PRODUCTION OPTIMIZATION OF A GAS CONDENSATE RESERVOIR USING A BLACK OIL SIMULATOR AND NODAL SYSTEM ANALYSIS: A CASE STUDY

A THESIS SUBMITTED TO

THE GRADUATE SCHOOL OF NATURAL AND APPLIED SCIENCES

OF

MIDDLE EAST TECHNICAL UNIVERSITY

BY

CEM MİNDEK

IN PARTIAL FULFILLMENT OF THE REQUIREMENTS FOR

THE DEGREE OF MASTER OF SCIENCE

IN

PETROLEUM AND NATURAL GAS ENGINEERING

JUNE 2005

Approval of the Graduate School of Natural and Applied Sciences

Prof. Dr. Canan Özgen
Director

I certify that this thesis satisfies all the requirements as a thesis for the degree of Master of Science

Prof. Dr. Birol Demiral
Head of Department

This is to certify that we have read this thesis and that in our opinion it is fully adequate, in scope and quality, as a thesis for the degree of Master of Science

Prof. Dr. Suat Bağcı
Supervisor

Examining Committee

Prof. Dr. Birol Demiral	(METU, PETE)
Prof. Dr. Suat Bağcı	(METU, PETE)
Prof. Dr. Mustafa Kök	(METU, PETE)
Prof. Dr. Mahmut Parlaktuna	(METU, PETE)
Prof. Dr. Nurkan Karahanoğlu	(METU, GEOE)

I hereby declare that all information in this document has been obtained and presented in accordance with academic rules and ethical conduct. I also declare that, as required by these rules and conduct, I have fully cited and referenced all material and results that are not original to this work.

Name, Last name: Cem Mindek

Signature :

ABSTRACT

PRODUCTION OPTIMIZATION OF A GAS CONDENSATE RESERVOIR USING A BLACK OIL SIMULATOR AND NODAL SYSTEM ANALYSIS: A CASE STUDY

MİNDEK, Cem

M. Sc., Department of Petroleum and Natural Gas Engineering

Supervisor: Prof. Dr. Suat Bağcı

June 2005, 162 pages

In a natural gas field, determining the life of the field and deciding the best production technique, meeting the economical considerations is the most important criterion.

In this study, a field in Thrace Basin was chosen. Available reservoir data was compiled to figure out the characteristics of the field. The data, then, formatted to be used in the commercial simulator, IMEX, a subprogram of CMG (Computer Modeling Group).

The data derived from the reservoir data, used to perform a history match between the field production data and the results of the simulator for a 3 year period between May 2002 and January 2005.

After obtaining satisfactory history matching, it was used as a base for future scenarios. Four new scenarios were designed and run to predict future production of the field. Two new wells were defined for the

scenarios after determining the best region in history matching. Scenario 1 continues production with existing wells, Scenario 2 includes a new well called W6, Scenario 3 includes another new well, W7 and Scenario 4 includes both new defined wells, W6 and W7.

All the scenarios were allowed to continue until 2010 unless the wellhead pressure drops to 500 psi. None of the existing wells reached 2010 but newly defined wells achieved to be on production in 2010.

After comparing all scenarios, Scenario 4, production with two new defined wells, W6 and W7, was found to give best performance until 2010. During the scenario 4, between January 2005 and January 2010, 7,632 MMscf gas was produced. The total gas production is 372 MMscf more than Scenario 2, the second best scenario which has a total production of 7,311MMscf. Scenario 3 had 7,260 MMscf and Scenario 1 had 6,821 MMscf respectively.

A nodal system analysis is performed in order to see whether the initial flow rates of the wells are close to the optimum flow rates of the wells, Well 1 is found to have 6.9 MMscf/d optimum production rate. W2 has 3.2 MMscf/d, W3 has 8.3 MMscf/d, W4 has 4.8 MMscf/d and W5 has 0.95 MMscf/d optimum production rates respectively.

Keywords: Gas condensate reservoir, History Matching, Simulator

ÖZ

GAZ KONDENSAT REZERVUARININ NÜMERİK SİMÜLASYON VE NOKTASAL SİSTEM ANALİZİ KULLANILARAK MODELLENMESİ: BİR DURUM ÇALIŞMASI

MiNDEK, Cem

Yüksek Lisans, Petrol ve Doğal Gaz Mühendisliği Bölümü

Tez Yöneticisi: Prof. Dr. Suat Bağcı

Haziran 2005, 162 sayfa

Bir doğalgaz sahasında ekonomik şartlara uygun olarak sahanın ömrünü belirlemek ve uygun üretim şeklini seçmek en önemli kriterdir.

Bu çalışmada Trakyadaki bir doğalgaz sahası seçilmiştir. Mevcut rezervuar verileri derlenerek sahanın karakteri belirlenmiştir. Bu veriler daha sonra CMG (Computer Modeling Group) alt simulatörü olan IMEXde kullanılabilecek bir veri grubu haline çevrilmiştir.

Rezervuar verilerinden elde edilen veri grubu simulator ve gerçek saha verileri arasında tarihsel eşleştirme yapmada kullanılmıştır.

Saha verileri ile simulator sonuçları arasında başarılı bir eşleşme sağlandıktan sonra veri grubu dört yeni senaryo için girdi olarak kullanılmıştır.

Tüm senaryolar kuyubaşı basınçları 500 psi altına düşmedikçe 2010 a kadar üretime devam etmişlerdir. Tarihsel eşleşmeden sonra, senaryolarda kullanılmak üzere sahanın en uygun yerlerinde iki yeni kuyu tanımlanmştır. Senaryo 1 de tarihsel eşleme bölümünden sonraki dört kuyuyla üretime devam edilmiştir, Senaryo 2 yeni tanımlanan W6 kuyusuyla beraber üretime devam edilmiştir, Senaryo 3, bir başka yeni tanımlanan W7 kuyusuyla üretime devam edilmiştir, ve Senaryo 4 her iki yeni tanımlanan W6 ve W7 ile üretime devam edilmiştir.

Tüm senaryolar kıyaslandıktan sonra, yeni tanımlanan iki kuyu, W6 ve W7 ile üretim yapan Senaryo 4 ün en çok üretimi verdiği ortaya çıkmıştır. Senaryo 4, 0cak 2005 ile Ocak 2010 arasında 7,632 MMscf gaz üretmiştir. Senaryo 4 ün üretimi en iyi ikinci senaryo olan Senaryo 2 nin üretim miktarı 7,311 MMscf den 372 MMscf fazladır. Senaryo 3 de 7,260 MMscf ve Senaryo 1 de 6,811 MMscf gaz üretilmiştir.

Ayrıca tubing çapının kuyular için uygun olup olmadığını belirlemek için noktasal sistem analizi gerçekleştirilmiş ve sonuçları kuyuların ilk üretim miktarlarıyla kıyaslanmıştır. Müşteri talepleri yüzünden üretim sırasında yapılan değişikliklerden dolayı, hesaplanan en uygun üretim miktarından sırasıyla, Well 1 0.80 MMscf, Well 2 0.60 MMscf, Well 3 0.60 MMscf, Well 4 0.80 MMsf ve Well 5 0.05 MMsf fark göstermiştir.

Anahtar Kelimeler: Gaz kondensat rezervuarı, Tarihsel eşleştirme , Modelleme

ACKNOWLEDGEMENTS

I would like to express my gratitude to Prof. Dr. A. Suat Bağcı, for his patience and understanding during my studies.

I would like to thank Amity Oil Int. Pty. Ltd for supplementing real field data.

Also I would like to express my gratitude to my friends for their hospitality and support.

Thanks to my family for their support.

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

ABBREVIATIONS

CMG	:	Computer Modeling Group
P	:	Pressure,psi
Res	:	Reservoir
K	:	Permeability, md
Sw	:	Water Saturation
Krw	:	Relative Permeability to water
Krg	:	Relative Permeability to gas
OD	:	Outside Diameter, inches
ID	:	Inside Diameter, inches
MMscf	:	Million standard cubic feet
T	:	Temperature, °F
W	:	Well
H	:	Height, ft
Rs	:	Solution Gas/Oil Ratio, scf/bbl
Bg	:	Gas Volume Factor, rbl/scf
Bo	:	Formation Volume Factor, rbl/bbl

CHAPTER 1

INTRODUCTION

Gas-condensate reservoirs behave like gas reservoirs at the first stage of their discovery, are characterized by the apparition of a condensate liquid phase once the dew point pressure is reached.

The liquid keeps accumulating until the critical liquid saturation is reached. At the moment liquid starts flowing, the flow of gas and liquid is subjected to the law of multiphase flow in porous media. The more interesting phenomena in gas condensate reservoirs is the re-vaporization of the liquid as the pressure crosses the lower dew point line on two-phase envelope of P-T phase diagram. This behavior is called retrograde behavior (1). Figure 1.1 shows the phase envelope for a typical phase diagram for a gas condensate reservoir

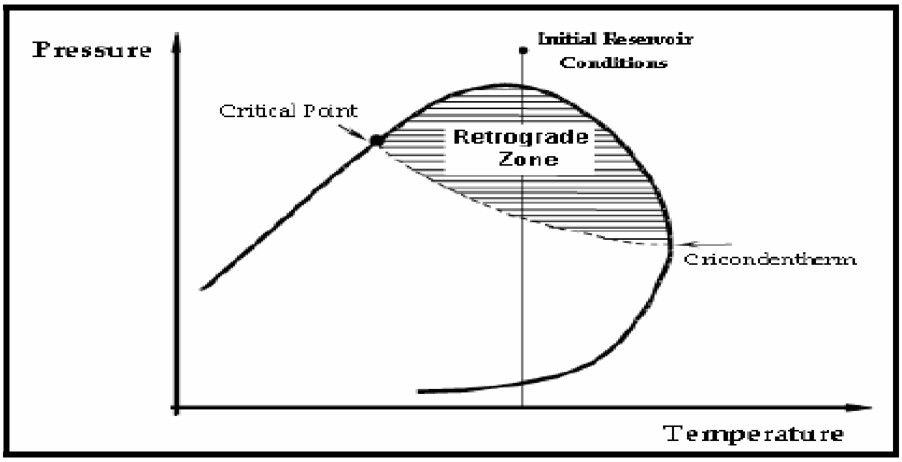

Figure 1.1. Phase Envelope for a typical gas condensate fluid (9)

In gas condensate reservoirs, the reservoir temperature is lower than the cricondentherm but higher than the critical temperature. Thus liquid drop-out takes place within the reservoir. As a result the composition of the well stream, the surface gas and the surface condensate change continuously while the reservoir is being depleted. Also the liquid content of the well stream will change with time (2)

Gas-condensate wells behavior is unique in a sense that it is characterized by a rapid loss of well productivity. Generally, when the flowing bottom-hole pressure drops below the dew point, a region of high condensate saturation builds up near the well bore, causing lower gas deliverability mainly due to a reduction in gas permeability (3).

The field used in this study is located in the Thrace Basin. In the field there were five producing wells and named as W1, W2, W3, W4 and W5 and Well Diagrams are illustrated in Appendix E. Production and Wellhead data of the field is illustrated in Appendix A.2. D. Newly described wells also named as W6 and W7.

IMEX simulator, a subgroup of CMG (Computer Modeling Group) was used for this study. Data used in the simulator is presented in Appendix A.1. IMEX is a three-phase black-oil simulator with gravity and capillary terms. Grid systems may be Cartesian, cylindrical, or variable depth/variable thickness. Two dimensional and three dimensional configurations are possible with any of these grid systems. Gas phase appearance/disappearance is handled by variable substitution (4).

In the study, first a history matching between the field data and the simulator data, for the period between May 2002 and January 2005 was performed. Then the results of the history matching were used as a basis for future scenarios, until January 2010. Results of the scenarios compared to find out the best future production option.

Also Nodal system analysis is performed and results are compared with the field production rates in order to see whether the field rates are close to the optimum rates.

CHAPTER 2

LITERATURE SURVEY

2.1 Gas Condensate Reservoirs

At the first stage of gas-condensate reservoirs, they act like gas reservoirs during depletion. When the dew point pressure is reached at reservoir conditions, a retrograde condensation phase develops in the reservoir which results in loss of well deliverability, therefore gas and condensate recovery, consequently loss of income.

When there is only one phase, it is assumed that production is proportional to the pressure difference between the reservoir and the well-bore. The constant of proportionality is the productivity index that is based on Darcy's law for the steady-state radial flow of single incompressible fluid. As the dew point pressure is reached, liquid flow starts and that gas and liquid flow is characterized by the law of multiphase flow.

The drawdown pressure for a horizontal well is smaller than a vertical well at the same flow rate and liquid saturation around a vertical well can reach up to 15% whereas it can not be greater than 6% in a horizontal well, so that less deposition of condensate occurs near the well-bore. Also low drawdown pressure is observed in thick formations; as a result, more liquid is recovered (5)

Hydrocarbons in a gas-condensate reservoir are either wholly or predominantly in the vapor phase at the time of discovery. Upon isothermal depletion , once the reservoir pressure falls below the dew point of the hydrocarbon phase, a liquid hydrocarbon phase is developed.

Apperance of a liquid phase upon vapor expansion is not possible for pure substances, thus, this behavior is categorized as “retrograde” for this type of mixtures. The retrograde liquid may revaporize if depletion continues. (6).

The production performance of a gas condensate well is the same as a dry gas well as long as the well flowing bottomhole pressure (FBHP) is above the initial reservoir dew point. Once the well’s FBHP drops below the dew point, the well’s performance starts to deviate from that of a dry gas well. Condensate begins to drop out first near the wellbore, ımmobile initially, liquid condensate accumulates until the critical condensate saturation is reached. This rich liquid zone grows outward deeper into the reservoir as depletion continues. Liquid accumulation , or condensate banking, causes a reduction in the gas relative permeability and acts as a partial blockage to gas production. Because condensate is left behind in the reservoir, condensate banking manifests itself as a rise in the well’s production gas-oil ratio GOR or inversely, a decline in the well condensate yield.

In predicting gas condensate well performance with reservoir simulators, local grid refinement is needed around the well in order to capture the impact of condensate banking. The determination of gas condensate well production performance can be performed by applying the two-phase pseudopressure technique.The two-phase pseudopressure technique, however, cannot be applied independently for well performance evaluation since it requires the well production gas-oil ratio as an input. Simplified methods have been published recently to calculate gas condensate well production deliverability without the use of reservoir simulators (7).

Well construction design and well performance diagnosis and optimization heavily rely on well deliverability modeling, which combines tubular hydraulic calculations with a reservoir deliverability model.

Gas-condensate wells behavior is unique in a sense that it is characterized by a rapid loss of well productivity. Generally, when the flowing bottom-hole pressure drops below the dew point, a region of high condensate saturation builds up near the well bore, causing lower gas deliverability mainly due to a reduction in gas permeability.

When the flowing bottom-hole pressure is below dew point, then the reservoir may contain three flow regions. Region 1 is defined as a closer zone to the inner near-well-bore where both gas and oil flow simultaneously. Outward into the reservoir, Region 2 contains a condensate buildup where only gas is flowing. Finally contiguous to Region 2, Region 3, which extends to the limits of the reservoir, exists only if the reservoir pressure is higher than the dew point pressure. The size of each region changes with time as the reservoir depletes (3).

2.2. Dynamic Nodal Analysis

The objective of nodal system analysis is to combine the various components of the oil or gas well in order to predict flow rates and to optimize the various components in the system from the outer boundary of the reservoir to the sand face, across the perforation and completion section to the tubing intake and up the tubing string, including any restrictions and down-hole safety valves, choke, flow line and the separator. Figure 2.1 shows a schematic of a simple producing system. Consisting of three sections; flow through porous medium, flow through vertical or directional conduit and flow through horizontal pipe or inclined flow line.

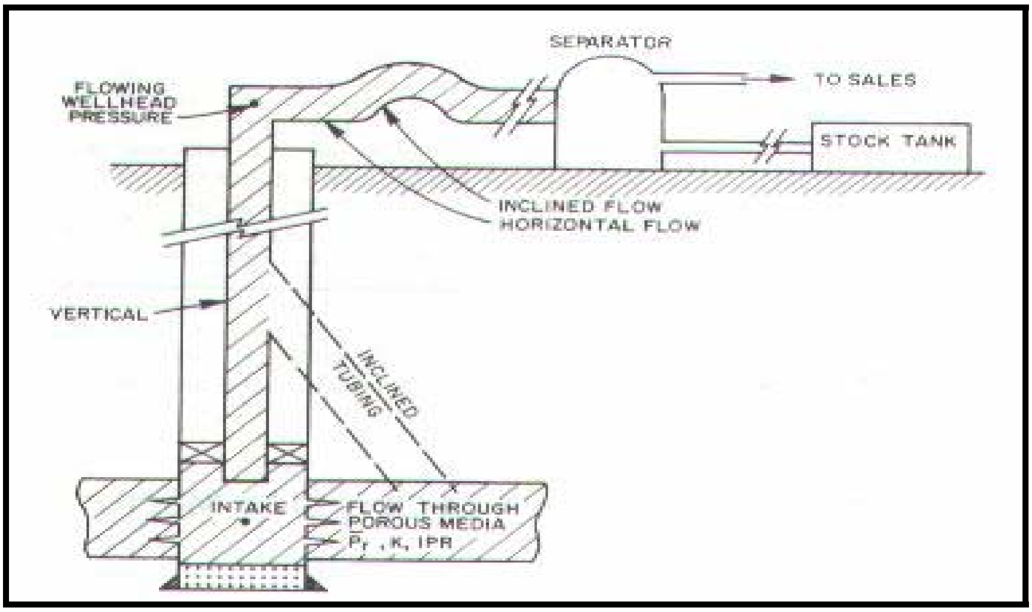

Figure 2.1 Complete Producing System (9)

In a more complex system various pressure losses may occur beginning from reservoir to the separator. Figure 2.2 shows the pressure losses in a complete system

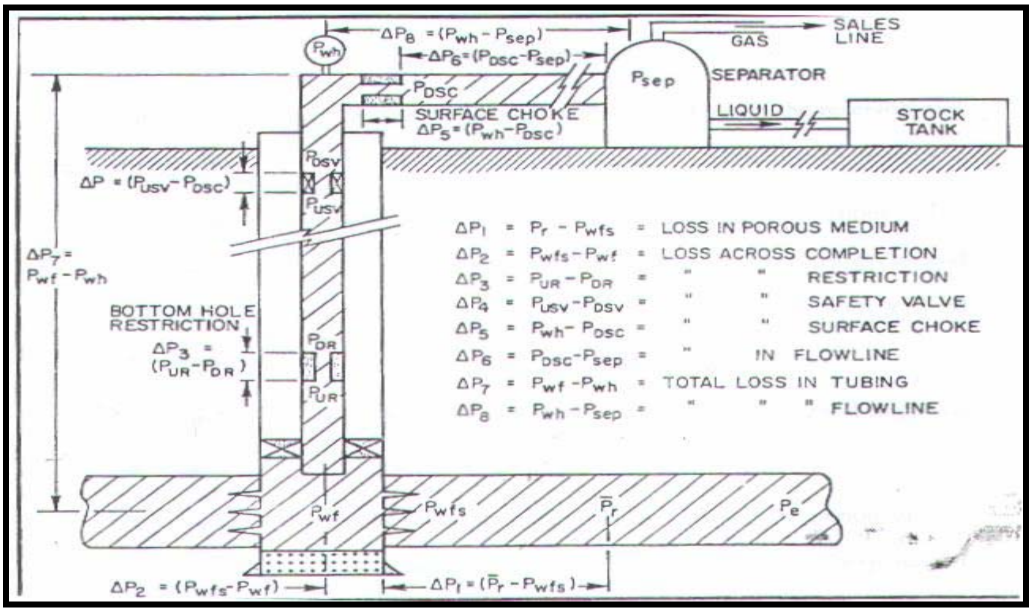

Figure 2. 1. Pressure losses in a complete system (9)

In particular, the ability of the well to produce fluids will be interfaced with the ability of the piping system to handle these fluids. In order to solve the total producing system problems, nodes are placed to segment the portion defined by different equations or correlations. Figure 2.3 is a modified type of Figure 2.2 showing the locations of the nodes. A node is classified as functional when a pressure differential exists across it and the pressure or flow rate response can be presented by some mathematical or physical function (8).

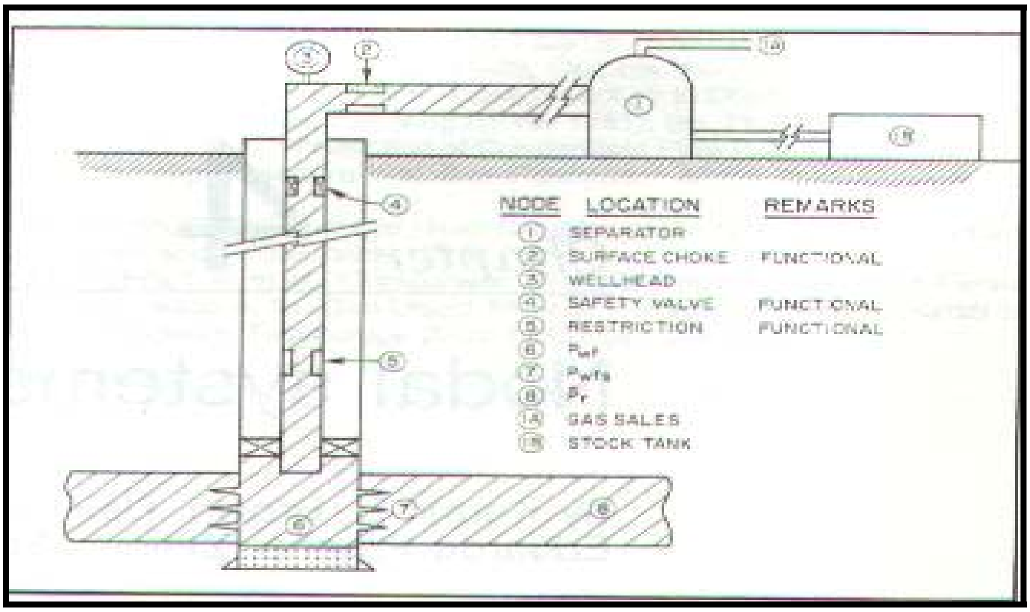

Figure 2.2 Location of Various Nodes (9)

The manner in which a well is completed is also very important. For example, the number of perforations necessary to prevent excessive pressure loss across completions for gravel-packed oil or gas wells can also be evaluated by nodal analysis.

The importance of the perforating procedure is very high because it appears that numerous wells, including some of the low flow rate pumping wells, may not be producing at capacity. Although the well may be pumping off and therefore indicating maximum production, there may still exist a pressure loss across the completion due to insufficient area open to flow. Some of these wells need to be re-perforated and several have shown increased production rates after doing so.

The nodal plot is a necessary tool in bringing high flow rate gravel packed well on production. The production rate and wellhead pressure can be used simultaneously to prevent excessive pressure loss across the gravel pack. Numerous gravel-packed completions are destroyed during the first 2-3 days. A proper system analysis will prevent this.

A check of well capability against well productivity in many instances shows a well to be much better than its present rate indicates. These are wells that must be tested to verify Kh values or to determine skin or any other restrictions. The nodal analysis concept can be applied to drill stem tests to determine correct completion practices, including selection of pipe sizes (9).

The major drawback of the conventional nodal analysis is that it only provides the user with a snapshot picture of the well production. It does not provide any information as to how the production will change as a function of time and the technique should overcome the following aspects.

- Predict the future performance as a function of time in the presence of various production components including the reservoir.

- Match the prior production data in the presence of various production components so that the appropriate parameters can be assigned for future production prediction. This is similar to decline curve analysis except that we need to include the production components in the system.

- Quantify the uncertainties with respect to various parameters (e.g., reservoir permeability, skin factor, tubing roughness, drainage area, the type of pressure drop correlation) by generating alternate possibilities of parameters which can match the production data.

- Predict the future performance under existing conditions as well as altered conditions to compare the production scenarios in the future.

- Quantify the uncertainty in predicting the future performance which can be combined with the price of gas to conduct a risk analysis.

- Optimize the producing well configuration so that the net profit over the life of the well is maximized (10).

2.3 Field Studies

Simulation studies are gaining more and more importance in optimization studies in last two decades. Companies are making more investments on optimization projects and most results are making good impacts and applied to production strategies immediately.

The analytical features of the automation software system allow the user to make changes to the operational parameters of the wells. For example, by monitoring the performance of the well on a daily basis, the operator can make changes to the well testing schedule that can increase gas production by shifting a high pressure, low volume well into a low pressure header to relieve back pressure on the wellhead, thereby increased productivity.

The concept of managing wells by “exception” promotes the ability to keep downtime to a minimum in two ways. First, when a well does go down, the operator can be notified immediately- even if the operator is off the operating property. Second, these automation tools provide indications that a well may be heading toward a shut-in of one type or another. With the second case, the user can prevent downtime by correcting the factors that are leading the well into a potential shut-in condition rather than just react to it.

The automation system provides tools for material balancing of gas, gas condensate, and free water production. By recognizing irregular production patterns in any of these phases, potential problems can be identified such as gas leaks, excessive gas flaring, relief system leaks or malfunction of relief equipment (pop valves).

Rather than requiring an operator to examine each well's status everyday, the concept of management by exception that is used to provide information about anomalies through the use of alarm grids color coded for easy recognition of problems. The software alerts the user to any parameter that is out of an ordinary operating range as defined by the user. This allows the user to focus on prioritizing recognized problems, rather than searching problems that may exist.

Users of an automation system have the ability to use information from different parts of the production operation to evaluate the state of the wells and production facilities. The well test information can be compared to the calculated production of each well and the total from the wells can be compared to the actual metered sales from the facility.

These software modules provide historical reports and trends that represent normal operating conditions for a well. Since this data is a part of an integrated database, it can be used for calculating accurate production data. The installation of a comprehensive automation system will redirect manpower to better focus on corrective and optimization measures.

Since data is presented "onscreen" in the production office, and is presented in a way that facilitates easy scanning of a large number of wells, companies that use automation software have found that they can substantially reduce the time necessary for someone to visit and personally inspect each well. (11)

The Kapuni field, consisting of 9 wells, is complicated and compartmentalized and suffer from declining reservoir pressures. The declining reservoir pressure decline was the main factor affecting the condensate recovery and maximizing short-term revenue. During the depletion of the reservoir retrograde hydrocarbons condense in the reservoir and can never be produced.

KAOS (Kapuni Apportioned Optimization Spreadsheet) combines thermodynamic understanding of the process with well characteristic data to form a non-linear optimization tool in MS-Excel and figured out satisfactory results when used by field operators to optimize production. An extension of this tool quantifies condensate deferment and loss caused by sub-optimal operation, to highlight improvement opportunities. (12)

Arun Gas field, a carbonate reef reservoir, facilities located within four individual clusters which contains the producing wells, well stream coolers and separators. Gas condensate and water are separated at each cluster through two identical process trains. Well and individual cluster process controls are located in, and mainly operated from the Cluster Control Room. By the use of this program condensate production improved up to 3% and regarding to the weather conditions, the well head pressures are reduced to maintain separator temperatures in acceptable operating limits (13).

Kuparuk River reservoir, located on the Alaskan North slope. The field faced variety of development processes including primary production, water-flood, gas storage, a water alternating immiscible gas injection project, a pilot scale water alternating miscible gas injection (MWAG) project, peripheral development, and infill drilling. The increase in production generated by these development projects has resulted in a facility constrained environment.

The objective of the optimization strategy was to maximize oil production by efficient allocation of lift gas to the producing wells. As there is a limit in this field due to compression capacity, a gas optimization strategy was very much important for the proper operation of the field. The computer program uses the field data and gives the lift gas allocation and producing well selection as an output (14).

Pierceland area implemented a field wise SCADA (Supervisory Control and Data Acquisition) system. The SCADA system remotely monitors the performance of 75 producing wells scattered over an area of 70 miles by 30 miles. The system managed production from 18 of 75 wells that have local control systems for the automatic recovery of liquids, which causes great operational problems especially during winter from the well-bore. The software has advantages over manual controls, mainly it exterminates the sanding problems that occur because of unloading wells to prevent liquid accumulation. The casing and tubing pressures are compared by the program and the well is controlled accordingly by the automatic switches which operate by the commands of the software (15).

Chunchula Field, an onshore Gulf Coast field is located approximately 30 miles north of Mobile, Alabama, USA. The field production started in 1974 and a gas plant was installed in 1980. The gas plant removes acidic gas and processes ethane, liquid propane, liquid butane, gasoline and residue gas for sales and re-injection. To forecast future performance, all wells were divided into three groups with specific flowing bottom hole pressure constraints for low yield wells with compression, low yield wells without compression and high yield wells. The strategies that were investigated include adding compression stations, partial re-injection of produced gas, blow-down, horizontal wells workovers and upgrading of gas plant capacity.

