FOUO

TRWPT/CRADA-002-1
(OSTI ID: 4203)

RECEIVED
MAR 17 1999
OSTI

EVALUATION OF IN SITU COMBUSTION FOR SCHRADER BLUFF

Topical Report
March 1999

By
Arden Strycker
Partha Sarathi
Shawn Wang

March 1999

Work Performed Under Contract No. DE-AC75-99AD45024
(GS-23F-8079H)

TRW Petroleum Technologies
Bartlesville, Oklahoma

**National Petroleum Technology Office
U. S. DEPARTMENT OF ENERGY
Tulsa, Oklahoma**

DISCLAIMER

This report was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government nor any agency thereof, nor any of their employees, makes any warranty, expressed or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government.

This report has been reproduced directly from the best available copy.

Available to DOE and DOE contractors from the Office of Scientific and Technical Information, P.O. Box 62, Oak Ridge, TN 37831; prices available from (615) 576-8401.

Available to the public from the National Technical Information Service, U.S. Department of Commerce, 5285 Port Royal Rd., Springfield, VA 22161

DISCLAIMER

Portions of this document may be illegible in electronic image products. Images are produced from the best available original document.

TRWPT/CRADA-002-1
Distribution Category UC-122

Evaluation of In Situ Combustion for Schrader Bluff

By
Arden Strycker
Partha Sarathi
Shawn Wang

March 1999

Work Performed Under Contract DE-AC75-99AD45024 (GS-23F-8079H)

Prepared for
U.S. Department of Energy
Assistant Secretary for Fossil Energy

Thomas B. Reid, Technology Manager
National Petroleum Technology Office
P.O. Box 3628
Tulsa, OK 74101

Prepared by
TRW Petroleum Technologies
P.O. Box 2543
Bartlesville, OK 74005

TABLE OF CONTENTS

1.0	EXECUTIVE SUMMARY	VII
2.0	OVERVIEW AND BACKGROUND	1
2.1.	PURPOSE	1
2.2.	SCOPE	1
2.3.	THIS REPORT	1
3.0	DESCRIPTION OF SCHRADER BLUFF	3
3.1.	OIL CHARACTERISTICS	3
4.0	INITIAL SCREENING	5
4.1.	SCREENING CRITERIA	5
4.1.1.	Screening Criteria Selection	5
4.1.2.	Results of Comparison	7
4.1.3.	Summary	8
4.2.	PREDICTIVE MODELS	8
4.2.1.	Results	9
4.2.2.	Summary	11
4.3.	ANALOGOUS RESERVOIRS	11
4.3.1.	Information Sources	12
4.3.2.	Results	13
4.3.3.	Summary	15
4.4.	INITIAL SCREENING SUMMARY	15
5.0	IN SITU COMBUSTION TUBE RUNS	17
5.1.	BACKGROUND	17
5.2.	IN SITU COMBUSTION TUBE RUN NO. 1	18
5.3.	IN SITU COMBUSTION TUBE RUN NO. 2	19
5.4.	RAMPED TEMPERATURE OXIDATION (RTO) CHARACTERISTICS	20
5.5.	SUMMARY	20
6.0	IN SITU COMBUSTION SIMULATION STUDIES	21
6.1.	BACKGROUND AND PURPOSE	21
6.2.	MODEL DESCRIPTION AND DATA INPUT	21
6.3.	SENSITIVITY STUDIES AND RESULTS	31
6.3.1.	Effect of Injection Rate	31
6.3.2.	Effect of Enriched Air	34
6.3.3.	Effect of Kinetic of Cracking Reaction	35
6.3.4.	Wet Versus Dry Combustion	36
6.3.5.	Effect of Phase Equilibrium K-values	38
6.3.6.	Effect of Well Spacing	40
6.4.	EXTINCTION RADIUS	40
6.5.	CONCLUSIONS	42
7.0	OVERALL CONCLUSIONS	43
8.0	BIBLIOGRAPHY	45

LIST OF TABLES

	<u>PAGE</u>
Table 1. – Summary of reservoir parameters for Schrader Bluff Milne Point, Alaska	4
Table 2. – Modified EOR Screening Criteria.....	6
Table 3. – Reservoir properties of selected sands in Schrader Bluff	9
Table 4. – Screening Parameter Ranges for Analogous Reservoirs	12
Table 5. – Number of analogous reservoirs by process and status	13
Table 6. – Summary of results for Run 1	19
Table 7. – Summary of results for Run 2.....	19
Table 8. – Properties of Heavy and Light Fractions.....	22
Table 9. – Four Chemical Reactions	22
Table 10. – Schrader Bluff Reservoir 36-Layer Model Description	23
Table 11. – Schrader Bluff Reservoir 14-Layer Model Description	25
Table 12(a). – Liquid-Gas and Water-Oil Relative Permeabilities for Layers 1, 8 and 9	26
Table 12(b). – Liquid-Gas and Water-Oil Relative Permeabilities for Layers 3 and 427	27
Table 12(c). – Liquid-Gas and Water-Oil Relative Permeabilities for Layer 628	28
Table 12(d). – Liquid-Gas and Water-Oil Relative Permeabilities for Layers 10 and 1129	29
Table 12(e). – Liquid-Gas and Water-Oil Relative Permeabilities for Layers 13 and 1430	30
Table 12(f). – Liquid-Gas and Water-Oil Relative Permeabilities for Layers 2, 5, 7 and 1231	31
Table 13. – Two Sets of K Values	39

LIST OF FIGURES

	<u>PAGE</u>
Figure 1. – Comparison of EOR methods from DOE Predictive Model Study.....	10
Figure 2. – Position of combustion front for various injection rates	32
Figure 3. – Effect of injection rates on cumulative oil production, oil recovery and AOR	33
Figure 4. – Comparison of cumulative oil recovery–14-layer vs. 8-layer (10 MMscf/D air inj.).....	34
Figure 5.– Effect of enriched oxygen on daily oil production and oil recovery	35
Figure 6.– Effect of kinetics of cracking reaction (10 MMscf/D air injection).....	36
Figure 7. – Oil recovery in wet combustion is superior to the corresponding dry combustion	36
Figure 8. – Comparison of producing AOR for wet and dry combustion	37
Figure 9. – Effect of the amount of water injected on oil recovery (5 MMscf/D air injection).....	37
Figure 10. – Effect of wet combustion on temperature distribution (5 MMscf/D air injection).....	38
Figure 11. – Effect of wet combustion on oil saturation (5 MMscf/D air injection).....	38
Figure 12. – Effect of phase equilibrium K-values on oil recovery (10 MMscf/D air injection).....	39
Figure 13. – Well spacing sensitivity study (10 MMscf/D air injection).....	40
Figure 14. – Extinction radius at various injection rates.....	41

1.0 EXECUTIVE SUMMARY

This report summarizes the work conducted for the U.S. Dept. of Energy (DOE) in support of a CRADA project with British Petroleum Exploration, Inc. (BPX). The CRADA is a joint project intended originally to enable BP Exploration to take advantage of the expertise residing at the National Institute for Petroleum and Energy Research as relates to enhanced oil recovery (EOR) technologies.

The purpose of the cooperative work between BP Exploration and U.S. Dept. of Energy is to develop methods to economically recover the viscous oil at Schrader Bluff Milne Point. Historical average initial well productivity of 500 BOPD, coupled with current cost, performance, and fiscal conditions, render the resource uneconomic. The purpose of the agreement is to develop technological innovations to maximize utilization of heavy oil residing in Alaska and to save this resource from abandonment.

The focus of this report is on the results related to evaluation of in situ combustion processes applied to Schrader Bluff. Initially, overall screening processes were applied to determine which of the EOR methods were most appropriate for Schrader Bluff. In situ combustion was among the methods considered potentially favorable and was evaluated further. Laboratory scale tube runs were conducted to determine if the kinetic parameters for the crude oil were favorable. Additional sensitivity studies were conducted to evaluate the recovery potential. Described in this report are the results of the (1) initial screening, (2) experimental tube runs, and (3) simulation sensitivity studies as related to in situ combustion in Schrader Bluff.

The following summarizes the results of this study.

1. Based on initial screening studies, polymer flooding, gas injection (miscible, immiscible), and in situ combustion have the greatest potential to successfully recover additional oil from Schrader Bluff. However, each of the process screening methods ranked a different EOR method for best choice. Further detailed studies of these processes are warranted.
2. A laboratory study of in situ combustion determined that Schrader Bluff crude oil has favorable burn characteristics. A stable front can be maintained and recovery efficiencies are good. Wet combustion, a process combining in situ combustion with water injection, appears to perform better than dry combustion. A first estimate of air requirements, burn rates, etc., were determined.
3. Results of a simulation study of in situ combustion were consistent with observed behavior in the laboratory.
4. The simulation study suggests that in situ combustion cannot be maintained in the low permeability sands (NE, NF, silt layers).
5. Extinction radius calculations indicated that to implement a successful 80 acre spacing in situ combustion project, a minimum of 5 MMscf/day air injection rate is required.

An in situ combustion field pilot project is recommended to assess the impact of other important factors such as heterogeneity, mineralogy, etc.

2.0 OVERVIEW AND BACKGROUND

This report summarizes the work conducted for the U.S. Dept. of Energy (DOE) in support of a Cooperative Research and Development Agreement (CRADA) project with British Petroleum Exploration, Inc. (BPX). The CRADA is a joint project initially intended to enable BP Exploration to take advantage of the expertise residing at the National Institute for Petroleum and Energy Research as relates to enhanced oil recovery (EOR) technologies. NIPER had ongoing DOE funded projects in the area of EOR, particularly as relates to viscous and heavy oil recovery methods.

2.1. PURPOSE

The purpose of the cooperative work between BP Exploration and U.S. Dept. of Energy is to develop methods to economically recover the viscous oil at Schrader Bluff Milne Point. Historical average initial well productivity of 500 BOPD, coupled with current cost, performance, and fiscal conditions, render the resource uneconomic. The purpose of the agreement is to develop technological innovations to save this resource from abandonment.

2.2. SCOPE

Milne Point, North Slope Alaska, contains in excess of 2 billion barrels original oil in place (OOIP) in the shallow, Late Cretaceous, Schrader Bluff Formation. This resource is part of a large accumulation in excess of 26 billion barrels OOIP overlying many of the deepest producing fields. It consists of a stacked sequence of reservoirs with variable oil/water contacts and variable API gravities, covering over 32,000 acres (50 square miles). It is one of the largest undeveloped accumulations in North America, and with even modest recoveries, reserves must be considered substantial.

A small waterflood pilot presently produces 5000 barrels of oil per day (BOPD) of 19° API oil from 2650 acres in Milne Point. Initial average well productivity of 500 BOPD render the resource uneconomic. Assuming waterflood support, and limiting production to existing producers, modeling indicates recoveries not exceeding 16 percent.

The reservoir and oil characteristics of the Schrader Bluff make it a prime candidate for various enhanced oil recovery (EOR) projects. Among the methods that have passed initial screening are air injection (combustion), various gas floods such as CO₂ or natural gas liquid projects and to a lesser degree, steamflooding. Scoping models of these processes yield possible incremental recoveries from 12-40 percent over those recovered by waterflood.

The primary purpose of the cooperative project is to further evaluate the means to economically recover heavy oil from Schrader Bluff formation in the Milne Point Unit. An economically viable candidate recovery method would be verified in a field pilot test.

2.3. THIS REPORT

This report focuses on evaluation results for in situ combustion in Schrader Bluff. Initially, overall screening processes were applied to determine which of the EOR methods were most appropriate for Schrader Bluff. In situ combustion was among the methods considered potentially favorable and was evaluated further as discussed in this report. Laboratory scale tube runs were conducted followed by simulation sensitivity studies to determine if the kinetic parameters for the crude oil were favorable. Described in this report are the results of the (1)

initial screening, (2) experimental tube runs, and (3) simulation sensitivity studies as related to in situ combustion in Schrader Bluff.

