# A TOP-INJECTION BOTTOM-PRODUCTION CYCLIC STEAM STIMULATION METHOD FOR ENHANCED HEAVY OIL RECOVERY

A Thesis

by

ERIC ROBERT MATUS

Submitted to the Office of Graduate Studies of
Texas A&M University
in partial fulfillment of the requirements for the degree of

MASTER OF SCIENCE

August 2006

Major Subject: Petroleum Engineering

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Approved by:

Chair of Committee, Daulat Mamora
Committee Members, Richard Startzman
Ray Guillemette
Head of Department, Stephen A. Holditch

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## ABSTRACT

A Top-injection Bottom-production Cyclic Steam Stimulation

Method for Enhanced Heavy Oil Recovery. (August 2006)

Eric Robert Matus, B.S., Texas A&M University

Chair of Advisory Committee: Dr. Daulat Mamora

A novel method to enhance oil production during cyclic steam injection has been developed. In the Top-Injection and Bottom-Production (TINBOP) method, the well contains two strings separated by two packers (a dual and a single packer): the short string (SS) is completed in the top quarter of the reservoir, while the long string (LS) is completed in the bottom quarter of the reservoir. The method requires an initial warm-up stage where steam is injected into both strings for 21 days; then the LS is opened to production while the SS continues to inject steam for 14 days. After the initial warm-up, the following schedule is repeated: the LS is closed and steam is injected in the SS for 21 days; then steam injection is stopped and the LS is opened to production for 180 days. There is no soak period.

Simulations to compare the performance of the TINBOP method against that of a conventional cyclic steam injector (perforated across the whole reservoir) have been made. Three reservoir types were simulated using 2-D radial, black oil models: Hamaca (9°API), San Ardo (12°API) and the SPE fourth comparative solution project (14°API). For the first two types, a 20x1x20 10-acre model was used that incorporated typical rock and fluid properties for these fields.

Simulation results indicate oil recovery after 10 years was 5.7-27% OIIP with TINBOP, that is 57-93% higher than conventional cyclic steam injection (3.3-14% OIIP). Steam-oil ratios were also decreased with TINBOP (0.8-3.1%) compared to conventional (1.2-5.3%), resulting from the improved reservoir heating efficiency.

## ACKNOWLEDGEMENTS

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# TABLE OF CONTENTS

Page

# LIST OF TABLES

Page

## LIST OF FIGURES

Page

# I. INTRODUCTION

Steam injection started in the 1940s to reduce the viscosity of heavy oil reservoirs. Typical injection methods are steam drive and cyclic steam injection. In steam drive, steam injected constantly from an injector well, and production occurs from one or more production wells in a pattern. Once steam injection starts the well injectivity can be very low due to the high oil viscosity, and once the injectivity improves the steam tends to override the oil and create a steam chest. Once the steam chest has formed, most of the steam used goes to maintaining the steam chest. To increase the injectivity in earlier times and to increase the steam's exposure to the reservoir, producers use cyclic steam injection.

In conventional cyclic steam injection, a well is completed across the total thickness of a heavy-oil reservoir. Steam is injected and oil produced from the same well in cycles. Each cycle consists of three stages, namely, injection, soak, and production. During the injection stage, which typically lasts about two weeks, steam is injected at a constant rate, forming a steam zone in the reservoir that propagates outwards from the well. Viscosity of the oil in the steam zone is thus reduced significantly, often by a few orders of magnitude. The well is then shut in to allow heating of the oil beyond the steam zone by conduction of heat from the steam zone.

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This thesis follows the style of the *SPE Reservoir Evaluation & Engineering Journal.*

This heat transfer from the steam zone and heat loss to the over- and under-burden result in lowering of the steam zone temperature. Thus to avoid too low a steam zone temperature, the soak period is typically limited to about one week. After the soak periods, the well is opened to production. Depending on the reservoir rock and fluid properties, the production period typically lasts several months, Prats (1986)[1].

With each cycle, the steam zone increases and more heat is lost to the over- and under-burden, decreasing the thermal efficiency of the process. In addition the reservoir pressure continues to decrease because of production of the oil and condensed steam injected. Consequently, peak oil production rate continues to decrease with each cycle until an economic limit is reached. Typically, cyclic steam injection recovers a maximum of some 15% of the original oil-in-place (OOIP) of the "drained area"[2].

During conventional cyclic steam injection, most of the heat in the injected steam is produced back primarily because the well is completed across the whole reservoir. If more of the steam (heat) could somehow be retained in the reservoir, the thermal efficiency of the process and thus oil recovery would be enhanced. The Top-Injection and Bottom-Production (TINBOP) cyclic steam injection method was developed with this in mind. In the TINBOP method, the well will be a dual-string completion. The short string (SS) will be completed in the top one-quarter of the reservoir, while the long string (LS) will be completed in the bottom quarter of the reservoir (**Figure 1.1**). Steam will be injected in the SS so that the steam will preferentially remain in the top part of the reservoir. Production will be from the LS.

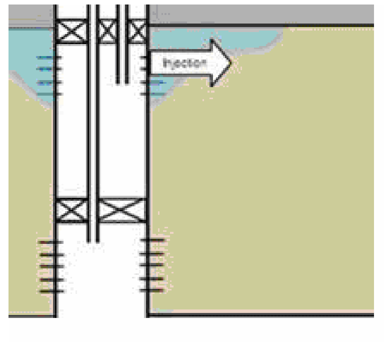


**Figure 1.1—Completion schematic for TINBOP**

## 1.1 Research Objectives

1. Develop a method to minimize steam production and maximize heat efficiency in vertical wells.
2. Test the new method with a thermal reservoir simulator and models based on typical heavy oil reservoirs.

## II. LITERATURE REVIEW

Cyclic steam injection has always been recognized as a way to accelerate recovery in steam flooding projects. The drawback is a reduction in the overall recovery. Typically cyclic steam injection is implemented early in the development of a new field before switching to steam drive. Typical papers on cyclic steam injection focus on the ideal spacing and combination of vertical and horizontal wells, or on the proper simulation and model construction techniques. The following is a literature review of previous studies on cyclic steam injection.

Marpriansyah et al. (2003) present several papers covering thermal stimulation with multisegment wells[3]. The papers focus on injecting steam down the tubing, and production up the annulus for horizontal SAGD wells, and for vertical cyclic wells. When discussing cyclic steam injection, the authors compare their results to a conventional base case cyclic steam model from the fourth SPE comparative solution project. Their results show a slight increase in recovery over the base case by injecting steam only in to the bottom of the reservoir. Production is allowed across the entire interval.

Rajtar (1999) compared several different cyclic steam injection projects with a 3D simulation model based on data from the Midway Sunset field in California[4]. The paper centered around the ideal location for a horizontal producer among a cyclic steam injection project, and the ideal timing for cyclic steam injection patterns. The evaluation of the different scenarios was based on the cumulative oil production.

Al-Hadrami et al. (1997) presented the framework for a gravity assited cyclic steam injection project[5]. Several different cases were simulated using a heavy oil simulator to determine the ideal combination of horizontal and vertical cyclic steam injection wells. A base case was presented with vertical cyclic steam stimulated wells, and all cases were presented as a recovery increase over this base case.

Aziz et al (1987) presented a comparison of several different commercial simulators for thermal simulation[2]. Test cases included runs with cyclic steam injection, steam drive, and different combinations of each. The reservoir parameters and production history presented provided the data used in construction of one of the reservoir models in this research.

Sandoval (2005) provided a detailed analysis of San Ardo crude oil properties, and the reservoir parameters necessary for thermal simulation[6]. Sandoval verified his reservoir and fluid property data with a provided history match to actual field data. Two separate fluid models: compositional and black oil were used. Both of these fluid models were used in construction of a 2D radial model for this study.

Venturini (2003) performed a study similar to Sandoval except with Hamaca fluid and reservoir properties[7]. Laboratory studies he performed provided the fluid properties for the Hamaca model in this study. While a compositional and a black oil model were presented, only the black oil model was used since a compositional model was already run with the San Ardo data set.

## III. SIMULATION STUDIES

Simulation studies were conducted to compare the performance of conventional cyclic steam injection against the TINBOP method. Simulation of cyclic steam injection was performed for three types of heavy oil reservoirs that covered a range of reservoir and fluid properties: SPE model (14°API oil), Hamaca (9°API oil), and San Ardo (12°API oil). Two-dimensional (2-D) radial layered black oil simulation models were used for the three reservoir types.

The simulations showed that, in the TINBOP method, after steam is injected in the SS and then the LS is opened to production, there is a delay of about three years in production response compared to that with conventional cyclic steam injection. This is due to the fact that the oil around the well between the top and bottom perforations is not heated as much as that under conventional cyclic steam injection where the oil around the well across the thickness of the reservoir is heated to steam temperature. To counteract this problem, a "warm-up" period is used at the beginning of the process. This "warm-up" period involves injecting steam to initially warm up the whole thickness of the reservoir.

The TINBOP cyclic steam injection method used in the three simulation models may be summarized as follows. First, steam is injected into both strings for 21 days. This is followed by a 14-day period in which the LS is opened to production while steam is injected into the SS. After this initial warm-up period, the following schedule is repeated for the life of the well: the LS is closed and steam is injected in the SS for 21 days; then steam injection is stopped and the LS is opened to production for 180 days. There is no soak period.

For conventional cyclic steam injection, for each reservoir model, the simulated steam injection rate, temperature and steam quality are the same as those for TINBOP. The conventional cyclic steam injection stages simulated were as follows: injection of 21 days, soak period of 5 days, and production period of 180 days.

## 3.1 Model Construction

The three reservoir models were simulated using a perforation configuration to simulate a conventional cyclic steam well and a TINBOP cyclic steam well. Conventional cyclic steam models were perforated in twenty out of twenty layers to imitate the wellbore being perforated along the entire interval. TINBOP model construction was exactly the same, but the perforations were changed to layers one through five, and sixteen through twenty. Simulation runs were also made for each reservoir type, in which the thickness of the reservoir was decreased from the original (base case) value, to investigate whether the application of TINBOP would be limited by the reservoir thickness. The numerical simulator *CMG STARS* was used in the study.

*STARS* is a reservoir simulator specifically designed for thermal and compositional applications, such as steam flooding, in-situ combustion, foam flooding and cyclic steam injection[8]. The use of STARS is ideally suited for simulating TINBOP, due to its extensive modeling of heat transfer and fluid flow processes. STARS was run on an HP Pavilion zv6000 laptop with an AMD Athlon 64 3500 processor and 512 Mb of RAM.

### 3.1.1 SPE Model

This 13x1x20 simulation model was a modification of the fourth SPE comparative solution project. The project presented a 2-D radial black oil model to be used for cyclic steam simulation. The original model had four grid blocks in the vertical direction, with finer grids near the top of the reservoir to better model steam override. For this study, the SPE model was modified to have 20 vertical grid layers, each 5 ft thick, to better simulate gravity segregation. The fluid properties and all other properties remained the same as the original model[2] (**Table 3.1**).

**Table 3.1— Model properties for the SPE model**

| Property | Value |
|---|---|
| Permeability, md | 2,000 |
| Porosity, percent | 30 |
| Reservoir temperature, °F | 125 |
| Area, acres | 5 |
| Thickness, ft | 80 |
| Number of grids | 13x1x20 |
| Steam temperature, °F | 450 |
| Steam quality, fraction | 0.7 |
| Injection rate, CWEBPD | 1,000 |
| Reservoir pressure, psia | 75 |

### 3.1.2 Hamaca Model

This 20x1x20 simulation model was based on typical Hamaca reservoir and fluid properties[9] first tabulated by Sandoval et al. (**Table 3.2**). The model represented a drainage area of 20 acres. Relative permeability curves used were based on actual measurements.

**Table 3.2— Reservoir properties for the Hamaca model**

| Property | Value |
|---|---|
| Permeability, md | 20,000 |
| Porosity, percent | 30 |
| Reservoir temperature, °F | 125 |
| Area, acres | 20 |
| Thickness, ft | 80 |
| Number of grids | 20x1x20 |
| Steam temperature, °F | 600 |
| Steam quality, fraction | 0.8 |
| Injection rate, CWEBPD | 1,000 |
| Reservoir pressure, psia | 1,300 |
| Oil viscosity @ res. temp, cp | 82,100 |

### 3.1.3 San Ardo Model

A 20x1x20 simulation model was used to simulate a 20 acre drainage area being cyclic-steamed in the San Ardo field[6]. The model was based on typical San Ardo reservoir and fluid properties (**Table 3.3**). Relative permeability curves were based on actual measurements.

**Table 3.3— Reservoir properties for the San Ardo model**

| **Property** | **Value** |
|---|---|
| Permeability, md | 6,922 |
| Porosity, percent | 34.5 |
| Reservoir temperature, °F | 127 |
| Area, acres | 20 |
| Thickness, ft | 115 |
| Number of grids | 20x1x20 |
| Steam temperature, °F | 582 |
| Steam quality, fraction | 0.8 |
| Injection rate, CWEBPD | 1,200 |
| Reservoir pressure, psia | 845 |
| Oil viscosity @ res. temp, cp | 6,695 |

# IV. RESULTS AND DISCUSSION

Runs were made to simulate ten years of cyclic steam injection under the conventional method and with the TINBOP method. Comparative results for the three reservoir models are summarized in the following section.