To achieve these goals a very unique simulation study, which integrates reservoir, gas plant and economics into a single feed-back loop for rich gas condensate reservoir was used. The benefits of the simulation were the correct simulation of the composition and the quantity of re-injected gas and wet inlet gas to plant, the correct simulation of liquid propane spike due to lean oil absorption unit, a workable algorithm to bridge reservoir and gas plant simulation at each step and a rapid turnover time for each scenario by integrating reservoir, gas plant and economics into a single loop (16).

Automated unloading can be used to increase production. For gas wells, production of water causes many operational problems up to chronic loss of production. Operators combat water problems by blowing the well-down, dropping soap sticks, stop-coking the well, or even rocking the well if the problem is severe.

Automation equipment has been adapted to perform some of the routine operations. Wellhead equipment can be set up to detect the presence of liquids in the well-bore and unload automatically. Unloading the well regularly allows the liquids to be sent down the flow-line, reducing the venting of the gas. Wells in the remote areas receive the attention they need constantly.

The pressure drop from perforations to surface is the sum of friction and the hydrostatic pressure. For steady state flow, the friction pressure drop should be fairly constant, and the difference between tubing and casing will only increase if liquids are accumulating in the well. Once an accumulation has been observed, logic within the automation system blows down the well (17).

Evaluation of all components of a producing well system, starting from static reservoir pressure ending in the separator, uses a Nodal Analysis. This analysis allows to determine the flow rate at which the well will produce at the given well geometry and completion, to see when the well will cease to produce, to decide when it is the most economical time to install artificial lift, to analyze each component in order to find whether it restricts flow.

The production optimization of oil and gas wells using computerized well models has contributed to improved completion techniques, better efficiency, and higher production with many wells. Two major reasons for the need of production optimization are changing of allowable producing rates and rapid calculation of complex algorithms and easily understood input and output.

There is too much error involved in the various multiphase flow tubing or flow-line correlations, completion formulas; consequently, it is difficult to get predictive well analysis plot to show an intersection at the exact rate as the well is currently being produced. Even though the exact production can not be matched, the analysis can show a percentage increase in production with a change, for instance, in well head pressure or tubing size (18).

Prediction of gas well load-up can be performed by using nodal system analysis. Gas well load-up is frequently the controlling factor in the abandonment of mature pressure-depletion reservoirs. Load-up occurs in gas wells at low producing pressures when the flow rate velocity becomes insufficient to carry and continuously remove the produced fluids from the well bore.

The accurate predictions of the producing conditions at which gas well load-up will occur is essential to asses operational modifications and determine reserves. Nodal analysis is often used to evaluate the performance of a well by analyzing the pressure-rate relationship at various points or nodes throughout the well's producing system. In the past, however, nodal system analysis has been considered unreliable for low-pressure gas wells since applications have routinely underestimated the reservoir pressure and rate at which load up occurs.

Gas produced from the reservoir contains water vapor, which condenses into liquid in the well bore as temperatures and pressures decline with flow. It is important in predicting flow performance to recognize that, although the water content of the produced gas is constant at any point in the well bore prior to the onset of load-up, the phase occupied by this water changes with flow up the tubing.

The increasing condensed water production that occurs with declining reservoir pressure will significantly increase the pressure required to keep a well unloaded. As a reservoir nears depletion, the gas flow rate will become too low to continuously carry the condensed water out of the well bore. This minimum flow rate and corresponding pressure mark the onset of load-up. Produced liquids will begin accumulating in the well bore until the hydrostatic pressure becomes too large for the well to overcome and the production flow ceases (19).

CHAPTER 3

STATEMENT OF THE PROBLEM

In this study a gas field located in Thrace Basin was investigated. The field was in a rapid depletion, and future production technique should be determined to be able to get maximum recovery from the field. For this purpose, first a history matching section was needed in order to figure out the characteristics of the field and adapt the field to the commercial software, which will be used to perform new scenarios for predicting the future performance of the field. Four new scenarios were designed to compare with each other to find out which scenario is the best one.

Scenario 1: Go on production with existing wells until 2010.

Scenario2: A new well, W6, is defined and field is allowed to produce until 2010

Scenario 3: A new well W7, is defined and field is allowed to produce until 2010

Scenario 4: Both new defined wells are allowed to be on production and field keeps on production until 2010.

In the history matching section, available flow rates from the field are used. In order to see if these rates are the optimum rates of these wells, a dynamic nodal analysis was performed. Results of the nodal analysis were compared with the flow rates gathered from the field data.

CHAPTER 4

RESERVOIR DESCRIPTION

4.1 Reservoir Properties

The field is located in Thrace basin. The first discovery was in 2000. Following the first discovery four additional wells were drilled and all were economically worth. The producing formation is called the Danismen formation, mainly sandstone with small indications of shale and has an anticlinal structure. The production mechanism is volumetric depletion. The top of the reservoir is in 1122 m (3681 ft). Average porosity is 15% and water saturation is 55% respectively. The production zone thickness is 45 m (148 ft) with an average permeability of 13 md. The original reservoir pressure is obtained as 1875 psi. The field started production on 2002. The reservoir fluid properties are presented in Table 4.1., the composition of the gas for each well and the field is in Table 4.2. Figure 4.1. shows the reservoir map with grids.

Table 4.1. Rock Fluid and General Properties of the reservoir

Initial Reservoir Pressure, psi	1875
Initial Reservoir Temperature, °F	135
Reference Depth, ft	3500
Water-Gas Contact, ft	3788
Specific Gravity of Gas	0.611
Viscosity of Gas, cp	0.0163
Compressibility of Gas, psi-1	5.3*10-4
Compressibility of Water, psi-1	3.58*10-6
Rock Compressibility, psi-1	3.0*10-6
Effective Compressibility, psi-1	3.3*10-6
Total Compressibility, psi-1	2.7*10-4
Density of Water, lb/ft3	62.46
Density of Oil, lb/ft3	48.56
Average Porosity, %	15
Average Permeability, md	13
Pay thickness, ft	148

Table 4.2. Components of the gas

Component	W-1	W-2	W-3	W-4	W-5	Reservoir
C_1 (%)	93.25	93.21	93.56	92.99	92.49	93.10
C_2 (%)	3.25	3.37	3.23	3.35	3.36	3.31
C_3 (%)	1.45	1.32	1.22	1.50	1.61	1.42
I-C4 (%)	0.36	0.37	0.29	0.39	0.43	0.37
N-C4 (%)	0.45	0.42	0.43	0.48	0.54	0.46
I-C5 (%)	0.16	0.17	0.15	0.18	0.21	0.17
N-C5 (%)	0.13	0.16	0.15	0.16	0.16	0.15
C_6 (%)	0.19	0.21	0.19	0.22	0.47	0.26
N_2 (%)	0.76	0.77	0.78	0.73	0.73	0.75

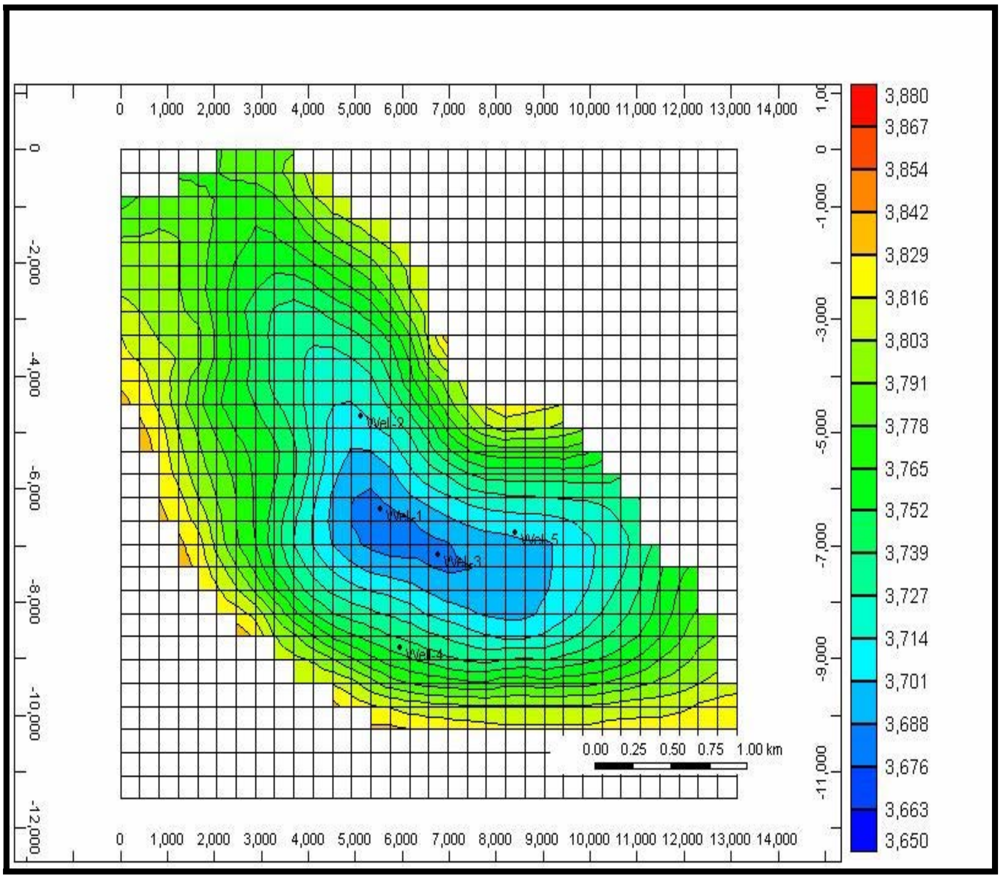

Figure 4.1 Reservoir Grid Map

In Figure 4.1 Reservoir depth distribution is illustrated including the locations of the wells.

4.2. Geological Characteristics

The tertiary age Thrace Basin is a triangular intermontane basin filled with middle Eocene to Pliocene. The middle Eocene deposits are trans-gressive over Palaeozoic metamorphic basement. The transgression reached its maximum extent during the early Oligocene. During the middle Eocene- early Oligocene, deep basin troughs were filled mostly by turbiditic clastic (Ceylan, Mezardere and Osmancik formations) whereas the northern shelf area had widespread carbonate deposition (Sogucak formation) overlain by thick fine grained marine clastics. Mezardere and

Osmancik formations inter-bedded with lesser dacitic and andestic tuffs, indicating active volcanism. Basin-wide regression followed, resulting in clastic sediments (Danismen formation) deposited successively in shallowing marine, marginal marine and terrestrial environments. Uplift in the miocene caused extensive erosion which was followed by widespread deposition of fluviatile and lacustrine clastics (Ergene formation) in the PlioPleistocene.

4.3. Rock Fluid Properties

4.3.1. Relative Permeability

Empirical equations used in calculations of Figure 4.2 and 4.3 are listed in Appendix C5

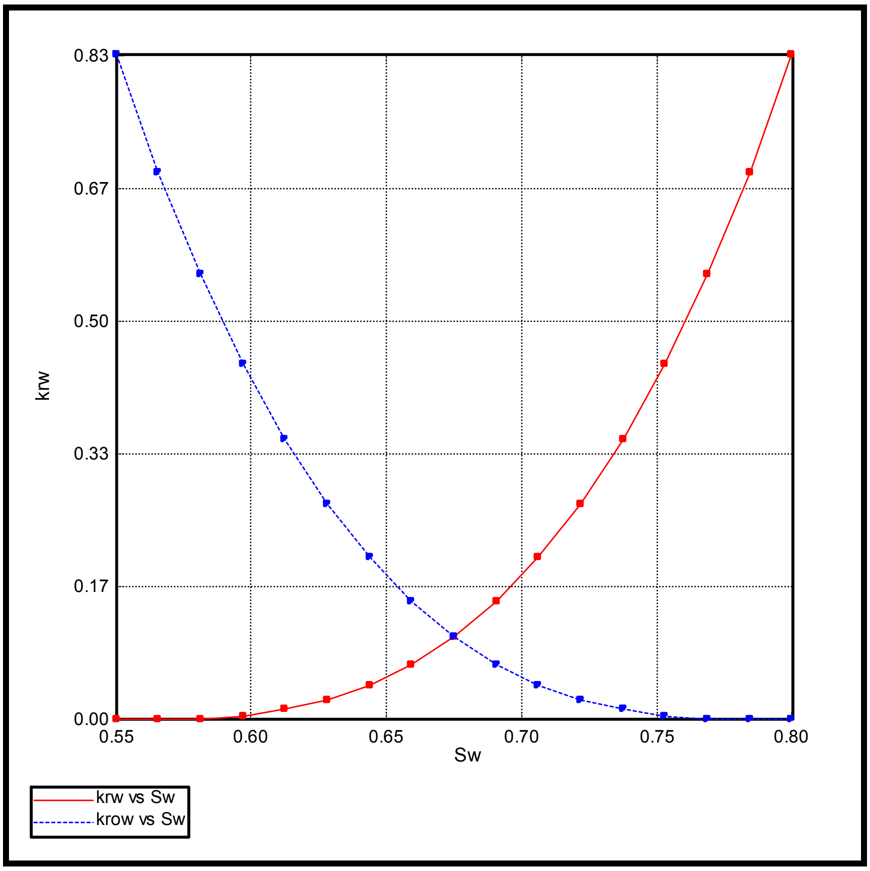

Figure 4. 1. Water Relative Permeability and Oil relative permeability to water versus water saturation

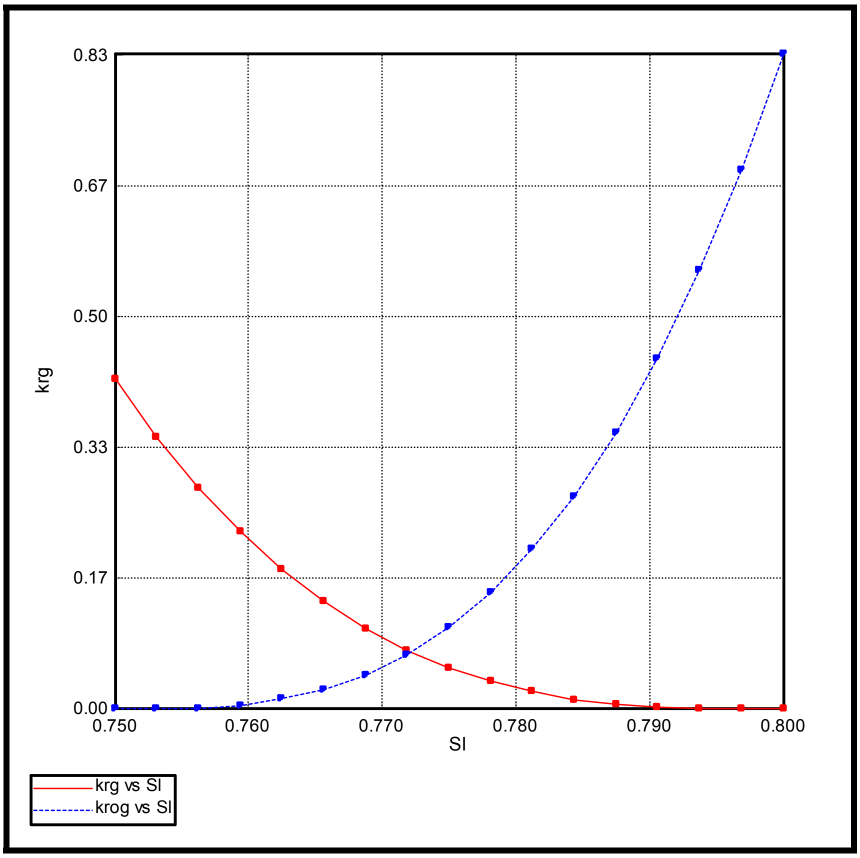

Figure 4. 2. Gas Relative Permeability and Oil relative permeability to gas versus total liquid saturation

In Figure 4.2. The intersection point of the curves representing the water saturation (Sw) is 0.67 that is slightly greater than the Sw obtained from log readings 0.55, whereas the total liquid saturation (Sl), the intersection of the curves at Figure 4.3., is 0.773.

4.3.2. Viscosity

As there is no core analysis results available, empirical formulas presented in Appendix C4. are used to calculate the oil and gas viscosity of the field, and the results are shown in Figure 4.4.

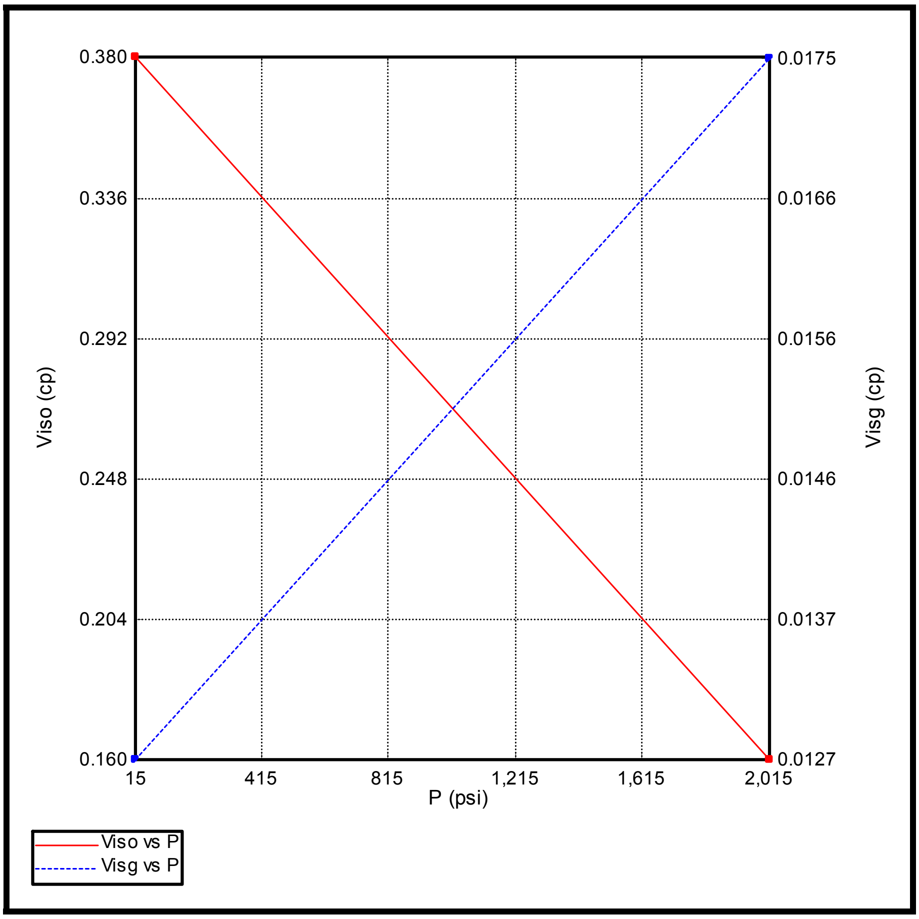

Figure 4. 3. Oil viscosity and Gas viscosity versus Pressure

Figure 4.4. shows the relation between oil viscosity (Viso), gas viscosity (Visg) and pressure (P)

.

CHAPTER 5

USE OF COMMERCIAL SOFTWARE

In this thesis, IMEX Simulator, a new generation simulator of CMG (Computer Modeling Group) was used to perform a production optimization

5.1. Introduction to IMEX

IMEX is a three-phase black-oil simulator with gravity and capillary terms. Grid systems may be Cartesian, cylindrical, or variable depth/variable thickness. Two dimensional and three dimensional configurations are possible with any of these grid systems. Gas phase appearance/disappearance is handled by variable substitution. IMEX can be used to model gas reservoirs with condensate. Oil is permitted to exist in the gas phase in the *GASWATER_WITH_CONDENSATE option. This model was used in the runs of this project.

IMEX uses the data set that you create initially and then creates three or four other files. Each IMEX run creates an output-file (OUT), an index-results-file (IRF) and a main-results-file (MRF). In addition a rewindable-results-file (RRF) may or may not be created depending on the options selected by the user.

5.2. Data Groups in the Keyword Input System

There are several points to remember when a data set is built using keyword input system:

There are several different data groups in the keyword input system

The groups must follow a certain input order:

- I/O Control
- Reservoir Description
- Component Properties
- Rock-fluid Data
- Initial Conditions
- Numerical Methods Control
- Well Data and Recurrent Data

The keywords belonging to each group cannot appear in other groups, unless it is specifically written. Usually, this happens with recurrent data from other sections, which may be changed in the Well Data section.

Also, the order of some keywords, within a group, is important.

5.2.1. Input/Output Control Section

All keywords used in "Input/ Output Control Section" are listed in Appendix B.1.

*TITLE1 'History Matching'

*TITLE2 'Primary Production'

*TITLE3 'No Group Controls'

*CASEID 'Gas-Cond'

5.2.2. Reservoir Description Section

All keywords used in “Reservoir Description Section” are given in Appendix B2.

In this section necessary inputs of the, array properties, sectors, aquifers, lease planes, rock compressibility and compaction/dilation regions are entered.

*PERMJ EQUALSI means Permeability in Y-direction is equal to Permeability in X-direction

*PERMK EQUALSI * 0.7 means Permeability in Z-direction is 70% of the Permeability in X-direction

*CPOR   4.0E-6

*PRPOR   2100.0

The reservoir is introduced as a grid system, with one producing layer. The reservoir consists of 894 blocks

For each grid block, depth of the reservoir, porosity and the permeability values are entered. Also null blocks are determined and entered with the former data. Porosity distribution of the field is in Appendix C1, Permeability distribution of the field is in Appendix C2 Grid block Map is in Appendix C3 There is no active aquifer data so that it is not described in any stage of the simulation.

5.2.3. Component Properties Section

All keywords used in “Reservoir Description Section” are given in Appendix B3 The wells are producing condensate at the same time with gas. So the model with condensate is chosen:

*MODEL GASWATER_WITH_CONDENSATE

Pressure dependence of water viscosity is neglected and entered as zero.

Like water viscosity, pressure dependence of oil phase viscosity is neglected and entered as zero.

Phase properties entered in the simulation is listed in Table 5.1.

Table 5.1. PVT Properties of the components

Reservoir Temperature ,°F	135
Density Oil Ibm/scf	48.56
Density Gas Ibm/scf	0.1109
Density Water Ibm/scf	62.46
Reference Pressure for water, psi	1875
Water Formation volume factor, rbl/stb	1
Water Viscosity, cp	1
Water Compressibility,psi^{-1}	$3.58*10^{-6}$

Pressure, psi (P), solution gas-oil ratio, scf/stb (Rs), Oil content for condensate saturated gas, stb /scf (Rv), Formation volume factor for saturated oil, RB/STB, Bo, gas formation volume factor for condensate saturated gas, Bg, gas viscosity of condensate saturated gas and viscosity of saturated oil data entered in the simulation is illustrated in Table 5.2. Calculations of the properties are listed in Appendix C4.

Peng Robinson Equation of State is used to make calculations and presented in Appendix C9.

Table 5.2. PVT Data used in the simulator

P	Rs	Rv	Bo	Bg	Viso	Visg
14.7	0	0	1.04	0.21015	0.38	0.01268
515	288.7	0.02506E-3	1.172	0.0068	0.28	0.01310
1015	618.7	0.02115E-3	1.362	0.002787	0.21	0.01407
1515	980.1	0.02644E-3	1.607	0.00177	0.18	0.01540
2015	1377.7	0.039146e-3	1.859	0.001306	0.16	0.01753

5.2.4. Rock-Fluid Properties Section

All keywords used in “Rock- Fluid Properties Section” are given in Appendix B4.

Relative permeability values are calculated by the IMEX relative permeability generator. Hence formulas necessary to calculate relative permeability values are listed in Appendix C5.

The saturation and relative permeability data entered in the simulation is presented in Table 5.3. and Table 5.4.

Table 5.3. Water saturation (Sw), Relative Permeability to water (Krw), relative permeability to oil (fraction) in the presence of the given water saturation (krow)

Sw (%)	Krw	Krow
0.55	0	0.8334
0.565625	0.000203467	0.6867
0.58125	0.00162773	0.558313
0.596875	0.0054936	0.447017
0.6125	0.0130219	0.351591
0.628125	0.0254333	0.270814
0.64375	0.0439488	0.203467
0.659375	0.0697891	0.148327
0.675	0.104175	0.104175
0.690625	0.148327	0.0697891
0.70625	0.203467	0.0439488
0.721875	0.270814	0.0254333
0.7375	0.351591	0.0130219
0.753125	0.447017	0.0054936
0.76875	0.558313	0.00162773
0.784375	0.6867	0.000203467
0.8	0.8334	0

Table 5.4. Total liquid saturation (Sl), Relative Permeability to gas (Krg), Relative permeability to oil (fraction) in the presence of gas and connate water for the given saturation (krow)

Sl (%)	Krg	Krog
0.75	0.42094	0
0.753125	0.346844	0.000203467
0.75625	0.281997	0.00162773
0.759375	0.225783	0.0054936
0.7625	0.177584	0.0130219
0.765625	0.136785	0.0254333
0.76875	0.102769	0.0439488
0.771875	0.0749183	0.0697891
0.775	0.0526175	0.104175
0.778125	0.0352496	0.148327
0.78125	0.022198	0.203467
0.784375	0.0128461	0.270814
0.7875	0.00657719	0.351591
0.790625	0.00277475	0.447017
0.79375	0.000822148	0.558313
0.796875	0.000102769	0.6867
0.8	0	0.8334

5.2.5. Initial Conditions Section

All keywords used in “Initial Conditions Section” are given in Appendix B5. Dew point graph is illustrated in Appendix C6.

Initial reservoir data entered in the simulation is illustrated in Table 5.5.

Table 5.5. Initial Reservoir Data

Reference Pressure, psi	1675
Reference Depth, ft	3500
Water-Gas Contact, ft	3900
Datum Depth, ft	4200
Dew Point Pressure, psi	900

5.2.6. Numerical Control Section

All keywords used in “Numerical Control Section” are given in Appendix B6.

5.2.7 Well and Recurrent Data Section

All keywords used in “Numerical Control Section” are given in Appendix B7.

All existing wells and the new wells defined in the scenarios are listed in Table 5.6.

Table 5.6. Producing wells

Well 1	W-1	Existing
Well 2	W-2	Existing
Well 3	W-3	Existing
Well 4	W-4	Existing
Well 5	W-5	Existing
Well 6	W-6	Scenario
Well 7	W-7	Scenario

CHAPTER 6

HISTORY MATCHING

In this study, history matching is performed to compare the results of the simulator obtained by using the reservoir characteristics with the real production data gathered from the field and use that data to make future evaluations. Data from the field was available between May 2002 and January 2005.

In this field there are five producing wells, first of which started production in 2002 and the other four started between 2002 and 2003 respectively. Field data is available for each well and compiled to achieve the total field data. The idea of history matching is to use the reservoir data and achieve as close as possible results with the real production data. In order to reach this goal several trial runs performed. According to the results of the trial runs, it is seen that some modifications must be done to the reservoir data. As the original reservoir porosity data was only available for each well and did not give out satisfactory results in the trial runs, the Surfer software (20) is used to figure out the porosity distribution of the field.

The problem observed in porosity is faced in permeability distribution, therefore the Surfer software is used again to calculate the permeability distribution in the field. The permeability in the y direction is assumed to be equal to the x direction and the z direction is taken as the 70% of the x direction respectively

6.1. Comparison of Wellhead Pressures for each well

From Figure 6.1. to Figure 6.5., there is a good match between the simulator results and the data obtained from the field. There are some differences in the early production times, because the wells were shut in several times because of build-up tests. RMSE Calculations for WHP are listed in Appendix C11.