3.0 DESCRIPTION OF SCHRADER BLUFF

The Schrader Bluff consists of Late Cretaceous, near shore marine sand sequences, informally referred to as the "N" and "O" sands. The individual reservoir units are predominantly, very fine to fine grained, moderately sorted, unconsolidated quartz sands with varying amounts of accessory minerals, mainly rock fragments, mica and glauconite. The reservoir units are amalgamations of storm deposits redistributed, for the most part, below wave base. Bioturbation, and burrows are common in some intervals whereas, others display finely laminated bedding, suggesting more rapid sedimentation. Calcareous interbeds are locally common, often associated with concentrations of bivalve debris.

The upper "N" sands consist of multiple reservoir layers varying in thickness between 5 and 15 feet, with permeability's ranging between 5 millidarcies to 5 darcies. The lower "O" sands consist of two main sand bodies that although are finer grained than the "N" sands, are generally more massive and competent. These sands are more continuous and correlative across the North Slope than the thinner, more discontinuous "N" interval. The "O" sands thickness varies between 10 to 35 ft with permeabilities between 10 millidarcies and 1 darcy. The average porosity in all sand units varies between 25 to 28 percent.

The formation dips gently north-northeast at a rate of approximately 70 ft per mile. The resulting monocline is broken by numerous faults of variable displacement, most of which trend north-northeast and progressively downdrop the reservoir to the northeast. Depths range from 3500 feet to 4500 feet. Faults, with throws between 20 to 150 feet compartmentalize the reservoir to some degree. This coupled with stratigraphic discontinuities, can hydraulically isolate individual reservoir units.

The fracture gradient is between 0.66-0.7 psi/ft with an overburden stress gradient of 0.85 psi/ft. The estimated net confining stress is between 1000 to 1300 psi.

Table 1 provides a summary of the reservoir properties for Schrader Bluff Milne Point.

3.1. OIL CHARACTERISTICS

The Schrader Bluff Pool is undersaturated by about 500 psi and correspondingly has no gas cap. The initial average reservoir pressure is 1750 psig at 4000 ft true vertical depth subsea with an average reservoir temperature of 81° F. These pressures are only slightly higher than the local hydrostatic pressures. Currently, the average reservoir pressure is between 1400 to 1750 psi depending on producing fault block.

The hydrocarbon quality varies between the N and O sands, the deeper O sand containing a better-quality crude than the N sand. The N sand oil gravities range from 14° to 19° API with viscosities between 40 and 140 centipois (cP). The oil gravities and viscosities improve in the O sands, oil gravities typically falling between 18° to 21.5° API with viscosities from 30 to 45 cP.

In general, the PVT properties of the Schrader Bluff hydrocarbons bear a resemblance to conventional heavy oil systems, namely:

1. Low API gravities (14-22°)

Table 1. – Summary of reservoir parameters for Schrader Bluff Milne Point, Alaska

Property	Value
OOIP (MMbbl)	1800 (Milne Point Unit)
Recoverable (MMbbl)	250
Produced (MMbbl)	3 (1996)
Areal Extent (Acres)	22,000 (MPU)
Depth (ft)	4300 (3700-4800)
Temperature (°F)	90 (85-100)
Gross Pay (ft)	270 (30-40, individual sands)
Net Pay (ft)	75 (15-20, individual sands)
Porosity (fraction)	0.25 (0.25-0.30)
Permeability (mD)	250-1250 (50-3000)
Swi (fraction PV)	0.35 (0.35-0.55)
FVF (bbl/STB)	1.06
Gravity (°API)	19 (14-21)
Viscosity (reservoir conditions, live oil, cP)	37 (30-600)
GOR (scf/stb)	200 (100-200)
Initial Pressure (psi)	1900 (1900-2000)

2. Low gas oil ratio (GOR 100-200 scf/stb)
3. Low oil formation volume factor (about 1.04-1.08 bbl/stb)
4. High average viscosity (30 to 70 cP at original conditions)

The live oils of the Schrader Bluff are dominated by the C7+ fractions (67 mole percent on average). This corresponds to an exceedingly small amount of C2-C6 intermediate hydrocarbons and suggests high biodegradation. The hydrocarbons contain no hydrogen sulfide, and very little quantities of carbon dioxide or nitrogen. The gas composition is primarily methane. The formation water contains approximately 27,000 ppm total dissolved solids, with an average salinity of 20,000 ppm NaCl equivalent.

In common with fluid systems from shallow and soft sands, the Schrader Bluff hydrocarbon properties exhibit significant variations across sand bodies. This variance is seen vertically, from sand to sand, and laterally within one sand as it is traced down dip. The mapped variance is poorly understood at this time.

4.0 INITIAL SCREENING

Typically, initial production of reservoirs results in only 5-15% recovery of the total petroleum resource. A number of methods have been developed for recovering a higher percentage of oil from the subsurface. The most commonly applied is waterflooding. However, for viscous and heavy oils, the mobility of water is much higher than that of oil and results in premature channeling of injected water through the reservoir. Sweep efficiencies and corresponding recovery efficiencies are poor.

A number of other methods (EOR) are then considered. This section discusses the initial phase of process evaluation. Schrader Bluff reservoir parameters are evaluated for applicability to each of these EOR methods for obvious go-no go situations. Classical screening criteria have been developed previously for EOR methods. These screening criteria are quickly compared to see what processes obviously don't make sense.

Similarly, the DOE have previously developed software predictive models for classic EOR processes. As with the screening criteria, these predictive models are based on the results of previous field projects and are empirically based. To the extent that Schrader Bluff reservoir parameters are similar to these field projects, results are likely to be similar.

Also, a literature search was conducted to identify published and otherwise available information on previously conducted field projects to compare directly. Those with parameters most similar to Schrader Bluff were discussed in the section on Analogous Reservoirs.

Results from any one of these approaches were not considered by itself absolute in deciding which processes warrant further consideration. They are general approaches, and because no two reservoirs are exactly alike results are likely to be inaccurate. More sophisticated simulators are needed to refine estimates of field performance as a function of project design. However, some processes are clearly not going to be very attractive, and these are likely to be so in all of the initial screening approaches conducted and described in this section.

After completing the initial screening of EOR processes as described later in this chapter, the EOR processes considered were ranked in order of decreasing effectiveness, and the most attractive processes were evaluated in more detail. In situ combustion was one of these processes. The results from this investigation are the primary focus of this report and are discussed in subsequent chapters.

4.1. SCREENING CRITERIA

Historically, parameter ranges or screening criteria have been developed to provide engineers a quick first-cut estimate of conditions favorable for a given EOR process. The engineer could take the parameters of a candidate reservoir, compare with the screening criteria, and determine if any of the processes warrant further investigation. Over the years, these screening criteria have been modified according to the preferences of the experts involved. However, the consensus has been that evaluating reservoirs on this basis can be very misleading, and results should not be trusted. Even so, because the process is quick and inexpensive, it is often applied.

4.1.1. Screening Criteria Selection

A more recent review (Taber et al., 1996) summarizes nicely screening criteria for EOR processes. A number of criteria have been published over the years and each is a little different. These may be found in the references of Taber's paper. For the purposes of this study, the

values from Taber et al., 1996, are used. The average reservoir properties in Table 1 are used for Schrader Bluff in this screening criteria comparison.

We have also put together an in-house version of the classical screening criteria. This version should be considered a draft, since it has not received any peer reviews from outside NIPER. However, it is based on published screening criteria with modifications from experts in the different areas of EOR residing at NIPER. This version is comprised of two values for each process: (1) acceptable range, and (2) possible range (given in parentheses in Table 2). Generally, the acceptable range is considered typical of projects economically successful, and the possible range is considered typical of projects technically challenged but still feasible. These are general definitions, but the intent was to differentiate between (1) good candidate, (2) possible candidate with creative engineering, and (3) not a good candidate. These criteria are provided in Table 2.

Table 2. – Modified EOR Screening Criteria

Parameter	Steamflood	Cyclic Steam	In Situ Combustion
API Gravity	8-35 (>4)	8-35	≥10
Oil Viscosity (cP)	10-10,000 (<100,000)	10-10,000 (<100,000)	6-2000 (≤100,000)
So (%)	45-80 (≥30)	50-80 (≥30)	>35
Net Pay (ft)	≥30 (≥15)	≥30 (≥20)	10-100 (≥5)
Depth (ft)	400-4000 (≤6000)	400-3000 (≤6000)	NA
Permeability (mD)	≥250 (≥50)	≥250 (≥50)	≥50
Porosity (%)	≥20 (≥15)	≥20 (≥15)	≥20 (≥10)
Transmissibility	≥50 (≥10)	≥50 (≥10)	≥10 (≥5)
So*Porosity	≥0.1 (≥0.07)	≥0.1 (≥0.07)	≥0.1 (≥0.09)

Parameter	Lean Gas, Miscible	Hydrocarbon, Miscible	Carbon Dioxide, Miscible
API Gravity	38-54 (NA)	24-54 (NA)	≥25 (≥13)
Oil Viscosity (cP)	0.07-0.3 (≤10)	0.04-2.3 (≤10)	≤12 (NA)
So (%)	60-80 (≥30)	≥30 (≥25)	≥30 (≥20)
Depth (ft)	7000-13,000 (≥5000)	4000-16,000 (≤2000)	≥1800 (≥1800)
Reservoir Pressure (psi)	≥4500 (≥3000)	NA*	≥1250* (≥800)

*MMP values can be estimated if additional information is known about crude oil

Table 2 (cont'd)

Parameter	Polymer Flood	Microbial Stimulation	Surfactant/Polymer Flood
API Gravity	NA	≥15 (NA)	≥25 (NA)
Oil Viscosity (cP)	10-115 (≤200)	NA	≤40 (≤100)
So (%)	NA	NA	≥25 (≥15)
Depth (ft)	≤8000 (NA)	≤8000 (NA)	900-6500 (≤9000)
Permeability (mD)	10-2500 (≥5)	≥50 (≥25)	≥50 (≥40)
Porosity (%)	NA	NA	17-25 (NA)
Mobile oil saturation (%)	≥10 (≥5)	NA	NA
Temperature (°F)	≤150 (≤250)	≤175 (NA)	65-200 (≤250)
Salinity (ppm TDS)	≤140,000 (≤200,000)	≤150,000 (NA)	400-150,000 (≤250,000)

Parameter	Alkaline Surfactant Polymer Flood	Steam-Assisted Gravity Drainage
API Gravity	24-40 (≥12)	NA
Oil Viscosity (cP)	2-20 (≤90)	10-10,000 (NA)
Net Pay (ft)	NA	≥50 (≥15)
Depth (ft)	2500-6500 (≥500)	400-3000 (≤6000)
Permeability (mD)	150-1400 (≥20)	NA
Porosity (%)	23-30 (≥20)	≥20 (≥15)
Temperature (°F)	130-160 (≤200)	NA
Salinity (ppm TDS)	4000-46,000 (≤100,000)	NA
Transmissibility	NA	≥50 (≥10)

NA-no limiting parameters provided for specified property

Values in parentheses indicate extreme limit of technical feasibility

4.1.2. Results of Comparison

Based on the classic screening criteria (Taber et al.), the following EOR processes would be acceptable for average reservoir properties: polymer flooding (prefer higher oil saturation),

immiscible gases, in situ combustion, and steam (would prefer higher net pay). The group of micellar/polymer, alkaline surfactant polymer, and alkaline flooding are possible for the lightest oils ($>20^\circ$ API, <35 cP) of Schrader Bluff. Miscible gases (nitrogen, flue gas, carbon dioxide, hydrocarbon) are excluded because of viscosity. Nitrogen and flue gas are also excluded because Schrader Bluff is too shallow (difficult to achieve miscibility). Microbial stimulation was not considered (no criteria provided).