## 4.1 SPE Model

At the end of ten years, oil recovery under conventional cyclic steam injection was 14.0% OOIP, compared to 27.0% OOIP using the TINBOP method (**Figure 4.1**). This represents an increase in oil recovery of 93% with TINBOP compared to conventional cyclic steam injection. The enhanced oil recovery is also apparent from the oil rate graph (**Figure 4.2**). The improved thermal efficiency with TINBOP – i.e. more heat is retained in the reservoir than under conventional cyclic steam injection - is evident from the higher reservoir temperatures under TINBOP. Under TINBOP, the volume of steam injected is 18% higher than that under conventional method. However, due to the improved thermal efficiency, the steam-oil ratio under TINBOP is decreased to 2.8 from that using conventional cyclic steam injection, 4.6 (**Figure 4.3**).

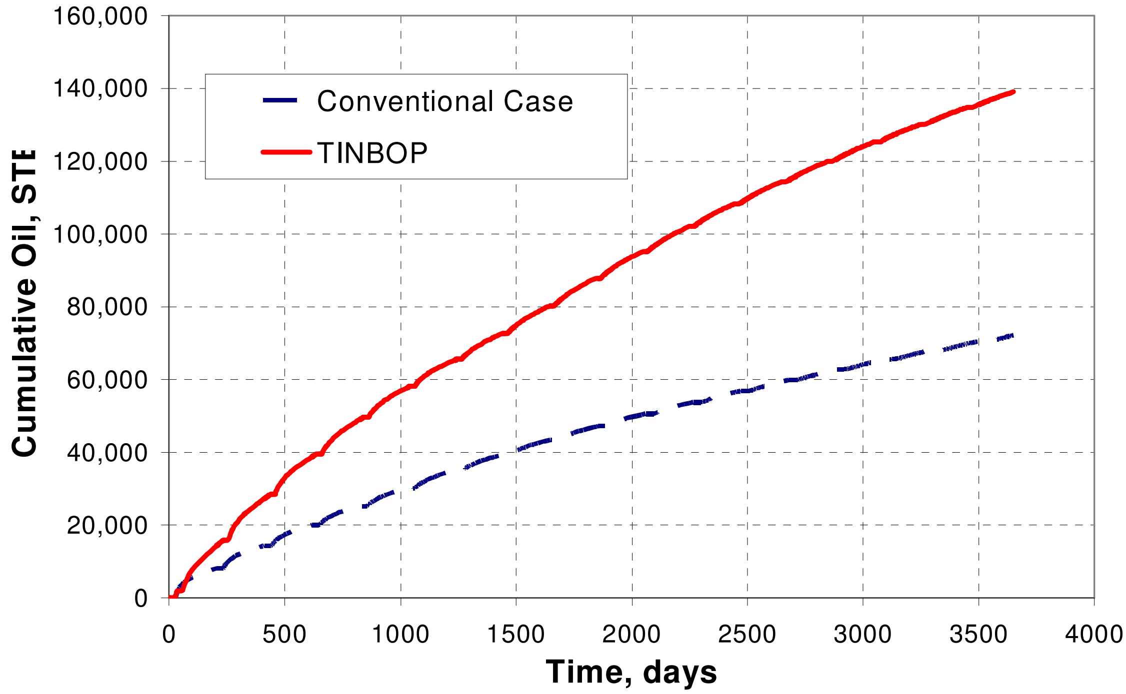


**Figure 4.1— Cumulative oil for the SPE model**

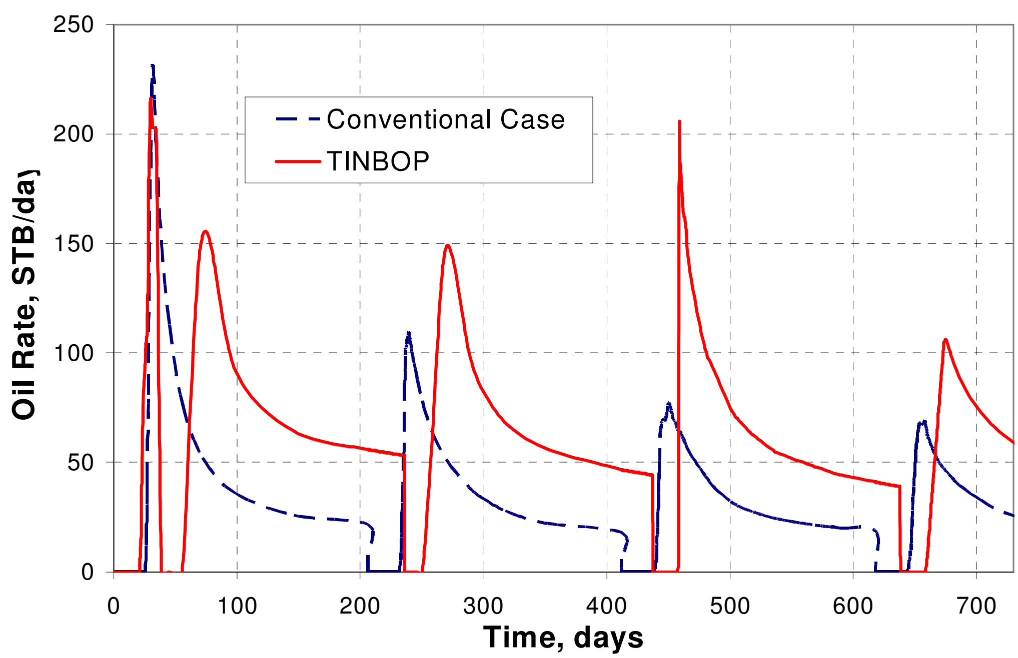


**Figure 4.2— Oil rate for the SPE model**

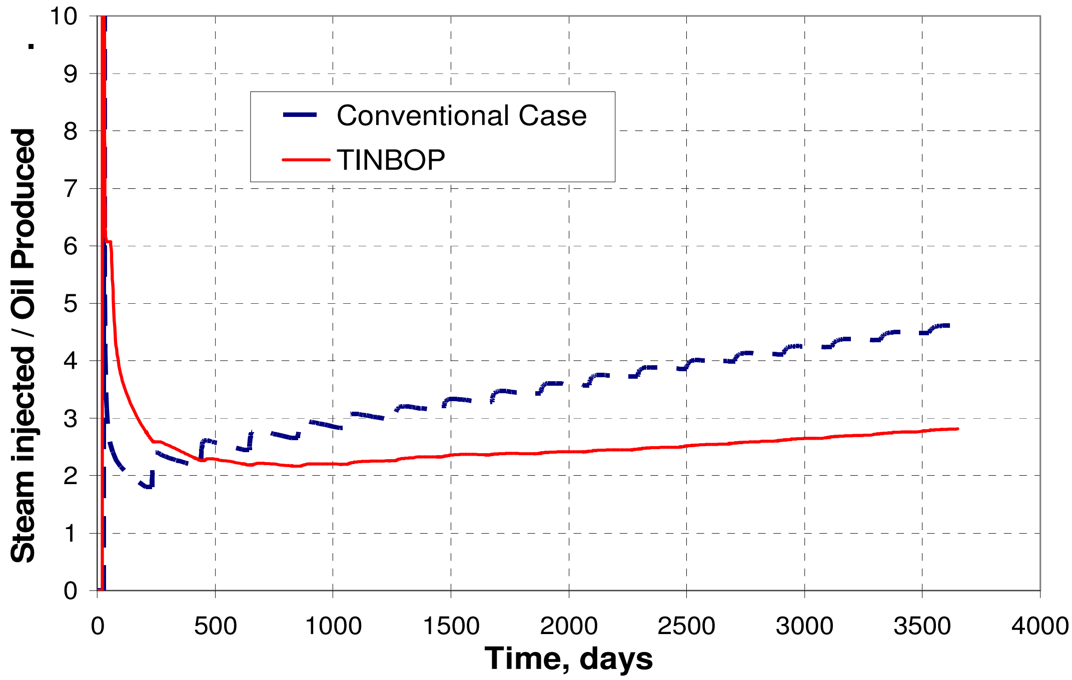


**Figure 4.3— Steam oil ratio for the SPE model**

Run times for the SPE model averaged 1 minute and 27 seconds, for 154 different simulation runs. All models converged, and no manual reduction in the timesteps was needed. Timesteps were limited to no less than one day during production, and no less than 0.1 days during injection.

## 4.2 Hamaca Model

Conventional cyclic steam injection for Hamaca recovered 3.3% OOIP, compared to 5.7% OOIP with TINBOP (**Figure 4.4**). This represents a 74% increase in oil recovery in ten years with TINBOP, as a result of more heat being retained in the reservoir. Cumulative steam injected under TINBOP was 25% more than that under conventional cyclic steam injection. However, the higher oil recovery under TINBOP resulted in a decrease of the steam-oil ratio to 2.1 from 2.9 with conventional cyclic steam injection (**Figure 4.5**).

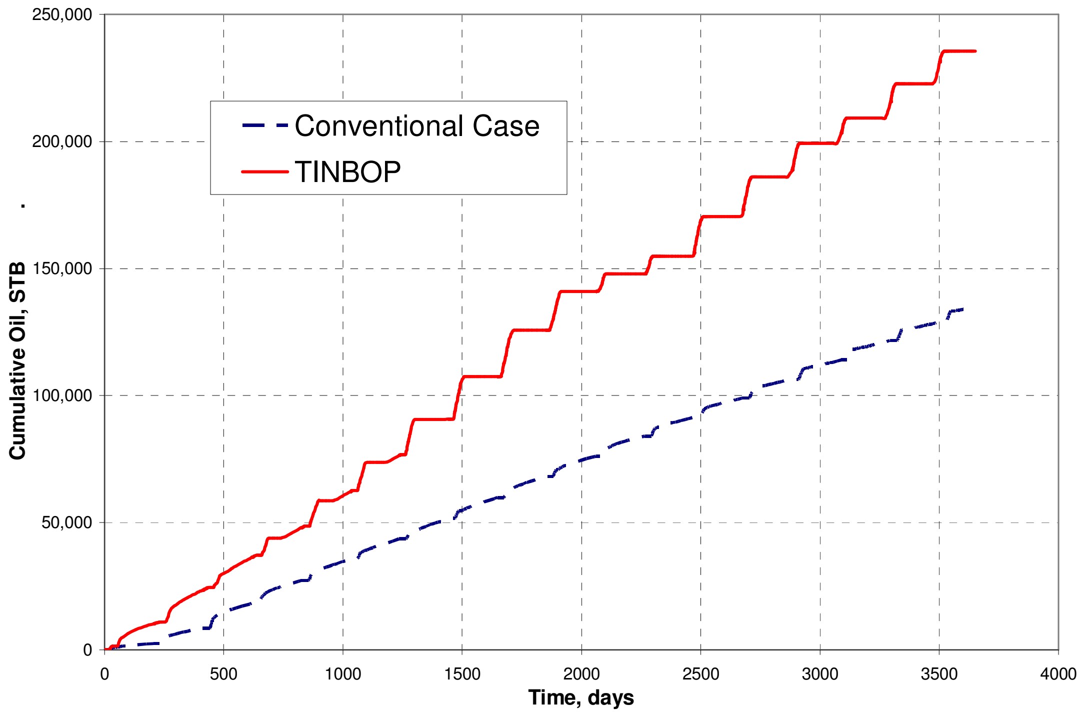


**Figure 4.4— Cumulative oil for the Hamaca model**

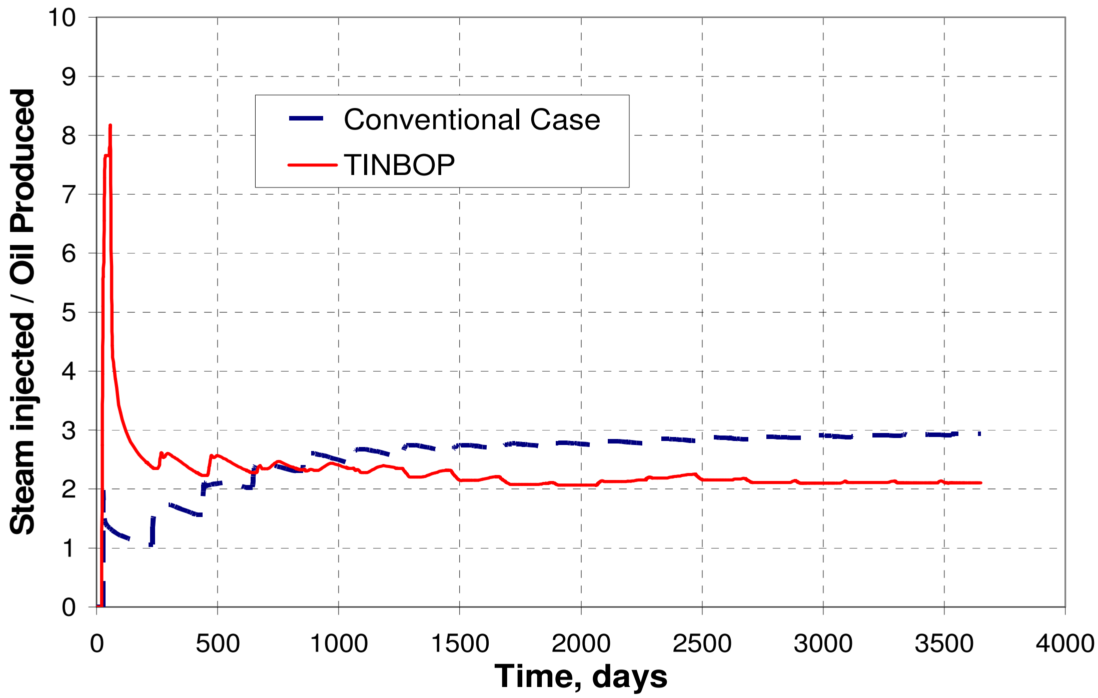


**Figure 4.5— Steam oil ratio for the Hamaca model**

Run times for the Hamaca model averaged 42 minutes and 9 seconds, for 215 different simulation runs. The model failed to converge for several of the runs due to the sharp temperature difference across adjacent gridblocks in the TINBOP model during injection. The adaptive timestep size selector had trouble adjusting for the large differences, which require a smaller timestep. The timestep was manually selected to be 8 seconds, instead of 0.1 days, to provide adequate resolution.