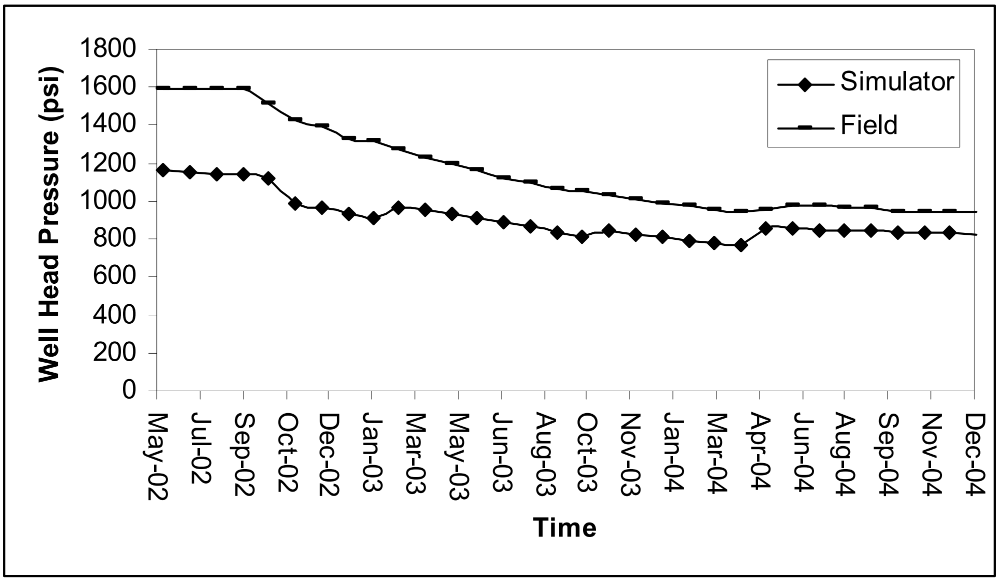

Figure 6.1. Comparison of Well head pressure for W1

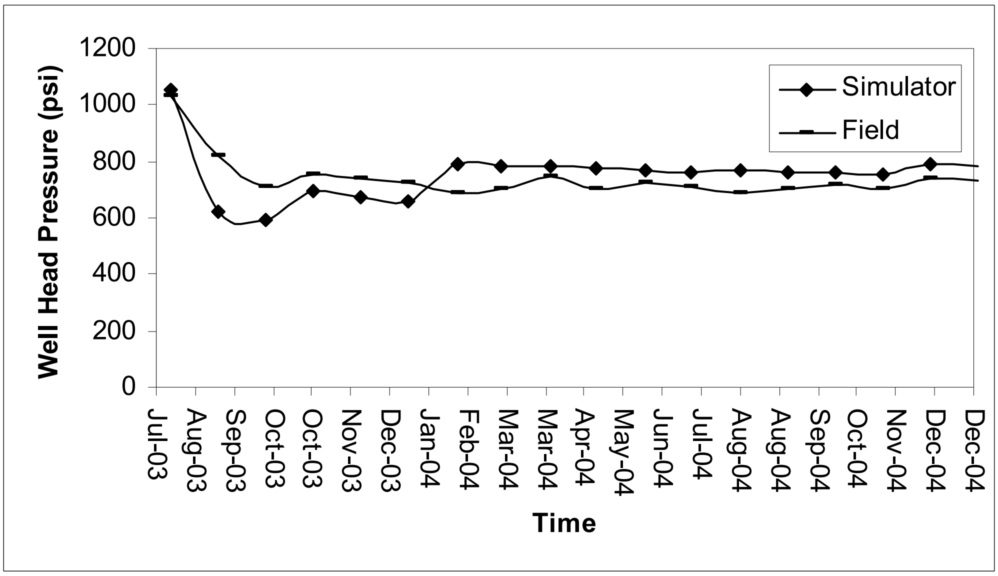

Figure 6. 2. Comparison of Wellhead Pressure for W2

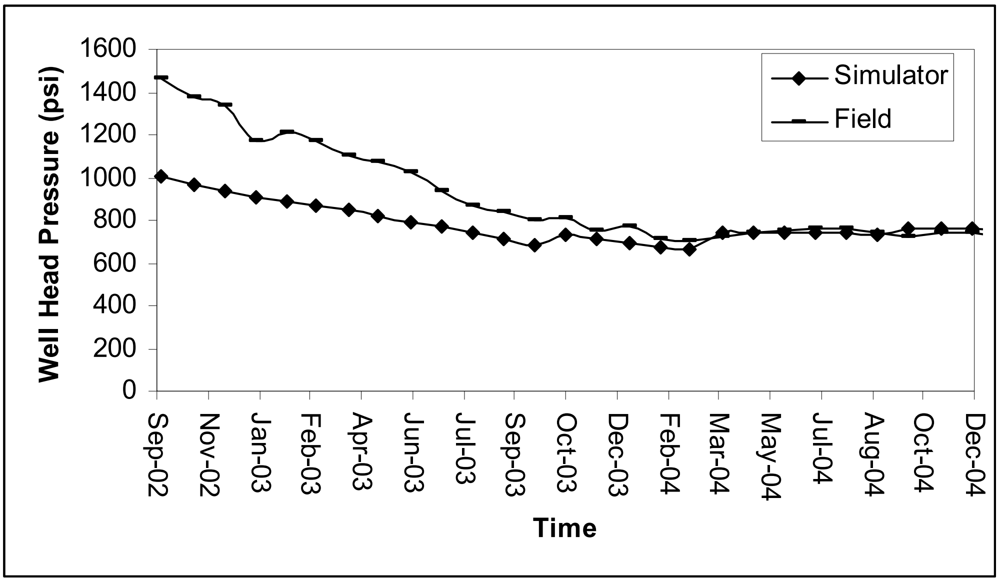

Figure 6. 3. Comparison of Wellhead Pressure for W3

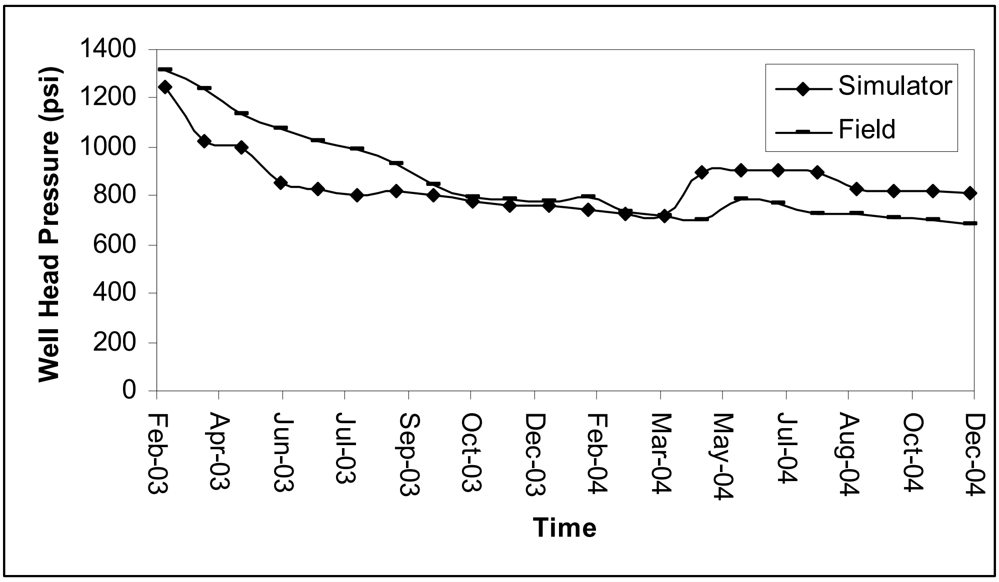

Figure 6. 4 Comparison of Wellhead Pressure for W4

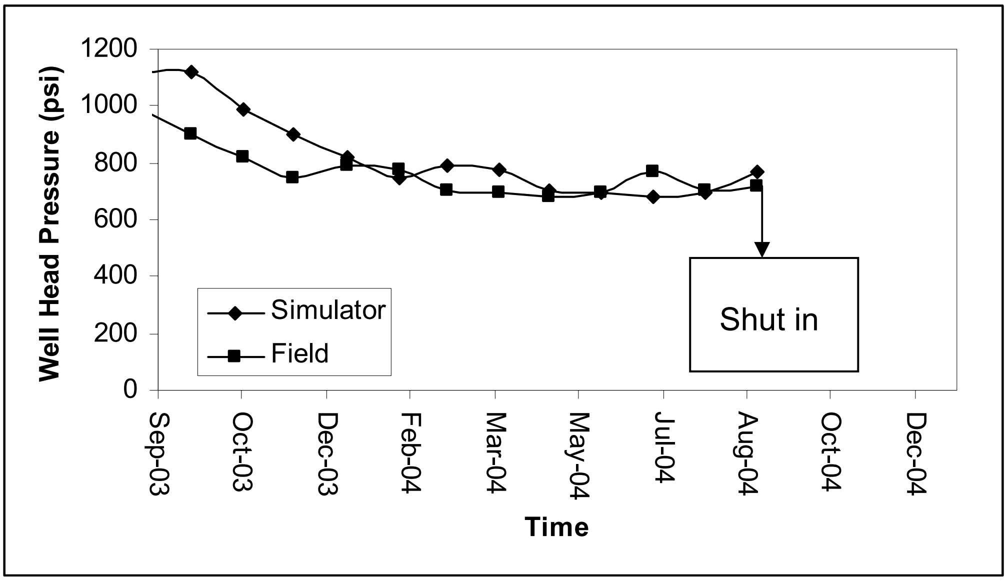

Figure 6. 5. Comparison of Wellhead Pressure for W5

6.2 Comparison of Gas Productions for each well

From Figure 6.6. to Figure 6.10. Gas production comparison for each well is presented. For the wells W1, W2, W3 and W4 the gas production curves are very close. The trends are good enough to make new scenarios. Even though the fit in W5 is not as close as the first four wells, the trend is sufficient to characterize the well.

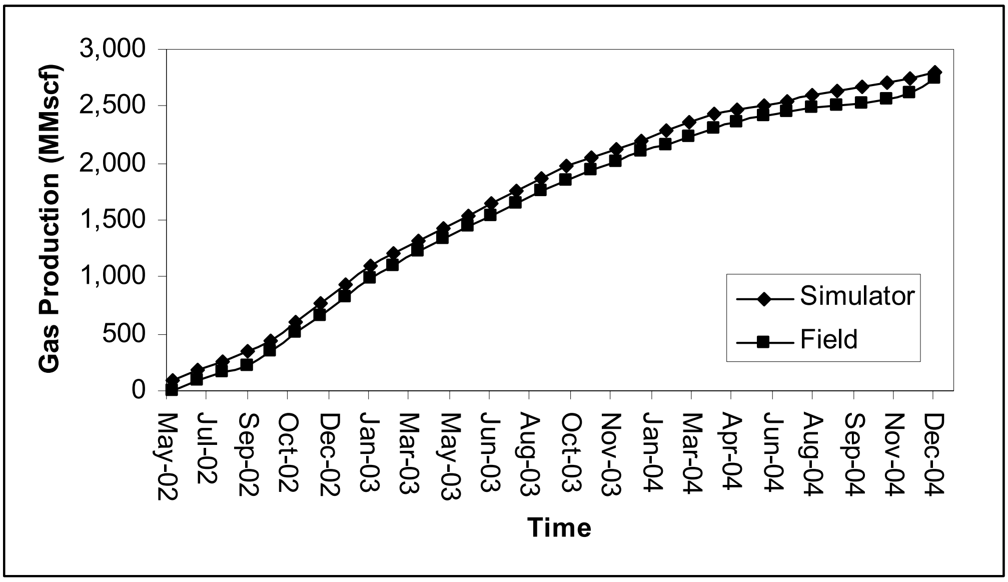

Figure 6. 6.Comparison of Gas Production for W1

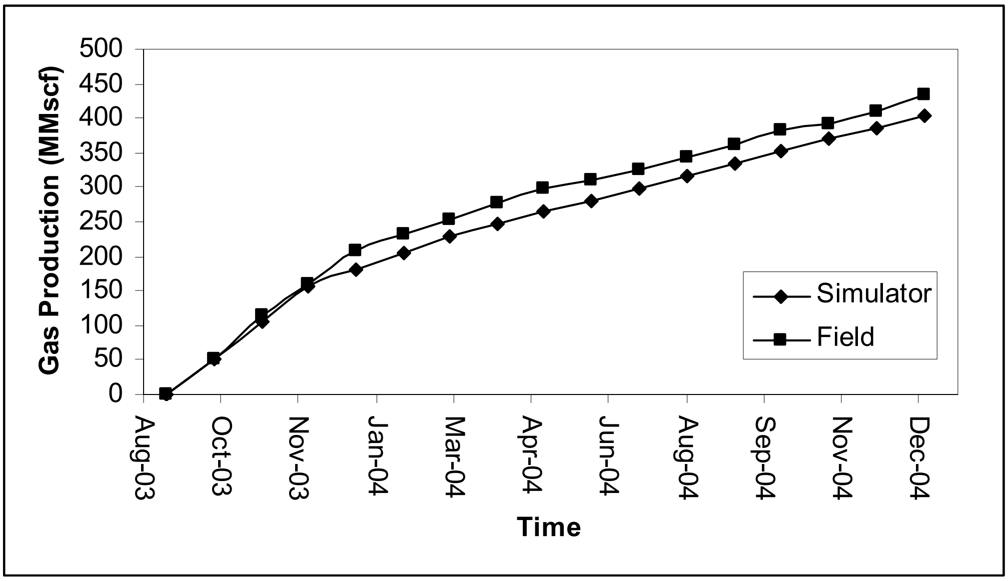

Figure 6. 7. Comparison of Gas Production for W2

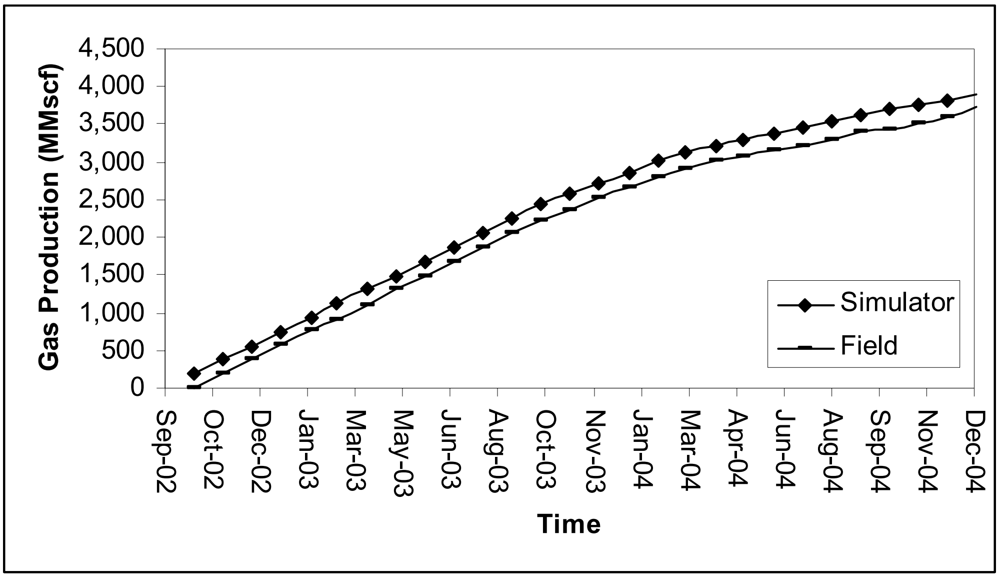

Figure 6. 8. Comparison of Gas Production for W3

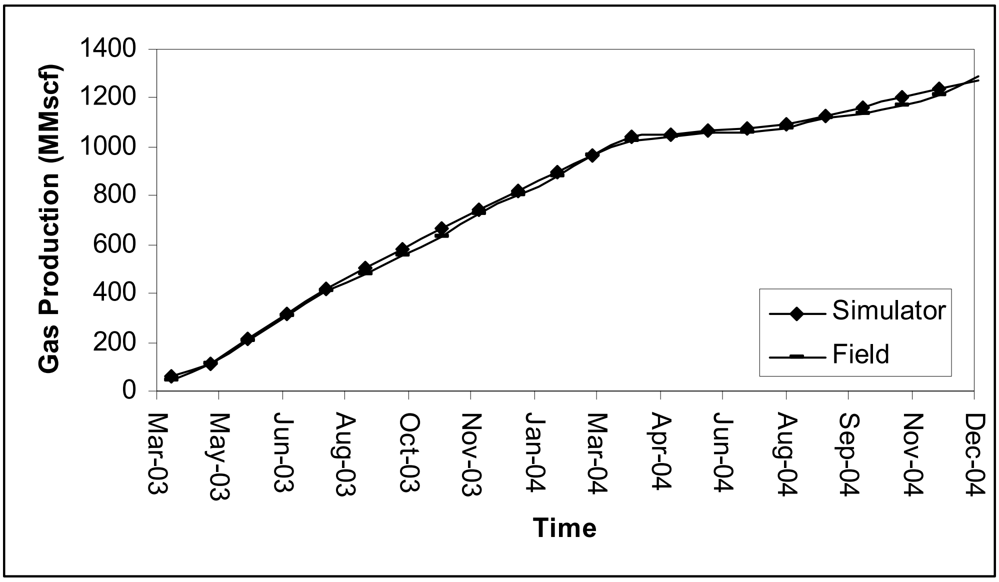

Figure 6. 9 Comparison of Gas Production for W4

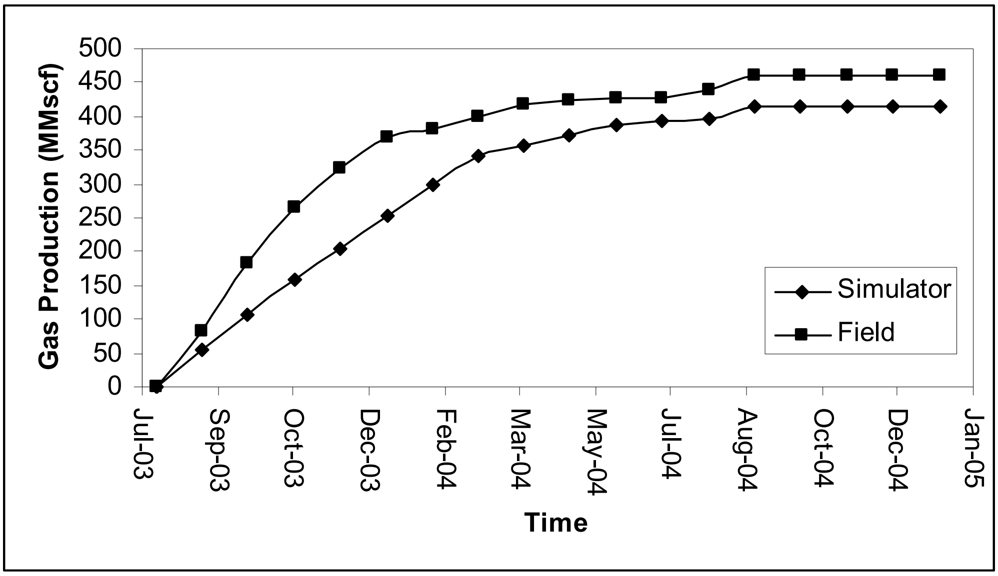

Figure 6. 10. Comparison of Gas Production for W5

6.3 Comparison of Condensate Production for each well

From Figure 6.11. to Figure 6.15 condensate production comparisons are illustrated. Like the gas production comparison curves, condensate production curves show the similar behavior. Unlike gas production comparison, W5 shows a very close trend for condensate production.

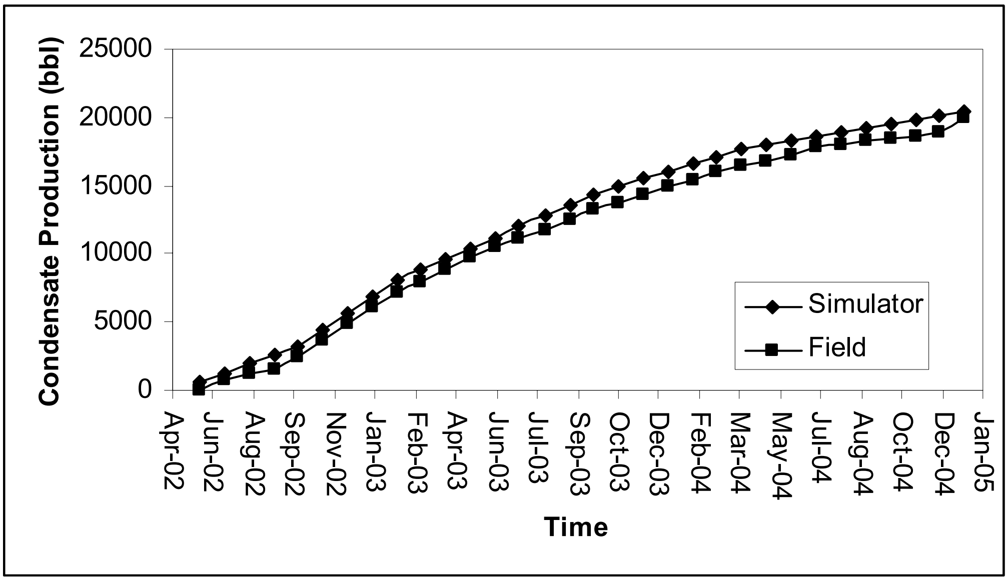

Figure 6. 11.Comparison of Condensate Production for W1

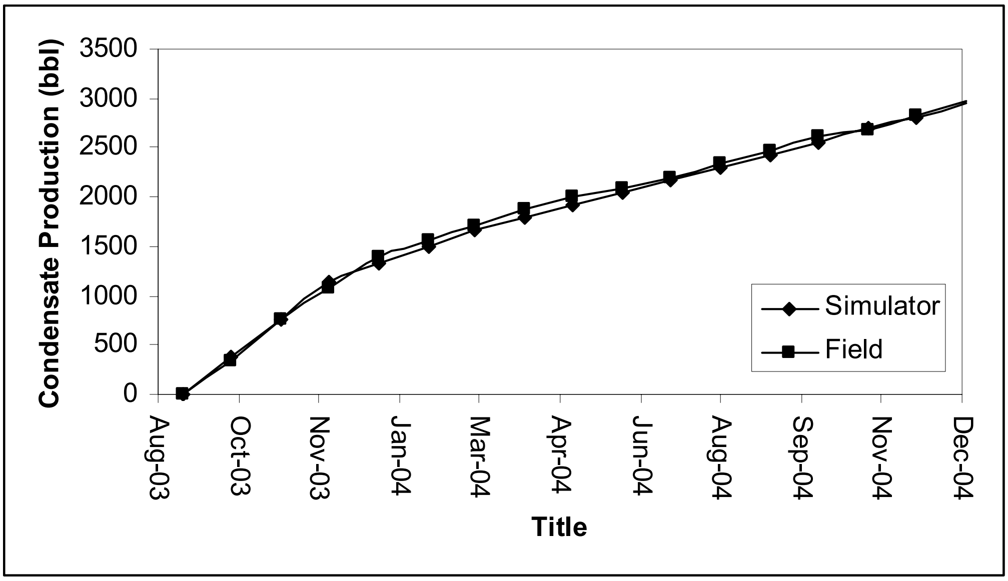

Figure 6. 12. Comparison of Condensate Production for W2

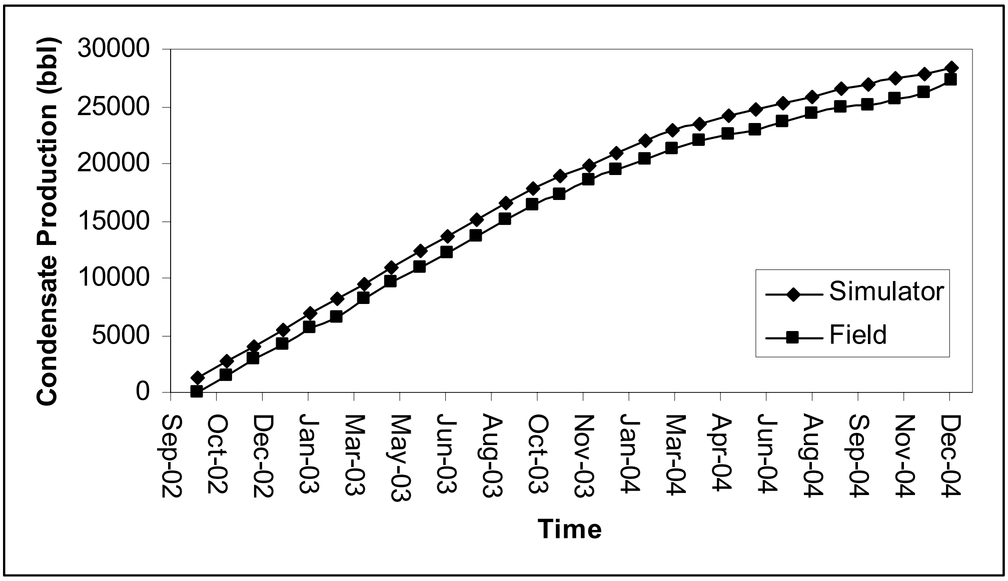

Figure 6. 13. Comparison of Condensate Production for W3

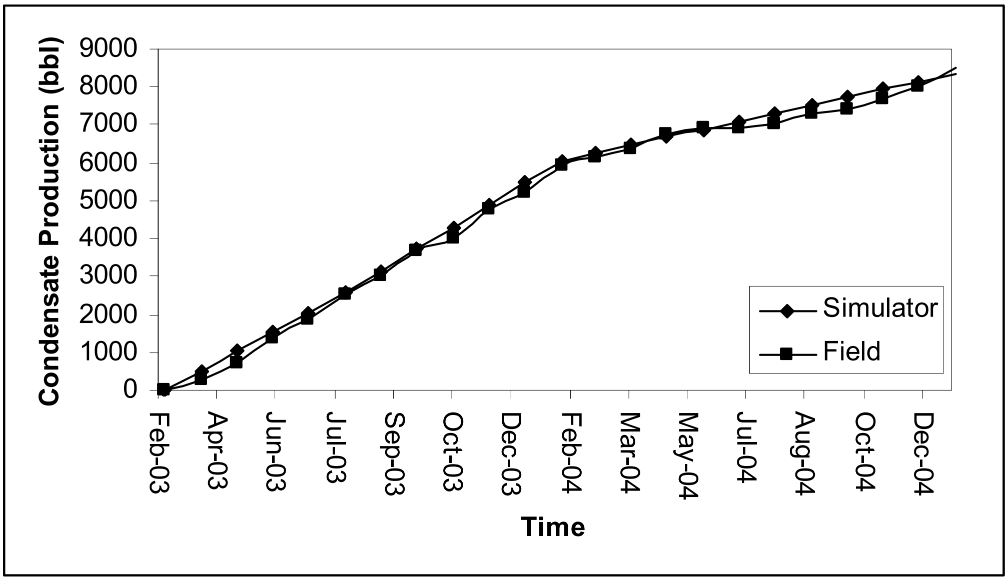

Figure 6. 14. Comparison of Condensate Production for W4

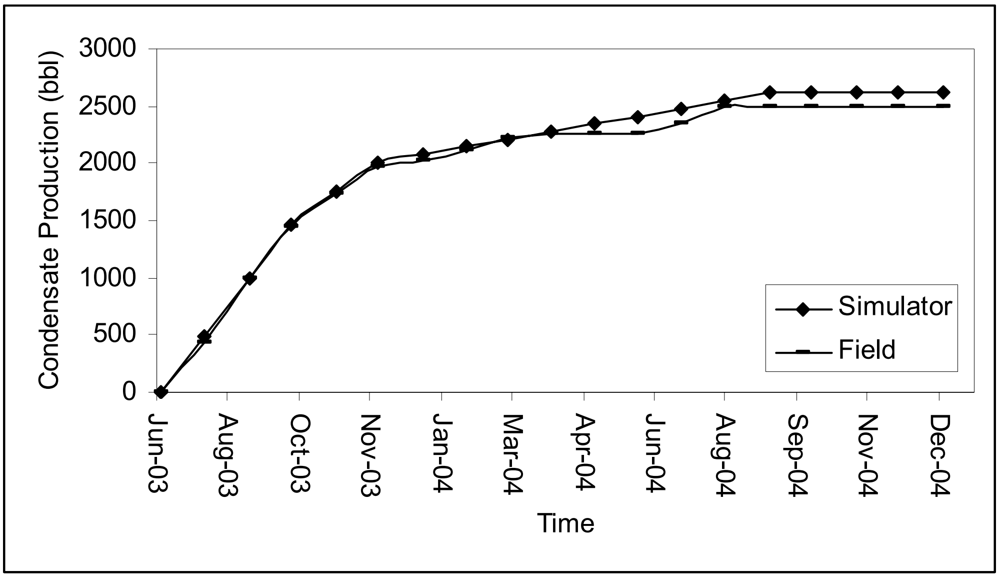

Figure 6. 15. Comparison of Condensate Production for W5

6.4 Comparison of Water Production

There is no active aquifer described in this reservoir. Therefore no water production results gathered from the simulator. In order to compare the water production of the field Katz's Chart is used. Katz's chart and the calculations of water production are presented in Appendix C10. Figure 6.16 shows the comparison of water production for the field.