Based on the NIPER modified screening criteria, the following EOR processes would be acceptable for the average reservoir properties: polymer flooding, microbial stimulation, immiscible carbon dioxide flooding, and in situ combustion. Other possible candidate processes that test the limits of conditions include: cyclic steam stimulation, steamflood, surfactant/polymer flood, alkaline surfactant polymer flood, and steam assisted gravity drainage (SAGD) processes. Lean gas and hydrocarbon miscible processes are rejected because of high fluid viscosity. Depth is also a problem for lean gas (difficult to achieve miscibility).

Sensitivity to the above processes was also tested for the range of reservoir parameters indicated in Table 1. For API gravity, the microbial stimulation process is challenged by the lower densities ($\leq 14^\circ$). Similarly, the higher viscosities (600 cP) eliminates polymer flood, surfactant/polymer flood, and alkaline surfactant polymer flood. These are values corresponding to the Ugnu sands of Schrader Bluff.

The lower values of net pay challenges the steam stimulation processes (steamflood, cyclic steam, and SAGD). If multiple sands are flooded simultaneously, heat efficiency would be improved reducing the adverse impact of thin sands. Similarly, depth strongly affects these processes. The shallowest (3700-3900 ft) depths reduce the heat losses from the wellbore and improves the chances of success. The impact of deep permafrost is not accounted for, however.

4.1.3. Summary

It is recognized that evaluating reservoirs based on screening criteria does not consider all factors and that results may not be valid. They represent only a first attempt at identifying better candidate processes and should be considered tentative. In this report, these results are being compared with other analyses before making any final assessments.

With this in mind, screening criteria evaluations suggest that polymer flood, immiscible gases, microbial stimulation, and in situ combustion appear to be the more promising EOR processes. Steam injection appears possible for the shallower and thicker sands. Injection of surfactant systems (surfactant/polymer, alkaline surfactant polymer) are limited to the lower viscosity oils (excluding Ugnu). Injection of miscible gases (nitrogen, flue gas, carbon dioxide, hydrocarbon) are not recommended for Schrader Bluff because of the higher oil viscosity. Miscibility will be most easily achieved for enriched carbon dioxide and hydrocarbon systems.

Some of the factors not accounted for in this analysis include the impact of the permafrost on steam injection, availability of gases for gas injection, transportation costs of chemicals to the North Slope, size of injection pattern (i.e., 40 acres), and harsh surface environment for chemical injection processes (including polymer flood). Furthermore, the familiarity of gas injection processes and availability of NGL's due to constrained shipping through the TAPS improves the chances of success of gas injection processes over the average case.

4.2. PREDICTIVE MODELS

The DOE has developed and makes available predictive models (they may be downloaded from <http://www.npto.doe.gov/Software/softindx.html>) for quickly estimating production of oil using certain EOR methods. Models available include steamflood, in situ combustion, polymer flood, chemical flood, carbon dioxide miscible flood, and basic waterflood models. These

models were used for predicting the performance of EOR processes in Schrader Bluff. In addition to these processes, hot waterflood was predicted by using the steamflood model and setting the steam quality to near zero. Immiscible gas (carbon dioxide, hydrocarbon) floods were predicted by using the gas flood models and ensuring that the viscosities were high enough (creating an immiscible condition).

While quick and convenient, these methods of predicting production performance are of limited value. As with screening criteria, they are empirically based on previously conducted field projects. Provided the field being tested is similar to those used in developing the predictive models, the results are likely to be representative. However, these models are relatively simple, and this approach should be considered with caution. Some of the reservoir parameters are not modeled. In our study, we used predictive model studies to compare with screening criteria and analogous reservoirs to develop a consensus of relative ranking for various EOR processes.

4.2.1. Results

There are 2 main oil zones in Schrader Bluff, labeled "N" and "O" sands. The reservoir properties between these two zones are quite different. Within each of these major zones are a number of sands or sand lenses having relatively similar properties. For the purposes of this study, a better sand was selected for each zone and properties for these sands are given in Table 3.

Table 3. – Reservoir properties of selected sands in Schrader Bluff

Property	NB Sand	OA Sand
Depth (ft)	4285	4410
Initial Pressure (psia)	1924	1981
Initial Temperature (°F)	89	93
Net Thickness (ft)	15.5	20
Gross Thickness (ft)	29	30
Permeability (mD)	1828	356
Porosity (fraction)	0.30	0.27
Initial Oil Sat. (fraction)	0.62	0.54
Initial Water Sat. (fraction)	0.38	0.46
Oil Gravity	16°	21°
Dead Oil Viscosity (cP)	500	40
Oil FVF (bbl/STB)	1.04	1.05
Total developed area (acres)	640	640
Total Producing Wells	16	16

Each of the EOR methods were evaluated and compared. Figure 1 shows production over a 10 year period. Clearly, the in situ combustion process did the best. The performance of the surfactant/polymer process was the worst. The others were intermediate between these two processes and similar to basic waterflooding. The large pattern spacing is likely to have contributed to the poor performance for steam, hot water, surfactant, and polymer floods. The heat loss rates (thin sands, deep reservoir, thick permafrost, etc.) also contributed to poorer performance for steam and hot water floods. Very little improvement was seen from hot waterflood over the normal waterflood process.

Figure 1. – Comparison of EOR methods from DOE Predictive Model Study

As mentioned previously, the DOE predictive models are empirically based to enable quick determinations of performance. However, some simplifications are needed in developing these models. As a result, results may be misleading when these simplifications ignore factors relevant to Schrader Bluff and different from the average properties derived for the models.

One common simplification is reservoir heterogeneity. This predictive model study assumed a homogeneous reservoir with homogeneous oil properties as defined in Table 3. This is obviously not the case, and heterogeneities in the reservoir are certain to affect the ultimate sweep efficiencies, overall recoveries, etc. In situ combustion is particularly sensitive to this

factor and the predictions may be overly optimistic. Reservoir engineers often have a difficult time predicting where in situ combustion fronts are likely to move and what the sweep efficiencies are likely to be.

Another issue is that a number of sands actually exists in Schrader Bluff with varying sand and oil properties. These variations are not accounted for in the predictive model study, as single layer systems were modeled.

In addition, these models were developed in the early 1980's. Consequently, the results on which the empirical correlations were based do not include anything conducted after about 1982 (1974 for in situ combustion). Since then, a number of developments were made and performance predictions improved. More up to date simulation models would be needed to incorporate relatively newer improvements in project design and process performance.

Permeability effects (relative permeability tables) are not incorporated in the steamflood model, although this property is incorporated in waterflood and polymer flood predictions. Adsorption in the chemical flood is not well modeled, either. The effects of salinity and temperature are not modeled, and of course, the adsorption isotherm itself was not determined for a specific surfactant. Typical literature values were used.

Gravity override and channeling effects are not incorporated in the steamflood model. Results are likely to be poorer than predicted. The gas injection models are based on first contact miscibility. This recovery mechanism rarely occurs in the field, but often is used to approximate the multiple contact miscibility that more commonly occurs.

Finally, as already mentioned the immiscible recovery process (carbon dioxide, hydrocarbon, etc.) and the hot waterflood process were approximated by controlling the input parameters. However, the miscible gas and steamflood models were not specifically designed for the immiscible and hot waterfloods, and the accuracy of these predictions are likely to be diminished.

Therefore, the predictive models are used to provide a quick and simple prediction of the EOR recovery processes in Schrader Bluff. These results should be compared with other screening processes before selecting the more promising methods for further study. These results should not be taken out of context nor accepted without further verification by other analytical and comparative studies.

4.2.2. Summary

In summary, the DOE predictive models showed that in situ combustion gave the highest recovery of the processes evaluated. Surfactant/polymer injection produced oil very poorly. The remaining processes (polymer, immiscible carbon dioxide, steamflood, and hot waterflood) were similar in performance giving intermediate results. These results should not be accepted in isolation, but compared with other studies to provide a more general assessment of EOR process potential in Schrader Bluff.

4.3. ANALOGOUS RESERVOIRS

The purpose for conducting a literature search of results published on similar projects is straightforward. In addition to identifying which processes are applicable to reservoirs similar to Schrader Bluff, one also has information on how those processes were best applied, and on what the expected production performance is likely to be. To the extent that the reservoirs are similar, results are likely to also be similar and one need not rely on inaccuracies of other predictive methods. Sophisticated simulators are very effective when all the input parameters are known. But this is never the case, and assumptions are always needed.

Unfortunately, 2 reservoirs are never exactly alike and comparison of analogous reservoirs is likewise an approximation. Furthermore, Schrader Bluff presents some very differentiating conditions. Due to the location in the Arctic circle, the temperature gradient is quite different from most reservoirs produced outside of Alaska. Because of this fact, no analogous reservoir was found that conformed reasonably close to all relevant reservoir parameters, and where some EOR process was applied. As a result, analogous reservoirs were sought for different sets of reservoir parameters, depending on the EOR process and its relative importance to the reservoir temperature gradient.

4.3.1. Information Sources

The following primary sources were reviewed:

1. Oil & Gas Journal EOR reports (1986-1996)
2. NIPER Heavy Oil Database
3. DOE EOR Database
4. Literature Reviews on EOR Processes (technical publications, government reports)
5. Technical Papers (SPE, etc.)
6. SIMTECH Report to BP Exploration

Table 1 provides a summary of reservoir parameters encompassing most of Schrader Bluff and uses the basis of comparison. Two separate sets of Screening parameters (sets A and B) were selected for identifying analogous reservoirs. Set B excluded steam, hot water, and miscible gas processes because depth is a critical parameter for these processes. The screening parameters are summarized in Table 4. Reservoirs were considered analogous if complying with either Set A or Set B criteria. Any reservoir not complying with all of Screening Set A or Screening Set B as described, was excluded from the final list.

Table 4. – Screening Parameter Ranges for Analogous Reservoirs

Parameter	Screening Set A	Screening Set B
Depth (ft)	3800-5000	NA
API Gravity*	12°-23° (OR viscosity criteria)	12°-23° (OR viscosity criteria)
Viscosity * (cP, reservoir conditions)	15-1000 (OR density criteria)	15-1000 (OR density criteria)
Permeability (mD)	>50	>50
Temperature (°F)	NA	80-100
Net Pay (ft)**	10-30	10-30

*Reservoirs were considered to apply when either the viscosity or API Gravity criteria was satisfied. For example, a reservoir would be included if viscosity were 900 cP, even if API gravity was 10°.

**Not applied rigorously. Excluded reservoirs on this basis when information was available. When net pay was not available, reservoir was assumed to comply.

4.3.2. Results

A number of analogous reservoirs were found that fit the criteria in Table 4, and a number of EOR processes were applied in these reservoirs. They include:

1. Polymer floods, 53 projects
2. In situ combustion, 11 projects
3. Carbon dioxide immiscible floods, 8 projects
4. Steamfloods, 8 projects
5. Alkaline floods including Alkaline Surfactant Polymer floods, 7 projects
6. Micellar/Polymer floods, 6 projects

Table 5 summarizes the number of projects considered economically successful and not successful, as stated in Oil & Gas Journal. As can be seen in the table, at least 1 project was successful and 1 project was not successful for each of these processes. Based on this cursory review, one cannot quickly dismiss any of these processes for Schrader Bluff.