## 4.3 San Ardo Model

Under conventional cyclic steam injection, oil recovery after ten years was 10.2% OOIP, compared to 16.1% OOIP with TINBOP (**Figure 4.6**). This represents a 57%

increase in oil recovery with TINBOP, while only increasing the cumulative steam injected by 2% over that with conventional cyclic steam injection. With TINBOP the steam-oil ratio was 1.0 compared to 1.6 under conventional cyclic steam injection (**Figure 4.7**).

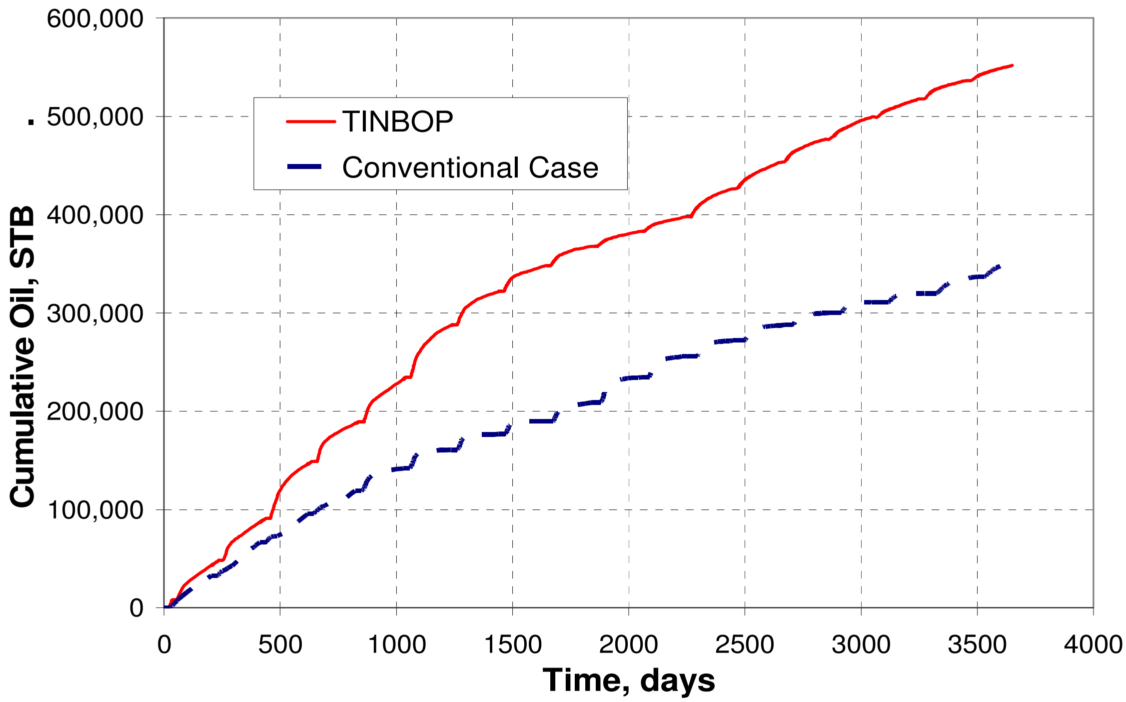


**Figure 4.6— Cumulative oil for the San Ardo model**

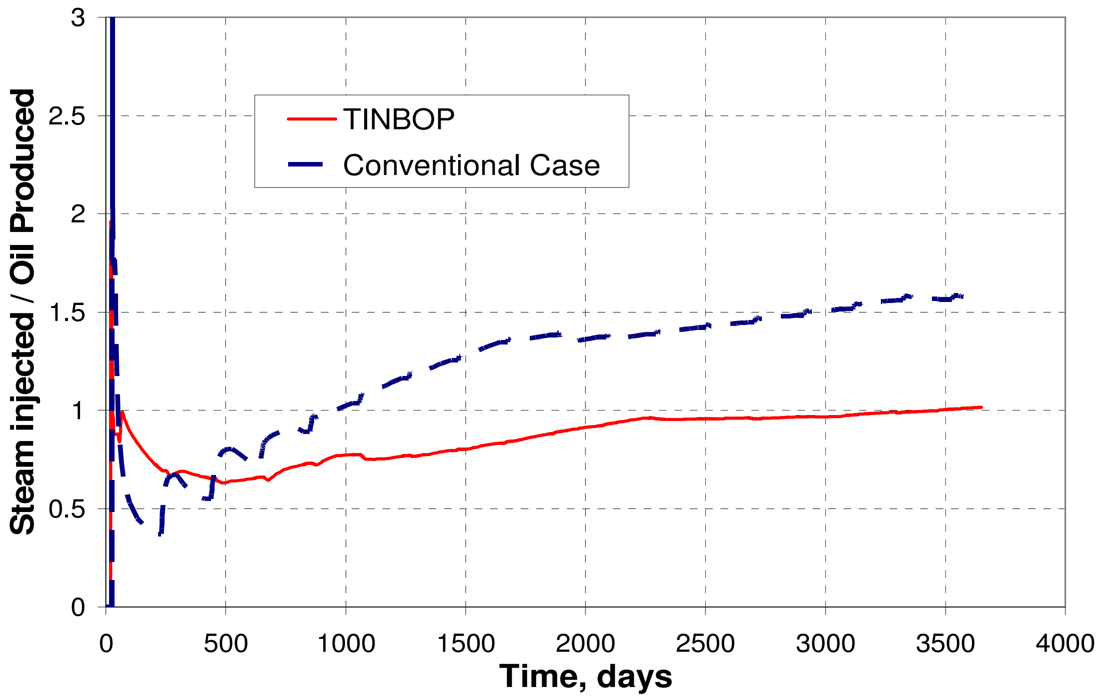


**Figure 4.7— Steam oil ratio for the San Ardo model**

Run times for the San Ardo model averaged 27 minutes and 48 seconds, for 198 different simulation runs. The model failed to converge for several of the runs due to the sharp temperature difference across adjacent gridblocks in the TINBOP model during injection. The adaptive timestep size selector had trouble adjusting for the large differences, which require a smaller timestep. The timestep was manually selected to be 8 seconds, instead of 0.1 days, to provide adequate resolution.

# V. SENSITIVITY RUNS

Runs were made to determine the TINBOP method's sensitivity to different parameters. Different runs were made with varying: thickness, vertical to horizontal permeability ratio and viscosity.

## 5.1 Thickness Sensitivity

### 5.1.1 SPE Model

Sensitivity runs (each for a period of 10 years) were made – for both conventional and TINBOP cyclic steam injection methods - in which the reservoir thickness was decreased from the original (base case) value of 80 ft down to 5 ft. It can be seen that the percent gain in oil recovery with TINBOP over conventional cyclic steam injection decreases from 93% (for 80 ft reservoir thickness) to 0% for reservoir thickness of about 25 ft (**Figure 5.1**). That is, for reservoirs similar to that of the SPE model, TINBOP appears to be beneficial if the reservoir thickness is greater than 25 ft. Clearly, gravity segregation of steam (a function of reservoir thickness) and therefore the benefit of a dual-string completion with TINBOP become less significant with decrease in reservoir thickness.

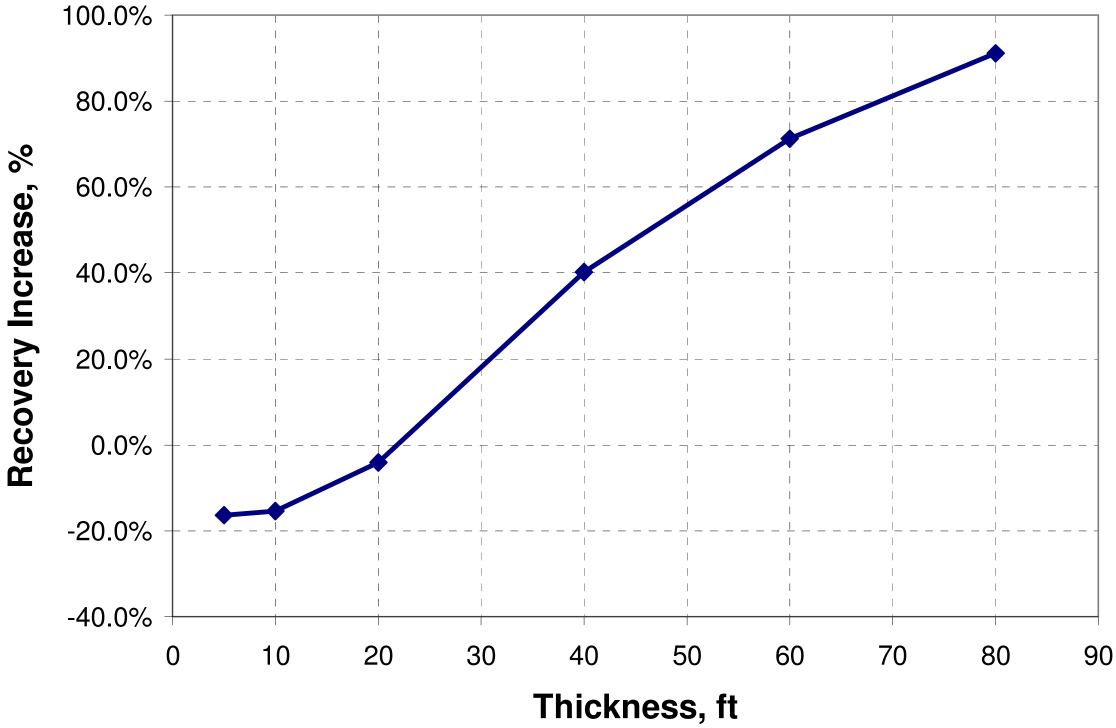


**Figure 5.1— Thickness sensitivity for the SPE model**

### 5.1.2 Hamaca Model

Sensitivity runs indicate percent gain in oil recovery with TINBOP over that with conventional cyclic steam injection decreases from about 74% for reservoir thickness of 80 ft to about 35% at reservoir thickness of 20 ft (**Figure 5.2**). Compared to the SPE model (0% gain with TINBOP at 25 ft), TINBOP is still beneficial for a heavy oil reservoir like Hamaca because of the oil's higher viscosity and thus gravity segregation of steam is still significant at reservoir thickness as low as 20 ft.

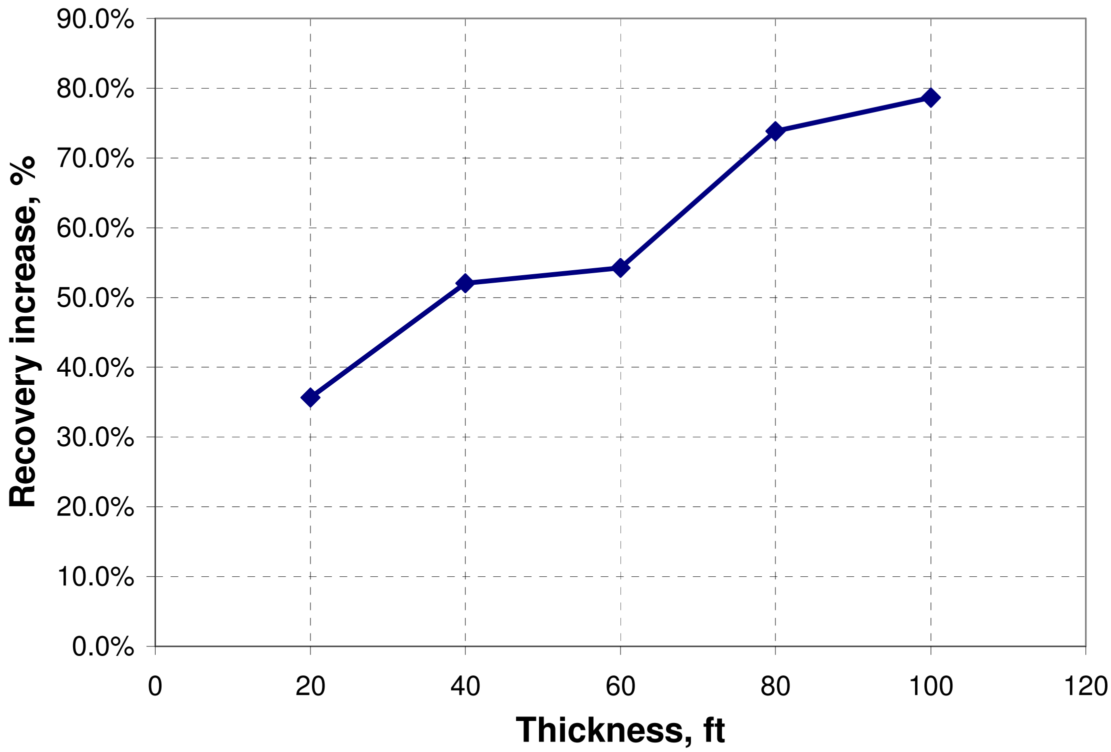


**Figure 5.2— Thickness sensitivity for the Hamaca model**

### 5.1.3 San Ardo Model

Decreasing the reservoir thickness from 115 ft to about 22 ft resulted in decrease in percent oil recovery gain with TINBOP from 57% to practically 0% (**Figure 5.3**).

