerator. Natural gas is added to the incinerator to support combustion of the low Btu gases. The amount of natural gas required to support combustion is determined by the composition of the produced gas to maintain a minimum combustion temperature of 1500°F. At this temperature, over 99% of the hydrocarbons in the produced gas will be oxidized.

Heat is recovered from the flue gases using a closed loop organic fluid system. The heater working fluid passes through the preheaters, which are upstream of the heater-treaters.

A gas flare is utilized to provide backup for gas incineration and to facilitate start-up of the system. The flare is 50 feet high with a 10–inch diameter flare burner. If the produced gas heating value is low, additional natural gas is used to ensure flame stability.

Wastewater Disposal

Produced water, separated in the treatment battery, is pumped to the wastewater storage tanks prior to disposal. During storage, some additional oil coalesces. Periodically, this oil is skimmed off and stored in the skim oil tanks from which it is slowly recycled to the inlet of the heater-treaters. The substantially oil-free wastewater is injected into the wastewater disposal well. If the wastewater injection operation is down for any reason, the wastewater is trucked to an off-site wastewater injection facility for disposal. Trucking wastewater to an off-site injection facility is a common practice within the oil patch.

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