Table 5. – Number of analogous reservoirs by process and status

EOR Process	Projects Successful	Projects Failed	Status Unknown	Total No. Projects
Polymer	22	7	24	53
In Situ Combustion	4	5	2	11
CO2 Immiscible	3	5	0	8
Alkaline	2	1	4	7
Micellar/Polymer	1	3	2	6

If the relative chance of success can be inferred by the number of projects tried, one would conclude that polymer floods are most likely to be successful. It was tried most often. Indeed, the proportion of successful to not successful projects are the greatest for this approach. However, the status for a number of projects were not known, and if inferred that the unknowns are more likely to be unsuccessful than successful (one is more likely to advertise a successful project than an unsuccessful one), the odds of success may not be any better for polymer floods.

The details of the reports associated with these projects were reviewed in a bit more detail. From this evaluation, the following conclusions were obtained.

Polymer Flood

- Many projects were identified from the analogous reservoirs that were considered economically successful with polymer floods.

- Polymer flooding improves the recovery rate by improving sweep efficiency and mobility ratio of waterflood—a particular problem for more viscous crude oils like that of Schrader Bluff.
- Schrader Bluff reservoir conditions appear to present no major barriers for this method of enhancing production from a technical perspective. Unique factors associated with the Arctic environment are not emphasized in this analysis, however, and may present unique challenges. For example, preparing a polymer solution at sub-zero temperatures would require additional equipment not typical of the examples found in the literature.

In Situ Combustion

- Some economically successful projects were found among the analogous reservoirs.
- Technically, Schrader Bluff reservoir parameters do not appear to present any major technical barriers. However, compartmentalization is particularly detrimental to poorly designed in situ combustion projects and was not included in the screening parameters. The issue of communication between the different sands is also a consideration that needs to be evaluated, but was not included in this cursory review. Therefore, the "lack" of major technical barriers needs to be more fully evaluated for in situ combustion.
- Finally, operational risks not considered in this screening are likely causes of economic failure in other cases. This factor must be considered for all in situ combustion projects

Gas Flooding

- Of the different types of gas injection, only carbon dioxide immiscible processes were found for analogous reservoirs to Schrader Bluff.
- Improved recoveries result from viscosity reduction, fluid swelling, and pressure maintenance for immiscible gas injection processes.
- Fluid swelling capacity is reduced in crude oils containing solution gas, which is the case for Schrader Bluff. More detailed simulation studies would be needed to estimate the recovery potential.
- Availability of a cheap source of gas is critical to economic success. At this time a cheap source of carbon dioxide is not available on the North Slope.

Steam Injection

- Some projects were found to be economically successful. These were all cyclic injection processes and did not include any steamflood (drive) across the pattern from injector to producer.
- While not reported, it is suspected that the successful projects were in reservoirs with pay zones much thicker than those typical of Schrader Bluff.
- Insulated tubing is generally required for reservoirs at depths exceeding 4000 ft. This is particularly so with Schrader Bluff because of the thick permafrost that exists. Insulated tubing adds additional cost to well completions.
- Large pattern sizes typical of Schrader Bluff (>10 acres) are likely to present a major barrier to economic success for any non-cyclic process, including that of steamflooding.

Alkaline Processes
(Alkaline, Alkaline/Surfactant Polymer, etc.)

- A few alkaline projects were found in Schrader Bluff analogous reservoirs. Two of these were considered economic successes.
- Very little detail is available on these projects. Very little can be said about these projects in Schrader Bluff type reservoirs.

Micellar/Polymer Floods

- A few micellar/polymer projects were found in Schrader Bluff analogous reservoirs. One of these was considered an economic success.
- Anticipated difficulties with this process includes high chemical costs and increased risks with large pattern spacing (>10 acres).

4.3.3. Summary

Based on a review of analogous reservoirs,

1. The process having the greatest potential for success is polymer flooding. All of the processes listed have some chance of success demonstrated in each case by at least one successful project in Schrader Bluff analogous reservoirs.
2. Based on a review of analogous reservoirs, those processes least likely to succeed include: micellar/polymer floods, alkaline injection processes, and steamfloods. Note that unlike steamfloods, cyclic injection of steam has worked in some analogous reservoirs.
3. Some of the unique circumstances of Schrader Bluff were not considered. These could strongly influence the final decision. Severe surface operation conditions, high shipping costs, high well completion and maintenance costs, geological compartmentalization, etc., all adversely impact ultimate production costs and the chances of economic success for EOR processes.
4. Microbial injection was not identified in any of the analogous reservoirs. Use of indigenous species has not been ruled out as a possibility for Schrader Bluff. It is uncertain whether any of the classical approaches of microbial injection would be successful.
5. Although injection of enriched hydrocarbon processes were not identified for any of the Schrader Bluff analogous reservoirs, this process has some unique advantages on the North Slope. Production engineers are familiar with this process. NGL's are available on the North Slope with unique economic advantages, because of the constrained transportation of it to other parts of the world. Finally, its absence in analogous reservoir cases is more the result of being limited to unique circumstances throughout the world where it is successfully applied (including the north slope of Alaska) than to the reservoir conditions defined in this review. Further investigation is warranted for this process.

4.4. INITIAL SCREENING SUMMARY

An initial screening process was conducted on Schrader Bluff to determine what EOR processes are obvious choices for further investigation. Other processes with modifications may be suitable, but would only be considered after more detailed studies suggest that the obvious first choices are unlikely to be economically successful.

Three approaches were taken in this initial screening evaluation of Schrader Bluff. Classic screening criteria were applied to Schrader Bluff reservoir properties. Simple DOE Predictive Models were used to compare the recovery potential of certain EOR processes. Finally, a search for reservoirs with properties similar to Schrader Bluff was made, where one or more EOR processes were applied. While each of these screening methods provided different types of answers, the following generalizations are made.

1. No one process was considered best by all three process screening methods.
2. Screening criteria suggested that polymer flood, immiscible gas injection, microbial stimulation, and in situ combustion processes may be applicable for Schrader Bluff.
3. DOE Predictive models indicated that in situ combustion had the greatest recovery potential for Schrader Bluff. All other processes were marginal or not promising.
4. Search for analogous reservoirs did not find any reservoirs comparable to Schrader Bluff where an EOR process was applied. However, by selecting key parameters examples were found for most of the EOR processes being tried at least once. The most commonly tried process was polymer flooding, with many of these projects being economically successful. Those processes found least likely to succeed include: alkaline processes, micellar/polymer processes, and steamfloods (excluding cyclic steam).
5. Miscible gas injection was not identified as a viable process by these screening methods. This is primarily because miscible recovery for more viscous hydrocarbons is usually quite expensive, and the poor mobility ratios are likely to result in poor sweep efficiencies (low ultimate recoveries). However, the unique circumstances for Schrader Bluff on the Alaska North Slope are sufficient to warrant further study of this process.
6. Three processes were recommended for further study: polymer flooding, gas injection (miscible, immiscible), and in situ combustion. The results of the in situ combustion study are outlined in the remaining sections of this report.

5.0 IN SITU COMBUSTION TUBE RUNS

5.1. BACKGROUND

In situ combustion is a sophisticated process where some oil is burned in situ to generate heat and secondarily steam or other gases. Heat is known to be very effective at reducing oil viscosity, and the application of heat is a very effective method of enhancing the production rates and overall recoveries of more viscous crude oils. When done properly, this process can be extremely efficient. Furthermore, because the heat is generated in situ, heat is not lost from the wellbore and surrounding formations behind the front as it would be with the injection of steam generated from the surface. Therefore, this process is not so severely limited by reservoir depth, reservoir thickness, etc., and has unique advantages over other enhanced recovery methods.

However, in situ combustion also has unique limitations that need to be considered. For example, the burning characteristics of the crude oil can strongly affect the results. These characteristics are not easily predicted and need to be tested for each reservoir in order to properly design the project. Several of the most critical factors in a in situ combustion process is the fuel formation, fuel combustion, and oil mobilization characteristics of the particular crude oil being considered. Laboratory tests have been developed to estimate the relative characteristics of individual crude oils, and results of these tests are the subject of this section.

The oxidation process is actually quite complicated. When a stable process is sustained, one can divide the front into several zones. Just ahead of the burning front is the zone where light hydrocarbons and water condense and heat up reservoir fluids. It is in this zone that much of the enhanced recovery mechanisms are active in producing oil. The next zone is at a higher temperature and is where light hydrocarbons are vaporized, heavier hydrocarbons are cracked into light hydrocarbons, and a layer of coke from the heaviest hydrocarbons is formed onto the rock surface. The proportion of these components is critical to the design of the flood (air requirements, front propagation rates, oil recovery efficiencies, etc.). The next zone is the burn zone where the coke layer is oxidized or reacted with the injected air or oxygen enriched air. Finally, behind the burn zone is a hot relatively clean zone. In a wet combustion process, water is simultaneously injected with air to capture this heat and transfer it to the vaporization zone for a more efficient heat propagation process.

The temperature of the oxidation process can also affect the overall performance. Two primary temperature ranges are often observed, although the actual temperature range as a function of oxygen uptake varies from oil to oil. Low temperature oxidation (LTO) is characterized by a burn temperature often below 400° F. Other characteristics of this process include production of partially oxygenated hydrocarbons, very little carbon oxides (carbon dioxide, carbon monoxide), and coking products. For heavy crude oils extended LTO results in increased viscosity and density oils, increased trapped oil, inefficient oxygen utilization, and very little enhanced oil production. For light crude oils, oil production tends to be less adversely affected at LTO conditions.

High temperature oxidation (HTO) is characterized by a burn temperature usually over 650° F. Other characteristics of this process include primarily carbon oxide products with water, reduced oil viscosity and density, efficient oxygen utilization, and very good oil recovery properties in the reservoir. To maintain the burning front at this temperature range, sufficient oxygen flow must be present. Unfortunately, the engineer needs to know what this value is prior to conducting the field project, because real-time monitoring of the oxidation process in the field is very expensive.

For example, as the front moves away from the wellbore local air flow will decrease (radial expansion) and the corresponding combustion rate will slow down. If the injection rates are too low, the initial HTO process will stop and the LTO will dominate. However, the operator will not know this is occurring for some time because the oxygen will continue to be consumed.

Three experiments were conducted at U. Calgary on Schrader Bluff oil and rock. These included 2 tube runs and 2 ramped temperature oxidation measurements. The details of these experiments are provided in the final report by U. Calgary and referenced in the bibliography. Only a summary of the studies are provided here.

Oil from Schrader Bluff was used as received by U. Calgary. The rock material was prepared according to their standard procedure (cleaned, crushed, fired, sieved) and packed in the in situ combustion core holder. Brine was prepared in the laboratory to represent the brine composition of Schrader Bluff. After being packed, the brine was injected into the sand pack, and was then displaced by the oil. Once prepared, the in situ combustion runs were conducted.

Run 1 was conducted with an air injection rate of 239 l/hr. No water was injected with this run. Run 2 was conducted with the same air injection rate, but was accompanied by water injection (starting 1 hr. after ignition with air) at a rate of 233 g/hr. Temperature profiles, front progression rates, and off gases were monitored for each run.

5.2. IN SITU COMBUSTION TUBE RUN NO. 1

The primary information of interest from laboratory tube runs for specified operational conditions include: general burning characteristics, fuel requirement, air requirement, air/fuel ratio, peak combustion temperature, and hydrocarbons recovered from swept zone. However, because many of the operational conditions of a laboratory experiment of this type is not scaled to field conditions, results should be considered qualitative. Certain combustion characteristics of the oil tested in the laboratory can be considered representative of a field operation.

For Schrader Bluff, a stable burn was maintained as expected at the designed injection rate. The coreholder is divided into 12 zones (6 in long) with 12 thermocouples to monitor the front progression. When the front reached zone 8, the temperature never reached the optimal range and it appeared that the burn began to die out. At 14 hr into the experiment, it was evident that a stable burn could not be reestablished and the experiment was terminated.

Upon inspection of the system after the experiment was concluded, it was found that the high pressures involved in the experiment resulted in the crushing of the downstream portion of the tube, and combined with high heat losses resulted in the quenching of the fire front. Even so, some results were obtained and are summarized in the following table.