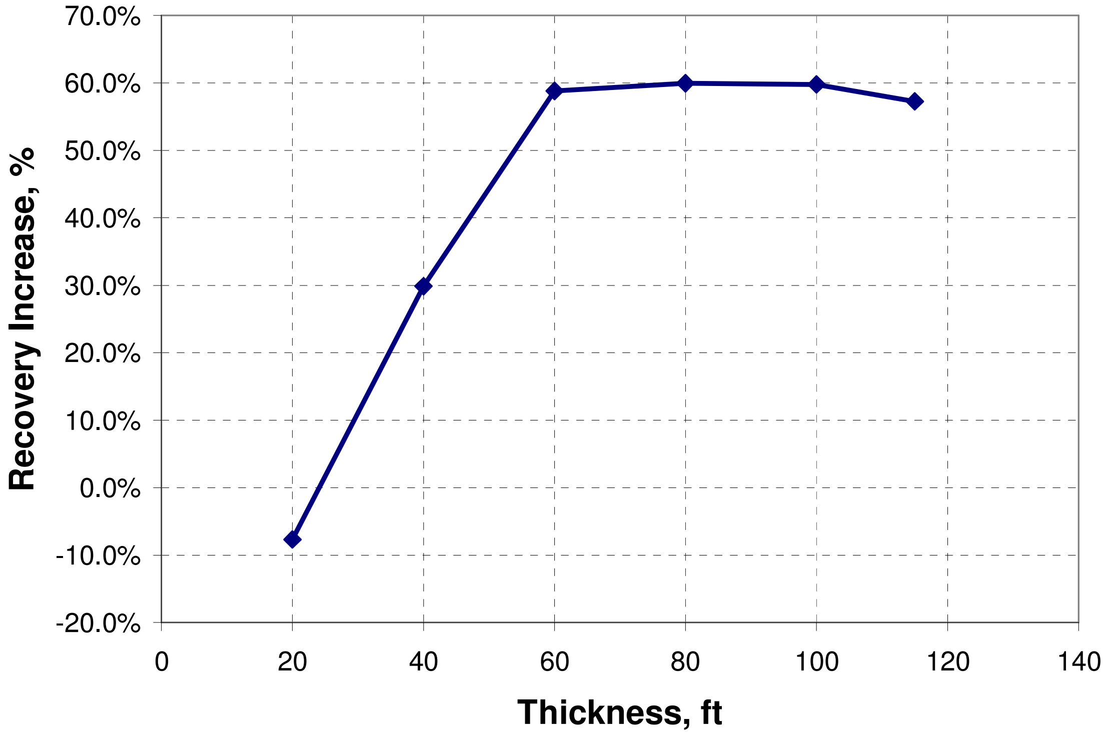


**Figure 5.3— Thickness sensitivity for the San Ardo model**

## 5.2 Vertical to Horizontal Permeability Ratio

### 5.2.1 SPE Model

Sensitivity runs for the SPE model indicate a decrease in the recovery as the vertical to horizontal permeability ratio increases (**Figure 5.4**). Fitting a curve to the data with linear regression of the modified Hoerl[10] form yields the following equation:

$$\text{Recovery Increase } = 40.809 \times 0.9353^{\frac{1}{kvkh}} \times (kvkh)^{-0.3744}$$

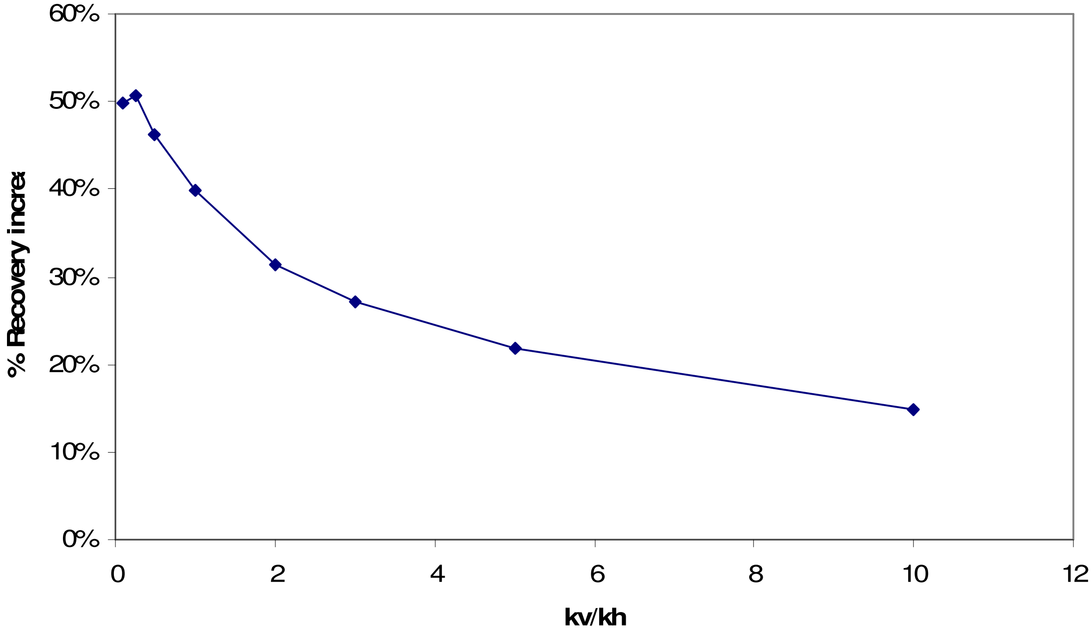


**Figure 5.4— The SPE model's sensitivity to the vertical to horizontal permeability ratio**

### 5.2.2 Hamaca Model

Sensitivity runs for the Hamaca model indicate a decrease in the recovery as the vertical to horizontal permeability ratio increases (**Figure 5.5**). Fitting a curve to the data of the modified Hoerl[10] form yields the following equation:

$$\text{Recovery Increase} = 40.630 \times 0.8720^{\frac{1}{kvkh}} \times (kvkh)^{-0.3037}$$

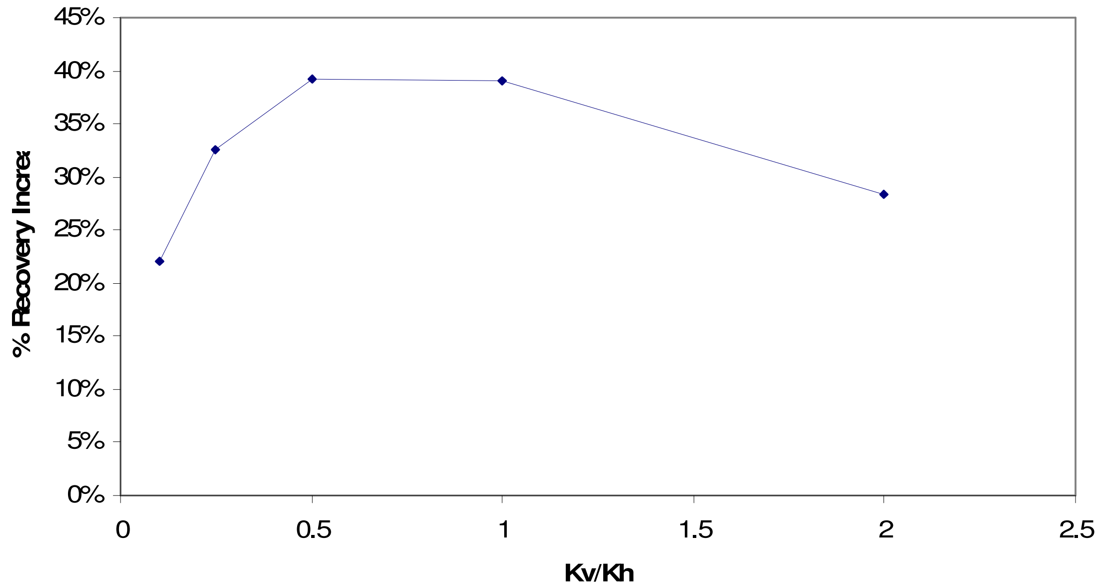


**Figure 5.5—The Hamaca model's sensitivity to the vertical to horizontal permeability ratio**

### 5.2.3 San Ardo Model

Sensitivity runs for the San Ardo model indicate a decrease in the recovery as the vertical to horizontal permeability ratio (*kvkh*) increases (**Figure 5.6**). Fitting a curve to the data of the modified Hoerl form yields the following equation:

$$\text{Recovery Increase} = 38.158 \times 0.9922^{\frac{1}{kvkh}} \times (kvkh)^{-0.2294}$$

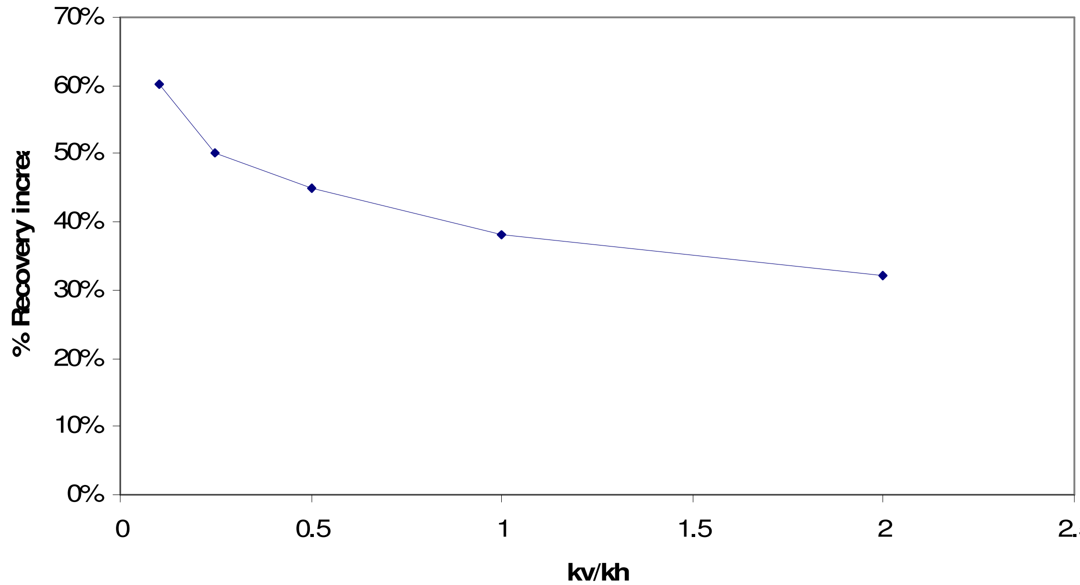


**Figure 5.6—The San Ardo model's sensitivity to the vertical to horizontal permeability ratio**

## 5.3 Viscosity Sensitivity Runs

Simulation runs were made using the SPE model sensitivity to changes in cold oil viscosity (μ). Runs were made with viscosity varying from $1/10^{th}$ to five times the original cold oil viscosity. The viscosity data were only altered by using a multiplier on the data set; the original exponential trend dependence on temperature was not altered. As the graph below shows (**Figure 5.7**), the overall dependence shows a modified Hoerl form, where the trend follows the following equation:

$$\text{Recovery Increase} = 45.301 \times 0.88420^{\frac{1}{\mu}} \times (\mu)^{-0.48799}$$