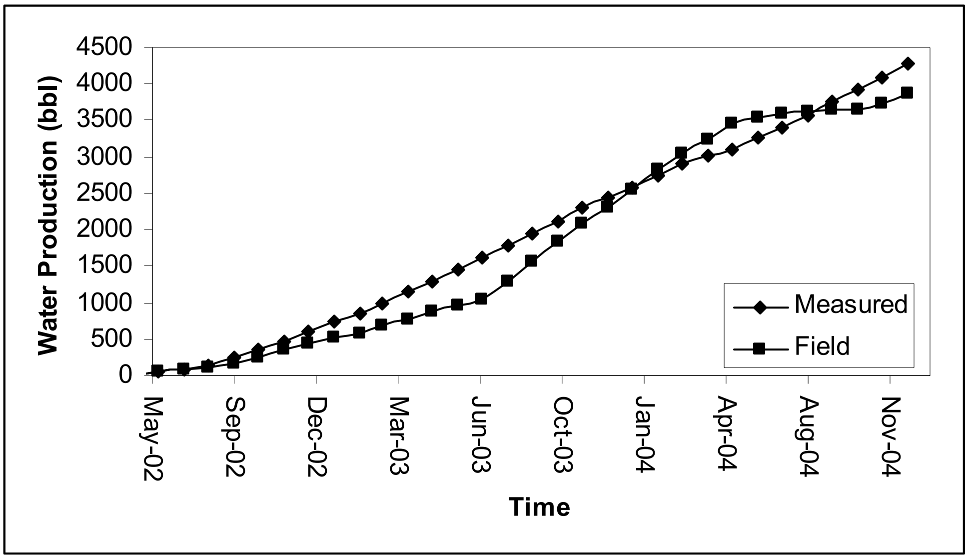

Figure 6.16. Comparison of Water Production

6.5 Comparison of Reservoir Properties

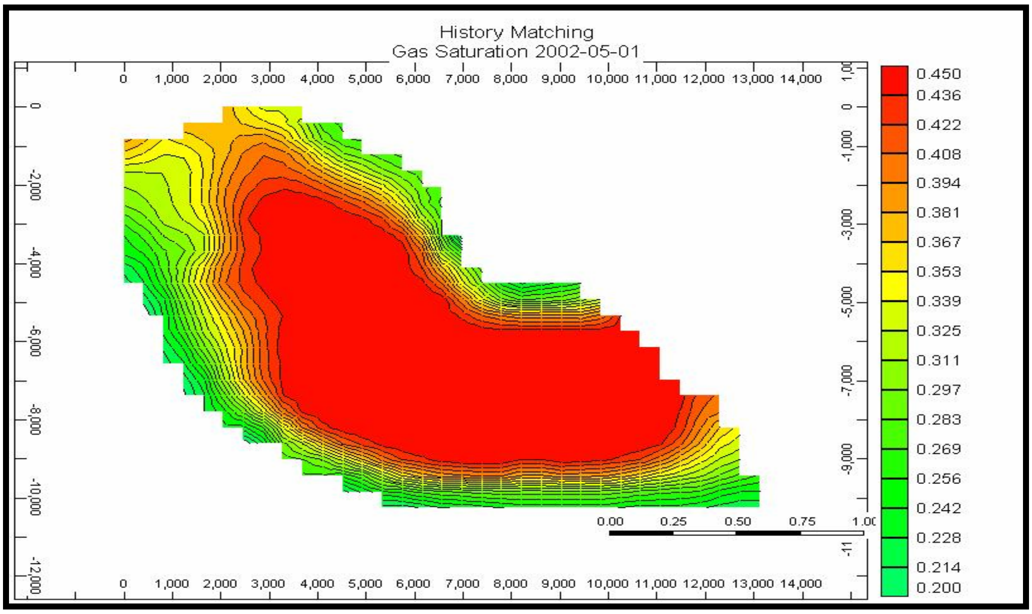

Figure 6. 17. Gas Saturation at the beginning of History Matching

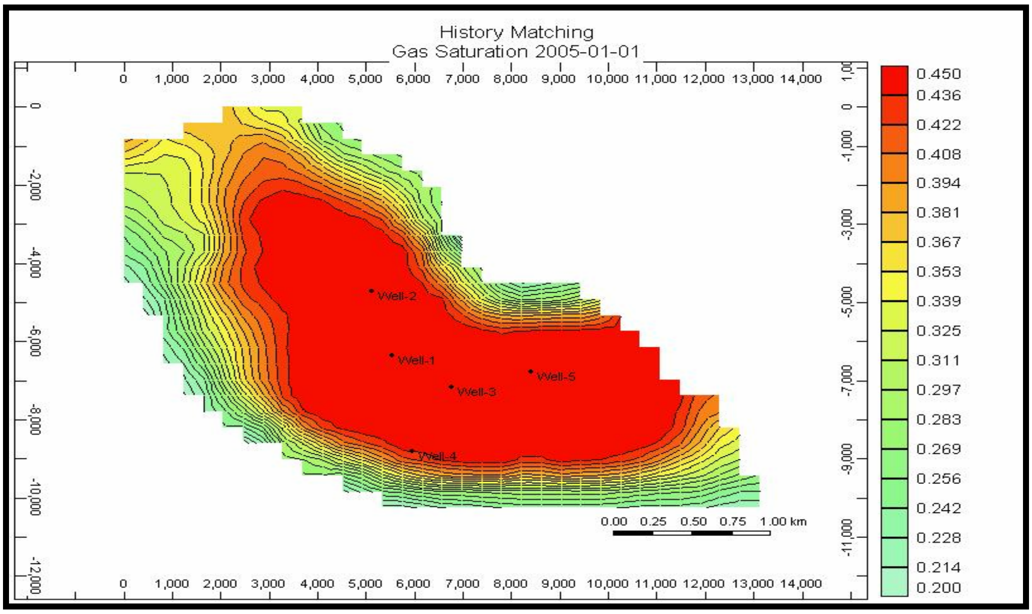

Figure 6. 18. Gas Saturation at the end of Simulation

Average gas saturation at the beginning of the field life is 0.45 and the final gas saturation at the end of history matching section is rather close because the field has a gas expansion production mechanism. The zone containing the producing wells has clearly more gas saturation than the zones closer to the boundaries of the reservoir.

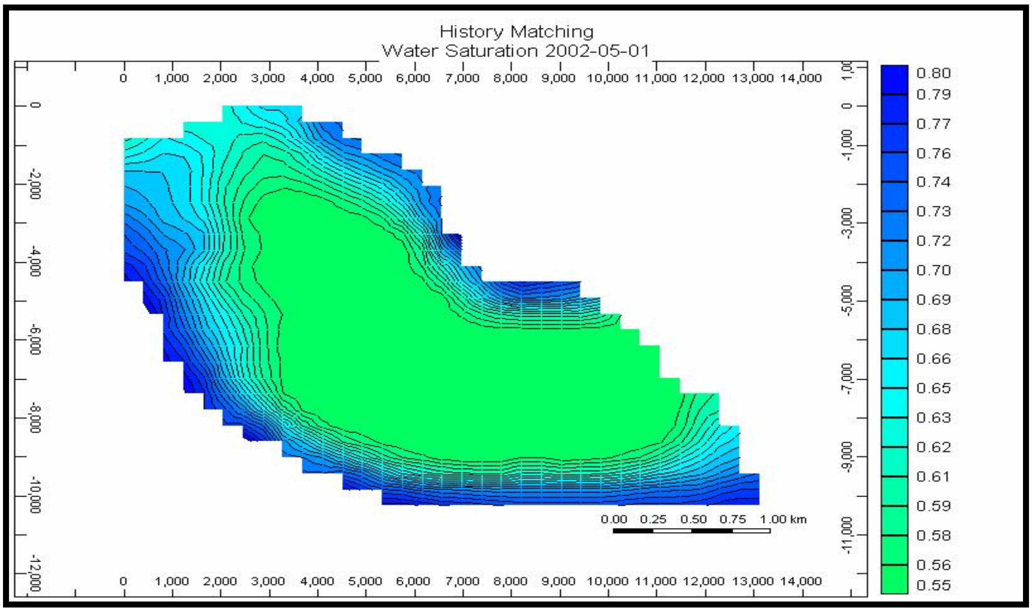

Figure 6. 19. Water Saturation at the beginning of History Matching

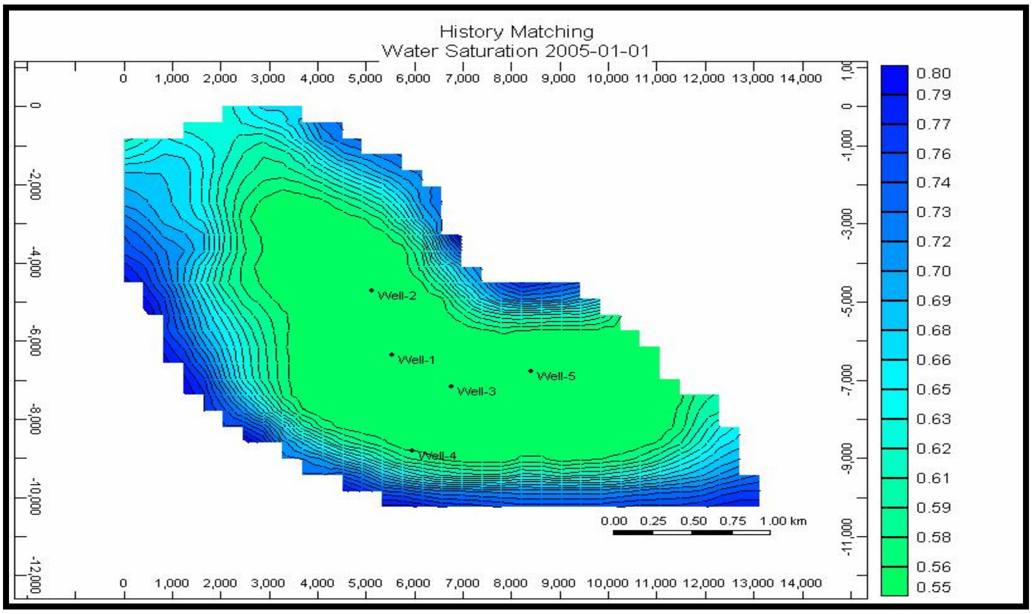

Figure 6. 20. Water Saturation at the end of History Matching

Similar to gas saturation behavior, water saturation increases in minor values. Maximum water saturation 0.78 is observed in the zones closer to the edges of the reservoir at the end of history matching section.

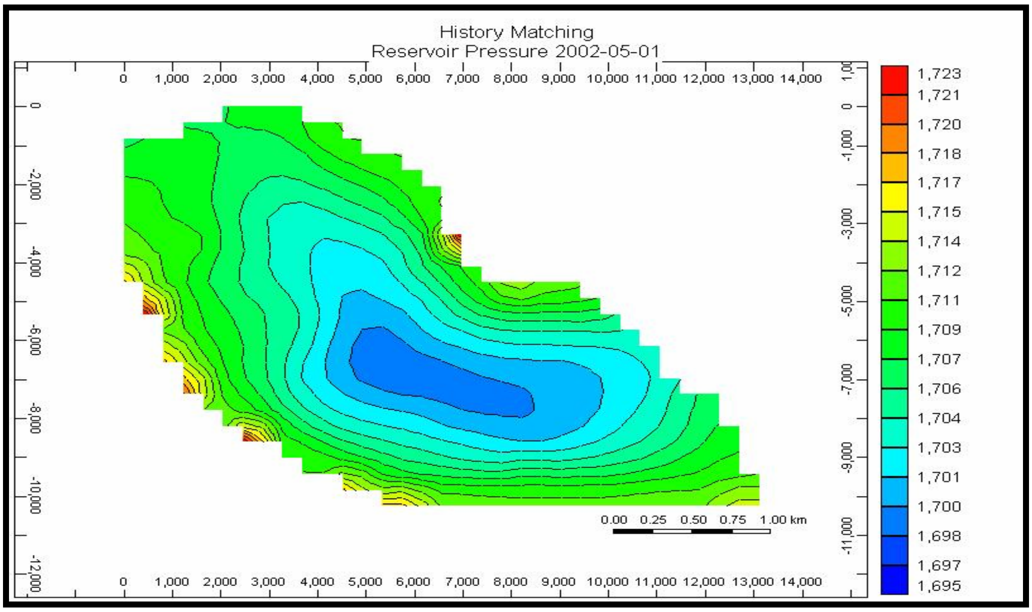

Figure 6. 21. Reservoir Pressure Distribution at Beginning of Simulation

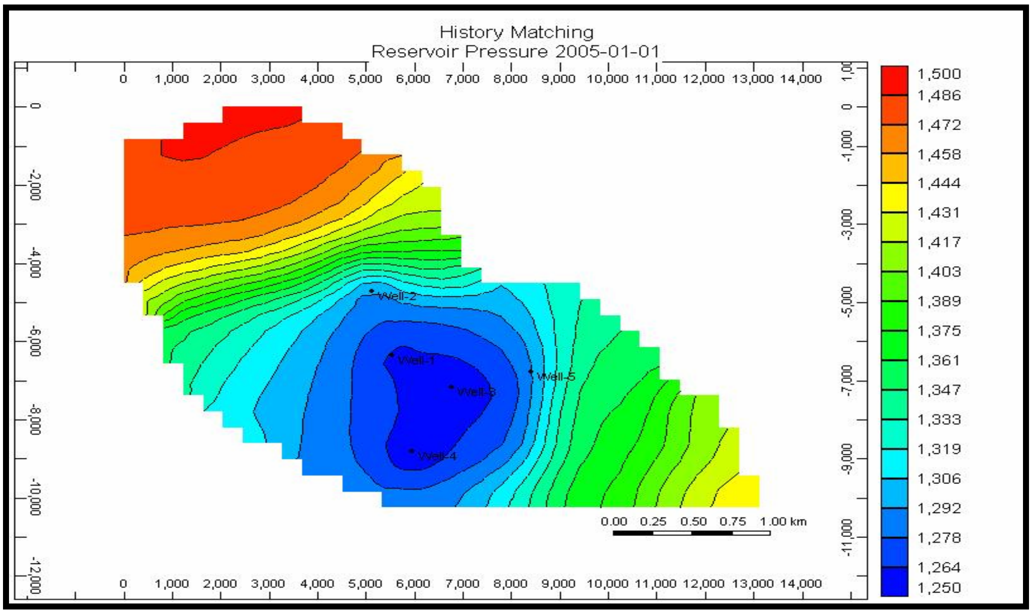

Figure 6. 22. Reservoir Pressure Distribution at the end of Simulation

Initial average reservoir pressure presented in the figure 6.20 was 1705 psi. After the decline during the history matching section, average pressure presented in Figure 6.21shows a 340 psi drop and decreases to 1365 psi.

6.6 Total Production Comparison

In Figures 6.21. and 6.22. Total production from the field is illustrated.

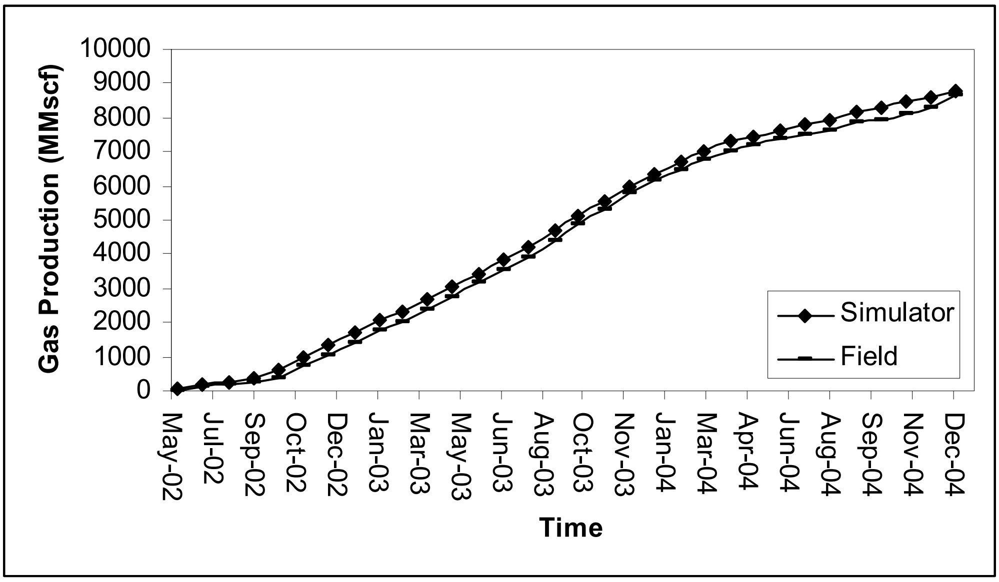

Figure 6. 23. Comparison of Total Gas Production of the field at the end of Simulation

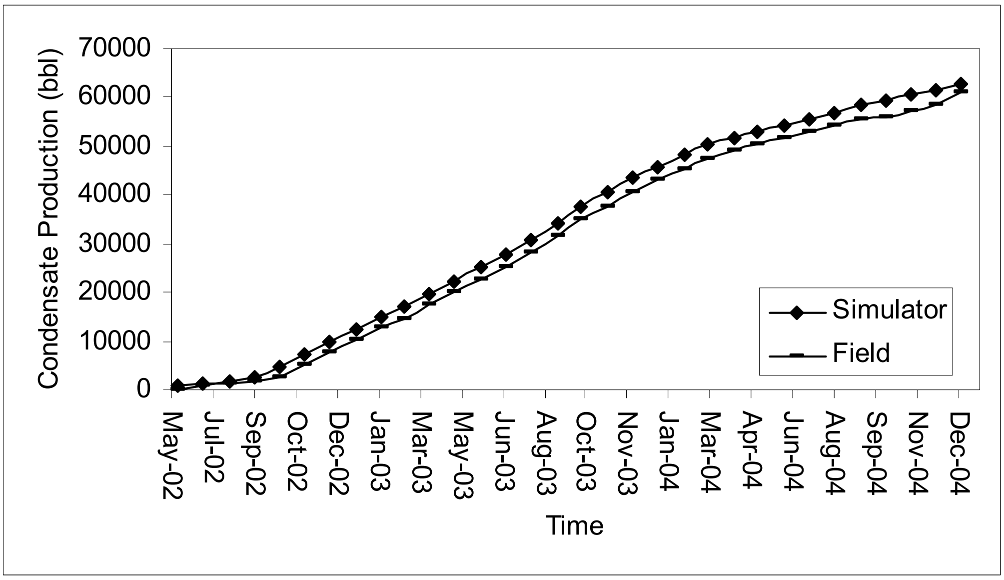

Figure 6. 24. Comparison of Total Condensate Production of the field at the end of simulation.

Total gas production and total condensate figures show the same trend and are very close to each other. Total production calculated from the simulator is 8,772 MMscf whereas the production amount gathered from the field is 8,648 MMscf.

Similarly, total condensate production calculated from the simulator is 62,669 and the field condensate production is 61,141, which gives out close results for the condensate production comparison.

CHAPTER 7

PERFORMANCE PREDICTIONS

In the history matching section, a very reliable match between the field data and the simulator data was achieved, which allows the output of the previous section used as guidelines for the future predictions in the field. The well-head pressure distribution will be the key feature in the future scenarios, determining the allowable flow rates of the wells.

In order to get more recovery from the filed, probable options are considered. First, existing four wells at the end of the history matching section are allowed to produce. Then new wells are defined in order to see their effect in the total production of the field. These wells are first produced individually, then together to see the differences in production.

7.1. Scenario 1- Production until 2010 with existing wells.

In this scenario four wells that were still on production at the end of the history matching section, on 01-01-2005, will continue production until 01-01-2010 unless well head pressure decline reaches 500 psi, which is the minimum allowable working pressure for the Tri-ethylene glycol pumps in the dehydration units (21). New production rates are defined for each well after several trial runs and listed in Table 7.1.

Table 7. 1. Production rates (Scf/d) during Scenario-1

Well ID	Rate (Scf/d)
W1	2,000,000
W2	679,000
W3	2,500,000
W4	1,600,000

7.1.1 Reservoir Properties at the end of Scenario 1

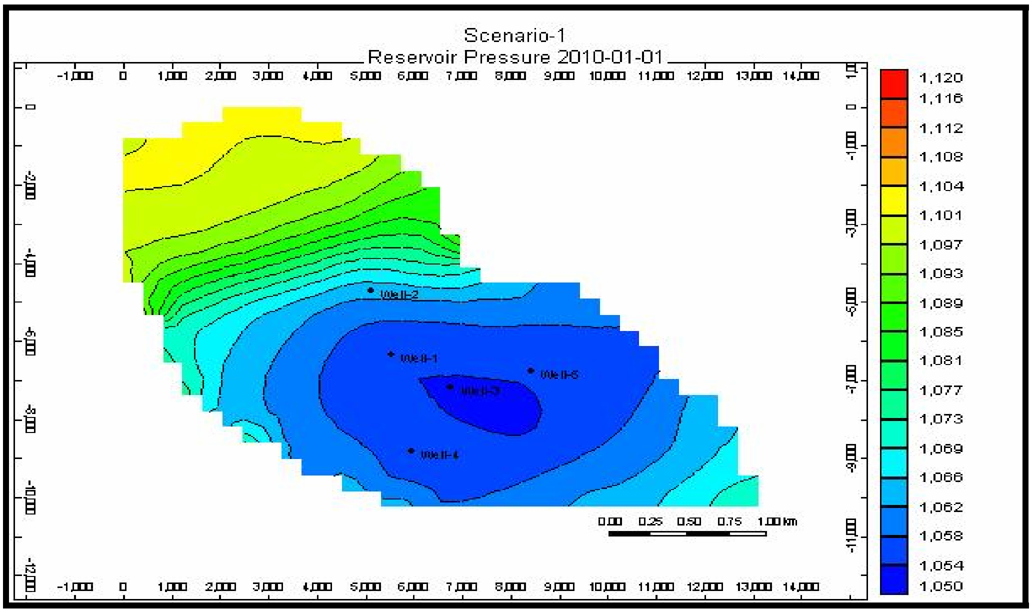

Figure 7. 1. Reservoir Pressure distribution at the end of Scenario 1

Average reservoir pressure which was 1365 psi shows a 300 psi drop and becomes 1065 psi. Lowest pressure region is the zone containing the producing wells whereas the highest point has only 70 psi more which is the western part of the Well 2.

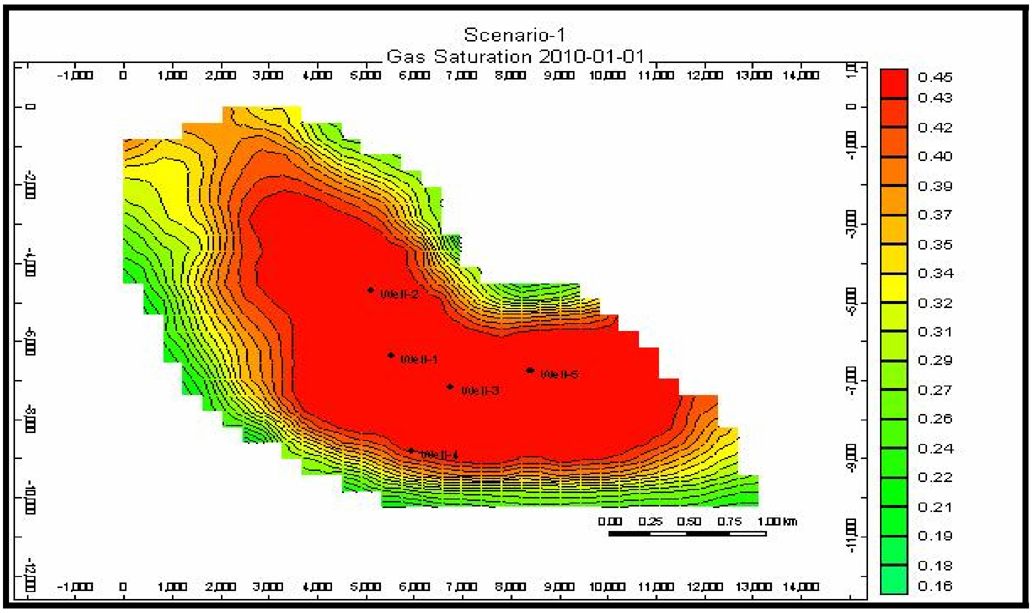

Figure 7. 2. Gas Saturation distribution at the end of Scenario 1

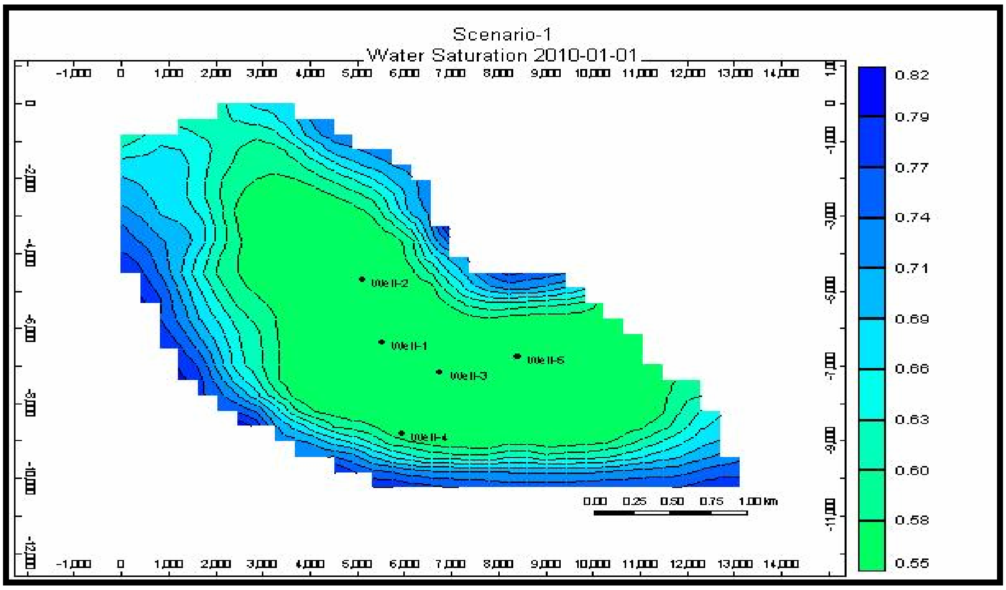

Figure 7. 3. Water Saturation distribution at the end of Scenario 1

Gas saturation averaging 0.445 at the end of history matching drops to 0.425 and the low gas saturated regions has 0.18 gas saturation. Water saturation reaches up to 0.82 nearer to the edges of the reservoir, averaging 0.555 at the end of history matching section, is now 0.575.

7.1.2. Total Production in Scenario 1

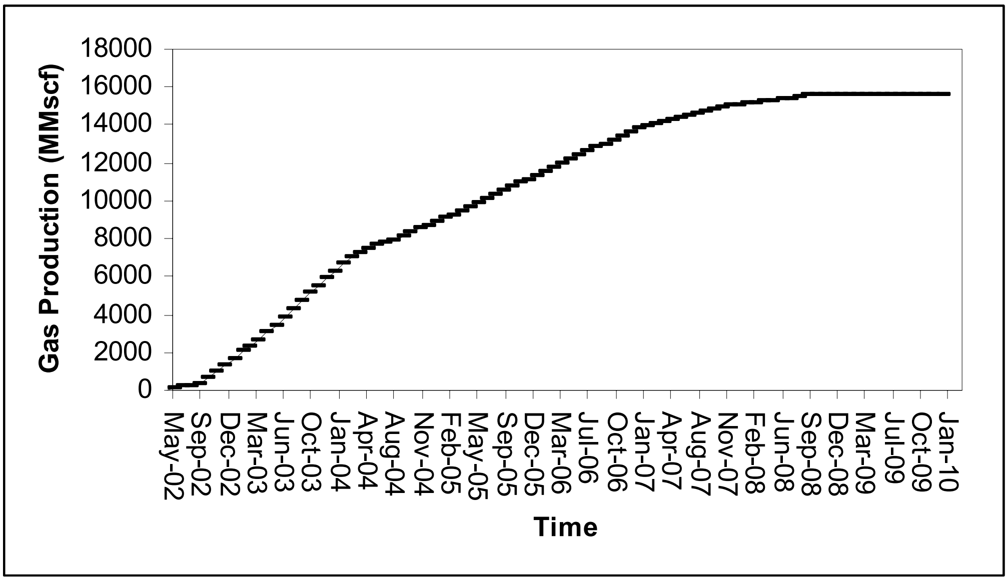

Figure 7. 4. Total Gas Production in Scenario 1

Table 7.2. Comparison of Gas Production during Scenario 1

Well ID	History Matching (MMscf)	Scenario1 (MMscf)	Total (MMscf)
W1	2,792	2,678	5,470
W2	404	537	941
W3	3,891	1,824	5,715
W4	1,271	1,720	2,991

At the end of the scenario, W1 produces 2.678 MMscf which is the highest production during Scenario 1 W3 is the second with 1,824 MMscf, and W4 is the third with 1,720 MMscf. Lowest production is obtained from W2.