Table 6. - Summary of results for Run 1

Core Porosity	0.436	Pre-Heat Temp.	89° F
Core Permeability	4.3 Darcy	Peak Temperature	1146° F
Pressure	1800 psig	Displ. Front Velocity	0.61 ft/hr
Inj. Air Flux	100 scf/ft ² hr	Air Requirement, Stabilized	166 l(ST)/l
Water/Air Ratio	0	Oxygen Requirement, Stabilized	35.7 l(ST)/l
Oil Sat., Initial	0.588	Fuel Requirement, Stabilized	1.04 lbm/ft ³
Water Sat., Initial	0.412	Air/Fuel Ratio Stabilized	160 scf/lb
Overall recovery	0.845*	Oxygen Utilization, Stabilized	0.983

*Not comparative with Run 2, since only 60% of the core was burned.

5.3. IN SITU COMBUSTION TUBE RUN NO. 2

The primary difference between this run and run 1 was the designed injection of water after a stable burn was established. The primary purpose of injecting water is to carry more of the heat forward from behind the front to the oil ahead of the front via steam generation. Air is very inefficient in heat transfer processes relative to water. Injection of brine was initiated 0.5 hr after the burn was initiated. The test was terminated at the normal time of 15 hr. The overall results with Schrader Bluff oil were very favorable for water injection.

Also, learning from the first run, care was taken to temporarily reduce injection rates (air, water) when system pressures reached high levels. For example, water injection was stopped for about 5 hr (starting about 0.5 hr. after water injection was started), but once resumed was continued for the remainder of the run. The lower core permeability was also a factor leading to high system pressures.

Table 7. - Summary of results for Run 2

Core Porosity	0.426	Pre-Heat Temp.	89° F
Core Permeability	0.5 Darcy	Peak Temperature	1053° F
Pressure	1800 psig	Displ. Front Velocity	0.48 ft/hr
Inj. Air Flux	100 scf/ft ² hr	Air Requirement, Stabilized	210 l(ST)/l
Water/Air Ratio	0.98 kg/l	Oxygen Requirement, Stabilized	41.2 l(ST)/l
Oil Sat., Initial	0.582	Fuel Requirement, Stabilized	1.40 lbm/ft ³
Water Sat., Initial	0.418	Air/Fuel Ratio Stabilized	151 scf/lb
Overall recovery	0.921	Oxygen Utilization, Stabilized	0.985

5.4. RAMPED TEMPERATURE OXIDATION (RTO) CHARACTERISTICS

In order to assess the kinetic properties of the combustion process of a specified crude oil, a ramped temperature oxidation (RTO) test was conducted (see references for more details). The core and fluids are prepared as described in the tube run experiments. However, a separate core is prepared absent of fluids. As air is simultaneously injected into the systems, the external temperature is gradually increased on both systems. Based on thermal comparisons of the two core systems, exothermic and endothermic reactions can be detected and at which temperatures these processes are initiated. As with the tube runs, fluids are monitored for both cores for injection and production rates.

Two ramped temperature oxidation tests were performed on re-constituted cores from Schrader Bluff. The first was performed at an air injection flux of 119 scf/ft²hr and was heated to a maximum heater temperature of 662° F. The second was performed at a flux of 45 scf/ft²hr and was heated to 500° F. All other operational parameters were kept the same.

The maximum peak temperature recorded for run 1 ranged from 660° F to 896° F (HTO). The range for run 2 was 555° F to 570° F (LTO). About half of the oil was produced in each case and the other half consumed as fuel. However, run 2 showed evidence of additional coke remaining after the burn. Inefficient burns are expected for LTO processes. Similarly, the oxygen requirement, oxygen/fuel ratio, and overall oxygen utilization values were less favorable for run 2.

The main conclusions were:

1. Both tests exhibited stable and well defined oxidation zones. This was a positive observation and suggests that the Schrader Bluff oil would exhibit stable combustion performance in a field project.
2. Effective mobilization of the oil was achieved when the oxidation zone was operating in either the low- or high-temperature range, although results suggested that oxygen utilization was less in the LTO range. This is also good, suggesting that the field performance may be less sensitive to air injection rates that is typical of heavier crude oils.

5.5. SUMMARY

The laboratory study based on tube runs and ramped temperature oxidation runs suggest that the burn characteristics of Schrader Bluff crude oil is very favorable. Stable burn fronts can be maintained with good recovery efficiencies. Although less favorable, oil can be mobilized and produced in the LTO range making the production operations less sensitive to oxygen injection rates. Furthermore, injection of water as part of a wet-combustion process showed improved production performance and should be considered for economic benefits.

A more detailed simulation study of in situ combustion oil recovery process for Schrader Bluff is recommended.

6.0 IN SITU COMBUSTION SIMULATION STUDIES

6.1. BACKGROUND AND PURPOSE

With the limitation energy resource and increased difficulty of discovering new reservoirs, the greater demand for crude oil has emphasized the need for enhanced recovery method to produce the crude economically in known reservoirs. Schrader Bluff, the largest of Milne Point's (North Slope Alaska) three productive oil bearing formations, is the eastern extension of West Sak formation. It contains in excess of 2 billion bbl of original oil in place (OOIP) with API gravities of 14-20°. This resource is part of a large accumulation of more than 26 billion bbl OOIP overlaying many of the deepest producing fields in Alaska. It consists of a stacked sequence of reservoirs with variable oil/water contacts and variable API gravities. It covers more than 32,000 acres and is one of the largest undeveloped accumulations in North America, which makes it substantial even with modest recoveries.

Commercial production from Schrader Bluff began in March 1991. Waterflood was initiated in four different fault blocks in 1992 and initial production averaged approximately 350 BOPD per well, which is low by North Slope standards and render the resource uneconomic. A multi-pronged approach dealing with productivity, drilling, facilities costs and performance improvements is underway to save this resource from abandonment.

The Schrader Bluff reservoir consists of two sand bodies, namely the lower Ugnu (N-sands) and the West Sak (O-sands). The upper 'N' sands consist of 6 layers of varying thickness (5 to 15 feet) and the lower 'O' sands consists of two main layers with various thickness between 10 to 35 feet and are generally more massive and competent than the 'N' sands. 'O' sands are more continuous and correlative across the North Slope than the thinner, more discontinuous 'N' interval. The permeabilities for 'O' sands are between 10 mD and 1 darcy, while for 'N' sands are 5 mD to 5 darcies. The average porosity in all sand units varies between 25 to 28 percent.

These reservoir and oil characteristics of the Schrader Bluff make it a prime candidate for various enhanced oil recovery (EOR) projects. Predictive model screening was performed with respect to thermal, gas, and chemical processes. Results indicated that in-situ combustion (dry or wet) was one of the more promising EOR methods to improve the heavy oil recovery from this field.

The purpose of this study was to perform detailed sensitivity studies to understand the effects of various reservoir, fluid and operational parameters on project performance. The Computer Modeling Group's (CMG) three-phase multi-component thermal and steam additive simulator STARS was employed.

6.2. MODEL DESCRIPTION AND DATA INPUT

Oil was divided into two components, light (CO_2 , C_1 - C_{16}) and heavy fractions (C_{17} - C_{36+}). The simulator modeled three phases: solid (coke), liquid (water, heavy oil, light oil) and gas (oxygen and inert gas) for a total of six components. Inert gas included all noncondensable gases other than oxygen. Its property was assumed to be that of nitrogen except molecular weight was assigned a value between that of nitrogen and carbon dioxide. The oil properties were molar average values derived from the individual component properties. The critical pressure, critical temperature, molecular weight, and component formula for light oil were 526 psi, 372° F, 82, and $\text{C}_{5.7}\text{H}_{13.6}$, respectively, while that for heavy oil were 158 psi, 1092° F, 409 and $\text{C}_{29.1}\text{H}_{60.24}$, respectively. Other properties, such as thermal expansion, fluid compressibility, and fluid heat capacity, were also reported in Table 8.

Table 8. – Properties of Heavy and Light Fractions

	Heavy Fraction	Light Fraction
Molecular Weight, lbm/lbm mol	409	82
Critical Pressure, psi	158	526
Critical Temperature, °F	1092	372
Gas-Phase Heat Capacities, $C_p = A + BT + CT^2 + DT^3$, Btu/(lbm mol-°F)		
A	-8.14	-1.89
B	0.549	0.1275
C	-1.68e-4	-3.9e-5
D	1.98e-8	4.6e-9
Compressibilities, psi ⁻¹	5e-6	5e-6
Thermal Expansion Coefficient, °F ⁻¹	1.496e-4	2.839e-4

Four chemical reactions were included in the simulation. They were cracking of heavy oil and oxidation of heavy oil, light oil, and coke. The stoichiometries were derived for the hydrogen, carbon, and oxygen separately, as shown in Table 9.

Table 9. – Four Chemical Reactions

Reaction Type	Reaction Equation
Cracking	$C_{29.1}H_{60.24} \rightarrow 2.754 C_{5.7}H_{13.6} + 13.4 CH_{1.7} + 2.00 \times 10^4 \text{ Btu/lbmol}$
Heavy Oil Burning	$C_{29.1}H_{60.24} + 44.16 O_2 \rightarrow 30.12 H_2O + 29.1 CO_2 + 3.49 \times 10^6 \text{ Btu/lbmol}$
Light Oil Burning	$C_{5.7}H_{13.6} + 9.1 O_2 \rightarrow 6.8 H_2O + 5.7 CO_2 + 9.48 \times 10^5 \text{ Btu/lbmol}$
Coke Burning	$CH_{1.7} + 1.425 O_2 \rightarrow 0.85 H_2O + CO_2 + 2.25 \times 10^5 \text{ Btu/lbmol}$

Note: Reaction rate is proportional to $A \exp(-E/RT)$

For combustion of the light oil, heat of reaction was assumed to be 948,000 Btu/lb-mol of oil, while that for the heavy oil was assumed to be 3,490,000 Btu/lb-moll. For the coke, heat of reaction was assumed to be 225,000 Btu/lb-moll of coke. These are average values typically found in published literature.

The reservoir was modeled based on a 36-layer model developed by BPX-Alaska. In our study, 36 layers were lumped into 14 layers. Average values for initial water saturation, oil saturation, porosity, permeability, and compressibility were calculated based on the 36 layer model. In each layer properties are constant and pertinent data of the 36 and 14 layer properties, such as initial

water and oil saturation, together with pay zone thickness, permeability, porosity, and compressibility are documented in Tables 10 and 11.