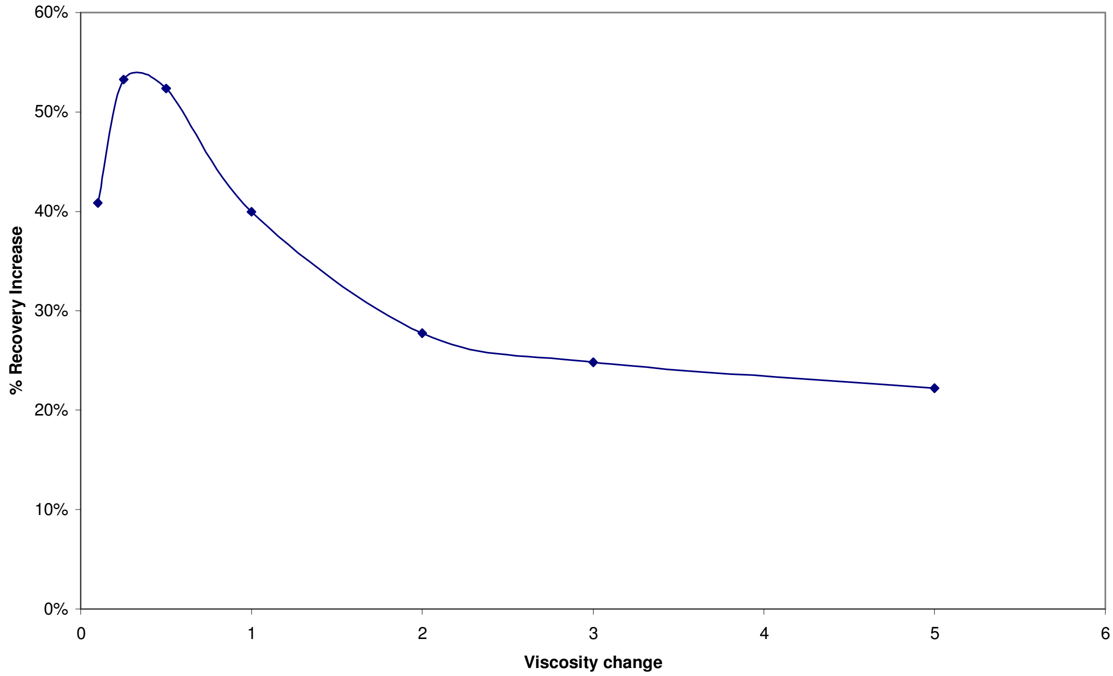


**Figure 5.7—The SPE model's sensitivty to the oil viscosity multiplier**

## 5.4 Permeability Sensitivity

Simulation runs were made to quantify the effect of the absolute permeability ($k$) on the TINBOP method's recovery increase. The runs were based on modifications to the SPE model. The permeability in all layers was set to an equal value ranging from 50 to 5000 md. **Figure 5.8** shows how the TINBOP improves with increased absolute permeability. Based on this graph, the breakeven permeability is around 360 md, which shows the TINBOP method is applicable to nearly all current heavy oil reservoirs with properties similar to the three reservoirs simulated for this study. TINBOP's dependence on permeability is shown to be of the logarithmic form:

$$\text{Recovery increase} = -140.67 + 24.291 \times \ln[k]$$

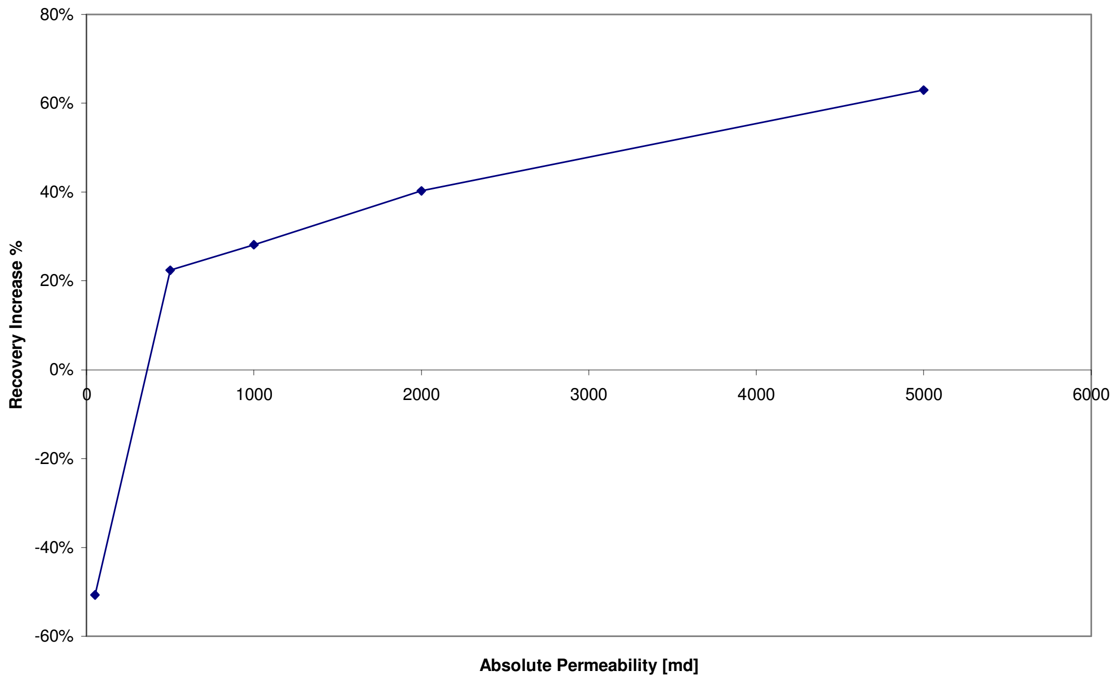


**Figure 5.8— SPE model sensitivity to absolute permeability**

## 5.5 Unified model

After models have been independently established for every sensitivity parameter, a unified model can be created to establish when TINBOP will work for any given reservoir (**Figure 5.9**). Combining the modified Hoerl model from the viscosity and vertical to horizontal permeability ratio parameters with the logarithmic and rational function forms for the permeability and thickness, a model of the following form is developed:

Recovery_Increase=

$$=\left(\left(156.38\times -0.1243^{\frac{1}{kvkh\times\mu}}\times\left(kvkh\times\mu\right)^{-0.8084}\right)+7.19937\times\ln[k]\right)\times\frac{(-1.681+0.1150\times h)}{\left(1+20.3714\times h-0.13059\times h^{2}\right)}$$

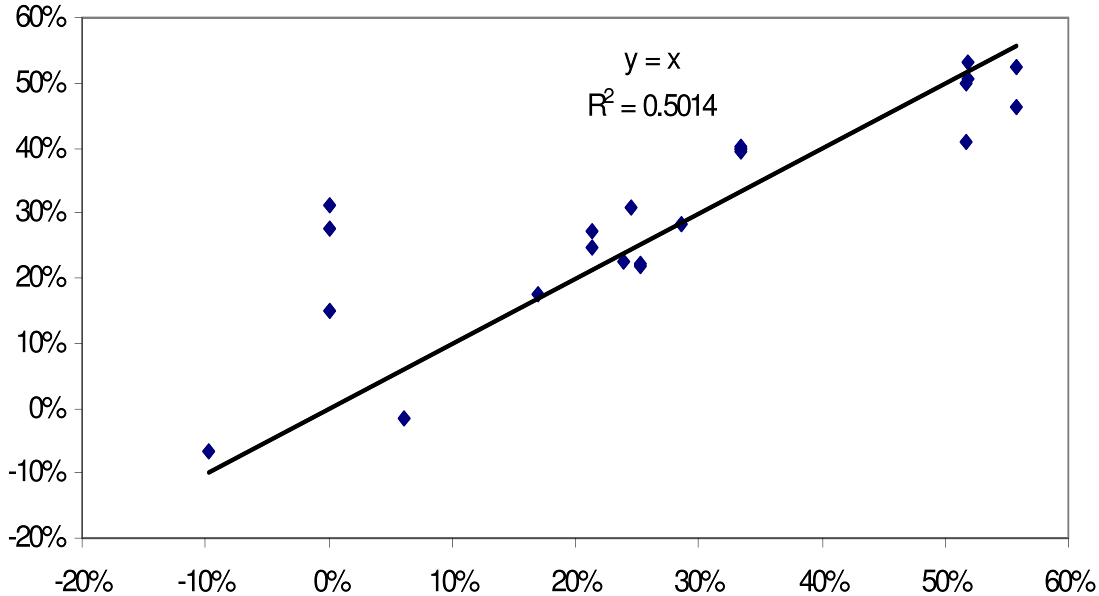


**Figure 5.9— Correlation for the unified model shows**

## VI. SUMMARY AND CONCLUSIONS

The following is a summary and the main conclusions of the simulation study with regard to TINBOP.

1. Simulation studies - using 2-D radial non-compositional models - were conducted to compare the performance of cyclic steam injection using the conventional method against the novel TINBOP method.
2. Three heavy oil reservoir types were used in the comparative simulation studies: SPE model (14°API oil), Hamaca (9°API oil), and San Ardo (12°API oil).
3. Simulation results indicate that the novel TINBOP method increases oil recovery in a ten-year period by 57%-93% over that with conventional cyclic steam injection.
4. Simulation results clearly indicate more heat is retained in the reservoir using TINBOP compared to conventional cyclic steam injection. This is due to the fact in TINBOP, steam is injected in the short string, rising to and being retained in the upper part of the reservoir, while at the same time production via the long string further minimizes steam production.
5. Although 2-25% more steam is injected during TINBOP compared to conventional cyclic steam injection, the steam-oil ratio decrease significantly because more heat is retained in the reservoir.
6. An initial warm-up period is required to reduce the viscosity of the oil surrounding the lower production perforations.
7. As expected, the gain in oil recovery with TINBOP decreases with decrease in reservoir thickness. For the SPE and San Ardo models, there appears to be no gain

with TINBOP at about 25 ft reservoir thickness, while for Hamaca the gain is still about 35% at 20 ft thickness due to effective gravity segregation at the higher oil viscosity.

8. Viscosity does affect the overall recovery improvement, although not very much. For lower viscosities there appears to be a breakeven point where TINBOP is not as effective as conventional cyclic steam.
9. TINBOP was found to have a logarithmic dependence on the permeability, with the highest gain in recovery with higher permeabilities. The lowest permeability for the TINBOP to be effective was around 360 md.
10. A unified model that includes the screening criteria for different reservoir properties gives an indication of the applicability to nearly any heavy oil field.

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## APPENDIX A

## SPE RESERVOIR SIMULATION FILE

```
***************************************************************************
*****
** Template (stspe001.dat): Fourth SPE Comparative Solution Project 1a     **
***************************************************************************
*****
***************************************************************************
************
**                                                                    **
** FILE :  STSPE001.DAT                                               **
**                                                                    **
** MODEL:  SINGLE WELL CYCLIC STEAM    FIELD UNITS   13X1X4 RADIAL
GRID          **
**                                                                    **
** USAGE:  SPE COMPARATIVE SOLUTION PROJECT FOR CYCLIC STEAM
STIMULATION          **
**                                                                    **
***************************************************************************
************
***************************************************************************
************
**                                                                    **
**   This is the STARS data set for problem 1A in "Fourth SPE              **
**  Comparative Solution Project - A Comparison of Steam Injection         **
**  Simulators", paper SPE 13510, presented at the eighth SPE symposium    **
**  on reservoir simulation at Dallas, Texas, Feb 10-13, 1985.             **
**  Also published in J. Pet. Tech. (Dec, 1987), pp 1576-1584              **
**                                                                    **
**   The problem is three cycles of steam stimulation, with water and      **
**  a dead oil.  A two-dimensional cross-sectional study is required.      **
**                                                                    **
**  Features:                                                         **
**                                                                    **
**  1)  Two-dimensional cross-sectional r-z coordinates.                   **
**                                                                    **
**  2)  Distinct permeability layering.                               **
**                                                                    **
**  3)  Black-oil type treatment of fluids.                           **
**                                                                    **
**  4)  Sharp changes in oil viscosity occur at the steam front            **
**     (487 cp at 125 F to 2.5 cp at 450 F).                          **
**                                                                    **
**  5)  Automatic initial vertical equilibrium calculation.                **
```

```
**                                                **
**  6)  Multi-layer well with additional injection and production          **
**      operating constraints.                                **
**                                                **
*****************************************************************************
************
```

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


RESULTS SIMULATOR STARS

*FILENAME *OUTPUT *INDEX-OUT *MAIN-RESULTS-OUT    ** Use default file
names

**CHECKONLY
*INTERRUPT *STOP

*TITLE1 'STARS Test Bed No. 6'
*TITLE2 'Fourth SPE Comparative Solution Project'
*TITLE3 'Problem 1A:  2-D CYCLIC STEAM INJECTION'

*INUNIT *FIELD   ** output same as input

*OUTPRN *GRID *PRES *SW *SO *SG *TEMP *Y *X *W *SOLCONC *OBHLOSS
*VISO *VISG
*OUTPRN *WELL *ALL
*WRST 200  *WPRN *GRID 200  *WPRN *ITER 200

*OUTSRF *SPECIAL *BLKVAR *PRES 0 15       ** pressure in block (2,1,2)
        *BLKVAR *SO 0 15         ** oil saturation in block (2,1,2)
        *BLKVAR *SG 0 15         ** gas saturation in block (2,1,2)
        *BLKVAR *TEMP 0 15       ** temperature in block (2,1,2)
        *BLKVAR *CCHLOSS 0 40    ** rate of heat loss/gain in block (1,1,4)
        *BLKVAR *CCHLOSS 0 46    ** rate of heat loss/gain in block (7,1,4)
        *MATBAL *WELL 2          ** cumulative oil production
        *MATBAL *WELL 1          ** cumulative water production
        *CCHLOSS                 ** cumulative heat loss/gain
*OUTSRF *GRID *PRES *SO *SG *TEMP
```

```
**  ==============  GRID AND RESERVOIR DEFINITION
=================


*GRID *RADIAL 13 1 20 *RW 0     ** Zero inner radius matches previous treatment

**  Radial blocks:  small near well;  outer block is large
*DI *IVAR  3 10*10 40 120

*DJ *CON 360  **  Full circle

*DK *CON 4.

*POR *CON 0.3
*PERMI *KVAR  5*2000. 5*500. 5*1000. 5*2000.
*PERMJ *EQUALSI
*PERMK *EQUALSI  / 2

*END-GRID

*CPOR 5e-4
*PRPOR 75
*ROCKCP 35
*THCONR 24
*THCONW 24
*THCONO 24
*THCONG 24
*HLOSSPROP  *OVERBUR 35 24  *UNDERBUR 35 24



**  ==============  FLUID DEFINITIONS  ======================


*MODEL 2 2 2   ** Components are water and dead oil.  Most water
             ** properties are defaulted (=0).  Dead oil K values
             ** are zero, and no gas properties are needed.