7.1.3 Wellhead Behaviors during Scenario 1

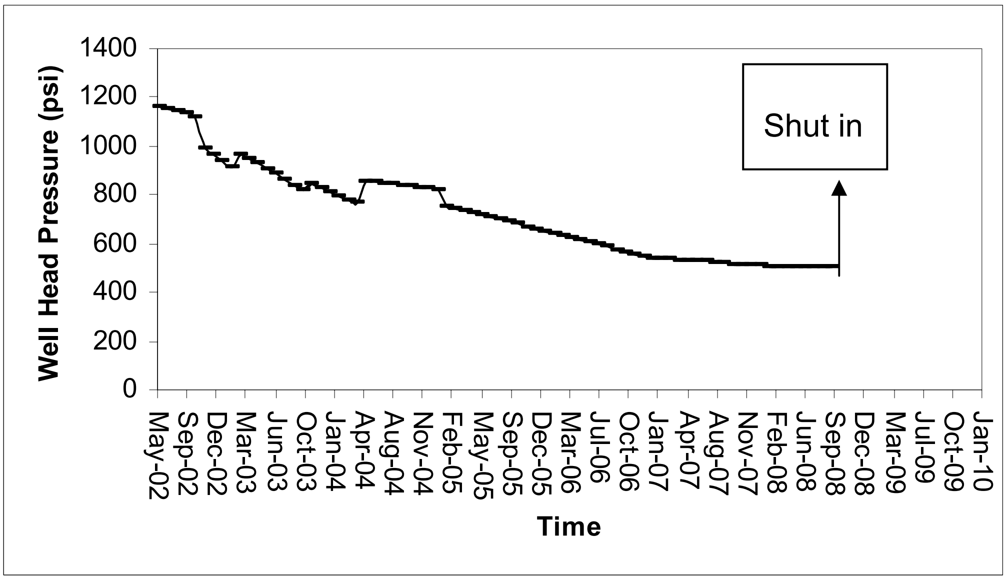

Figure 7. 5. Wellhead Pressure behavior of W1 during Scenario 1

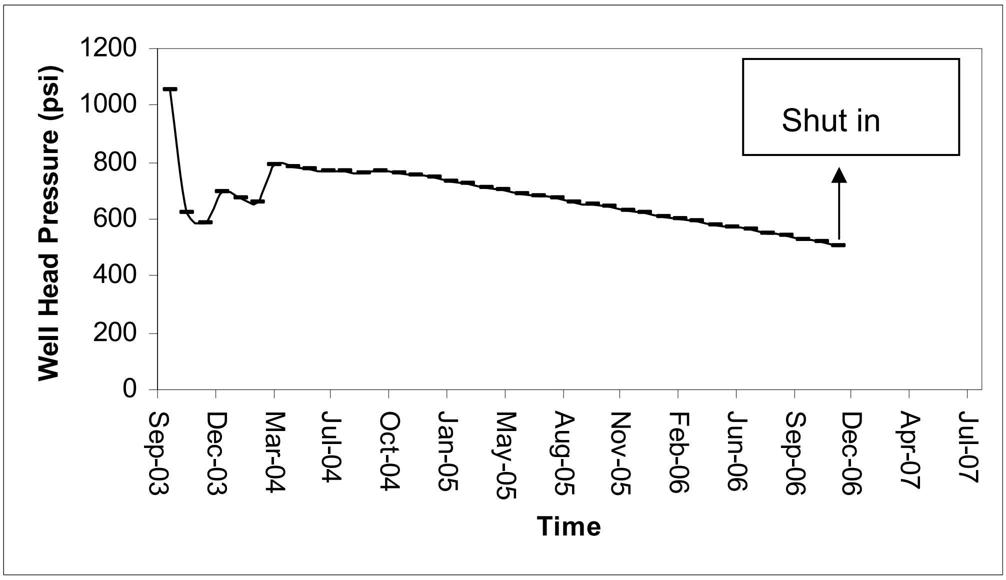

Figure 7.6. Well-head Pressure behavior of W2 during Scenario 1

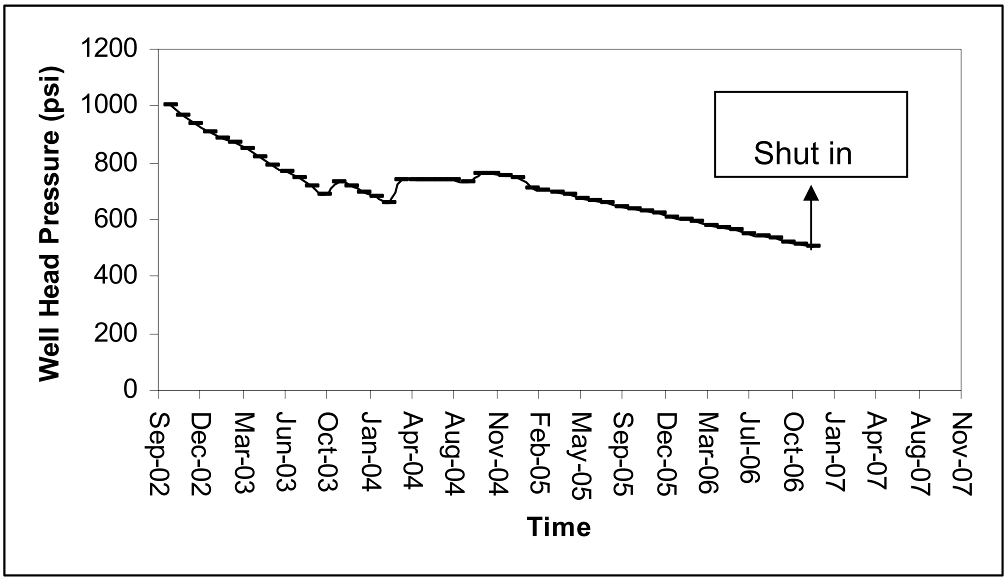

Figure 7. 7. Wellhead Pressure behavior of W3 during Scenario 1

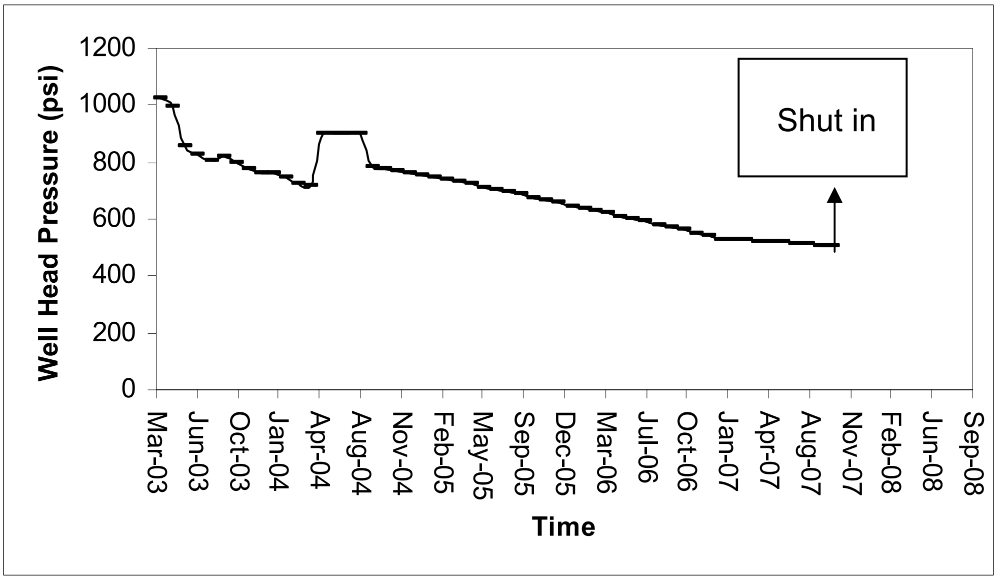

Figure 7. 8. Wellhead Pressure behavior of W4 during Scenario 1

The life span of W1 ends in October 2008, which is the longest life, and the production amount.W4 wellhead pressure drops to 500 psi in November 2007, W2 and W3 in January 2007.

7.2. Scenario 2: Production with Well-6

In this scenario a new well is defined after the history matching. The well location choice is performed according to final reservoir pressure distribution in 2005-01-01. The field went on production with five wells by the addition of the new well, W-6. The well head pressure constraint is applied as 500 psi like the first scenario. Production rates used during the scenario is shown in Table 7.3

Table 7.3. Production rates (Scf/d) during Scenario 2

Well ID	Rate (Scf/d)
W-1	2,000,000
W-2	679,000
W-3	2,500,000
W-4	1,600,000
W-6	1,100,000

7.2.1. Reservoir properties at the end of Scenario 2

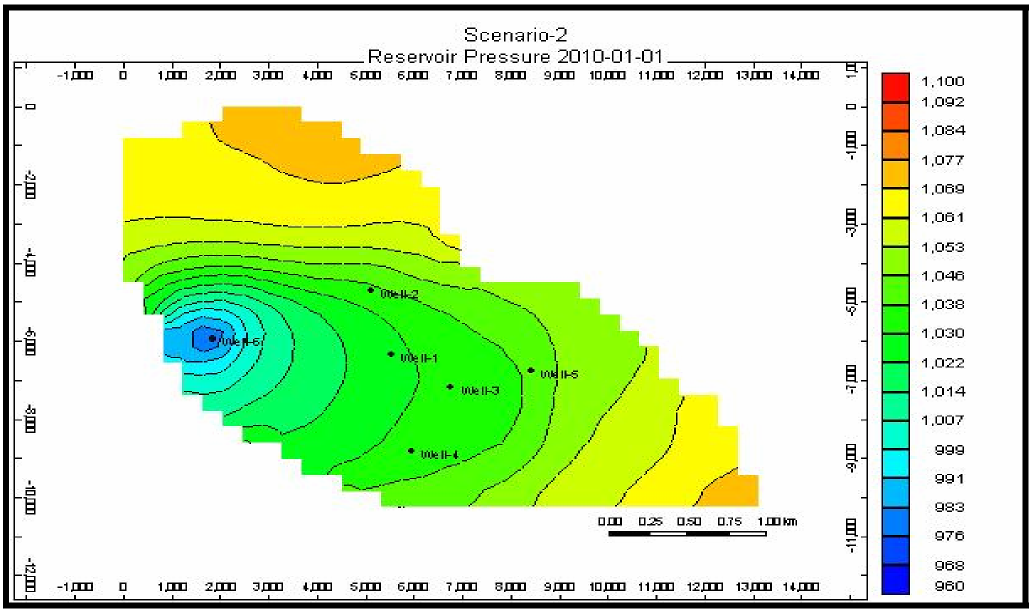

Figure 7. 9.Reservoir Pressure Distribution at the end of Scenario 2

Average reservoir pressure drops to 1035 psi, from 1365 psi, results a 330 psi drop. Lowest pressure region is 960 psi, the zone containing W6, and the highest pressured region is 1075 psi.

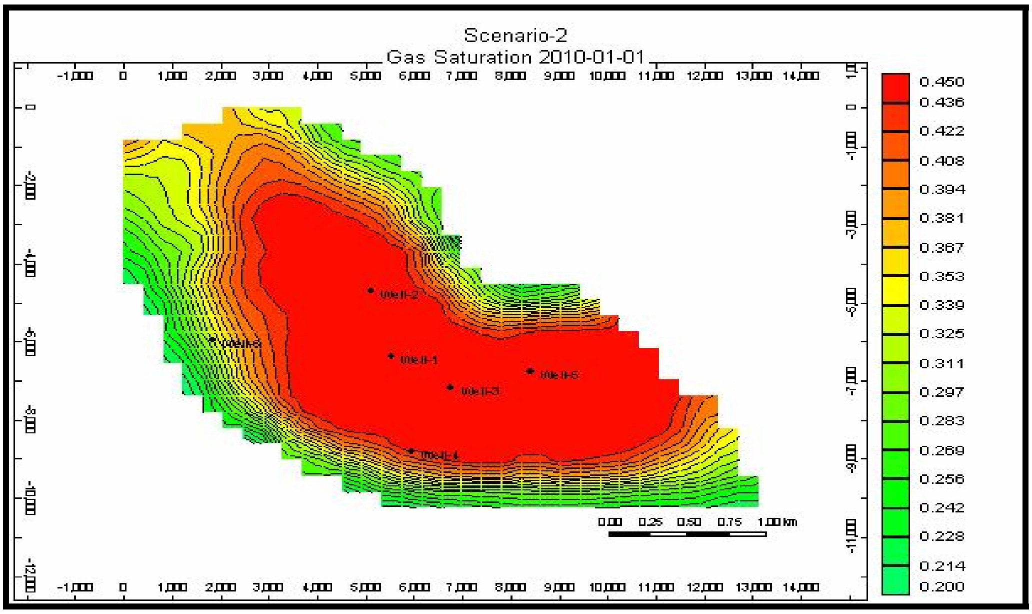

Figure 7. 10. Gas Saturation Distribution at the end of Scenario 2

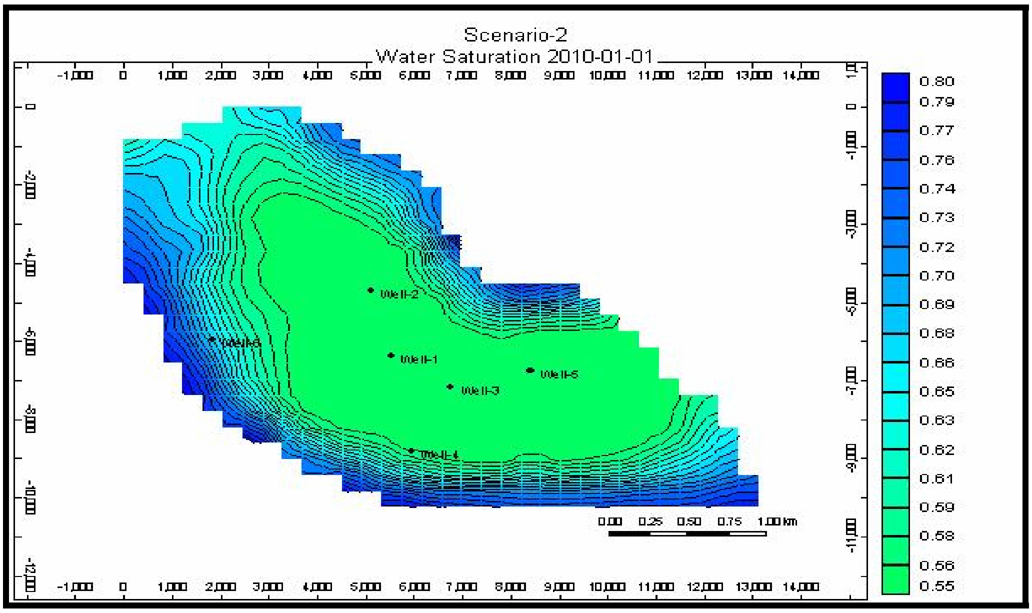

Figure 7. 11. Water Saturation Distribution at the end of Scenario 2

Average gas saturation drops to 0.420 at the end of Scenario 2 and the lowest gas saturated zone is 0.22. Average water saturation is 0.578 and the highest region has a saturation of 0.78.

7.2.2. Total Production in Scenario 2

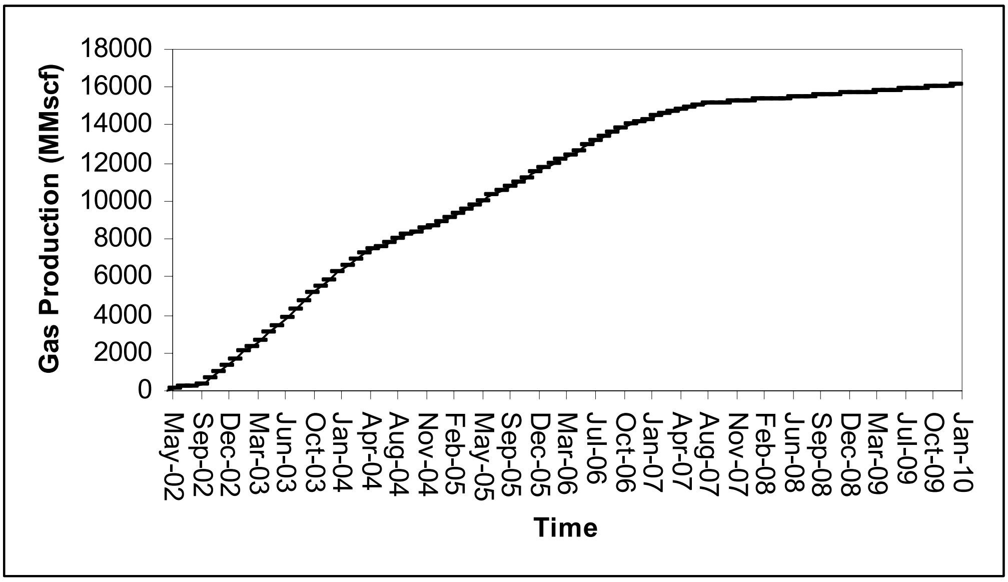

Figure 7. 12. Gas Production during Scenario 2

Table 7.4. Comparison of Gas Production for each well

Well ID	History Matching (MMscf)	Scenario2 (MMscf)	Total (MMscf)
W-1	2,792	1,884	4,676
W-2	404	510	914
W-3	3,891	1,594	5,485
W-4	1,271	1,312	2,583
W-6	-	2,008	2,008

The well introduced in this scenario, W6, has the maximum production during scenario 2, with 2008 MMscf. W1, W3, W4 and W2 has the other production rates in a decreasing order.

7.2.3. Well head Pressures Behavior during Scenario 2

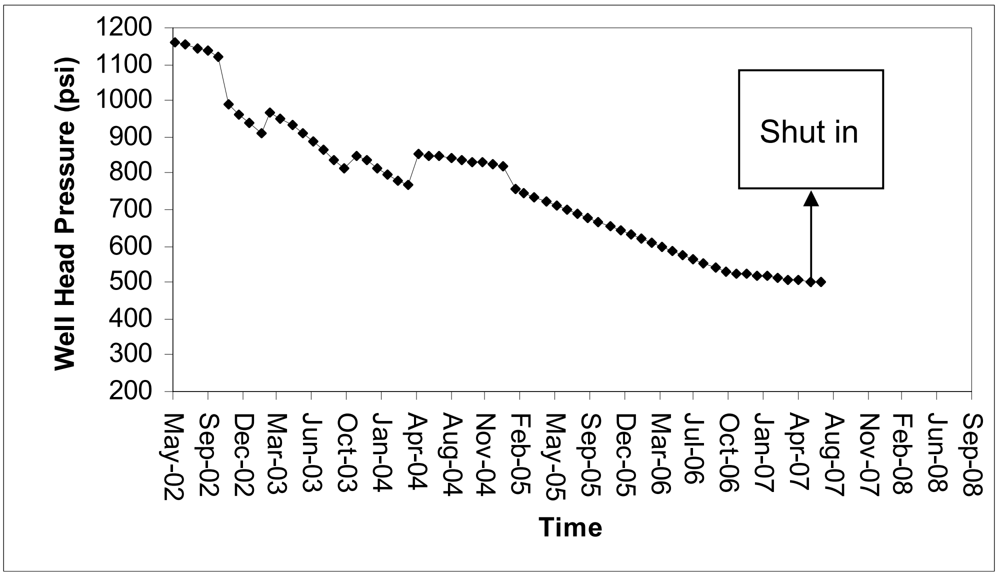

Figure 7. 13. Well Head Pressure Behavior of W1 during Scenario 2

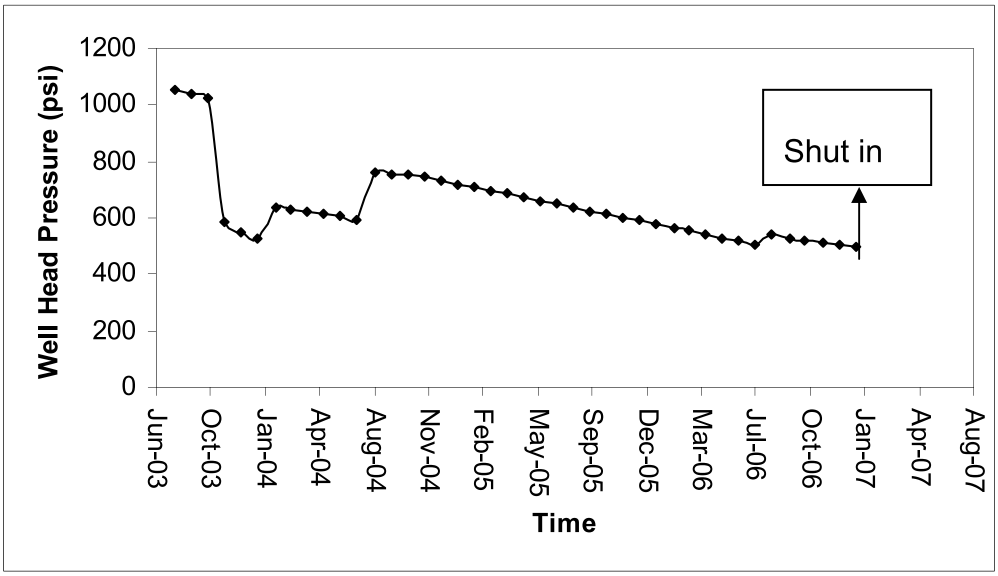

Figure 7. 14. Well Head Pressure Behavior of W2 during Scenario 2

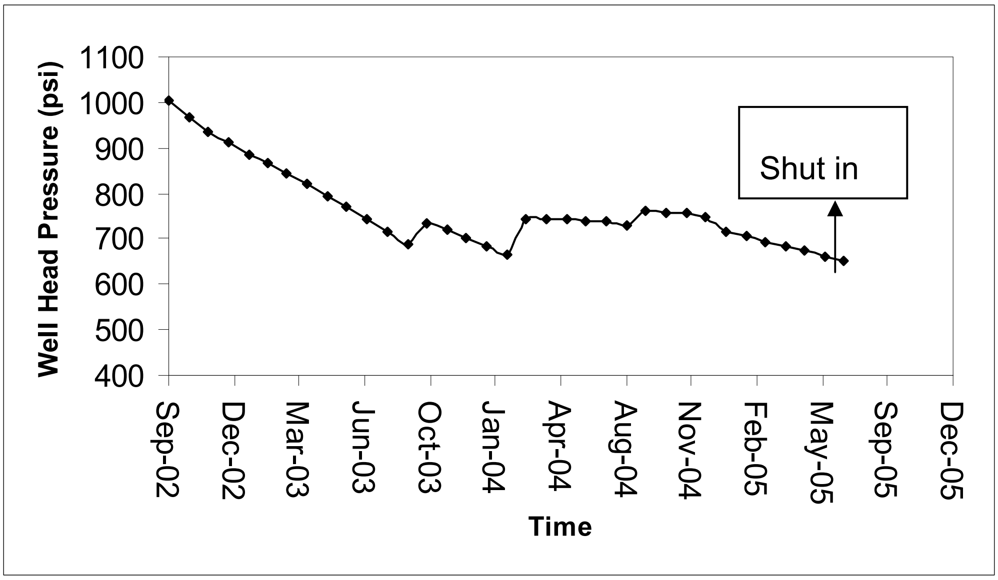

Figure 7. 15. Well Head Pressure Behavior of W3 during Scenario 2

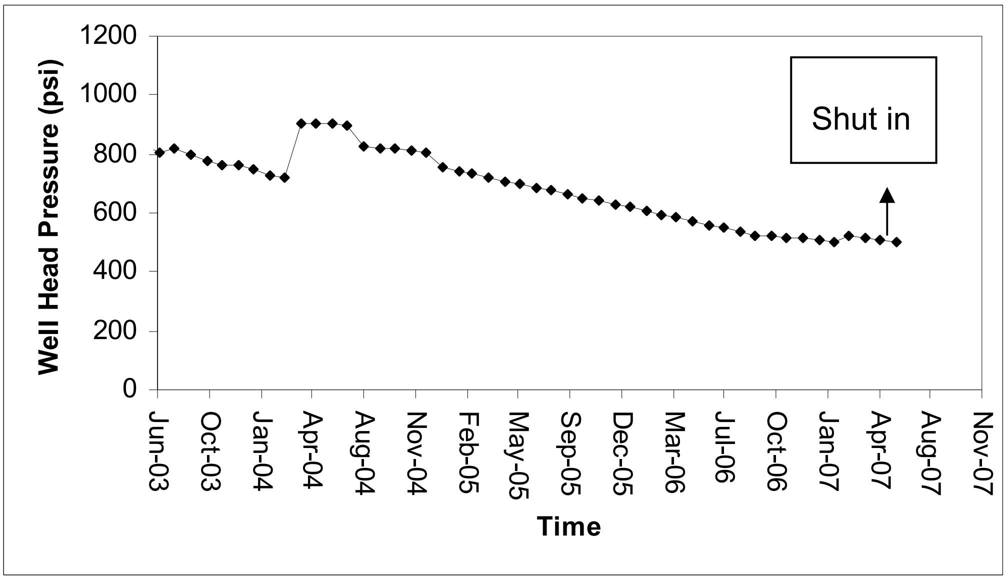

Figure 7. 16. Well Head Pressure Behavior of W4 during Scenario 2

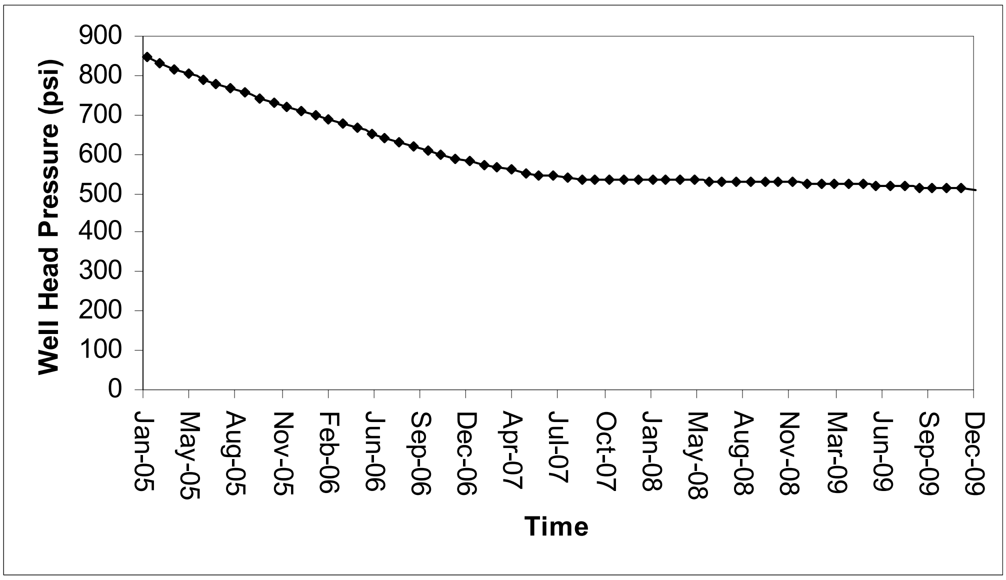

Figure 7. 17. Well Head Pressure Behavior of W6 during Scenario 2

W6 is still in production at the end of the scenario, whereas W1, W4, W2 and W3 have life spans in a descending order. The difference between W1 and W3 is 11 months.

7.3. Scenario 3: Production with Well-7

In This scenario another well is defined and put on production. . The well location choice is performed according to final reservoir pressure distribution in 2005-01-01. The field went on production with five wells by the addition of the new well, W-7. The well head pressure constraint is applied as 500 psi like the first scenario. Production rates used during the scenario is shown in Table 7.5.