Table 10. – Schrader Bluff Reservoir 36-Layer Model Description

Zone	36-layer Model							14-Layer Model
	Layer	Layer Thickness, Dz, ft	Net-to-Gross multiplier, netgrs	Porosity, Por	Compressibility, Cr	Water Saturation, Sw	X-direction Permeability, Kx, md	layer
NA	1	4	0.671	0.304	6.2E-5	0.5235	234	1
	2	4	0.762	0.319	5.6E-5	0.5235	445	
	3	4	0.963	0.306	4.6E-5	0.5235	343	
	4	4	0.42	0.235	3.8E-5	0.5235	23	
Silt	5	10.11	0.08	0.24	3.18E-4	1	0.7	2
NB	6	4.21	0.633	0.24	3.3E-5	0.4283	51	3
	7	4.21	0.76	0.3	5.0E-5	0.4283	261	
	8	4.21	0.76	0.324	5.2E-5	0.4283	501	
	9	4.21	0.76	0.316	3.8E-5	0.4283	409	4
	10	4.21	0.62	0.29	2.8E-5	0.4283	46	
	11	4.21	0.61	0.221	3.6E-5	0.4283	6	
Silt	12	11.24	0.08	0.23	1.96E-4	1	0.7	5
NC/ND	13	1.07	0.923	0.304	4.6E-5	0.4	292	6
	14	1.07	0.624	0.328	6.7E-5	0.4	312	
	15	1.07	0.76	0.31	5.2E-5	0.4	358	
	16	1.07	0.868	0.231	2.6E-5	0.4	7	
Silt	17	9.43	0.08	0.24	2.04E-4	1	0.7	7
NE	18	48.01	0.549	0.262	2.04E-4	0.5511	20	8
NF	19	36.72	0.08	0.24	2.04E-4	0.5073	0.7	9
OA	20	3.75	0.687	0.238	5.5E-5	0.398	33	10

Table 10 (cont'd)

Zone	Layer	Dz, ft	netgrs	Por	Cr	Sw	Kx, md	layer
	21	3.75	0.946	0.315	6.7E-5	0.398	417	
	22	3.75	0.505	0.183	3.3E-5	0.398	27	
	23	3.75	0.946	0.262	5.0E-5	0.398	111	
	24	3.75	0.964	0.306	5.6E-5	0.398	246	11
	25	3.75	0.837	0.279	5.0E-5	0.398	159	
	26	3.75	0.711	0.225	3.1E-5	0.398	63	
	27	3.75	0.883	0.244	3.3E-5	0.398	84	
Silt	28	31.83	0.07	0.22	3.5E-4	1	0.7	12
OB	29	3.84	0.882	0.262	4.6E-5	0.4571	75	13
	30	3.84	0.943	0.285	5.3E-5	0.4571	135	
	31	3.84	0.941	0.29	4.5E-5	0.4571	186	
	32	3.84	0.941	0.307	4.6E-5	0.4571	279	
	33	3.84	0.836	0.274	4.0E-5	0.4571	129	14
	34	3.84	0.08	0.217	3.7E-5	0.4571	7	
	35	3.84	0.08	0.228	3.5E-5	0.4571	10	
	36	3.84	0.941	0.257	4.3E-5	0.4571	75	

Table 11. – Schrader Bluff Reservoir 14-Layer Model Description

Zone	14-Layer Model						
	Layer	Dz, ft	netgrs	Por	Cr	Sw	Kx, md
NA	1	16.00	0.704	0.298	5.133E-5	0.5235	296.90
Silt	2	10.11	0.080	0.240	3.180E-4	1.0000	0.70
NB	3	12.63	0.718	0.291	4.571E-5	0.4283	283.98
	4	12.63	0.663	0.279	3.427E-5	0.4283	172.37
Silt	5	11.24	0.080	0.230	1.960E-4	1.0000	0.70
NC/ND	6	4.28	0.794	0.290	4.610E-5	0.4000	233.81
Silt	7	9.43	0.080	0.240	2.040E-4	1.0000	0.70
NE	8	48.01	0.549	0.262	2.040E-4	0.5511	20.00
NF	9	36.72	0.080	0.240	2.040E-4	0.5073	0.70
OA	10	15.00	0.771	0.260	5.354E-5	0.3980	173.73
	11	15.00	0.849	0.266	4.330E-5	0.3980	144.09
Silt	12	31.83	0.070	0.220	3.500E-4	1.0000	0.70
OB	13	15.36	0.927	0.286	4.753E-5	0.4571	170.22
	14	15.36	0.484	0.261	4.113E-5	0.4571	92.81

Capillary pressure was neglected and initial pressure (1981 psi) and temperature (88°F) were kept the same as in the BPX-Alaska 36 layer model. Relative permeabilities vary with different types of rock. In this simulation, 14 layers are classified as six types of rock and their relative permeabilities for each layer are list in Table 12.

Table 12(a). – Liquid-Gas and Water-Oil Relative Permeabilities for Layers 1, 8 and 9

Liquid-Gas Relative Permeabilities			Water-Oil Relative Permeabilities		
Liquid Saturation, S_l	K_{rg}	K_{rog}	Water Saturation, S_w	K_{rw}	K_{row}
0.00	1.0000	0.0000	0.00	0.0000	1.0000
0.05	0.8563	0.0013	0.05	0.0061	0.909
0.10	0.7342	0.0046	0.10	0.0122	0.818
0.15	0.6378	0.0107	0.15	0.0204	0.7271
0.20	0.5627	0.0199	0.20	0.0294	0.6301
0.25	0.4794	0.0332	0.25	0.0387	0.5167
0.30	0.4171	0.0510	0.30	0.0482	0.4116
0.35	0.361	0.0735	0.35	0.0587	0.305
0.40	0.3081	0.1020	0.40	0.0703	0.2136
0.45	0.2567	0.1362	0.45	0.0815	0.1475
0.50	0.2042	0.1767	0.50	0.094	0.1048
0.55	0.1559	0.2236	0.55	0.1101	0.0759
0.60	0.1201	0.2773	0.60	0.1322	0.0569
0.65	0.0863	0.3383	0.65	0.1566	0.0385
0.70	0.067	0.4072	0.70	0.1928	0.0243
0.75	0.0517	0.4843	0.75	0.2397	0.0186
0.80	0.0398	0.5698	0.80	0.3006	0.0125
0.85	0.0299	0.6639	0.85	0.3915	0.0094
0.90	0.0199	0.7667	0.90	0.5106	0.0062
0.95	0.01	0.8788	0.95	0.6948	0.0031
1.00	0.0000	1.0000	1.00	1.0000	0.0000

Table 12(b). – Liquid-Gas and Water-Oil Relative Permeabilities for Layers 3 and 4

Liquid-Gas Relative Permeabilities			Water-Oil Relative Permeabilities		
Liquid Saturation, S_l	K_{rg}	K_{rog}	Water Saturation, S_w	K_{rw}	K_{row}
0.00	1.0000	0.0000	0.00	0.0000	1.0000
0.05	0.8563	0.0013	0.05	0.0045	0.8466
0.10	0.7342	0.0046	0.10	0.009	0.7489
0.15	0.6378	0.0107	0.15	0.0136	0.6588
0.20	0.5627	0.0199	0.20	0.0181	0.5768
0.25	0.4794	0.0332	0.25	0.0226	0.5144
0.30	0.4171	0.0510	0.30	0.0286	0.4494
0.35	0.361	0.0735	0.35	0.0355	0.3871
0.40	0.3081	0.1020	0.40	0.0446	0.3333
0.45	0.2567	0.1362	0.45	0.0574	0.2831
0.50	0.2042	0.1767	0.50	0.0743	0.2192
0.55	0.1559	0.2236	0.55	0.0965	0.1696
0.60	0.1201	0.2773	0.60	0.1254	0.128
0.65	0.0863	0.3383	0.65	0.1622	0.0929
0.70	0.067	0.4072	0.70	0.2104	0.0654
0.75	0.0517	0.4843	0.75	0.2736	0.0469
0.80	0.0398	0.5698	0.80	0.3544	0.0314
0.85	0.0299	0.6639	0.85	0.4588	0.0208
0.90	0.0199	0.7667	0.90	0.5971	0.0122
0.95	0.01	0.8788	0.95	0.7741	0.0056
1.00	0.0000	1.0000	1.00	1.0000	0.0000

Table 12(c). – Liquid-Gas and Water-Oil Relative Permeabilities for Layer 6

Liquid-Gas Relative Permeabilities			Water-Oil Relative Permeabilities		
Liquid Saturation, S_l	K_{rg}	K_{rog}	Water Saturation, S_w	K_{rw}	K_{row}
0.00	1.0000	0.0000	0.00	0.0000	1.0000
0.05	0.8563	0.0013	0.05	0.0038	0.8466
0.10	0.7342	0.0046	0.10	0.0075	0.7489
0.15	0.6378	0.0107	0.15	0.0113	0.6588
0.20	0.5627	0.0199	0.20	0.0151	0.5768
0.25	0.4794	0.0332	0.25	0.0189	0.5144
0.30	0.4171	0.0510	0.30	0.0243	0.4494
0.35	0.361	0.0735	0.35	0.0305	0.3871
0.40	0.3081	0.1020	0.40	0.0398	0.3333
0.45	0.2567	0.1362	0.45	0.0521	0.2831
0.50	0.2042	0.1767	0.50	0.0681	0.2192
0.55	0.1559	0.2236	0.55	0.0888	0.1696
0.60	0.1201	0.2773	0.60	0.1167	0.1280
0.65	0.0863	0.3383	0.65	0.153	0.0929
0.70	0.067	0.4072	0.70	0.2	0.0645
0.75	0.0517	0.4843	0.75	0.261	0.0469
0.80	0.0398	0.5698	0.80	0.3418	0.0314
0.85	0.0299	0.6639	0.85	0.4486	0.0208
0.90	0.0199	0.7667	0.90	0.5873	0.0122
0.95	0.01	0.8788	0.95	0.7672	0.0056
1.00	0.0000	1.0000	1.00	1.0000	0.0000

Table 12(d). – Liquid-Gas and Water-Oil Relative Permeabilities for Layers 10 and 11

Liquid-Gas Relative Permeabilities			Water-Oil Relative Permeabilities		
Liquid Saturation, S_l	K_{rg}	K_{rog}	Water Saturation, S_w	K_{rw}	K_{row}
0.00	1.0000	0.0000	0.00	0.0000	1.0000
0.05	0.8444	0.0013	0.05	0.0033	0.9209
0.10	0.7310	0.0046	0.10	0.006	0.8361
0.15	0.6464	0.0107	0.15	0.009	0.7427
0.20	0.5742	0.0199	0.20	0.0122	0.6413
0.25	0.4994	0.0332	0.25	0.0153	0.5369
0.30	0.4458	0.0510	0.30	0.0185	0.4261
0.35	0.3973	0.0735	0.35	0.0223	0.3342
0.40	0.3454	0.1020	0.40	0.0266	0.2581
0.45	0.2964	0.1362	0.45	0.0326	0.1919
0.50	0.2429	0.1767	0.50	0.0395	0.1411
0.55	0.2011	0.2236	0.55	0.0483	0.0999
0.60	0.1656	0.2773	0.60	0.0598	0.0648
0.65	0.1311	0.3383	0.65	0.0768	0.0464
0.70	0.0988	0.4072	0.70	0.1063	0.0318
0.75	0.0733	0.4843	0.75	0.1491	0.0229
0.80	0.0514	0.5698	0.80	0.2159	0.0143
0.85	0.0350	0.6639	0.85	0.3134	0.0107
0.90	0.0178	0.7667	0.90	0.4649	0.0071
0.95	0.0088	0.8788	0.95	0.6736	0.0036
1.00	0.0000	1.0000	1.00	1.0000	0.0000

Table 12(e). – Liquid-Gas and Water-Oil Relative Permeabilities for Layers 13 and 14

Liquid-Gas Relative Permeabilities			Water-Oil Relative Permeabilities		
Liquid Saturation, S_l	K_{rg}	K_{rog}	Water Saturation, S_w	K_{rw}	K_{row}
0.00	1.0000	0.0000	0.00	0.0000	1.0000
0.05	0.8444	0.0013	0.05	0.0025	0.8516
0.10	0.7310	0.0046	0.10	0.0049	0.7032
0.15	0.6464	0.0107	0.15	0.0074	0.5658
0.20	0.5742	0.0199	0.20	0.0098	0.4680
0.25	0.4994	0.0332	0.25	0.0118	0.3848
0.30	0.4458	0.0510	0.30	0.0153	0.3150
0.35	0.3973	0.0735	0.35	0.0195	0.2541
0.40	0.3454	0.1020	0.40	0.0267	0.2013
0.45	0.2964	0.1362	0.45	0.0372	0.1582
0.50	0.2429	0.1767	0.50	0.0512	0.1269
0.55	0.2011	0.2236	0.55	0.0696	0.0997
0.60	0.1656	0.2773	0.60	0.0954	0.0769
0.65	0.1311	0.3383	0.65	0.1289	0.0529
0.70	0.0988	0.4072	0.70	0.1696	0.0368
0.75	0.0733	0.4843	0.75	0.2288	0.0207
0.80	0.0514	0.5698	0.80	0.3069	0.0123
0.85	0.0350	0.6639	0.85	0.4140	0.0092
0.90	0.0178	0.7667	0.90	0.5620	0.0062
0.95	0.0088	0.8788	0.95	0.7625	0.0031
1.00	0.0000	1.0000	1.00	1.0000	0.0000

Table 12(f). – Liquid-Gas and Water-Oil Relative Permeabilities for Layers 2, 5, 7 and 12

Liquid-Gas Relative Permeabilities			Water-Oil Relative Permeabilities		
Liquid Saturation, S_l	K_{rg}	K_{rog}	Water Saturation, S_w	K_{rw}	K_{row}
0.00	0.7	0.	0.00	0.0000	0.7
1.00	0.	0.7	1.00	0.7	0.