*COMPNAME       'Water'    'OIL'
**              -----      -------
    *CMM        18.02      600
    *PCRIT      3206.2     0        ** These four properties
    *TCRIT      705.4      0        ** are for the gas phase.
    *AVG        1.13e-5    0        ** The dead oil component does
    *BVG        1.075      0        ** not appear in the gas phase.
```

```
    *MOLDEN     0        0.10113
    *CP         0       5.e-6
    *CT1        0       3.8e-4

    *CPL1       0       300

*VISCTABLE

**      Temp
         75     0       5780
        100     0        1380
        150     0        187
        200     0         47
        250     0         17.4
        300     0          8.5
        350     0          5.2
        500     0          2.5
        700     0          2.5

*PRSR 14.7
*TEMR 60
*PSURF 14.7
*TSURF 60



**  =============  ROCK-FLUID PROPERTIES  =====================


*ROCKFLUID

*SWT   **  Water-oil relative permeabilities

**   Sw       Krw        Krow
**  ____     _________    _______-
   0.45     0.0         0.4
   0.47     0.000056    0.361
   0.50     0.000552    0.30625
   0.55     0.00312     0.225
   0.60     0.00861     0.15625
   0.65     0.01768     0.1
   0.70     0.03088     0.05625
   0.75     0.04871     0.025
   0.77     0.05724     0.016
   0.80     0.07162     0.00625
   0.82     0.08229     0.00225
```

```
   0.85    0.1        0.0

*SLT   **  Liquid-gas relative permeabilities

**   Sl       Krg        Krog
**  -----    -------    -------
   0.45    0.2        0.0
   0.55    0.14202    0.0
   0.57    0.13123    0.00079
   0.60    0.11560    0.00494
   0.62    0.10555    0.00968
   0.65    0.09106    0.01975
   0.67    0.08181    0.02844
   0.70    0.06856    0.04444
   0.72    0.06017    0.05709
   0.75    0.04829    0.07901
   0.77    0.04087    0.09560
   0.80    0.03054    0.12346
   0.83    0.02127    0.15486
   0.85    0.01574    0.17778
   0.87    0.01080    0.20227
   0.90    0.00467    0.24198
   0.92    0.00165    0.27042
   0.94    0.0        0.30044
   1.      0.0        0.4


**  ==============  INITIAL CONDITIONS  ======================


*INITIAL

** Automatic static vertical equilibrium
*VERTICAL *DEPTH_AVE
*REFPRES 75
*REFBLOCK 1 1 20

*TEMP *CON 125



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


*NUMERICAL   ** All these can be defaulted.  The definitions
```

```
        ** here match the previous data.

*SDEGREE GAUSS
*DTMAX 90

*NORM    *PRESS 200  *SATUR 0.2   *TEMP 180  *Y 0.2   *X 0.2


*RUN



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


**    The injection and production phases of the single cycling well
**  will be treated as two distinct wells which are in the same
**  location but are never active at the same time.  In the well data
**  below, both wells are defined immediately, but the producer is
**  shut in, to be activated for the drawdown.


*DATE 1973 9 25.5

  *DTWELL .02

  ** INJECTOR:  Constant pressure steam injection type

  WELL  1 'Injector 1'
INJECTOR MOBWEIGHT 'Injector 1'
TINJW 450.
QUAL 0.7
INCOMP WATER  1.0 0.0
OPERATE MAX BHP  1000. CONT REPEAT
OPERATE MAX STW  1000. CONT REPEAT

PERF WI   'Injector 1'
        1 1 20  15615.074
        1 1 19  15615.074
        1 1 18  15615.074
        1 1 17  15615.074
        1 1 16  15615.074


WELL  2 'Producer 1'
PRODUCER 'Producer 1'
```

```
OPERATE MAX STL  1000. CONT REPEAT
OPERATE MIN BHP  17. CONT REPEAT

GEOMETRY K 0.3 0.5 1. 0.
PERF GEO   'Producer 1'
          1 1 5  1.
          1 1 4  1.
          1 1 3  1.
          1 1 2  1.
          1 1 1  1.

WELL  3 'Injector 2'
INJECTOR MOBWEIGHT 'Injector 2'
TINJW 450.
QUAL 0.7
INCOMP WATER  1.0 0.0
OPERATE MAX BHP  1000. CONT REPEAT
OPERATE MAX STW  1000. CONT REPEAT

PERF WI   'Injector 2'
          1 1 20  15615.074
          1 1 19  15615.074
          1 1 18  15615.074
          1 1 17  15615.074
          1 1 16  15615.074
          1 1 15  7807.536
          1 1 14  7807.536
          1 1 13  7807.536
          1 1 12  7807.536
          1 1 11  7807.536
          1 1 10  19518.842
          1 1 9  19518.842
          1 1 8  19518.842
          1 1 7  19518.842
          1 1 6  19518.842
          1 1 5  39037.686
          1 1 4  39037.686
          1 1 3  39037.686
          1 1 2  39037.686
          1 1 1  39037.686

WELL  4 'Producer 2'
PRODUCER 'Producer 2'
OPERATE MAX STL  1000. CONT REPEAT
OPERATE MIN BHP  17. CONT REPEAT
```

```
GEOMETRY K 0.3 0.5 1. 0.
PERF GEO   'Producer 2'
        1 1 20  1.
        1 1 19  1.
        1 1 18  1.
        1 1 17  1.
        1 1 16  1.
        1 1 15  1.
        1 1 14  1.
        1 1 13  1.
        1 1 12  1.
        1 1 11  1.
        1 1 10  1.
        1 1 9  1.
        1 1 8  1.
        1 1 7  1.
        1 1 6  1.
        1 1 5  1.
        1 1 4  1.
        1 1 3  1.
        1 1 2  1.
        1 1 1  1.

  SHUTIN 'Producer 1'
SHUTIN 'Injector 1'
SHUTIN 'Producer 2'

  TIME 10      **
*OUTSRF *GRID *REMOVE *PRES
SHUTIN 'Injector 2'
TIME 17
DTWELL 1
OPEN 'Producer 2'
TIME 365
DTWELL 0.01
SHUTIN 'Producer 2'
OPEN 'Injector 1'
TIME 375
DTWELL 7
SHUTIN 'Injector 1'
TIME 382
DTWELL 1
OPEN 'Producer 1'
TIME 730
DTWELL 0.01
SHUTIN 'Producer 1'
```

```
OPEN 'Injector 1'
TIME 740
DTWELL 7
SHUTIN 'Injector 1'
TIME 747
DTWELL 1
OPEN 'Producer 1'
TIME 1095
DTWELL 0.01
SHUTIN 'Producer 1'
OPEN 'Injector 1'
TIME 1105
DTWELL 7
SHUTIN 'Injector 1'
TIME 1112
DTWELL 1
OPEN 'Producer 1'
TIME 1460
DTWELL 0.01
SHUTIN 'Producer 1'
OPEN 'Injector 1'
TIME 1470
DTWELL 7
SHUTIN 'Injector 1'
TIME 1477
DTWELL 1
OPEN 'Producer 1'
TIME 1825
DTWELL 0.01
SHUTIN 'Producer 1'
OPEN 'Injector 1'
TIME 1835
DTWELL 7
SHUTIN 'Injector 1'
TIME 1842
DTWELL 1
OPEN 'Producer 1'
TIME 2190
DTWELL 0.01
SHUTIN 'Producer 1'
OPEN 'Injector 1'
TIME 2200
DTWELL 7
SHUTIN 'Injector 1'
TIME 2207
DTWELL .5
```

```
OPEN 'Producer 1'
TIME 2555
DTWELL 0.00001
SHUTIN 'Producer 1'
OPEN 'Injector 1'
TIME 2565
DTWELL 7
SHUTIN 'Injector 1'
TIME 2572
DTWELL .5
OPEN 'Producer 1'
TIME 2920
DTWELL 0.00001
SHUTIN 'Producer 1'
OPEN 'Injector 1'
TIME 2930
DTWELL 7
SHUTIN 'Injector 1'
TIME 2937
DTWELL .5
OPEN 'Producer 1'
TIME 3285
DTWELL 0.00001

SHUTIN 'Producer 1'
OPEN 'Injector 1'
TIME 3295
DTWELL 7
SHUTIN 'Injector 1'
TIME 3302
DTWELL .5
OPEN 'Producer 1'
TIME 3650
STOP
```

## APPENDIX B

## SAN ARDO RESERVOIR SIMULATION FILE

```
RESULTS SIMULATOR STARS
RESULTS SECTION INOUT
*TITLE1  'San Ardo Field - Lombardi Reservoir'
*TITLE2  'Vertical-Vertical System'
*TITLE3  'Continuous Steam Injection'
*CASEID  'First'
*INUNIT *FIELD



*INTERRUPT *INTERACTIVE
*WPRN *GRID  20
*WPRN *SECTOR  0
*WSRF *WELL 20
*WSRF *GRID 20
*WSRF *SECTOR  0
*WPRN *ITER 20
*OUTPRN *WELL *ALL
*OUTPRN *GRID *ALL
*OUTPRN *RES *ALL
*OUTPRN *ITER *BRIEF
*OUTSRF *WELL *COMPONENT *ALL *LAYER *ALL
*OUTSRF *GRID *PRES *SO *SW *SG *TEMP *VISO

*XDR *ON
*PRINT_REF *ON
*OUTSOLVR *OFF
*MAXERROR  20
*SR2PREC *DOUBLE



RESULTS XOFFSET 0.
RESULTS YOFFSET 0.
RESULTS ROTATION 0

GRID RADIAL 20 1 20 RW 3.00000000E-1
KDIR UP
DI IVAR
         0.13599 0.19764 0.28723 0.41743 0.60666 0.88167 1.28133 1.86217 2.7063
```

```
        3.93309 5.716 8.30711 12.0728 17.5455 25.499 37.0579 53.8566 78.2702
113.751
        165.315

DJ CON 360.

DK CON 5.75
DTOP
        20*1900.




**$ RESULTS PROP NULL  Units: Dimensionless
**$ RESULTS PROP Minimum Value: 1  Maximum Value: 1
**$ 0 = NULL block, 1 = Active block
NULL CON 1.

**$ RESULTS PROP PINCHOUTARRAY  Units: Dimensionless
**$ RESULTS PROP Minimum Value: 1  Maximum Value: 1
**$ 0 = PINCHED block, 1 = Active block
PINCHOUTARRAY CON 1.
RESULTS SECTION GRID

RESULTS SPEC 'Grid Thickness'
RESULTS SPEC SPECNOTCALCVAL 0
RESULTS SPEC REGION 'All Layers (Whole Grid)'
RESULTS SPEC REGIONTYPE 0
RESULTS SPEC LAYERNUMB 0
RESULTS SPEC PORTYPE 1
RESULTS SPEC CON 5
RESULTS SPEC STOP

RESULTS SPEC 'Grid Top'
RESULTS SPEC SPECNOTCALCVAL 0
RESULTS SPEC REGION 'Layer 1 - Whole layer'
RESULTS SPEC REGIONTYPE 1
RESULTS SPEC LAYERNUMB 1
RESULTS SPEC PORTYPE 1
RESULTS SPEC CON 1400
RESULTS SPEC STOP
RESULTS PINCHOUT-VAL      0.0002 'ft'
RESULTS SECTION NETPAY
RESULTS SECTION NETGROSS
RESULTS SECTION POR
```

```
**$ RESULTS PROP POR  Units: Dimensionless
**$ RESULTS PROP Minimum Value: 0.345  Maximum Value: 0.345
POR CON 0.345
RESULTS SECTION PERMS

**$ RESULTS PROP PERMI  Units: md
**$ RESULTS PROP Minimum Value: 6922  Maximum Value: 6922
PERMI CON 6922.

**$ RESULTS PROP PERMJ  Units: md
**$ RESULTS PROP Minimum Value: 6922  Maximum Value: 6922
PERMJ CON 6922.

**$ RESULTS PROP PERMK  Units: md
**$ RESULTS PROP Minimum Value: 692.2  Maximum Value: 692.2
PERMK CON 692.2
RESULTS SECTION TRANS
RESULTS SECTION FRACS
RESULTS SECTION GRIDNONARRAYS
RESULTS SECTION VOLMOD
RESULTS SECTION VATYPE
RESULTS SECTION SECTORLEASE

RESULTS SECTION THTYPE
END-GRID

ROCKTYPE 1
  CPOR 9.E-05
  ROCKCP 35.02
  THCONR 1.
  THCONW 0.36
  THCONO 1.2
  THCONG 0.0833
  HLOSSTDIFF 0.01
  HLOSSPROP +K 60. 60.
    -K 60. 60.