Table 7. 5. Production rates (Scf/d) during Scenario 3

Well ID	Rate (Scf/d)
W-1	2,000,000
W-2	679,000
W-3	2,500,000
W-4	1,600,000
W-7	1,100,000

7.3.1. Reservoir properties at the end of Scenario 3

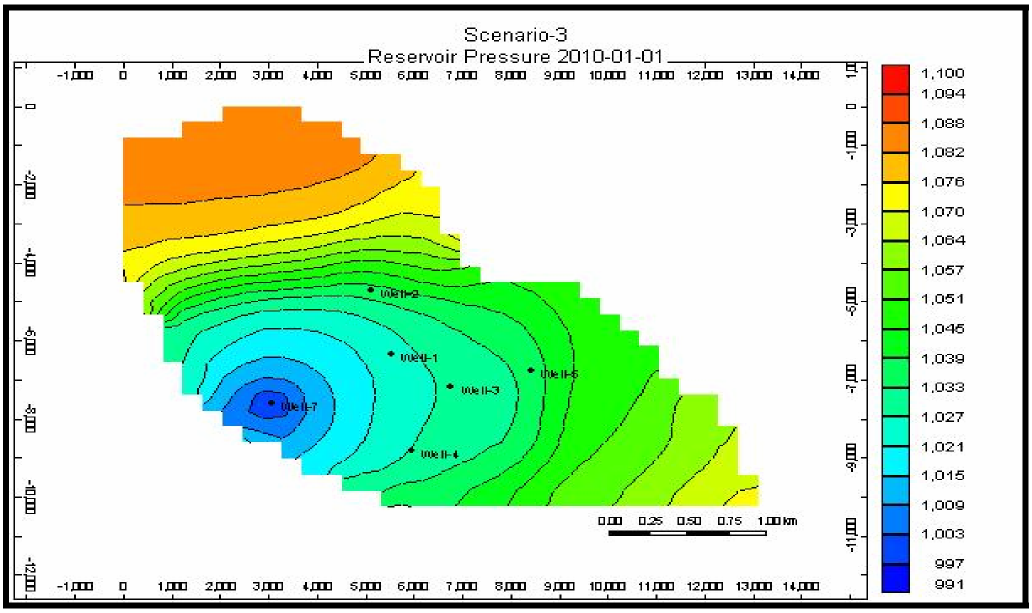

Figure 7. 18. Reservoir Pressure Distribution at the end of Scenario 3

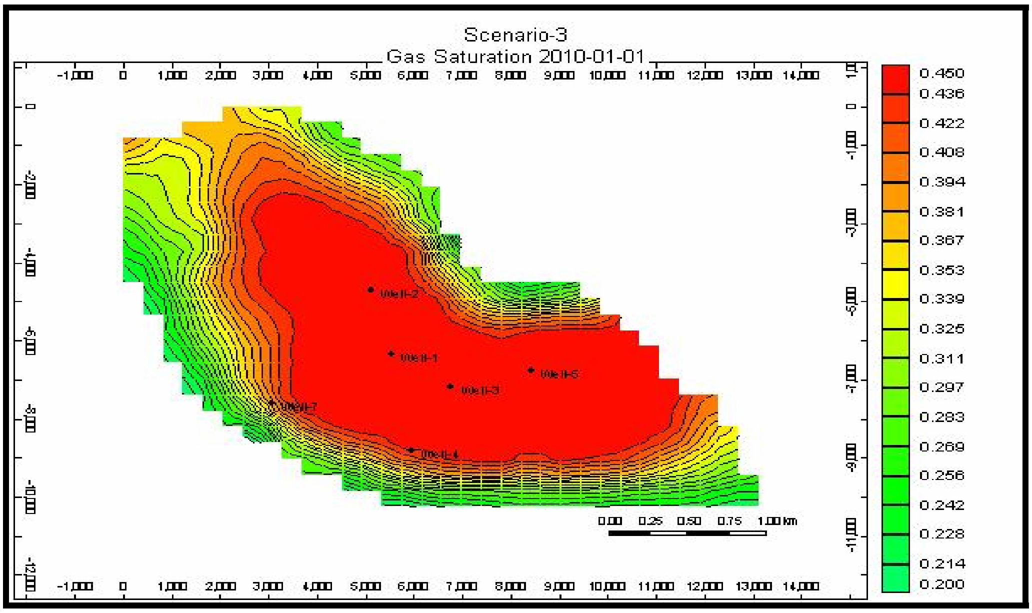

Figure 7. 19. Gas Saturation Distribution at the end of Scenario 3

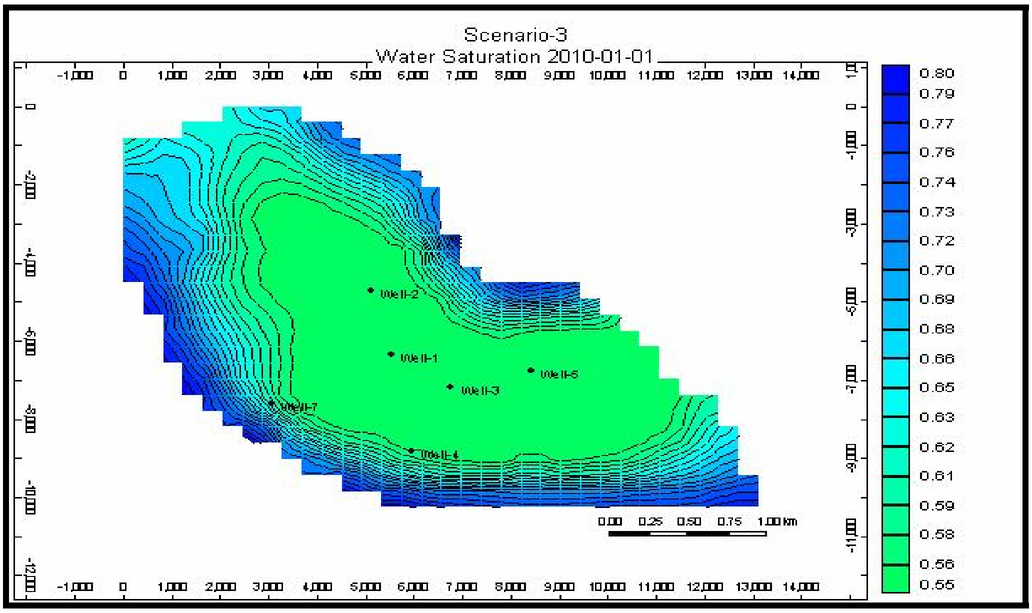

Figure 7. 20. Water Saturation Distribution at the end of Scenario 3

Average reservoir pressure is 1030 psi at the end of the scenario. Minimum pressure is 990 psi and the maximum pressured zone is 1090 psi. Average gas saturation is 0.415 and the average water saturation is 0.585.

7.3.2. Total Production in Scenario 3

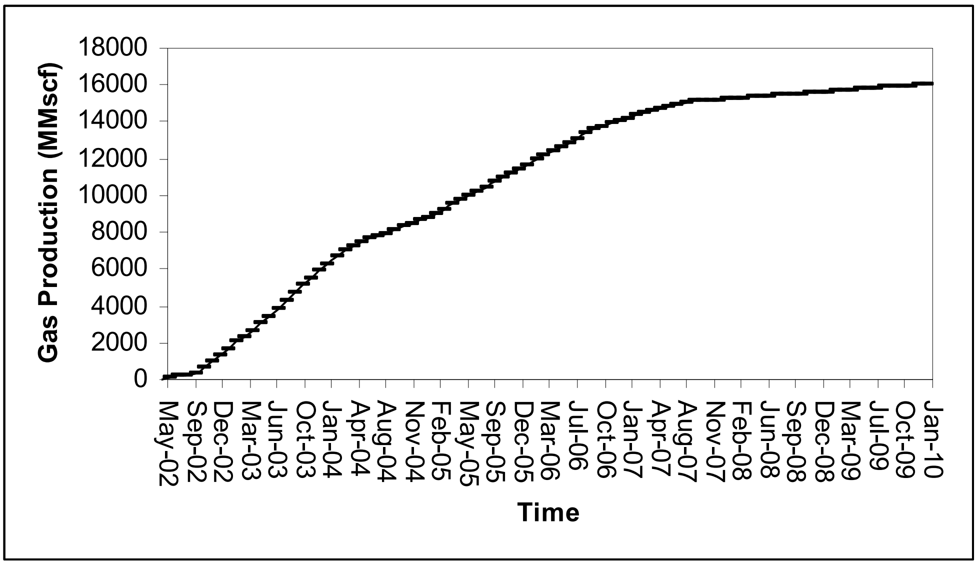

Figure 7. 21. Gas Production during Scenario 3

Table 7.6. Comparison of Gas Production for each well

Well ID	History Matching (MMscf)	Scenario3 (MMscf)	Total (MMscf)
W-1	2,792	1,884	4,676
W-2	404	472	876
W-3	3,891	1519	5,410
W-4	1,271	1,312	2,583
W-7	-	2,008	2,008

New described well, W7 has the maximum production during the scenario 3 with 2,008 MMscf. W1, W3, W4 and W2 has the other production rates in a decreasing order.

7.3.2. Well Head Pressure Behavior during Scenario 3

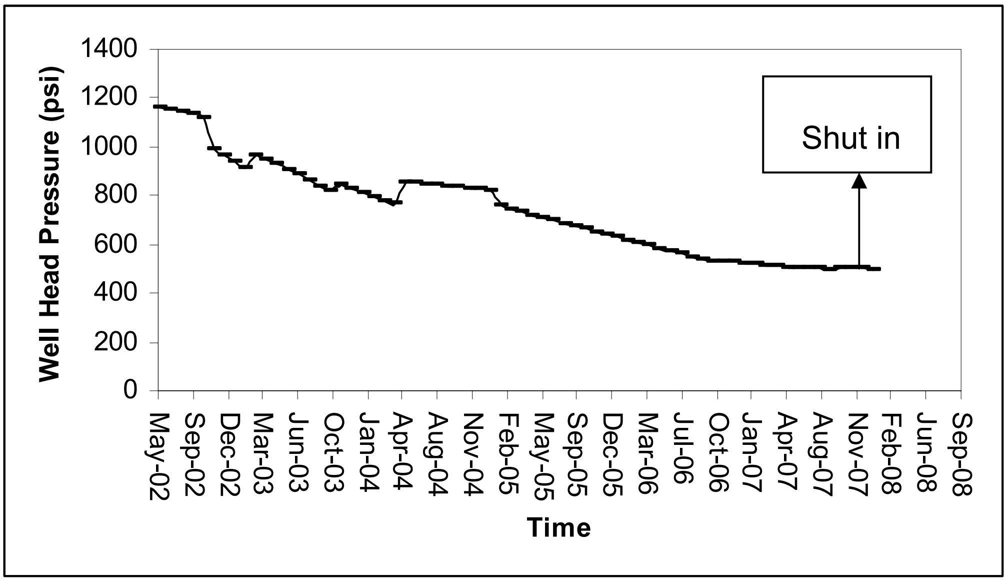

Figure 7. 22. Well Head Pressure Behavior of W1 during Scenario 3

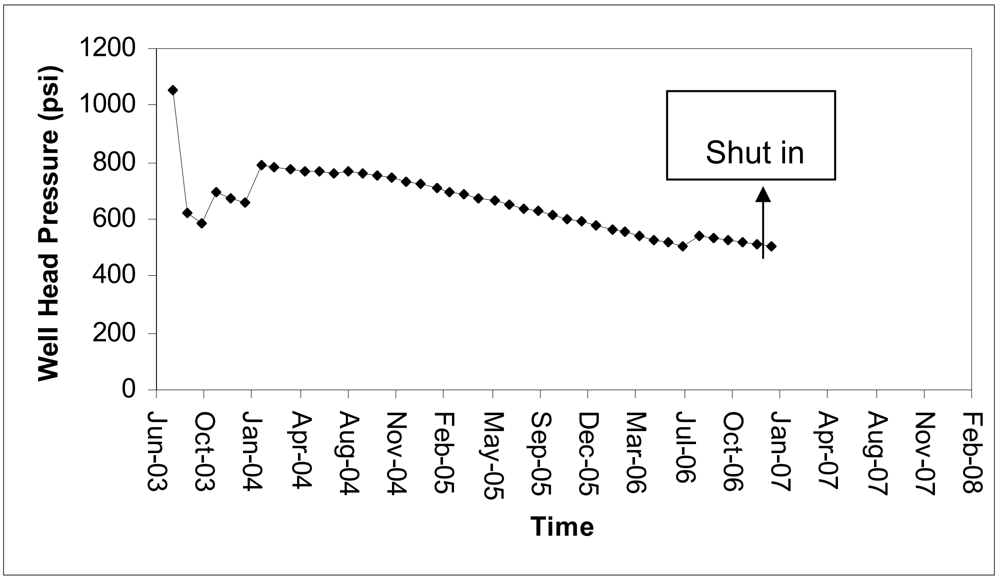

Figure 7. 23. Well Head Pressure Behavior of W2 during Scenario 3

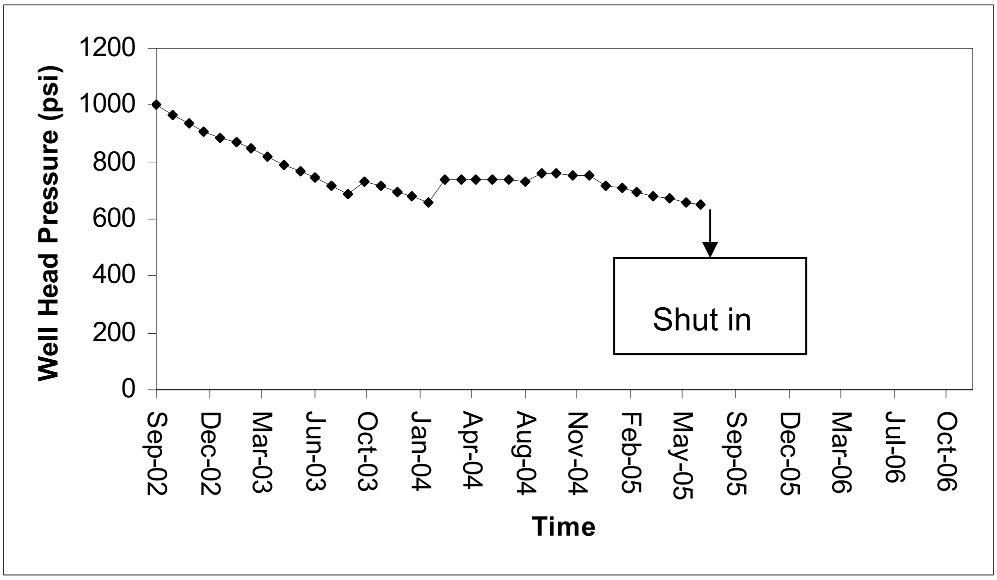

Figure 7 24. Well Head Pressure Behavior of W3 during Scenario 3

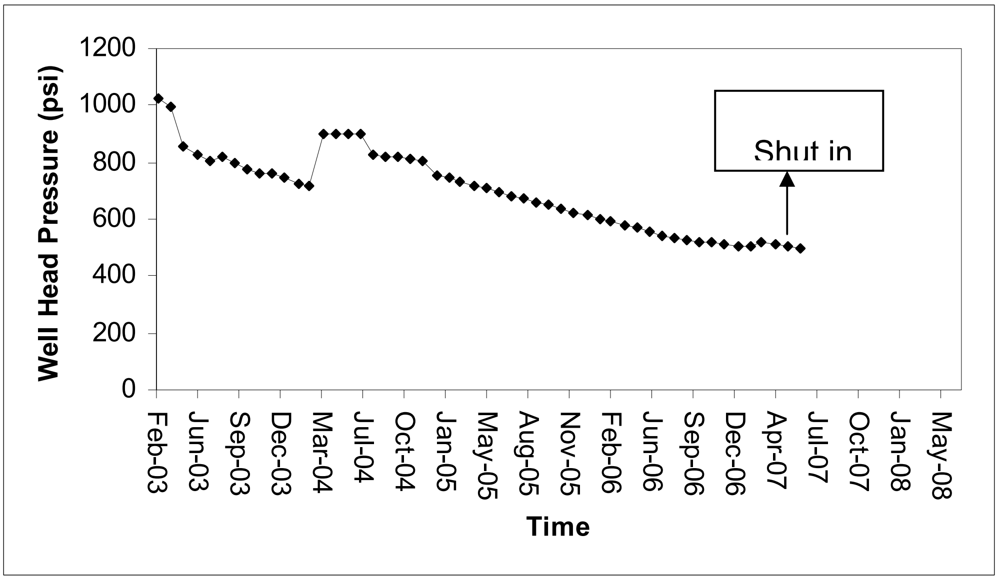

Figure 7. 25. Well Head Pressure Behavior of W4 during Scenario 3

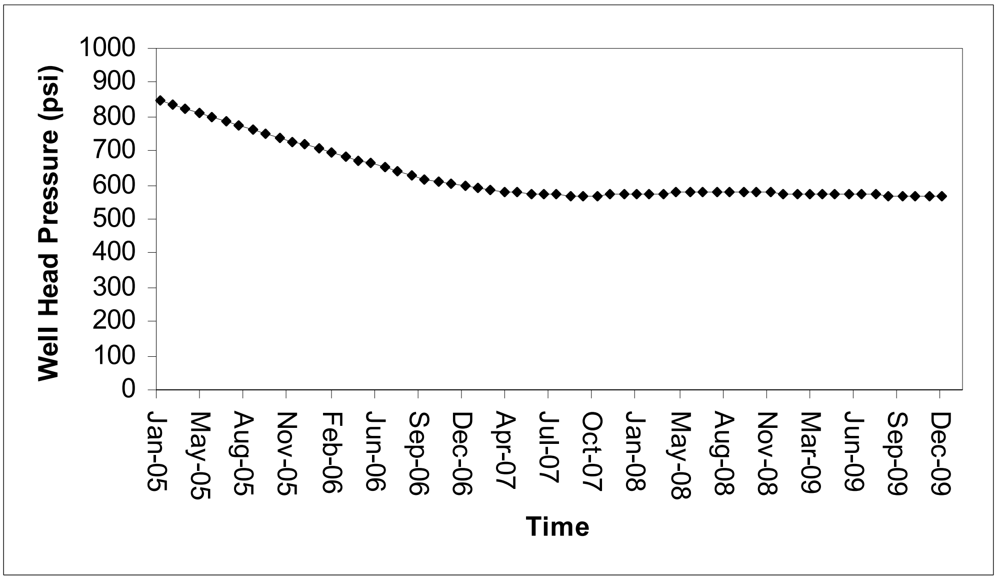

Figure 7. 26. Well Head Pressure Behavior of W7 during Scenario 3

W7 is still in production in 2010, with a well pressure of 600 psi. W1, W4, W2 and W3 have the life times in a decreasing order. Difference between W1 and W3 is 15 months.

7.4. Scenario 4 Production with both W6 and W7

In this scenario, the wells described in the Scenario 2 and Scenario 3 are put into production together. The production constraint will be minimum well head pressure, 500 psi, just like the first three scenarios. Production rates used during the scenario is shown in Table.7.4.1

Table 7. 7. Production rates (Scf/d) during Scenario 3

Well ID	Rate (Scf/d)
W-1	2,000,000
W-2	679,000
W-3	2,500,000
W-4	1,600,000
W-6	1,100,000
W-7	1,100,000

7.4.1. Reservoir Properties at the end of Scenario 4

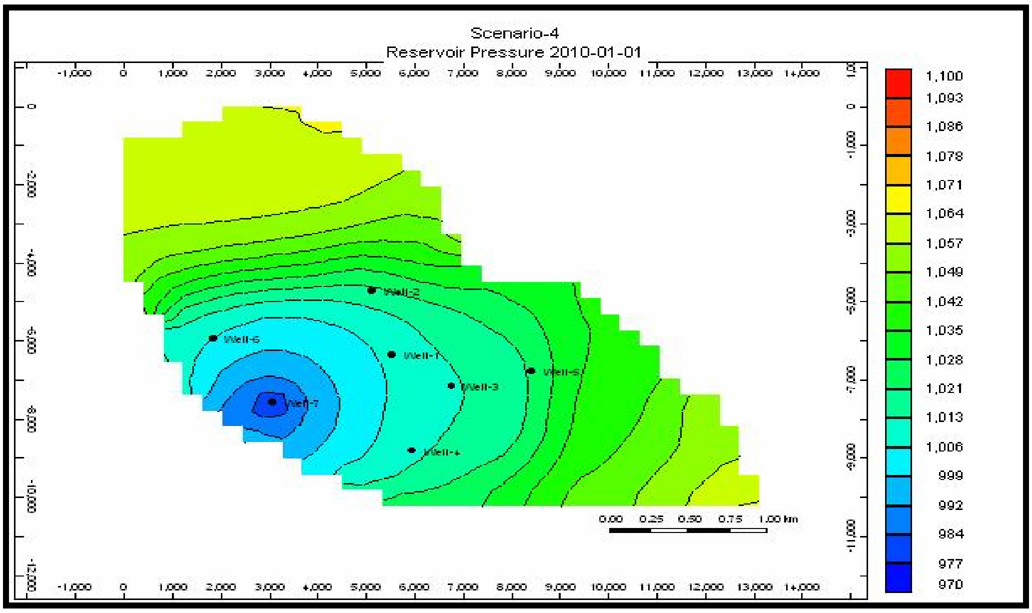

Figure 7. 27. Reservoir Pressure Distribution at the end of Scenario 4

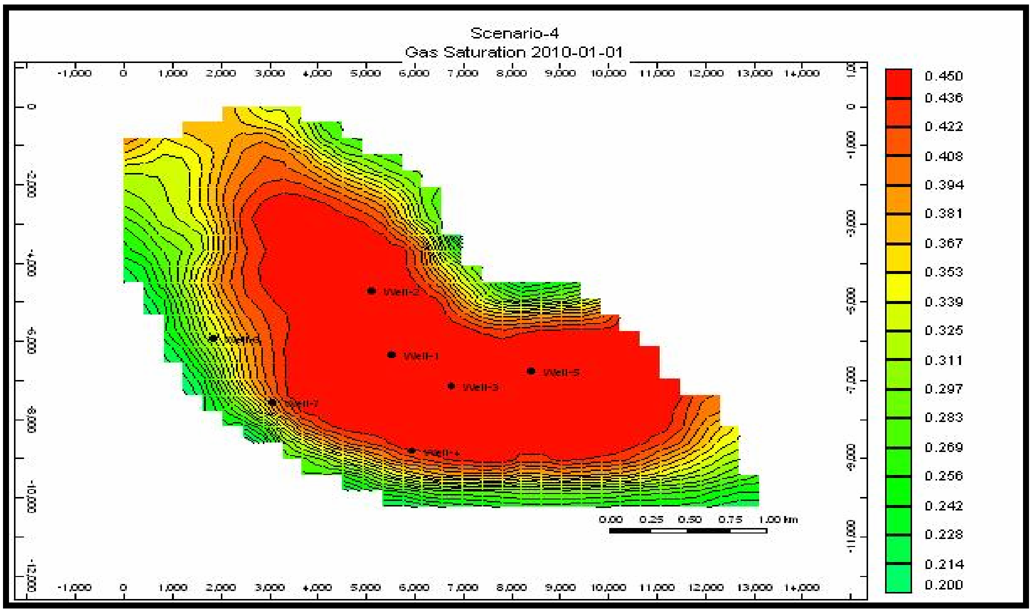

Figure 7. 28. Gas Saturation Distribution at the end of Scenario 4

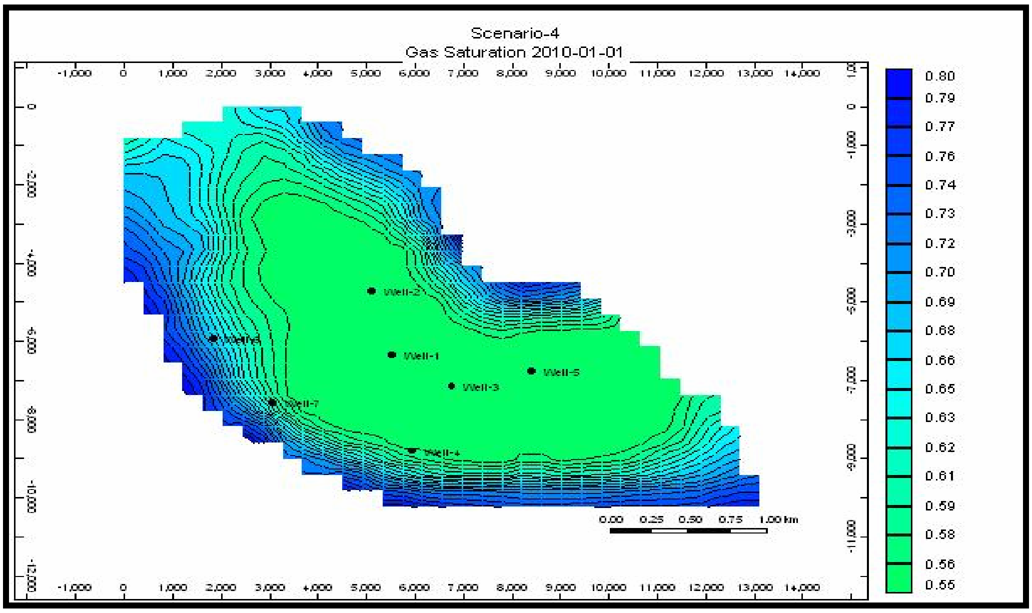

Figure 7. 29. Water Saturation Distribution at the end of Scenario 4

Average reservoir pressure is 1020 psi at the end of scenario 4. Lowest pressured zone is 970 and the zone with the highest pressure is 1060 psi.

Average gas saturation drops to 0.41 and the average water saturation becomes 0.59

7.4.2. Total Production in Scenario 4

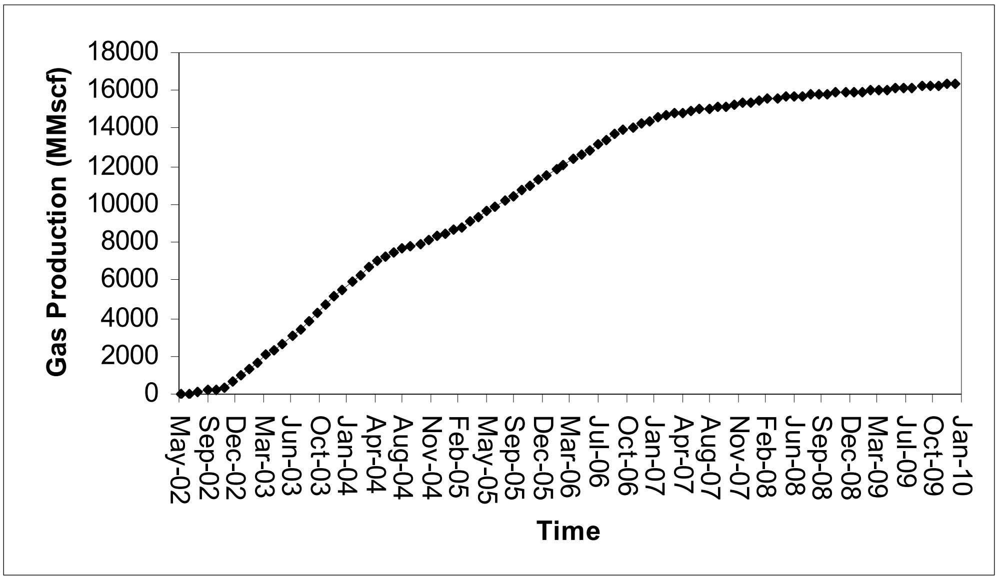

Figure 7. 30. Gas Production during Scenario 4

Table 7.8. Comparison of Gas Production for each well during Scenario3

Well ID	History Matching (MMscf)	Scenario4 (MMscf)	Total (MMscf)
W-1	2,792	1,522	4,314
W-2	404	408	812
W-3	3,891	1,364	5,255
W-4	1,271	1,070	2,341
W-6	-	1,304	1,304
W-7	-	2,008	2,008

W7 has the maximum production amount in scenario 4. W6, W1, W3, W4 and W2 have the production rates in a decreasing order.