Pattern selection should be based on such considerations as well investment resources, well productivity, reservoir structure, etc. In this study, the injector was set in the center of four 20-acre squares surrounded by eight producers. This formed an 80-acre inverted 9-spot pattern. One-fourth of an 80 acre 9-spot pattern was used in our simulation, and initial oil, water, and pore volume in place are $2.3397E7 \text{ ft}^3$, $3.4001E7 \text{ ft}^3$, and $5.7399E7 \text{ ft}^3$, respectively.

Choosing a grid system is always one of the most critical tasks. A total of nine primary equations (six mass balances, one energy balance, and two mole-fraction constraints) need to be solved simultaneously at each node. Computer time rises dramatically as the total number of nodes increases. The number of nodes in the grid system was minimized without sacrificing simulation accuracy. The maximum grid number allowed for STARS is 13440, and the product of block number and components is limited to 26880. A $10 \times 10 \times 14$ grid, with a block size of $93.338 \text{ ft} \times 93.338 \text{ ft} \times \text{thickness}$, was utilized. For such large grid blocks the block temperature corresponds to the average temperature instead of the combustion front temperature. This resulted in failure of the block to ignite and caused unrealistically high heat losses in our early simulations. To get around this difficulty, the heat loss parameters were lowered sufficiently to enable average temperature to reach combustion temperature at the combustion front.

6.3. SENSITIVITY STUDIES AND RESULTS

Many parameters can influence the predicted performance. Gaining this information will help in the project design and economic evaluation. Our study focused on the operational parameters as well as the reservoir and fluid parameters such as, injection rate, air enrichment, cracking reaction kinetics, wet versus dry combustion, phase equilibrium constant, and well spacing.

6.3.1. Effect of Injection Rate

The effect of injection rate on the recovery was investigated for three different rates, 10 MMSCFPD (11.48 Scf/Dft^2), 7 MMSCFPD (8.03 Scf/Dft^2) and 5 MMSCFPD (5.74 Scf/Dft^2). Air was injected simultaneously into all 14 layers. The injection pressure was kept just above the reservoir pressure (1981 psi). Ignition time varies with the injection rate. In this study, external heat was provided for the first two years, long enough to ensure that ignition had been established. All simulation runs were limited to 10 years to avoid excessive run time.

The temperature distribution of plane $Y=1$ and $Z=3$ was captured in Figure 2. It shows the location of the combustion front at various times and injection rates. A higher injection rate results in a higher combustion front temperature due to greater oxygen availability. This greater availability of oxygen accelerated the burning rate of fuel. Since the combustion front cannot advance until all the fuel is consumed, accelerated consumption of fuel translated into higher predicted peak temperature and rapid advancement of combustion front through the reservoir.

Figure 2. – Position of combustion front for various injection rates

In the eighth year the position of the combustion front for 5 MMSCFPD is in grid block 7, while for 7 MMSCFPD is in block 9, and for 10 MMSCFPD is in block 10, indicating breakthrough. Note higher temperatures during the early time period in block 1 are caused by the external heat added into the block. Sharp temperature decrease in block 1 after two years is due to the heat loss to the cold injection air and the surrounding while external heaters were turned off.

Figure 3 presents the effect of injection rates on cumulative oil production, cumulative oil recovery and air/oil ratio (AOR). Higher injection rate can accelerate the oil production, therefore, correspond to higher oil recovery rates. Oil recovery in this study refers to volumetric oil recovery expressed as a percentage of initial oil in place. As injection rate increases from

Figure 3. – Effect of injection rates on cumulative oil production, oil recovery and AOR

5 MMSCFPD to 10 MMSCFPD, the cumulative oil recovery increases from 19.6% to 32.9% in 10 years.

The accelerated oil production rate and increased oil recovery at higher injection rate are caused by: (1) the availability of large volumes of combustion gas to displace the oil from the pores, (2) greater distillation and cracking effect due to higher temperature, and (3) enhanced swelling and solvent effect resulting from the generation of large volumes of CO₂ and lighter ends. It is also believed that the higher temperature caused the water near the combustion front to vaporize much more rapidly, accelerated the build up of steam bank ahead of the combustion front and contributed to the increased recovery.

AOR values for all three runs are lower than 24 Mscf/bbl, the upper limit being considered economically. However, 7 MMSCFPD case has much lower AOR compared to that of 10 MMSCFPD case, and slightly higher AOR and 6.4% additional oil recovery than that of 5 MMSCFPD case. No breakthrough occurred in the 10 year period run and this 7 MMSCFPD case appeared to be the best case.

Figure 4. – Comparison of cumulative oil recovery–14-layer vs. 8-layer (10 MMscf/D air inj.)

Since all these runs are very time consuming, one run was performed to study the possibility of reducing computation time without sacrificing the accuracy. Air was injected into eight high permeability layers by shutting in the six low permeability layers (NE and NF layers plus four silt layers). The result shows that computation time can be reduced by almost 40%, while ultimate oil recovery remains essentially the same as the case of injections into all 14 layers, as shown in Figure 4. Extinction radius calculation, which will be discussed later, also shows that these six layers couldn't maintain combustion. All this indicates that the low permeability NE and NF sands and silt layers contribute very little toward the oil production.

6.3.2. Effect of Enriched Air

Reductions of the oxygen content from the injection gas can result in incomplete burn, promote Low Temperature Oxidation (LTO) reactions, lower the peak temperature and recovery. Thus, enriching the injection air with oxygen was investigated and compared with normal air injection (21%). For comparison on equal amount of oxygen basis, the air injection rates were adjusted to maintain the same total oxygen for both enriched air and normal air. The effect of

enriched air was investigated by injecting 30% and 40% (by volume) oxygen content air separately and the results were compared with normal air injection.

Figure 5 shows the comparison among these three cases. Though the peak oil production was accelerated with enriched air injection (i.e. the peak daily production rates occurred 4 and 2 years earlier, respectively, compared to the normal air injection), the final cumulative oil recovery was only marginally higher.

The slightly higher oil overall recovery with enriched air can be attributed to the somewhat higher CO₂ and steam production. The increased steam production is the result of more rapid evaporation of connate and produced water.

Figure 5.- Effect of enriched oxygen on daily oil production and oil recovery

6.3.3. Effect of Kinetic of Cracking Reaction

The kinetic model employed in the simulator is that of Arrhenius:

$$R_A = A \exp (-E/RT)$$

where A is pre-exponential factor, E is activation energy and R is universal gas constant. Increasing A values can accelerate the combustion reaction rates. Conducting this study can give us the insight of the role of the kinetics or reaction rate played in the combustion process. Three runs were made to evaluate the effect of pre-exponential factor on oil recovery. The cases studied were: $A=1.0E05$ (base case), $A=1.0E08$, and $A=1.0E11$. Figure 6 shows that the oil recovery rate in this study is not controlled by the kinetics of the combustion or reaction rate. The pre-exponential factor increased by one thousand times over the base case had resulted in oil recovery 1.16% OIP decrease, while a million times increase in the pre-exponential factor resulted in only 0.93% decrease in oil recovery.

6.3.4. Wet Versus Dry Combustion

In terms of heat reaching the displacement front, the dry combustion process is less efficient because much of the heat released by the burning oil remains behind the combustion front. To improve this situation, water is injected simultaneously with the air after initial combustion has been established. Water, with a specific heat of approximately four times that of air, can recover

Figure 6.— Effect of kinetics of cracking reaction (10 MMscf/D air injection)

Figure 7. – Oil recovery in wet combustion is superior to the corresponding dry combustion

part of the heat remaining behind the combustion zone and carry that heat downstream beyond the combustion zone either as superheated steam or saturated steam.

To further understand the effect of the injection water, we simulated the following two cases. Same amounts of water, 1000 STB/D, were simultaneously injected with the air at the end of two years dry combustion, the air injection rates for these two cases were 10 MMSCFPD and 7 MMSCFPD, respectively. Simulation results were compared with the corresponding dry combustion runs.

Figure 7 shows that at constant water injection rate, the oil recovery is a function of air injection rate. The recovery in both cases was superior to the corresponding dry combustion cases. The additional recovery due to wet combustion was around 3.5%. Higher recovery is the result of the more rapid combustion front movement, the increased utilization of energy, and increased volume of fluid injected.

The air requirement is lower in wet combustion process because of the lower amount of coke deposited and lower amount of fuel consumed, which resulted in the lower AOR, as presented in Figure 8.

Figure 8. – Comparison of producing AOR for wet and dry combustion

Figure 9. – Effect of the amount of water injected on oil recovery (5 MMscf/D air injection)

Figure 10. – Effect of wet combustion on temperature distribution (5 MMscf/D air injection)

The contradictory behavior occurred when we lowered the air injection rate to 5 MMSCFPD. The ultimate oil recovery dropped to 15.2% OIP, 4.4% lower than that of the corresponding dry combustion, as presented in Figure 9. Figure 10 captures the profile of the temperature

distribution at the fifth year. It clearly shows that the combustion front moved much more slowly and temperature was much lower than that of dry combustion. Apparently this high water injection partially quenched the combustion, which resulted in the lower oil recovery rate. Figure 11 is the snapshot of the saturation profile at the same time. Note that oil saturation was zero in the burned zone. This distribution also indicated that less oil was produced in this high water injection case. Thus, there appears to be a minimum air injection rate for a given water injection rate, below which, the recovery is likely to decline.

Figure 11. – Effect of wet combustion on oil saturation (5 MMscf/D air injection)

6.3.5. Effect of Phase Equilibrium K-values

Providing accurate phase equilibrium constants, K , is always troublesome. An initial attempt was made to calculate K -values by using CMG WINPROP. Unfortunately, the K -values converged to the trivial solution. To examine the effect of this K -value, studies were conducted

by introducing two sets of K-values: one was adopted from STARS used as base K values, the other was generated from Schrader Bluff crude composition and an equation of state (EOS). Table 13 shows the two sets of K-values for pressure 1915 psi and 2015 psi, and temperature from 77 °F to 927 °F with 50 degrees intervals.