RESULTS SECTION GRIDOTHER
RESULTS SECTION MODEL
*MODEL     3 3 3 1
*COMPNAME 'WATER' 'OIL' 'GAS'
*KV1       0.E+00 5.165000E+06 1.53400E+05
*KV4       0.E+00 -1.53625E+04 -1.9141E+03
```

```
*KV5       0.E+00 -4.5967E+02 -4.5967E+02
*CMM       0 456.015 16.7278
*PCRIT     0.0E+0 1.7902E+2 6.7046E+2
*TCRIT     0.0E+0 1.03621E+3 -1.0735E+2
*SURFLASH *KVALUE
*PRSR     275
*TEMR     127
*PSURF    1.4696E+1
*TSURF    6.0E+1

*MOLDEN    6.24E+1 1.356E-1 4.515E-2
*CP       0.0E+0 3.805E-6 3.754E-3
*CT1      0.0E+0 1.66E-4 1.91E-3
*CT2      0.0E+0 0.0E+0 0.0E+0

*VISCTABLE
** T, deg F      'WATER'   'OIL'    'GAS'
**              ________  _____-   ________

   50        1.56523     312554      0.011018
   100        0.68986     12070.3     0.011882
   150        0.42719     1321.07     0.012721
   200        0.304049    252.353     0.013536
   250        0.2335585   67.417      0.014326
   300        0.1882796   28.86265    0.015094
   350        0.1569178   13.88694    0.01584
   400        0.1340065   7.86136     0.016566
   450        0.1165906   4.97111     0.017273
   500        0.1029386   3.402065    0.017962
   550        0.0919712   2.468885    0.018635
   600        0.0829824   1.873853    0.019293
   650        0.0754913   1.473124    0.019937
   700        0.06916     1.19115     0.020568


RESULTS SECTION MODELARRAYS
RESULTS SECTION ROCKFLUID
**  =============  ROCK-FLUID PROPERTIES  =====================

*ROCKFLUID


*RPT 1 *WATWET *STONE2
*SWT            **
**   Sw       Krw       Krow
```

```
**  _____   __________   _______-

0.450000  0.000000  0.400000  0.000000
0.470000  0.000056  0.361000  0.000000
0.500000  0.000552  0.306250  0.000000
0.550000  0.003120  0.225000  0.000000
0.600000  0.008610  0.156250  0.000000
0.650000  0.017680  0.100000  0.000000
0.700000  0.030880  0.056250  0.000000
0.750000  0.048710  0.025000  0.000000
0.770000  0.057240  0.016000  0.000000
0.800000  0.071620  0.006250  0.000000
0.820000  0.082290  0.002250  0.000000
0.850000  0.100000  0.000000  0.000000

*SLT            **
**   Sl       Krg        Krog
**  _____   _______-   _______-

0.450000  0.200000  0.000000  0.000000
0.550000  0.142020  0.000000  0.000000
0.570000  0.131230  0.000790  0.000000
0.600000  0.115600  0.004940  0.000000
0.620000  0.105550  0.009680  0.000000
0.650000  0.091060  0.019750  0.000000
0.670000  0.081810  0.028440  0.000000
0.700000  0.068560  0.044440  0.000000
0.720000  0.060170  0.057090  0.000000
0.750000  0.048290  0.079010  0.000000
0.770000  0.040870  0.095600  0.000000
0.800000  0.030540  0.123460  0.000000
0.830000  0.021270  0.154860  0.000000
0.850000  0.015740  0.177780  0.000000
0.870000  0.010800  0.202270  0.000000
0.900000  0.004670  0.241980  0.000000
0.920000  0.001650  0.270420  0.000000
0.940000  0.000000  0.300440  0.000000
1.000000  0.000000  0.400000  0.000000


RESULTS SECTION ROCKARRAYS

**$ RESULTS PROP KRTYPE  Units: Dimensionless
**$ RESULTS PROP Minimum Value: 1  Maximum Value: 1
KRTYPE CON 1.
```

```
RESULTS SECTION INIT
*INITIAL
*VERTICAL *ON
**$ Data for PVT Region 1
**$ ————————————————————————————————————-
*INITREGION 1
*REFDEPTH 1957.5
*REFPRES 845.



RESULTS SECTION INITARRAYS

**$ RESULTS PROP SW  Units: Dimensionless
**$ RESULTS PROP Minimum Value: 0.45  Maximum Value: 0.45
SW CON 0.45

**$ RESULTS PROP SO  Units: Dimensionless
**$ RESULTS PROP Minimum Value: 0.55  Maximum Value: 0.55
SO CON 0.55

**$ RESULTS PROP TEMP  Units: F
**$ RESULTS PROP Minimum Value: 127  Maximum Value: 127
TEMP CON 127.

**$ RESULTS PROP MFRAC_GAS 'GAS'  Units: Dimensionless
**$ RESULTS PROP Minimum Value: 0.21096  Maximum Value: 0.21096
MFRAC_GAS 'GAS' CON 0.21096

**$ RESULTS PROP MFRAC_OIL 'OIL'  Units: Dimensionless
**$ RESULTS PROP Minimum Value: 0.78904  Maximum Value: 0.78904
MFRAC_OIL 'OIL' CON 0.78904
RESULTS SECTION NUMERICAL
**PRES CON 845
**PRES CON 845.
**DWOC  4000.
*NUMERICAL
*MAXSTEPS 9999999
**MAXSTEPS 6000
*DTMAX 1.   **140.
*ITERMAX 200
*NCUTS 400
**CONVERGE *TOTRES *TIGHTER
**UNRELAX -0.9
*AIM *STAB *BACK 20
*NORM *PRESS 290.
```

```
    *SATUR 0.05
    *TEMP 270.
*CONVERGE *PRESS 2.
        *SATUR 0.01
        *TEMP 2.
        *Y 0.01
        *X 0.01
        *W 0.01
        *BHP 2.
        *ZO 0.01
        *ZNCG 0.01
        *ZAQ 0.01
*CONVERGE *TOTRES *TIGHT
*MAXPRES 1.450377E+05

RESULTS SECTION NUMARRAYS
RESULTS SECTION GBKEYWORDS
RUN



TIME 0

DTWELL 0.02

*OUTSRF *GRID *REMOVE *PRES


WELL  1 'injector 1'
INJECTOR MOBWEIGHT 'injector 1'
TINJW 582.
QUAL 0.8
INCOMP WATER  1.0 0.0 0.0
OPERATE MAX STW  1200. CONT
OPERATE MAX BHP  1350. CONT REPEAT

GEOMETRY K 0.3 0.5 1. 0.
PERF GEO   'injector 1'
          1 1 20  1.
          1 1 19  1.
          1 1 18  1.
          1 1 17  1.
          1 1 16  1.
```

```
WELL  2 'producer 1'
PRODUCER 'producer 1'
OPERATE MAX STL  1200. CONT
OPERATE MIN BHP  145. CONT

**OPERATE MAX STG  3E+04 CONT
GEOMETRY K 0.3 0.5 1. 0.
PERF GEO   'producer 1'
         1 1 5  1.
         1 1 4  1.
         1 1 3  1.
         1 1 2  1.
         1 1 1  1.


WELL  3 'injector 2'
INJECTOR MOBWEIGHT 'injector 2'
TINJW 582.
QUAL 0.8
INCOMP WATER  1.0 0.0 0.0
OPERATE MAX STW  1200. CONT
OPERATE MAX BHP  1350. CONT REPEAT

**OPERATE MAX STG  3E+04 CONT
GEOMETRY K 0.3 0.5 1. 0.
PERF GEO   'injector 2'
         1 1 5  1.
         1 1 4  1.
         1 1 3  1.
         1 1 2  1.
         1 1 1  1.


SHUTIN 'producer 1'

TIME 21        **Steam

SHUTIN 'injector 2'

OPEN 'producer 1'

TIME 35

SHUTIN 'producer 1'

TIME 56
```

```
DTWELL 100.
SHUTIN 'injector 1'
OPEN 'producer 1'
TIME 236
DTWELL 0.0001
SHUTIN 'producer 1'
OPEN 'injector 1'
TIME 257
DTWELL 100.
SHUTIN 'injector 1'
OPEN 'producer 1'
TIME 437
DTWELL 0.0001
SHUTIN 'producer 1'
OPEN 'injector 1'
TIME 458
DTWELL 100.
SHUTIN 'injector 1'
OPEN 'producer 1'
TIME 638
DTWELL 0.0001
SHUTIN 'producer 1'
OPEN 'injector 1'
```

TIME 659

DTWELL 100.

SHUTIN 'injector 1'

OPEN 'producer 1'

TIME 839

DTWELL 0.0001

SHUTIN 'producer 1'

OPEN 'injector 1'

TIME 860

DTWELL 100.

SHUTIN 'injector 1'

OPEN 'producer 1'

TIME 1040

DTWELL 0.0001

SHUTIN 'producer 1'

OPEN 'injector 1'

TIME 1061

DTWELL 100.

SHUTIN 'injector 1'

OPEN 'producer 1'

TIME 1241

DTWELL 0.0001

SHUTIN 'producer 1'

OPEN 'injector 1'

TIME 1262

DTWELL 100.

SHUTIN 'injector 1'

OPEN 'producer 1'

TIME 1442

DTWELL 0.0001

SHUTIN 'producer 1'

OPEN 'injector 1'

TIME 1463

DTWELL 100.

SHUTIN 'injector 1'

OPEN 'producer 1'

TIME 1643

DTWELL 0.0001

SHUTIN 'producer 1'

OPEN 'injector 1'

TIME 1664

DTWELL 100.

SHUTIN 'injector 1'

OPEN 'producer 1'

TIME 1844

DTWELL 0.0001

```
SHUTIN 'producer 1'
OPEN 'injector 1'
TIME 1865
DTWELL 100.
SHUTIN 'injector 1'
OPEN 'producer 1'
TIME 2045
DTWELL 0.0001
SHUTIN 'producer 1'
OPEN 'injector 1'
TIME 2066
DTWELL 100.
SHUTIN 'injector 1'
OPEN 'producer 1'
TIME 2246
DTWELL 0.0001
SHUTIN 'producer 1'
OPEN 'injector 1'
TIME 2267
DTWELL 100.
SHUTIN 'injector 1'
OPEN 'producer 1'
TIME 2447
```

DTWELL 0.0001

SHUTIN 'producer 1'

OPEN 'injector 1'

TIME 2468

DTWELL 100.

SHUTIN 'injector 1'

OPEN 'producer 1'

TIME 2648

DTWELL 0.0001

SHUTIN 'producer 1'

OPEN 'injector 1'

TIME 2669

DTWELL 100.

SHUTIN 'injector 1'

OPEN 'producer 1'

TIME 2849

DTWELL 0.0001

SHUTIN 'producer 1'

OPEN 'injector 1'

TIME 2870

DTWELL 100.

SHUTIN 'injector 1'

OPEN 'producer 1'

TIME 3050

DTWELL 0.0001

SHUTIN 'producer 1'

OPEN 'injector 1'

TIME 3071

DTWELL 100.

SHUTIN 'injector 1'

OPEN 'producer 1'

TIME 3251

DTWELL 0.0001

SHUTIN 'producer 1'

OPEN 'injector 1'

TIME 3272

DTWELL 100.

SHUTIN 'injector 1'

OPEN 'producer 1'

TIME 3452

DTWELL 0.0001

SHUTIN 'producer 1'

OPEN 'injector 1'

TIME 3473

DTWELL 100.

SHUTIN 'injector 1'

OPEN 'producer 1'

TIME 3650

STOP
****************************** TERMINATE SIMULATION
******************************

RESULTS SECTION WELLDATA
RESULTS SECTION PERFS

## APPENDIX C

## HAMACA RESERVOIR SIMULATION FILE

```
RESULTS SIMULATOR STARS
RESULTS SECTION INOUT
*TITLE1  'STARS Test Bed No. 6'
*TITLE2  'Fourth SPE Comparative Solution Project'
*TITLE3  'Problem 1A:  2-D CYCLIC STEAM INJECTION'
*INUNIT *FIELD



**CHECKONLY
*INTERRUPT *STOP
*WRST 200
*WPRN *GRID  200
*WPRN *ITER 200
*OUTPRN *WELL *ALL
*OUTPRN *GRID *PRES *SW *SO *SG *TEMP *Y *X *W *SOLCONC *OBHLOSS
*VISO *VISG

*OUTSRF *GRID *PRES *SO *SG *TEMP

*OUTSRF *SPECIAL *BLKVAR *PRES 0 15
            *BLKVAR *SO 0 15
            *BLKVAR *SG 0 15
            *BLKVAR *TEMP 0 15
            *BLKVAR *CCHLOSS 0 40
            *BLKVAR *CCHLOSS 0 46
            *MATBAL WELL 'OIL'
            *MATBAL WELL 'WATER'
            *CCHLOSS




RESULTS XOFFSET 0.
RESULTS YOFFSET 0.
RESULTS ROTATION 0

GRID RADIAL 20 1 20 RW 3.00000000E-1
KDIR UP
DI IVAR
         0.13599 0.19764 0.28723 0.41743 0.60666 0.88167 1.28133 1.86217 2.7063
```

```
        3.93309 5.716 8.30711 12.0728 17.5455 25.499 37.0579 53.8566 78.2702
113.751
        165.315

DJ CON 360.

DK CON 5.
DTOP
        20*3100.




**$ RESULTS PROP NULL  Units: Dimensionless
**$ RESULTS PROP Minimum Value: 1  Maximum Value: 1
**$ 0 = NULL block, 1 = Active block
NULL CON 1.