7.4.2. Well Head Pressure Behavior during Scenario 4

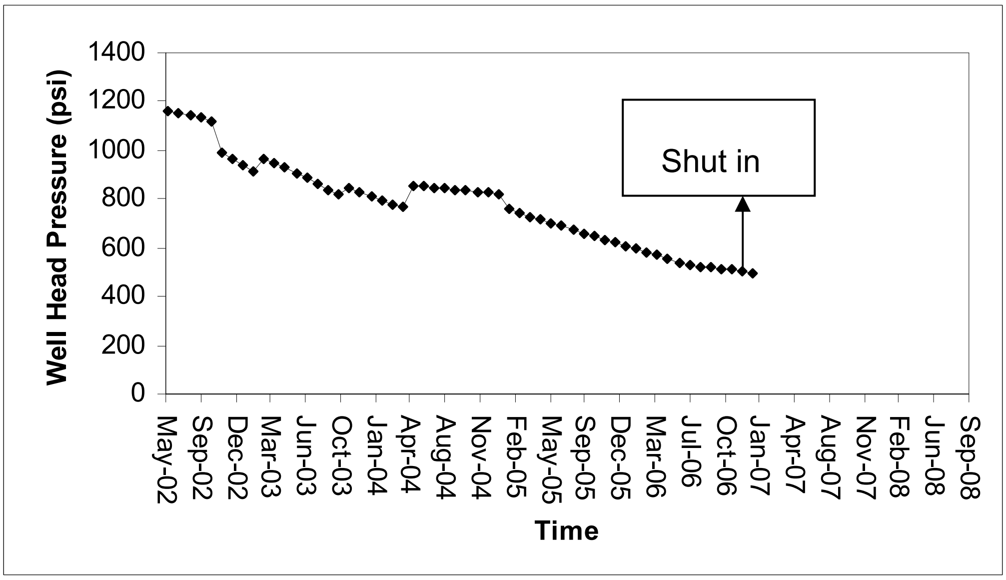

Figure 7. 31. Well Head Behavior of W1 during Scenario 4

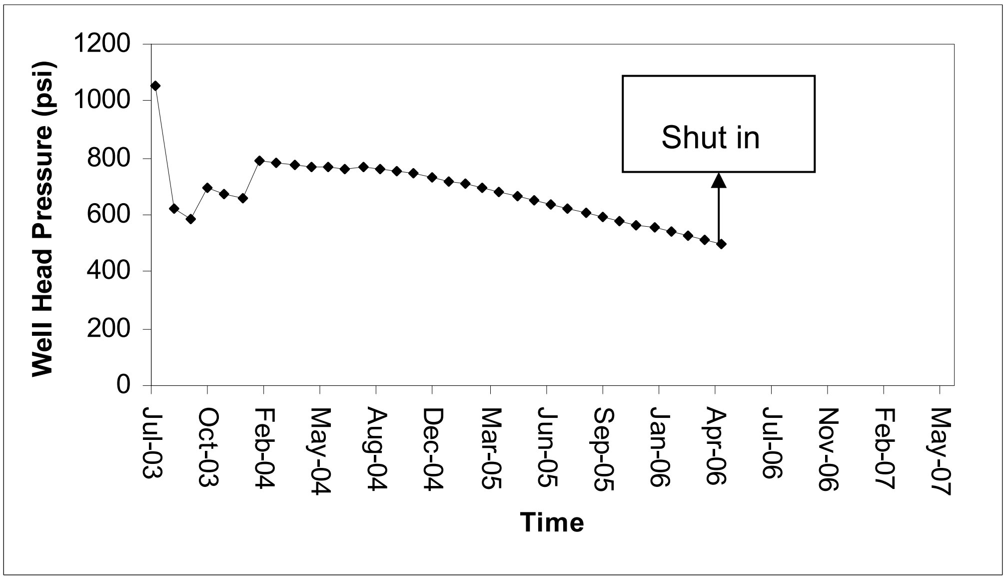

Figure 7. 32. Well Head Behavior of W2 during Scenario 4

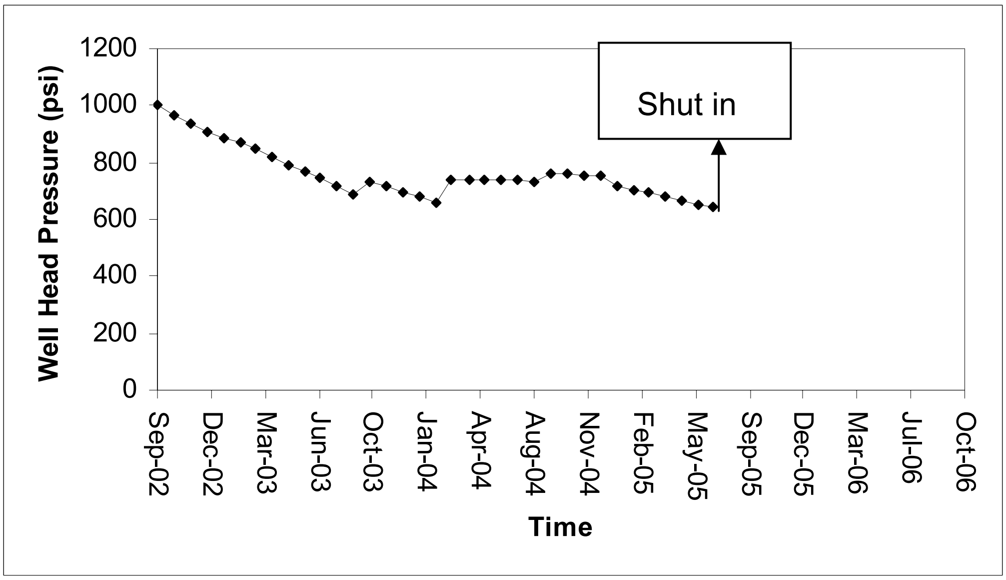

Figure 7. 33. Well Head Behavior of W3 during Scenario 4

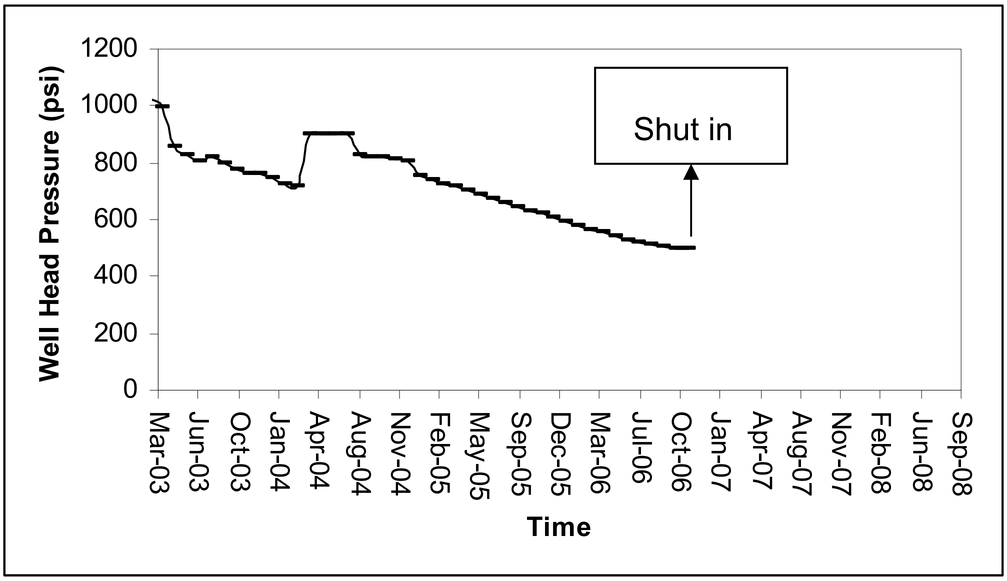

Figure 7. 34. Well Head Behavior of W4 during Scenario 4

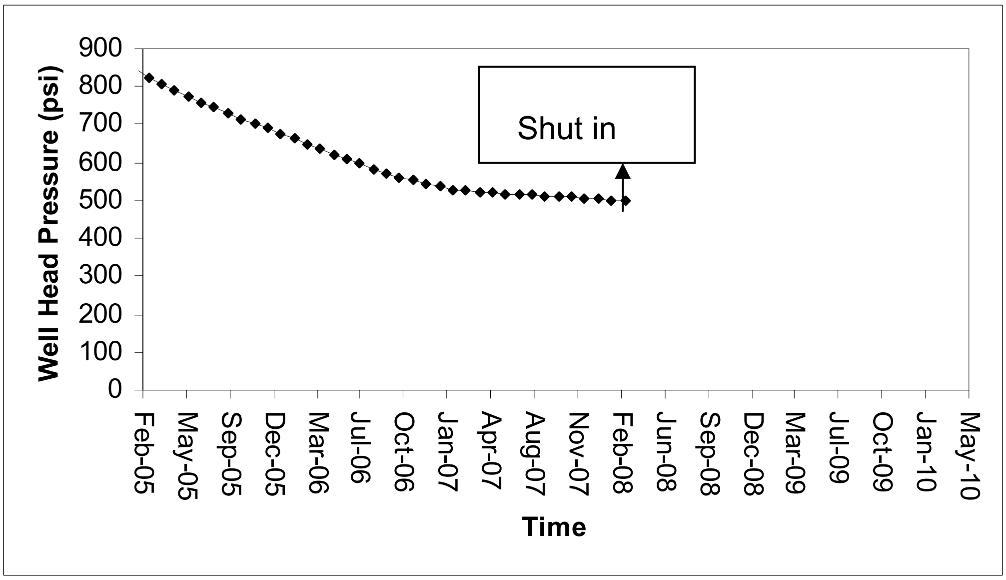

Figure 7. 35. Well Head Behavior of W6 during Scenario 4

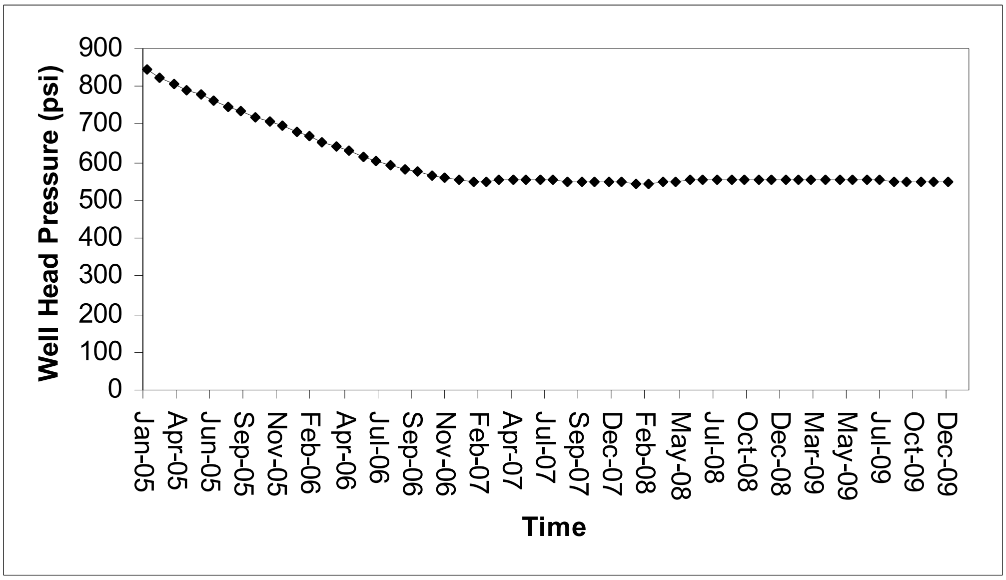

Figure 7. 36. Well Head Behavior of W7 during Scenario 4

W7 is still in production at the end of the Scenario 4. W6, W1, W4, W3 and W2 drops to 500 psi well head pressure respectively.

CHAPTER 8

RESULTS AND DISCUSSION

8.1. General Comparison of Performance Predictions

In this section, results obtained from each scenario is evaluated and compared with each other. Best future production option is characterized.

First, total gas production of each well for each scenario is compared in Table 8.1

Table 8. 1 Gas Production Comparison for each well for each Scenario

Well ID	History Matching (MMscf)	Scenario 1 (MMscf)	Scenario 2 (MMscf)	Scenario 3 (MMscf)	Scenario 4 (MMscf)
W1	2,742	2,678	1,884	1,884	1,522
W2	433	537	510	472	408
W3	3.725	1,824	1,594	1519	1,364
W4	1,287	1,720	1,312	1,312	1,070
W6	-	-	2,008	-	1,304
W7	-	-	-	2,008	2,008

According to Table 8.2, in Scenario 1, W1 produced 98% of the gas it produced in the history matching section. In Scenario 2 and Scenario 3 69%, in Scenario 4 56% of the gas produced in the history matching section is achieved. W2 produced 124% of the history matching section in Scenario 1, the maximum production in all scenarios, then 43% in Scenario 2, 41% in Scenario 3 and finally 37% in Scenario 4.Like W1 and W2, W3 has its maximum production in Scenario 1 with 49% of its production in History Matching period. Then it has a descending production amount in Scenario2, 3 and 4 respectively. W4 has a similar trend like W2, because it has more production then the history matching section, 134% in Scenario 1. It also has more production in Scenario 2 and 3 but has less production than the history matching section with 83% in Scenario 4.

Table 8.2. Recovery Percentage Comparison for each well

Well ID	Scenario 1 (%)	Scenario 2 (%)	Scenario 3 (%)	Scenario 4 (%)
W1	98	69	69	56
W2	124	118	109	94
W3	49	43	41	37
W4	134	102	102	83

In Table 8.3 overall gas production for each scenario is presented. Those numbers include the production in history matching period

Table 8.3 Overall Gas Production for each scenario in 2010

Scenario	Total Gas Production (MMscf)	Gas Production between 2005-2010
Scenario 1	15,593	7,406
Scenario 2	16,083	7,896
Scenario 3	16,032	7,845
Scenario 4	16,404	8,217

In Table 8.4. Total gas produced during each scenario and recovery percentage in each scenario is presented. According to table 8.4., in Scenario 4 100% of the gas produced in the history matching section is produced during the scenario. In Scenario 2 and Scenario 3, 96% in Scenario 1 90% of the gas produced in history matching section is produced.

Table 8.4. Gas Production and Recovery Percentage Comparison for each scenario

Scenario	Gas Production (MMscf)	Recovery Percentage (%)
Scenario 1	7,406	90
Scenario 2	7,896	96
Scenario 3	7,845	96
Scenario 4	8,217	100

In a gas production field, gas production duration may be the major aspect. Table 8.5. Shows the decline times of each well for each scenario.

In table 8.5, it is clear that life span of existing wells shortens with the addition of newly defined wells. W1 has the longest production duration in Scenario 1, which is without any new wells, but has 21 months shorter time in Scenario 4, with two new wells. Similar to W1, W2 has 9 months, W3 has 7 months, and W4 has 12 months shorter life spans in Scenario 4 compared to Scenario 1. However revenue

Table 8.5 Decline Times of each Well for each Scenario.

Well ID	Scenario 1	Scenario 2	Scenario 3	Scenario 4
W1	October/2008	July/2007	December/2007	January/2007
W2	January/2007	January/2007	February/2007	April/2006
W3	January/2007	August/2006	August/2006	June/2006
W4	November/2007	June/2007	June/2007	November/2006
W6		Producing		March/2008
W7			Producing	Producing

8.2. Production Optimization by Nodal System Analysis

The producing system for a gas well can be divided into components- that are the reservoir, the vertical or direct conduit, surface flow line and the separator pressure.

The separator pressure for a gas well has particular significance since the gas is normally being placed into the sales outlet such as 1000 psi. The operator is faced with the problem of determining sufficiently high to put gas directly into the sales line or buy a compressor to raise the pressure in order to place the gas into the sales line. This problem becomes one involving economic considerations, and the cost of compression must be weighed against increased production (22).

In estimation of individual performance of oil wells at any stage of depletion or at any time, for solution gas-drive reservoirs, or for two or three phase flow, in many of the cases, the utilization of numerical simulators results in a very high time consumption while IPR curves can be utilized to represent reservoir performance with low computation effort. IPR curves can also be used to optimize production parameters such as tubing diameter and choke sizes (23).

By employing nodal analysis with compositional handling at the numerous nodes throughout the tubing, it is found that the onset of gas well load-up generally occurs at a depth o one-half to one-third the total well bore depth. The additional pressure required to maintain gas well flow with condensed water present can be determined from compositional nodal analysis. Although the critical rate is independent of the volume of condensed water produced, the corresponding pressure necessary to lift the condensed water is directly related to the amount of water produced. Based on the gas wells studied, approximately 10 psig of additional pressures required to lift each unit (bbl/MMscf) yield of condensed water.

Typically an increase in pressure of 25-30% has been observed due to condensed water production at the onset of load-up (19).

In this section an analysis is performed for the five producing wells. The optimum flow rate for each of the wells are determined and compared with the starting production rate of each well. Pressure versus rate graphs are presented below. Formulas used to perform the calculations are listed in Appendix C7.

Table 8.6 Data used in the calculation for each well.

Well ID	W-1	W-2	W-3	W-4	W-5
P_r , psi	1875	1875	1875	1875	1875
D ,ft	4200	4200	4200	4200	4200
d_g	0.611	0.611	0.611	0.611	0.611
T, °F	135	135	135	135	135
Tu, OD, in	2.875	2.875	2.875	2.875	2.875
Tu, ID, in	2.441	2.441	2.441	2.441	2.441
K,md	13	5	18	8	2
H, ft	50	50	50	50	50
h_p, ft	20	20	20	20	20
$r_{e,}$ ft	2107	2107	2107	2107	2107
r_w , ft	0,583	0,583	0,583	0,583	0,583

From Figure 8.1. to Figure 8.5. Optimum production rate for each well is described. TPR readings are taken regarding to separator pressure of 1000 psi (22). Figure is illustrated in Appendix C8.

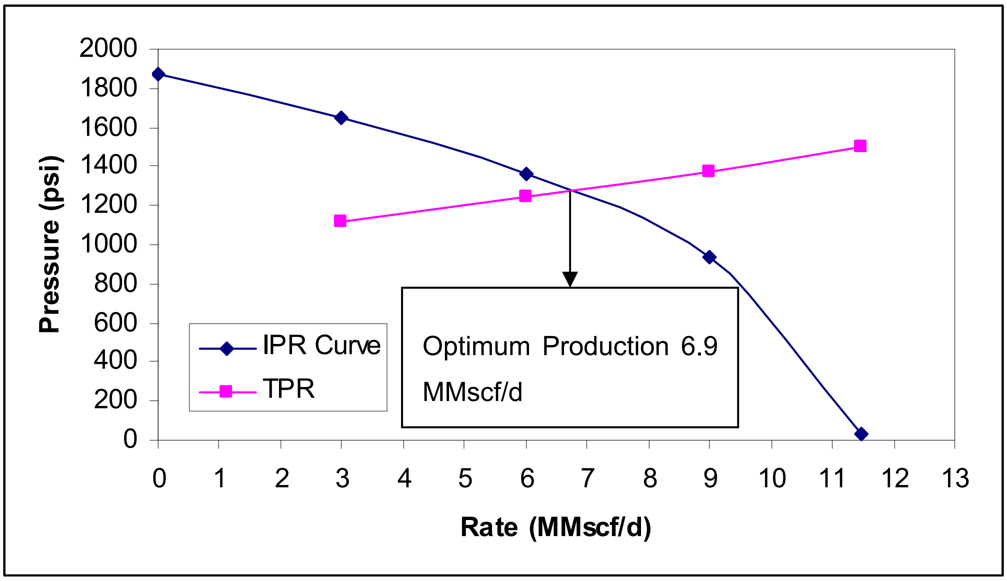

Figure 8. 1.Nodal Analysis applied to W-1

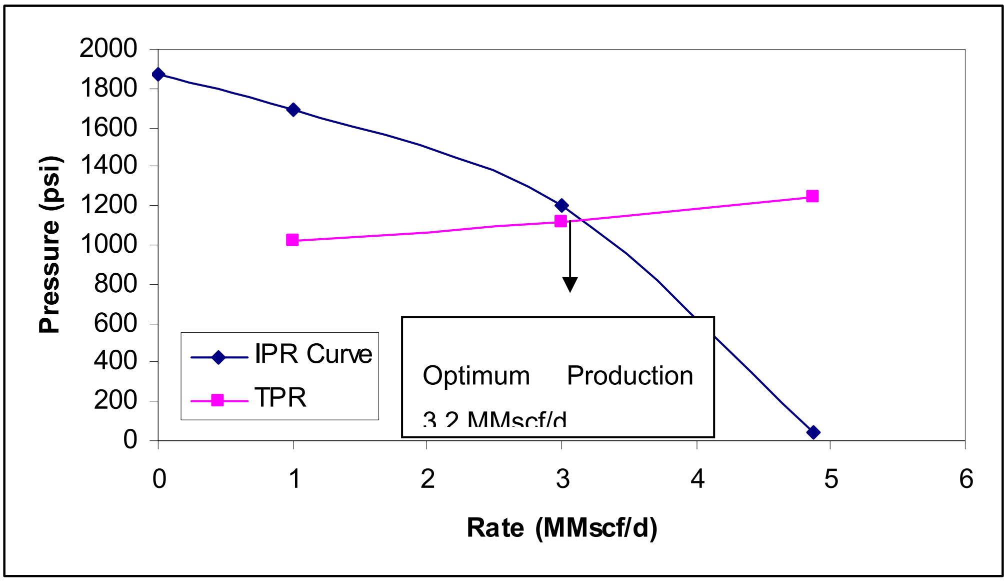

Figure 8. 2. Nodal Analysis applied to W-2

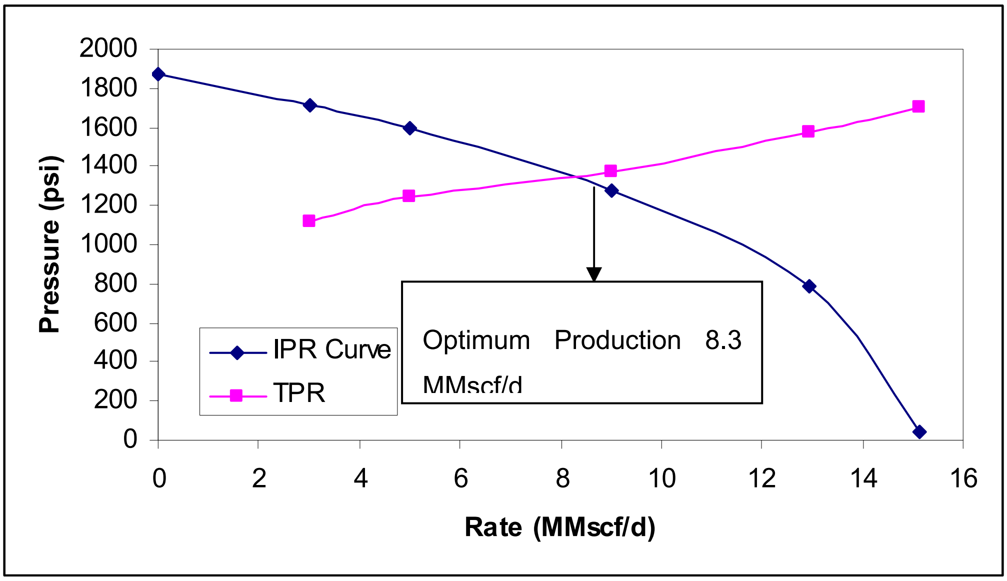

Figure 8. 3. Nodal Analysis applied to W-3

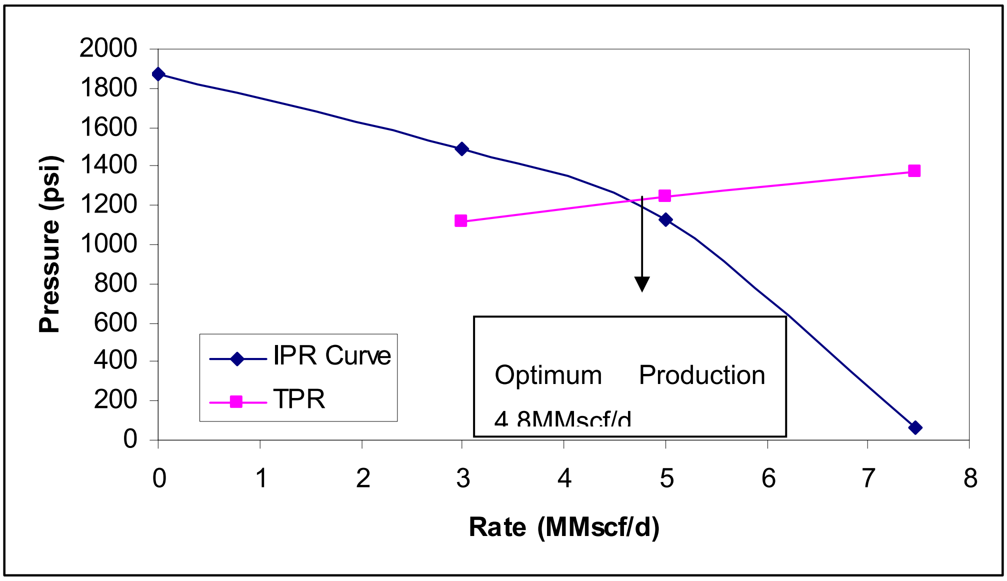

Figure 8. 4. Nodal Analysis applied to W-4

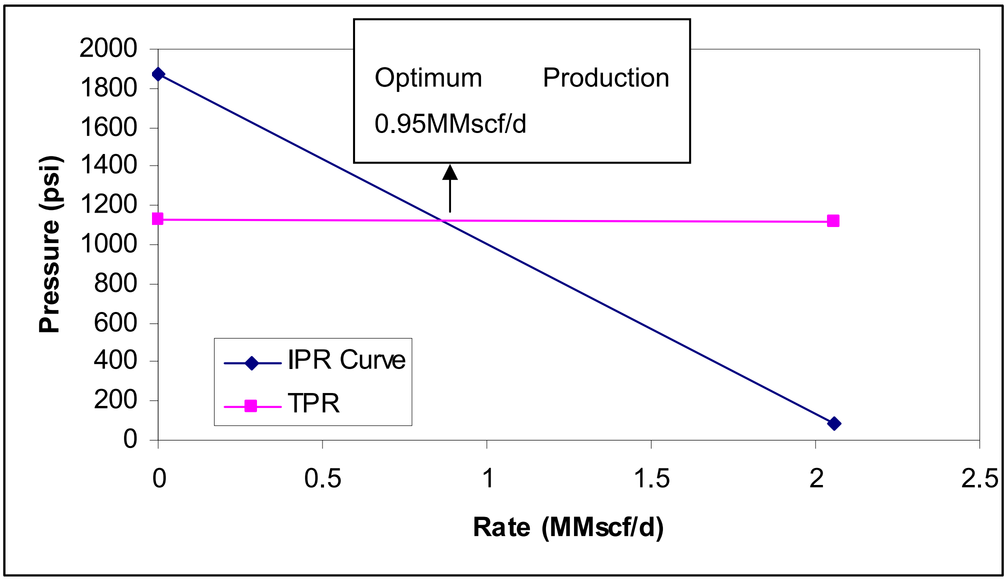

Figure 8. 5. Nodal Analysis applied to W-5

The initial production rates of the field and the results of the nodal analysis are shown in Table.8.7. It is seen that W1 started production0.8 MMscf/d less than the optimum rate whereas W2 was 0.5 MMscf/d, W3 was 0.6 MMscf/d and W4 was 0.7 MMscf/d.less than the optimum rate. W5 was very close, with only 0.05 MMscf/d difference. All wells have tubing sttring of 2 7/8” which seems to be best tubing diameter for each well depending on the results of the nodal analysis.

Table 8 7. Comparison of Nodal Analysis and Field initial Flow Rates

Well ID	Field (MMscf/d)	NodalAnalysis(MMscf/d)
W-1	6.10	6.90
W-2	2.70	3.20
W-3	7.70	8.30
W-4	4.10	4.80
W-5	0.90	0.95

8.3. Economical Comparison

Maximum gas production is obtained from Scenario 4, hence existing wells show a rapid decline in Scenario 4 compared to Scenario 1. In order to determine which scenario is feasible, an economical evaluation is performed. Calculations are illustrated in Appendix D1

According to economical evaluation, even though Scenario 4 has $ 2,018,371extra expenditure because of drilling expenses and production costs , it has still 4,133,693 income from gas sales to customers, so Scenario 4 has $ 2,115,322 more revenue than Scenario 1 over 5 years. So Scenario 4 is more feasible than Scenario 1 in economical considerations.

When examining Table 9.1. W7 produces same amount gas in both Scenario 3 and Scenario 4 but in Scenario 4, W6 production decreases to 65% of the production of Scenario 3. Again an economical evaluation is performed for comparing both scenarios3 and 4 to see the effect of W6 clearly. Appendix D2 shows the calculations.

While comparing Scenario 3 and Scenario4, the latter scenario has $ 1,008,427 more expenditure than the first one but has $ 1,896,096 more income, which at the end gives $ 887,669 more revenue for Scenario 4.

Regarding to the results of the economical evaluations, Scenario 4 has again advantages over Scenario 3 but it is not as encouraging as the advantages over Scenario1. Even, in some cases, depending on the company policy, Scenario 3 may be chosen as the best scenario

CHAPTER 9

CONCLUSIONS

- In the history matching section, gas, condensate and water production values are compared. Total gas production from the field was 8,648 MMscf, whereas the simulator result was 8,772 MMscf. Field condensate production total was 61,141 bbl, whereas simulator result was 62,669 bbl. In water production comparison, as there was no active aquifer described, field data was compared with the water production obtained from Katz's chart. Calculated water production was 4,396 bbl whereas field water production was 4,001 bbl.

- In Scenario 1, production with existing wells, 15,593 MMscf gas is produced and all well head pressures drop to 500 psi before 0ctober 2008. This scenario shows the necessity for adding new wells to the field to get more recovery until 2010.

- In Scenario 2, a new well, Well 6 is added and production continues with five wells. Total production becomes 16,083 MMscf which shows the positive effect of adding a new well to the field. In Scenario 2, 490 MMscf more gas is produced than Scenario 1. Only W6 reaches 2010 which also points the benefit of the new well.

- In Scenario 3 another new well is introduced, W7. Again producing with five wells, cumulative production is 16,032 MMscf, again 439 MMscf more than Scenario 1. Like Scenario 2, in Scenario 3 only the new introduces well reaches 2010, which shows the necessity to consider an option including both new wells.

- In Scenario 4, W6 and W7 are on production at the same time, presenting 16,404 MMscf total production, which is more than all scenarios

- W7 is the only well that reaches 2010 and shows stable production in both scenarios. Although W6 was able to reach 2010 in Scenario 3, it showed a rapid decline in Scenario 4. Location of W7 is found to be better than W6.

- After performing a nodal system analysis in order to check the initial flow rates of the wells, results are found to be close enough to consider the tubing sizes appropriate and the rates are worth using in the calculations.

REFERENCES

1) A.Dehane, Sonatrach, D.Tiab, and S.O.Osianya: ”Comparison of the Performance of Vertical and Horizontal Wells in Gas-Condensate Reservoirs” SPE paper 63164, presented in Annual Technical Conference and Exhibition held in Dallas, Texas,2000.

2) Jacques Hagoort, Elsevier, “Fundamentals of gas reservoir engineering” p 33, 1988.

3). James P. Brill Dr. H. Dale Beggs: “Two phase flow in pipes” 6.Edition January 1998.

4) IMEX version 2004.10 User’s Guide, Computer Modeling Group Ltd.