Table 13. – Two Sets of K Values

Base K Values				The EOS generated K values			
Heavy Oil		Light Oil		Heavy Oil		Light Oil	
2.51e-9	2.39e-9	1.54e-4	1.46e-4	9.78e-20	8.89e-20	0.009103	0.008268
2.23e-8	2.12e-8	4.80e-4	4.56e-4	2.35e-16	2.14e-16	0.019943	0.018115
1.54e-7	1.46e-7	0.00128	0.00122	6.83e-14	6.21e-14	0.038548	0.035013
8.5e-7	8.08e-7	0.00304	0.00289	5.12e-12	4.65e-12	0.067585	0.061388
3.91e-6	3.72e-6	0.00648	0.00616	1.53e-10	1.39e-10	0.109676	0.099618
2.63e-5	2.50e-5	0.01260	0.012	2.37e-9	2.15e-9	0.167211	0.151878
8.42e-5	8.00e-5	0.01790	0.017	2.26e-8	2.06e-8	0.242239	0.220025
2.42e-4	2.30e-4	0.02310	0.022	1.50e-7	1.37e-7	0.336388	0.305541
4.10e-4	3.90e-4	0.02950	0.028	7.52e-7	6.83e-7	0.450855	0.409511
5.89e-4	5.60e-4	0.03470	0.033	3.01e-6	2.73e-6	0.586406	0.532632
8.84e-4	8.40e-4	0.04000	0.038	1.00e-5	9.12e-6	0.743414	0.675242
0.00166	0.00158	0.04520	0.043	2.89e-5	2.63e-5	0.921906	0.837366
0.00284	0.0027	0.05050	0.048	7.38e-5	6.70e-5	1.121608	1.018756
0.00389	0.0037	0.05680	0.054	0.00017	0.000154	1.342004	1.218941
0.00558	0.0053	0.06310	0.060	0.000359	0.000326	1.582379	1.437273
0.00768	0.0073	0.06940	0.066	0.000705	0.000641	1.841869	1.672968
0.01050	0.0100	0.07680	0.073	0.001301	0.001181	2.119497	1.925137
0.01790	0.0170	0.08840	0.084	0.00227	0.002062	2.414210	2.192825

The EOS generated K values were much higher for the light oil and lower for the heavy oil than the base K values. In other words, the EOS made the oil lighter. This presumes that most light oil will evaporate before it burns. Thus, the amount of residual oil available for burning and cracking was lowered, the rate of advancement of combustion front will be increased and oil recovery will be higher.

Figure 12. – Effect of phase equilibrium K-values on oil recovery (10 MMscf/D air injection)

Figure 12 illustrates oil recoveries by incorporating these two sets of K-values. The EOS generated K values resulted in additional 4% oil recovery over the base K values, which clearly underscored the importance of estimating this parameter correctly.

6.3.6. Effect of Well Spacing

In this study the air injection rates were kept the same at 10 MMSCFPD while the well spacings were arbitrarily changed to 40 and 160 acres, respectively. Smaller well spacing resulted in higher flux which translated to higher oil recovery. Figure 13 gives the comparisons of oil recovery among three different well spacings. As expected, the 40 acres well spacing has the highest oil recovery.

Figure 13. – Well spacing sensitivity study (10 MMscf/D air injection)

6.4. EXTINCTION RADIUS

The extinction radius is defined as the radial distance (from the injection well) beyond which it is no longer possible to support combustion. For a combustion process to succeed, the extinction radius at any given injection rate must exceed the spacing between the injector and producer. The extinction radius is a function of air injection rate and rock-fluid properties.

A spread sheet program was developed. Details are discussed below.

Four chemical reactions, cracking of heavy oil and oxidation of heavy oil, light oil, and coke, can be written as,

Multiplying the last equation by 13.4 and adding to the summation of the first three equations, one can get

Knowing the amount of oxygen consumption or heavy oil cracking enable the calculation of the total reaction heat, Q . This reaction heat is equal to the heat loss to the surrounding rock and heat absorbed by the mixture, which includes unoxidized oxygen, nitrogen, CO_2 , H_2O (connate and produced), and oil (heavy and light oils). The energy balance equation is expressed as,

$$Q = \sum (nC_p)_i (T - T_0) + (T - T_0)t / (h / KA)$$

where T_0 is initial reservoir temperature, t is the time, A is the area, and K is the rock conductivity. Reaction heat Q and mixture moles, n_i , are functions of time; C_p is specific heat (Btu/lb) and h is pay thickness (ft).

Figure 14. – Extinction radius at various injection rates

Since average radial velocity, U , is equal to

$$U = r/t = Q_i / (2\pi rh) = Q_0 (P_0 / P_1) (T_1 / T_0) / (2\pi rh)$$

Where Q_0 , P_0 , P_1 , T_1 , T_0 and h is the injection rate, initial injection pressure, reservoir pressure, reservoir temperature, initial injection temperature and pay zone thickness, respectively. Rewriting this equation and expressing time t as a function of radius gives,

$$t = (2\pi r^2 h) / [Q_0 (P_0 / P_1) (T_1 / T_0)]$$

Substituting this equation into the energy balance equation and using a trial-and-error method, the extinction radius is calculated with assumed minimum supporting combustion temperature.

Assuming the injection rate for each layer is proportional to its permeability. Figure 14 shows the extinction radius in each layer as a function of injection rates. In each layer, a higher injection rate results in a higher extinction radius. In six low permeability layers, the combustion couldn't be maintained and therefore these layers contribute very little toward the oil production.

In this study, the injector was set in the center of four 20-acre squares surrounded by eight producers. Hence, the extinction radius should be greater than 934 feet. Figure 14 indicates that

a minimum air injection rate of 5 MMSCFPD must be maintained to implement the successful combustion.

6.5. CONCLUSIONS

The following conclusions can be drawn from the results of this study.

1. Higher air injection rate results in higher oil recovery. Combustion in six low permeability layers (NE and NF sands and silt layers) couldn't be maintained. Therefore, injections to higher permeability zones have the same ultimate oil recovery as injections to all layers. However, computation time may be greatly reduced.
2. There is no pronounced advantage in using high oxygen content air on Schrader Bluff reservoir. Enriched air will accelerate peak oil production but has minimal effect on the overall oil recovery.
3. The pre-exponential factor of the combustion kinetics has only marginal effect on oil recovery. However, the phase equilibrium K values have significant impact on the ultimate oil recovery.
4. Wet combustion causes higher oil recovery and requires lower AOR than that of dry combustion. AOR values for both dry and wet combustion are within the acceptable range. However, high water injection and/or low air injection rate may partially quench the combustion and reduce the recovery.
5. The extinction radius is a function of air injection rate and rock-fluid properties. Higher injection rate results in higher extinction radius. A minimum 5 MMSCFPD injection rate must be maintained to implement the successful combustion for the 80-acre spacing wells.

7.0 OVERALL CONCLUSIONS

This CRADA project was conducted by DOE and BP Exploration to identify the most promising recovery processes for Schrader Bluff Milne Point, Alaska. Discussed in this report are the results of TRW's evaluation of in situ combustion.

The following summarizes the results of this study.

1. Based on initial screening studies, polymer flooding, gas injection (miscible, immiscible), and in situ combustion have the greatest potential to successfully recover additional oil from Schrader Bluff. However, each of the process screening methods ranked a different EOR method for best choice. Further detailed studies of these processes are warranted.
2. A laboratory study of in situ combustion determined that Schrader Bluff crude oil has favorable burn characteristics. A stable front can be maintained and recovery efficiencies are good. Wet combustion, a process combining in situ combustion with water injection, appears to perform better than dry combustion. A first estimate of air requirements, burn rates, etc., were determined.
3. Results of a simulation study of in situ combustion were consistent with observed behavior in the laboratory.
4. The simulation study suggests that in situ combustion cannot be maintained in the low permeability sands (NE, NF, silt layers).
5. Extinction radius calculations indicated that to implement a successful 80 acre spacing in situ combustion project, a minimum of 5 MMscf/day air injection rate is required.

An in situ combustion field pilot project is recommended to assess the impact of other important factors such as heterogeneity, mineralogy, etc.

8.0 BIBLIOGRAPHY

- Bailey, H.R., and B.K. Larkin: "Conduction-Convection in Underground Combustion," AIME Petroleum Transactions, Vol. 219, pp. 320-331, 1960.
- Bidinger, C.R. and J.F. Dillon: "Milne Point Schrader Bluff: Finding the Keys to Two Billion Barrels," SPE Paper 30289, June 19-21, 1995.
- Buchanan, L. and M. Raicar: "Sensitivity Study of Field Scale Combustion Simulation for a Lloydminster-Type Heavy Oil Reservoir," Petroleum Society of CIM, paper No. 83-34-47.
- Coats, K.H.: "In Situ Combustion Model," Soc. Pet. Eng. J., Vol. 20(6), pp. 533-554, December 1980.
- Craig, F. F., Jr., and D.R. Parrish: "A Multipilot Evaluation of the COFCAW Process," J. Pet. Tech. pp. 659-666, June 1974.
- Crookston, R.B., W.E. Culham, and W.H. Chen: "A Numerical Simulation Model for Thermal Recovery Processes," SPE Paper 6724, October 9-12, 1977.
- Dingley, A.J.: "The Combustion Recovery Process -- Principles and Practice," J. Canadian Pet. Tech., pp. 196-205, October-December 1965.
- Farouq Ali, S.M.: "Multiphase, Multidimensional Simulation of In-Situ Combustion," SPE Paper 6896, presented at SPE 52nd Annual Technical Conference and Exhibition, Denver, Oct. 9-12, 1977.
- Kumar, Mridul: "A Cross-Sectional Simulation of West Heidelberg In-Situ Combustion Project," SPE Reservoir Engineering, pp. 46-54, February 1991.
- Laureshen, C.J., S.A. Mehta, R.G. Moore, and M.G. Ursenbach: "Ramped Temperature Oxidation Characteristics of Alaska Crude Oil," report submitted by Dept. Chemical & Petroleum Eng., U. Calgary, September 11, 1998.
- Laureshen, C.J., S.A. Mehta, R.G. Moore, N.E. Okazawa, and M.G. Ursenbach: "BDM Petroleum Technologies Combustion Tube Test No. 1 (Test No. 287), Alaska Reservoir," report submitted by Dept. Chemical & Petroleum Eng., U. Calgary, December 10, 1998.
- Laureshen, C.J., S.A. Mehta, R.G. Moore, N.E. Okazawa, and M.G. Ursenbach: "BDM Petroleum Technologies Combustion Tube Test No. 2 (Test No. 287), Alaska Reservoir," report submitted by Dept. Chemical & Petroleum Eng., U. Calgary, December 10, 1998.
- Moore, R.G., M.G. Ursenbach, C.J. Laureshen, J.D.M. Belgrave, and R. Mehta: "Ramped Temperature Oxidation Analysis of Athabasca Oil Sands Bitumen," Petroleum Society of CIM paper 95-23, pres. 46th Annual Technical Meeting, Banff, Alberta Canada, May 14-17, 1995.
- Moore, R.G., C.J. Laureshen, M.G. Ursenbach, R. Mehta, and J.D.M. Belgrave: "Combustion/Oxidation Behavior of Athabasca Oil Sands Bitumen," SPE Paper 35392, pres. SPE/DOE Improved Oil Recovery Symposium, Tulsa, Oklahoma, April 21-24, 1996.
- Parrish, D.R., and Craig, F. F.: "Laboratory Study of a Combination of Forward Combustion and Waterflooding," the COFCAW Process, J. Pet. Tech. pp. 753-761, June 1969.
- Rubin, B. and W.L. Buchanan: "A General Purpose Thermal Model," SPE Paper 11713, presented at the 1983 California Regional Meeting, Ventura, California, March 23-25, 1983.

Taber, Joseph J., F. David Martin, and R.S. Seright: "EOR Screening Criteria Revisited," SPE/DOE Paper 35385, pres. SPE/DOE Tenth Symposium on Improved Oil Recovery, Tulsa, Oklahoma, April 21-24, 1996.

Todd, M.R., P.M. O'Dell, and G.J. Hiraski: "Methods for Increased Accuracy in Numerical Reservoir Simulators," Soc. Pet. Eng. J. pp. 515-530, December 1972; Trans. , AIME, p. 253.

Youngren, G.K.: "Development and Application of an In-Situ Combustion Reservoir Simulator," Soc. Pet. Eng. J., pp. 39-51, February 1980.