**$ RESULTS PROP PINCHOUTARRAY  Units: Dimensionless
**$ RESULTS PROP Minimum Value: 1  Maximum Value: 1
**$ 0 = PINCHED block, 1 = Active block
PINCHOUTARRAY CON 1.
RESULTS SECTION GRID

RESULTS SPEC 'Grid Top'
RESULTS SPEC SPECNOTCALCVAL 0
RESULTS SPEC REGION 'Layer 20 - Whole layer'
RESULTS SPEC REGIONTYPE 1
RESULTS SPEC LAYERNUMB 20
RESULTS SPEC PORTYPE 1
RESULTS SPEC CON 3100
RESULTS SPEC STOP
RESULTS PINCHOUT-VAL       0.0002 'ft'
RESULTS SECTION NETPAY
RESULTS SECTION NETGROSS
RESULTS SECTION POR

**$ RESULTS PROP POR  Units: Dimensionless
**$ RESULTS PROP Minimum Value: 0.3  Maximum Value: 0.3
POR CON 0.3
RESULTS SECTION PERMS

**$ RESULTS PROP PERMI  Units: md
**$ RESULTS PROP Minimum Value: 20000  Maximum Value: 20000
PERMI KVAR
```

```
        20*2.E+04


**$ RESULTS PROP PERMJ  Units: md
**$ RESULTS PROP Minimum Value: 20000  Maximum Value: 20000
PERMJ EQUALSI

**$ RESULTS PROP PERMK  Units: md
**$ RESULTS PROP Minimum Value: 20000  Maximum Value: 20000
PERMK EQUALSI
RESULTS SECTION TRANS
RESULTS SECTION FRACS
RESULTS SECTION GRIDNONARRAYS
RESULTS SECTION VOLMOD
RESULTS SECTION VATYPE
RESULTS SECTION SECTORLEASE

RESULTS SECTION THTYPE
END-GRID

ROCKTYPE 1
  PRPOR 75.
  CPOR 0.0005
  ROCKCP 35.
  THCONR 24.
  THCONW 24.
  THCONO 24.
  THCONG 24.
  HLOSSPROP OVERBUR 35. 24.
    UNDERBUR 35. 24.



RESULTS SECTION GRIDOTHER
RESULTS SECTION MODEL
*MODEL    2 2 2 1
*COMPNAME 'WATER' 'OIL'
*CMM      18 363.48
*PCRIT    0.0E+0 0.0E+0
*TCRIT    0.0E+0 0.0E+0
*CPG1     0.0E+0 0.0E+0
*CPG2     0.0E+0 0.0E+0
*CPG3     0.0E+0 0.0E+0
*CPG4     0.0E+0 0.0E+0

*MASSDEN  6.27401E+1 6.099E+1
```

```
*CP        0.0E+0 5.0E-6
*CT1       0.0E+0 5.005E-4
*CT2       0.0E+0 0.0E+0

*WATPHASE
*VISCTABLE
  110      0.61636     325000        **
  130      0.505917    82155.4
  140      0.463487    43725.8
  150      0.42719     24104.86
  170      0.368443    8077.48
  190      0.323053    3047.18
  210      0.2870103   1277.603
  230      0.25775     588.57
  240      0.2451043   412.51
  260      0.222978    214.801
  280      0.204277    120.0453
  300      0.1882796   71.4554
  320      0.174451    44.9924
  340      0.1623875   29.7859
  360      0.1517788   20.6202
  370      0.146942    17.4199
  380      0.1423825   14.8553
  390      0.1380773   12.7812
  400      0.1340065   11.0892
  410      0.1301518   9.6977
  420      0.126497    8.5443
  430      0.1230272   7.5815
  440      0.119729    6.7721
  450      0.1165906   6.0873
  460      0.1136007   5.5044
  470      0.1107493   5.0053
  480      0.1080273   4.5756
  490      0.1054263   4.2038
  500      0.1029386   3.8805
  510      0.100557    3.598
  520      0.0982754   3.3502
  530      0.0960874   3.1319
  540      0.0939878   2.9389
  550      0.0919712   2.7675
  560      0.0900331   2.6149
  570      0.0881691   2.4785
  580      0.0863751   2.3562
  590      0.0829824   2.2463
  800      0.059062    0.7509
```

```
*OILPHASE
*VISCTABLE
  110      0.61636    325000
  130      0.505917   82155.4
  140      0.463487   43725.8
  150      0.42719    24104.86
  170      0.368443   8077.48
  190      0.323053   3047.18
  210      0.2870103  1277.603
  230      0.25775    588.57
  240      0.2451043  412.51
  260      0.222978   214.801
  280      0.204277   120.0453
  300      0.1882796  71.4554
  320      0.174451   44.9924
  340      0.1623875  29.7859
  360      0.1517788  20.6202
  370      0.146942   17.4199
  380      0.1423825  14.8553
  390      0.1380773  12.7812
  400      0.1340065  11.0892
  410      0.1301518  9.6977
  420      0.126497   8.5443
  430      0.1230272  7.5815
  440      0.119729   6.7721
  450      0.1165906  6.0873
  460      0.1136007  5.5044
  470      0.1107493  5.0053
  480      0.1080273  4.5756
  490      0.1054263  4.2038
  500      0.1029386  3.8805
  510      0.100557   3.598
  520      0.0982754  3.3502
  530      0.0960874  3.1319
  540      0.0939878  2.9389
  550      0.0919712  2.7675
  560      0.0900331  2.6149
  570      0.0881691  2.4785
  580      0.0863751  2.3562
  590      0.0829824  2.2463
  800      0.059062   0.7509


RESULTS SECTION MODELARRAYS
**  =============  ROCK-FLUID PROPERTIES  =====================
```

```
*ROCKFLUID

*SWT   **  Water-oil relative permeabilities

**   Sw       Krw        Krow
**  -----     ---------    --------
   0.45     0.0         0.4
   0.47     0.000056    0.361
   0.50     0.000552    0.30625
   0.55     0.00312     0.225
   0.60     0.00861     0.15625
   0.65     0.01768     0.1
   0.70     0.03088     0.05625
   0.75     0.04871     0.025
   0.77     0.05724     0.016
   0.80     0.07162     0.00625
   0.82     0.08229     0.00225
   0.85     0.1         0.0

*SLT   **  Liquid-gas relative permeabilities

**   Sl       Krg        Krog
**  -----     --------    --------
   0.45     0.2         0.0
   0.55     0.14202     0.0
   0.57     0.13123     0.00079
   0.60     0.11560     0.00494
   0.62     0.10555     0.00968
   0.65     0.09106     0.01975
   0.67     0.08181     0.02844
   0.70     0.06856     0.04444
   0.72     0.06017     0.05709
   0.75     0.04829     0.07901
   0.77     0.04087     0.09560
   0.80     0.03054     0.12346
   0.83     0.02127     0.15486
   0.85     0.01574     0.17778
   0.87     0.01080     0.20227
   0.90     0.00467     0.24198
   0.92     0.00165     0.27042
   0.94     0.0         0.30044
   1.       0.0         0.4

**  =============  INITIAL CONDITIONS  =====================
```

```
*INITIAL
*VERTICAL *DEPTH_AVE
**$ Data for PVT Region 1
**$ ————————————————————————-
*INITREGION 1
** Automatic static vertical equilibrium
*REFPRES 1300.
*REFBLOCK 1 1 1



RESULTS SECTION INITARRAYS

**$ RESULTS PROP SW  Units: Dimensionless
**$ RESULTS PROP Minimum Value: 0.45  Maximum Value: 0.45
SW CON 0.45

**$ RESULTS PROP TEMP  Units: F
**$ RESULTS PROP Minimum Value: 125  Maximum Value: 125
TEMP CON 125.
RESULTS SECTION NUMERICAL
**  ==============  NUMERICAL CONTROL  =====================
*NUMERICAL
*DTMAX 90. **
** here match the previous data.
*SDEGREE *GAUSS
*NORM *PRESS 200.
    *TEMP 180.

RESULTS SECTION NUMARRAYS
RESULTS SECTION GBKEYWORDS
RUN




**  ==============  RECURRENT DATA  =====================
**    The injection and production phases of the single cycling well
**  will be treated as two distinct wells which are in the same
**  location but are never active at the same time.  In the well data
**  below, both wells are defined immediately, but the producer is
**  shut in, to be activated for the drawdown.
DATE 1973 09 25.5

DTWELL 0.02
```

```
*OUTSRF *GRID *REMOVE *PRES


WELL  1 'injector 1'
INJECTOR MOBWEIGHT 'injector 1'
TINJW 600.
QUAL 0.8
INCOMP WATER  1.0 0.0
OPERATE MAX BHP  1500. CONT REPEAT
OPERATE MAX STW  1000. CONT REPEAT

GEOMETRY K 0.3 0.5 1. 0.
PERF GEO   'injector 1'
          1 1 20  1.
          1 1 19  1.
          1 1 18  1.
          1 1 17  1.
          1 1 16  1.


WELL  2 'producer 1'
PRODUCER 'producer 1'
OPERATE MAX STL  1000. CONT REPEAT
OPERATE MIN BHP  600. CONT REPEAT

GEOMETRY K 0.3 0.5 1. 0.
PERF GEO   'producer 1'
          1 1 5  1.
          1 1 4  1.
          1 1 3  1.
          1 1 2  1.
          1 1 1  1.


WELL  3 'injector 2'
INJECTOR MOBWEIGHT 'injector 2'
TINJW 600.
QUAL 0.8
INCOMP WATER  1.0 0.0
OPERATE MAX BHP  1500. CONT REPEAT
OPERATE MAX STW  1000. CONT REPEAT

GEOMETRY K 0.3 0.5 1. 0.
PERF GEO   'injector 2'
          1 1 20  1.
          1 1 19  1.
```

```
    1 1 18  1.
    1 1 17  1.
    1 1 16  1.

SHUTIN 'producer 1'

TIME 21

SHUTIN 'injector 2'

OPEN 'producer 1'

TIME 35

SHUTIN 'producer 1'

TIME 56

SHUTIN 'injector 1'

OPEN 'producer 1'

TIME 236

DTWELL 0.0001

SHUTIN 'producer 1'

OPEN 'injector 1'

TIME 257

SHUTIN 'injector 1'

OPEN 'producer 1'

TIME 437

DTWELL 0.0001

SHUTIN 'producer 1'

OPEN 'injector 1'

TIME 458
```

```
SHUTIN 'injector 1'
OPEN 'producer 1'
TIME 638
DTWELL 0.0001
SHUTIN 'producer 1'
OPEN 'injector 1'
TIME 659
SHUTIN 'injector 1'
OPEN 'producer 1'
TIME 839
DTWELL 0.0001
SHUTIN 'producer 1'
OPEN 'injector 1'
TIME 860
SHUTIN 'injector 1'
OPEN 'producer 1'
TIME 1040
DTWELL 0.0001
SHUTIN 'producer 1'
OPEN 'injector 1'
TIME 1061
SHUTIN 'injector 1'
OPEN 'producer 1'
```

```
TIME 1241
DTWELL 0.0001
SHUTIN 'producer 1'
OPEN 'injector 1'
TIME 1262
SHUTIN 'injector 1'
OPEN 'producer 1'
TIME 1442
DTWELL 0.0001
SHUTIN 'producer 1'
OPEN 'injector 1'
TIME 1463
SHUTIN 'injector 1'
OPEN 'producer 1'
TIME 1643
DTWELL 0.0001
SHUTIN 'producer 1'
OPEN 'injector 1'
TIME 1664
SHUTIN 'injector 1'
OPEN 'producer 1'
TIME 1844
DTWELL 0.0001
```

```
SHUTIN 'producer 1'

OPEN 'injector 1'

TIME 1865

SHUTIN 'injector 1'

OPEN 'producer 1'

TIME 2045

DTWELL 0.0001

SHUTIN 'producer 1'

OPEN 'injector 1'

TIME 2066

SHUTIN 'injector 1'

OPEN 'producer 1'

TIME 2246

DTWELL 0.0001

SHUTIN 'producer 1'

OPEN 'injector 1'

TIME 2267

SHUTIN 'injector 1'

OPEN 'producer 1'

TIME 2447

DTWELL 0.0001

SHUTIN 'producer 1'

OPEN 'injector 1'
```

```
TIME 2468

SHUTIN 'injector 1'

OPEN 'producer 1'

TIME 2648

DTWELL 0.0001

SHUTIN 'producer 1'

OPEN 'injector 1'

TIME 2669

SHUTIN 'injector 1'

OPEN 'producer 1'

TIME 2849

DTWELL 0.0001

SHUTIN 'producer 1'

OPEN 'injector 1'

TIME 2870

SHUTIN 'injector 1'

OPEN 'producer 1'

TIME 3050

DTWELL 0.0001

SHUTIN 'producer 1'

OPEN 'injector 1'

TIME 3071

SHUTIN 'injector 1'
```

```
OPEN 'producer 1'

TIME 3251

DTWELL 0.0001

SHUTIN 'producer 1'

OPEN 'injector 1'

TIME 3272

SHUTIN 'injector 1'

OPEN 'producer 1'

TIME 3452

DTWELL 0.0001

SHUTIN 'producer 1'

OPEN 'injector 1'

TIME 3473

SHUTIN 'injector 1'

OPEN 'producer 1'

TIME 3650

STOP
**************************** TERMINATE SIMULATION
****************************

RESULTS SECTION WELLDATA
RESULTS SECTION PERFS
```

# VITA

| | |
|---|---|
| Name: | Eric Robert Matus |
| Place of Birth: | Fort Worth, Texas, USA |
| Parents: | Richard Matus<br>Lois Matus |
| Permanent Address: | 7113 Sparrow Pt<br>Fort Worth, TX 76133 |
| Education: | Texas A&M University<br>B.S. Petroleum Engineering<br>May 2004<br><br>Texas A&M University<br>M.S. Petroleum Engineering<br>August 2006 |
| Prof. Aff.: | Society of Petroleum Engineers, Member |
| Experience: | EOG Resources, Fort Worth, 2005<br>El Paso Production, Houston, 2004<br>Rowan Companies, Gulf of Mexico, 2003 |