Calgary, Alberta Canada, 2004.

5) A.Dehane, Sonatrach, D. Tiab, and S.O. Osisanya: “Performance of Horizontal Wells in Gas-Condensate Reservoirs, Djebel Bissa Field, and Algeris” SPE paper 65504 presented in International Conference on Horizontal Well Technology held in Calgary, Alberta, Canada, 2000.

6) Lus F. Ayala, Turgay Ertekin, and Michael A. Adewumi: “Analysis of Recovery Mechanisms for Naturally Fractured Gas-Condensate Reservoirs”, SPE paper 90010 presented at the International Petroleum Conference held in Mexico, 2004.

7) J.J.Xiao and Ahmad J. AL-Muaraikhi: “A New Methodfor the Determination of Gas Condensate Well Production Performance”, SPE

paper 90290 presented at the Annual Technical Conference and Exhibition held in Houston, Texas, 2004.

8) The technology of Artificial Lift Methods Volume 4 Production Optimization of Oil and Gas Wells by Nodal Systems Analysis pages 89-90, 1984.

9)The technology of Artificial Lift Methods Volume 4 Production Optimization of Oil and Gas Wells by Nodal Systems Analysis pages 1-2, 1984.

10) A.B.Bitsindou, and M.G.Keikar, “Gas Well Optimization Using Dynamic Nodal Analysis” SPE paper 52170 presented at the Mid-Continent Operations Symposium held in Oklahoma, 1999.

11) Louis Ray and Kenneth Juran: “Benefits of Using Automation Software for Gas Production Optimization” SPE paper 59713 presented at the Permian Basin Oil and Gas Recovery Conference held in Midland, Texas, 2000.

12) Claire E. Scott: “Computer Applications to Enhance Production Optimization and Process Efficiency” SPE paper 72168 presented at the Asia Pacific Improved Oil Recovery Conference held in Kuala Lumpur, Malaysia, 2001.

13) R.M, Risan, S.Abdullah and Z.Hidayet: “Condensate Production Optimization in the Arun Gas Field” OSEA paper 88200 presented at the South East Asia Conference held in Singapore, 1988.

14) .R.F. Stoisits, P.W. Scherer and S.E. Schmidt: “Gas Optimization at the Kuparuk River Field”. SPE paper 28467 presented at the Annular Technical Conference and Exhibition held in New Orleans, U.S.A, 1994.

15) Dan Mc Lean and Heather Goranson: “Gas Well Production Optimization Using Expert Systems Technology” SPE paper 38807

presented at the Annular Technical Conference and Exhibition held in San Antonio, Texas, 1997.

16) S.W. Wang, D.P.Ringe, M.M Gable, and D.J. Staples: "Integrated Simulation of Reservoir, Gas Plant and Economics for A Rich Gas Condensate Reservoir" SPE paper 71598 presented at the Annular Technical Conference and Exhibition held in New Orleans, Louisiana, 2001.

17) David B. Foo: "Optimization of Gas Wells by Automated Unloading: Case Histories" SPE paper, 59748 presented at the Gas Technology Synposium held in Calgary, Alberta, 2000.

18) J.F.Lea and Kermit Brown: "Optimization Using a Computerized Well Model" SPE paper 14121 presented at the International Meeting on Petroleum Engineering held in Beijing, China, 1986.

19) A.K. Moltz: "Predicting Gas Well Load-Up Using Nodal System Analysis" SPE paper 24860 presented at the Annular Technical Conference and Exhibition held in Washington D.C., 1992.

20) Surfer Version 7.0 Aug-25 1999 Surface Mapping System Golden Software Inc. 809 14th Street, Golden Colorado, 80401-1866

21) C. Richard Sivalls, "Glycol Dehydration Design" presented at the Laurance Reid Gas Conditioning Conference in Alberta, p 39 February 25-28, 2001.

22) The technology of Artificial Lift Methods Volume 4 Production Optimization of Oil and Gas Wells by Nodal Systems Analysis page 118, 1984.

23) J.R.Cadena, D.J.Schiozer, and A.A. Triggia: "A Simple Procedure to Develop Analytical Curves of IPR from Reservoir Simulators with Application in Production Optimization" SPE paper 36139 presented at the

Latin American and Caribbean Petroleum Engineering Conference held in Trinidad and Tobago, 1995.

24) Baker Hughes Centrilift 9 Step Pages 4-5 2001

25) Beggs H.D. and Robinson J.R. "Estimating the Viscosity of Crude oil Systems", Jour. Pet. Tech, Sept.1975 pg.1140

26) Mehdi Honarpour, Leonard Koederitz A.Herbert Harvey Relative permeability of Petroleum reservoirs, pages37-40, 1986,

27) Adel M. Elsharkawy: Characterization of the Plus Fraction and Prediction of the Dew-point Pressure for Gas Condensate Reservoirs, SPE paper 68776 presented at the Western Regional Meeting held in Bakersfield, California, 2001.

28) VLEFlash Version 3.12 A two phase vapor-liquid equilibrium calculator based on NIST Standard Reference Database 4. , 2002

29) The technology of Artificial Lift Methods Volume 4 Production Optimization of Oil and Gas Wells by Nodal Systems Analysis pages 118-120, 1984

30) http://www.answers.com/topic/equation-of-state

31) Katz D.: Handbook of Natural Gas Engineering, Mc Graw-Hill Book Co. Inc., 1959

APPENDIX A: INPUT DATA

A1: DATA USED IN THE SIMULATOR

** **

** mxflu004.dat: Gas Condensate Reservoir (Gaswater with Condensate Option) **

** **

** MODEL: 32x28x1 NODAL SYSTEM ANALYSIS** **

** CONTACT: CMG, (403)531-1300; 282-6495 (fax);support@cmgl.ca (Internet) **

RESULTS SIMULATOR IMEX 200410

FILENAMES OUTPUT INDEX-OUT MAIN-RESULTS-OUT

TITLE1 'Nodal System Analysis’

TITLE2 'Primary Production'

TITLE3 'No Group Controls'

CASEID 'Gas-Cond'

*INUNIT FIELD

*OUTUNIT FIELD

WRST TIME

WPRN WELL TIME

WPRN GRID TIME

OUTPRN WELL LAYER

OUTPRN WELL RESERVOIR

OUTPRN GRID DATUMPRES IMEXMAP PRES SG SW

WSRF WELL TIME

WSRF GRID TIME

OUTSRF GRID DATUMPRES PRES SG SW

OUTSRF RES ALL

*GRID   VARI 32 28 1

*KDIR DOWN

** Block dimensions in X (I) direction.

DI CON 410

** Block dimensions in Y (J) direction.

DJ CON 410

DK CON 148.

** Block thicknesses in Z (K) direction.

*DTOP

3855.175	3855.175	3855.175	3855.175	3855.175
3776.431	3789.555	3789.555	3789.555	3855.175
3855.175	3855.175	3855.175	3855.175	3855.175
3855.175	3855.175	3855.175	3855.175	3855.175
3855.175	3855.175	3855.175	3855.175	3855.175
3855.175	3855.175	3855.175	3855.175	3855.175
3855.175	3855.175	3855.175	3855.175	3855.175
3776.431	3776.431	3779.712	3773.15	3779.712
3789.555	3805.96	3812.522	3855.175	3855.175
3855.175	3855.175	3855.175	3855.175	3855.175
3855.175	3855.175	3855.175	3855.175	3855.175
3855.175	3855.175	3855.175	3855.175	3855.175

3855.175	3855.175	3855.175	3855.175	3773.15
3782.993	3786.274	3782.993	3779.712	3773.15
3766.588	3766.588	3773.15	3789.555	3805.96
3812.522	3799.398	3815.803	3855.175	3855.175
3855.175	3855.175	3855.175	3855.175	3855.175
3855.175	3855.175	3855.175	3855.175	3855.175
3855.175	3855.175	3855.175	3855.175	3855.175
3855.175				

3789.555	3792.836	3792.836	3789.555	3779.712
3773.15	3766.588	3763.307	3766.588	3773.15
3789.555	3796.117	3805.96	3812.522	3809.241
3855.175	3855.175	3855.175	3855.175	3855.175
3855.175	3855.175	3855.175	3855.175	3855.175
3855.175	3855.175	3855.175	3855.175	3855.175
3855.175	3855.175	3796.117	3792.836	3792.836
3789.555	3776.431	3766.588	3763.307	3760.026
3763.307	3766.588	3773.15	3782.993	3789.555
3796.117	3809.241	3819.084	3855.175	3855.175
3855.175	3855.175	3855.175	3855.175	3855.175
3855.175	3855.175	3855.175	3855.175	3855.175
3855.175	3855.175	3855.175	3855.175	3799.398
3796.117	3792.836	3789.555	3776.431	3766.588
3760.026	3753.464	3746.902	3753.464	3760.026
3766.588	3773.15	3786.274	3799.398	3809.241
3855.175	3855.175	3855.175	3855.175	3855.175
3855.175	3855.175	3855.175	3855.175	3855.175
3855.175	3855.175	3855.175	3855.175	3855.175
3855.175	3802.679	3796.117	3792.836	3789.555
3776.431	3763.307	3753.464	3743.621	3737.059
3737.059	3746.902	3756.745	3760.026	3773.15
3789.555	3815.803	3855.175	3855.175	3855.175
3855.175	3855.175	3855.175	3855.175	3855.175
3855.175	3855.175	3855.175	3855.175	3855.175
3855.175	3855.175	3855.175	3815.803	3799.398
3796.117	3792.836	3789.555	3763.307	3750.183
3737.059	3733.778	3730.497	3733.778	3737.059
3743.621	3756.745	3776.431	3799.398	3838.77

3855.175	3855.175	3855.175	3855.175	3855.175
3855.175	3855.175	3855.175	3855.175	3855.175
3855.175	3855.175	3855.175	3855.175	3855.175

3815.803	3809.241	3802.679	3802.679	3789.555
3760.026	3766.588	3737.059	3733.778	3727.216
3723.935	3730.497	3733.778	3740.34	3750.183
3782.993	3838.77	3855.175	3855.175	3855.175
3855.175	3855.175	3855.175	3855.175	3855.175
3855.175	3855.175	3855.175	3855.175	3855.175
3855.175	3855.175	3822.365	3812.522	3805.96
3799.398	3782.993	3766.588	3753.464	3737.059
3733.778	3727.216	3717.373	3717.373	3723.935
3733.778	3756.745	3773.15	3789.555	3842.051
3855.175	3855.175	3855.175	3855.175	3855.175
3855.175	3855.175	3855.175	3855.175	3855.175
3855.175	3855.175	3855.175	3855.175	3832.208
3819.084	3799.398	3789.555	3766.588	3760.026
3756.745	3740.34	3733.778	3727.216	3717.373
3714.092	3714.092	3723.935	3743.621	3763.307
3789.555	3809.241	3838.77	3855.175	3855.175
3855.175	3855.175	3855.175	3855.175	3855.175
3855.175	3855.175	3855.175	3855.175	3855.175
3855.175	3855.175	3825.646	3809.241	3789.555
3779.712	3760.026	3760.026	3750.183	3740.34
3727.216	3714.092	3710.811	3714.092	3720.654
3727.216	3743.621	3756.745	3789.555	3805.96
3828.927	3822.365	3822.365	3815.803	3855.175
3855.175	3855.175	3855.175	3855.175	3855.175
3855.175	3855.175	3855.175	3855.175	3838.77
3812.522	3799.398	3786.274	3773.15	3760.026
3760.026	3746.902	3733.778	3714.092	3700.968
3704.249	3707.53	3717.373	3730.497	3753.464
3773.15	3779.712	3789.555	3789.555	3789.555
3789.555	3792.836	3855.175	3855.175	3855.175
3855.175	3855.175	3855.175	3855.175	3855.175

3855.175	3855.175	3822.365	3796.117	3789.555
3779.712	3766.588	3760.026	3753.464	3733.778
3717.373	3700.968	3694.406	3697.687	3707.53
3723.935	3727.216	3743.621	3756.745	3756.745
3756.745	3756.745	3756.745	3756.745	3756.745
3855.175	3855.175	3855.175	3855.175	3855.175
3855.175	3855.175	3855.175	3855.175	3825.646
3805.96	3792.836	3782.993	3769.869	3753.464
3750.183	3727.216	3707.53	3694.406	3684.563
3691.125	3697.687	3714.092	3717.373	3723.935
3730.497	3733.778	3733.778	3733.778	3733.778
3733.778	3737.059	3740.34	3743.621	3855.175
3855.175	3855.175	3855.175	3855.175	3855.175
3855.175	3832.208	3815.803	3799.398	3786.274
3773.15	3756.745	3740.34	3723.935	3704.249
3691.125	3684.563	3684.563	3691.125	3694.406
3700.968	3707.53	3710.811	3714.092	3717.373
3717.373	3720.654	3720.654	3720.654	3723.935
3740.34	3855.175	3855.175	3855.175	3855.175
3855.175	3855.175	3855.175	3855.175	3828.927
3805.96	3786.274	3763.307	3760.026	3730.497
3717.373	3704.249	3691.125	3684.563	3681.282
3678.001	3684.563	3691.125	3694.406	3700.968
3697.687	3700.968	3700.968	3697.687	3710.811
3714.092	3717.373	3727.216	3743.621	3855.175
3855.175	3855.175	3855.175	3855.175	3855.175
3855.175	3835.489	3815.803	3789.555	3779.712
3756.745	3737.059	3720.654	3710.811	3697.687
3691.125	3684.563	3684.563	3684.563	3681.282
3684.563	3691.125	3691.125	3697.687	3697.687
3700.968	3704.249	3714.092	3717.373	3727.216
3743.621	3750.183	3855.175	3855.175	3855.175
3855.175	3855.175	3855.175	3855.175	3825.646
3805.96	3789.555	3766.588	3746.902	3733.778
3720.654	3717.373	3707.53	3704.249	3700.968
3697.687	3691.125	3687.844	3687.844	3687.844
3691.125	3697.687	3700.968	3707.53	3714.092
3720.654	3730.497	3746.902	3760.026	3766.588

3855.175	3855.175	3855.175	3855.175	3855.175
3855.175	3855.175	3822.365	3805.96	3789.555
3766.588	3743.621	3733.778	3723.935	3723.935
3717.373	3717.373	3707.53	3700.968	3697.687
3694.406	3694.406	3694.406	3697.687	3704.249
3707.53	3717.373	3730.497	3737.059	3746.902
3763.307	3773.15	3855.175	3855.175	3855.175
3855.175	3855.175	3855.175	3855.175	3855.175
3838.77	3812.522	3789.555	3773.15	3756.745
3743.621	3740.34	3733.778	3730.497	3723.935
3717.373	3714.092	3707.53	3700.968	3697.687
3700.968	3710.811	3717.373	3727.216	3733.778
3743.621	3753.464	3763.307	3779.712	3786.274
3855.175	3855.175	3855.175	3855.175	3855.175
3855.175	3855.175	3855.175	3855.175	3809.241
3799.398	3782.993	3769.869	3763.307	3750.183
3746.902	3740.34	3737.059	3730.497	3727.216
3723.935	3723.935	3723.935	3727.216	3733.778
3740.34	3746.902	3753.464	3763.307	3776.431
3782.993	3796.117	3855.175	3855.175	3855.175
3855.175	3855.175	3855.175	3855.175	3855.175
3855.175	3855.175	3812.522	3812.522	3799.398
3786.274	3773.15	3766.588	3760.026	3753.464
3746.902	3746.902	3743.621	3769.869	3746.902
3756.745	3756.745	3760.026	3766.588	3773.15
3782.993	3789.555	3796.117	3799.398	3855.175
3855.175	3855.175	3855.175	3855.175	3855.175
3855.175	3855.175	3855.175	3855.175	3855.175
3855.175	3832.208	3815.803	3802.679	3792.836
3789.555	3789.555	3789.555	3786.274	3789.555
3789.555	3789.555	3789.555	3789.555	3789.555
3792.836	3796.117	3799.398	3799.398	3802.679
3812.522	3812.522	3855.175	3855.175	3855.175
3855.175	3855.175	3855.175	3855.175	3855.175
3855.175	3855.175	3855.175	3855.175	3855.175
3832.208	3832.208	3825.646	3825.646	3822.365
3822.365	3819.084	3819.084	3819.084	3819.084
3819.084	3819.084	3822.365	3822.365	3822.365

3822.365	3825.646	3828.927	3828.927	3855.175
3855.175	3855.175	3855.175	3855.175	3855.175
3855.175	3855.175	3855.175	3855.175	3855.175
3855.175	3855.175	3855.175	3855.175	3855.175
3855.175	3855.175	3855.175	3855.175	3855.175
3855.175	3855.175	3855.175	3855.175	3855.175
3855.175	3855.175	3855.175	3855.175	3855.175
3855.175	3855.175	3855.175	3855.175	3855.175
3855.175	3855.175	3855.175	3855.175	3855.175
3855.175	3855.175	3855.175	3855.175	3855.175
3855.175	3855.175	3855.175	3855.175	3855.175
3855.175	3855.175	3855.175	3855.175	3855.175
3855.175	3855.175	3855.175	3855.175	3855.175
3855.175	3855.175	3855.175	3855.175	3855.175
3855.175	3855.175	3855.175	3855.175	3855.175
3855.175	3855.175	3855.175	3855.175	3855.175
3855.175	3855.175	3855.175	3855.175	3855.175
3855.175	3855.175	3855.175	3855.175	3855.175
3855.175	3855.175	3855.175	3855.175	3855.175
3855.175	3855.175	3855.175	3855.175	3855.175

*NULL *IJK

1:5	1:1	1:1	0
10:32	1:1	1:1	0
1:3	2:2	1:1	0
12:32	2:2	1:1	0
13:32	3:3	1:1	0
15:32	4:4	1:1	0
16:32	5:5	1:1	0
17:32	6:6	1:1	0
17:32	7:7	1:1	0

17:32	8:8	1:1	0
18:32	9:9	1:1	0
18:32	10:10	1:1	0
19:32	11:11	1:1	0
1:1	12:12	1:1	0
24:32	12:12	1:1	0
1:1	13:13	1:1	0
25:32	13:13	1:1	0
1:2	14:14	1:1	0
26:32	14:14	1:1	0
1:2	15:15	1:1	0
27:32	15:15	1:1	0
1:2	16:16	1:1	0
28:32	16:16	1:1	0
1:3	17:17	1:1	0
28:32	17:17	1:1	0
1:3	18:18	1:1	0
29:32	18:18	1:1	0
1:4	19:19	1:1	0
31:32	19:19	1:1	0
1:5	20:20	1:1	0
31:32	20:20	1:1	0
1:6	21:21	1:1	0

32:32	21:21	1:1	0
1:8	22:22	1:1	0
32:32	22:22	1:1	0
1:9	23:23	1:1	0
32:32	23:23	1:1	0
1:11	24:24	1:1	0
1:13	25:25	1:1	0
1:32	26:26	1:1	0
1:32	27:27	1:1	0
1:32	28:28	1:1	0

*POR ALL

1	1	1	1	0.07	0.07	0.07	0.07	0.07	1
1	1	1	1	1	1	1	1	1	1
1	1	1	1	1	1	1	1	1	1
1	1	1	1	1	0.06	0.06	0.07	0.07	0.07
0.07	0.07	0.07	1	1	1	1	1	1	1
1	1	1	1	1	1	1	1	1	1
1	1	1	1	0.063	0.061	0.061	0.067	0.061	0.061
0.06	0.07	0.07	0.07	0.07	0.07	1	1	1	1
1	1	1	1	1	1	1	1	1	1
1	1	1	1	1	1	0.06375		0.0635	0.06315
0.063	0.061	0.0675	0.0615	0.061	0.06	0.07	0.07	0.07	0.07
0.07	1	1	1	1	1	1	1	1	1
1	1	1	1	1	1	1	1	1	0.0645
0.064	0.0635	0.06315		0.063	0.0675	0.0615	0.061	0.061	0.06
0.07	0.07	0.07	0.07	0.07	1	1	1	1	1
1	1	1	1	1	1	1	1	1	1
1	1	0.065	0.06475		0.0645	0.064375		0.064	0.064
0.064	0.06375		0.0615	0.061	0.061	0.07	0.07	0.04	0.05
0.06	1	1	1	1	1	1	1	1	1

1	1	1	1	1	1	1	0.0659	0.0658	0.066
0.0661	0.066	0.0659	0.0657	0.0655	0.065	0.064	0.063	0.061	0.06
0.06	0.05	0.06	1	1	1	1	1	1	1
1	1	1	1	1	1	1	1	1	0.06605
0.0661	0.0664	0.0668	0.0668	0.0666	0.0664	0.0661	0.0661	0.0661	0.066
0.0658	0.064	0.061	0.061	0.159	1	1	1	1	1
1	1	1	1	1	1	1	1	1	1
1	0.0675	0.0677	0.0678	0.068	0.0681	0.0683	0.0685	0.069	0.0693
0.0695	0.0697	0.0693	0.068	0.065	0.063	0.061	0.159	1	1
1	1	1	1	1	1	1	1	1	1
1	1	1	0.0681	0.0685	0.0687	0.069	0.0691	0.0696	0.07
0.071	0.0715	0.071	0.0711	0.0711	0.071	0.071	0.07	0.066	0.061
1	1	1	1	1	1	1	1	1	1
1	1	1	1	1	0.0685	0.06875		0.069	0.0695
0.07	0.071	0.0715	0.071	0.073	0.08	0.08	0.04	0.03	0.04
0.08	0.08	0.08	0.061	1	1	1	1	1	1
1	1	1	1	1	1	1	1	1	0.0695
0.07	0.071	0.0715	0.0715	0.071	0.08	0.08	0.08	0.06	0.04
0.03	0.02	0.06	0.06	0.06	0.06	0.064	0.063	0.061	0.0605
0.06	1	1	1	1	1	1	1	1	1
1	0.07	0.0705	0.071	0.0715	0.071	0.073	0.08	0.08	0.08
0.06	0.04	0.04	0.05	0.07	0.07	0.07	0.07	0.066	0.064
0.063	0.061	0.061	0.06	1	1	1	1	1	1
1	1	1	1	0.0705	0.071	0.0715	0.0715	0.073	0.08
0.08	0.08	0.06	0.05	0.06	0.05	0.05	0.05	0.05	0.069
0.066	0.066	0.065	0.063	0.061	0.061	0.0605	0.06	1	1
1	1	1	1	1	1	0.0705	0.071	0.0715	0.0715
0.073	0.08	0.08	0.08	0.06	0.05	0.12	0.12	0.12	0.12
0.05	0.071	0.069	0.067	0.065	0.064	0.063	0.061	0.0615	0.061
0.06	1	1	1	1	1	1	1	0.0705	0.071
0.0715	0.0715	0.073	0.08	0.08	0.08	0.06	0.05	0.13	0.15
0.14	0.12	0.05	0.071	0.09	0.07	0.02	0.02	0.02	0.061
0.0615	0.061	0.06	1	1	1	1	1	1	1
1	0.071	0.0713	0.0715	0.0711	0.08	0.08	0.08	0.06	0.05
0.05	0.16	0.14	0.14	0.21	0.0715	0.11	0.05	0.02	0.02
0.02	0.063	0.061	0.0615	0.061	1	1	1	1	1

1	1	1	0.071	0.0715	0.071	0.0715	0.08	0.08	0.08
0.071	0.071	0.12	0.17	0.18	0.19	0.2	0.17	0.07	0.05
0.02	0.02	0.02	0.063	0.061	0.0615	0.061	0.061	1	1
1	1	1	1	1	1	0.071	0.0715	0.071	0.071
0.071	0.071	0.0715	0.071	0.12	0.15	0.16	0.13	0.13	0.07
0.069	0.069	0.067	0.067	0.065	0.065	0.064	0.063	0.063	0.061
0.061	0.061	1	1	1	1	1	1	1	0.071
0.071	0.071	0.071	0.071	0.071	0.071	0.12	0.13	0.13	0.13
0.13	0.07	0.07	0.068	0.067	0.067	0.066	0.065	0.064	0.063
0.063	0.061	0.061	0.061	1	1	1	1	1	1
1	1	0.071	0.071	0.071	0.071	0.071	0.071	0.12	0.12
0.12	0.12	0.12	0.07	0.069	0.068	0.067	0.067	0.066	0.065
0.065	0.064	0.063	0.061	0.061	0.061	0.061	1	1	1
1	1	1	1	1	1	0.071	0.071	0.071	0.071
0.07	0.07	0.07	0.07	0.07	0.07	0.069	0.068	0.067	0.067
0.066	0.065	0.065	0.064	0.063	0.061	0.061	0.061	0.061	1
1	1	1	1	1	1	1	1	1	0.071
0.07	0.07	0.07	0.07	0.07	0.07	0.069	0.067	0.067	0.067
0.067	0.066	0.065	0.065	0.065	0.064	0.063	0.063	0.063	0.063
0.061	1	1	1	1	1	1	1	1	1
1	1	1	0.069	0.069	0.069	0.069	0.069	0.069	0.068
0.068	0.067	0.067	0.066	0.065	0.065	0.065	0.065	0.064	0.063
0.063	0.063	0.063	0.061	1	1	1	1	1	1
1	1	1	1	1	1	1	0.069	0.069	0.069
0.068	0.068	0.067	0.067	0.067	0.067	0.066	0.066	0.066	0.066
0.064	0.063	0.063	0.063	0.063	0.061	1	1	1	1
1	1	1	1	1	1	1	1	1	1
1	1	1	1	1	1	1	1	1	1
1	1	1	1	1	1	1	1	1	1
1	1	1	1	1	1	1	1	1	1
1	1	1	1	1	1	1	1	1	1
1	1	1	1	1	1	1	1	1	1
1	1	1	1	1	1	1	1	1	1
1	1	1	1	1	1	1	1	1	1
1	1	1	1	1	1	1	1	1	1
1	1								

*PERMI ALL

100	100	100	100	100	9	8	6	4	100
100	100	100	100	100	100	100	100	100	100
100	100	100	100	100	100	100	100	100	100
100	100	100	100	100	7.2	7.2	6.2	6.2	5
4	3.1	2	100	100	100	100	100	100	100
100	100	100	100	100	100	100	100	100	100
100	100	100	100	10.3	10.5	10.3	10.6	10.4	10.5
11.2	11.4	11.3	10	9	8	6	4	100	100
100	100	100	100	100	100	100	100	100	100
100	100	100	100	100	100	9.1	9.2	9.3	9.2
9.3	9.3	9.4	9.3	9.4	7	7	6	5	4
100	100	100	100	100	100	100	100	100	100
100	100	100	100	100	100	100	100	8	8
8	7	7	6	6.1	6.1	6.2	5	4.1	3.1
3.2	2.1	6	100	100	100	100	100	100	100
100	100	100	100	100	100	100	100	100	100
7.2	7.2	6.2	6.2	5	4	3.1	3.1	3.2	3.2
3.2	3.1	3.1	6	6	7	100	100	100	100
100	100	100	100	100	100	100	100	100	100
100	100	6	6.1	5.2	5.2	4	3	2	2
2	2	2	2	2	2	7	6	100	100
100	100	100	100	100	100	100	100	100	100
100	100	100	100	5	4	4	3	3	2
2	1.1	1.2	1	1	1	1	5	6	6
100	100	100	100	100	100	100	100	100	100
100	100	100	100	100	100	5	4	4	3
2	2	1	1	1	1	1	1	1	4
3	3	3	100	100	100	100	100	100	100
100	100	100	100	100	100	100	100	4	3
3	2	2	1	1	1	1	1	1	1
1	1	3	3	3	100	100	100	100	100
100	100	100	100	100	100	100	100	100	100
3	3	2	2	2	1	1	1	1	1
1	3	3	3	3	3	3	11	100	100
100	100	100	100	100	100	100	100	100	100
100	100	100	3	3	2	2	2	1	1
1	1	1	3	2	3	3	1	1	1
1	1	1	1	1	100	100	100	100	100

100	100	100	100	100	10.1	2	2	2	2
2	2	2	2	2	5	5	3	4	3
4	4	4	4	3	2	4	2	100	100
100	100	100	100	100	100	100	100	8	8
8	8	7	7	7	7	7	7	7	7
7	7	7	7	8	7	7	3	7	7
7	9	100	100	100	100	100	100	100	100
8.2	8.4	8.2	8.1	13	13	13	13	13	13
13	13	13	13	13	13	13	9	2	2
4	7	7	9	100	100	100	100	100	100
100	100	8.2	8.3	8.1	7.3	14	14.3	15	15.1
15.1	15	16	16	16	16.1	17	13	13	8
2	1	1	7	9	9	1	100	100	100
100	100	100	100	100	7	7.1	7	14	14.1
14.2	14.3	15.1	15.1	15.2	15.1	16	16	16	13
13	6	1	1	1	7	9	9	1	1
100	100	100	100	100	100	100	6.1	6.2	6.2
13.1	13.1	13	14.1	14.3	14.3	14.5	15	15.2	15.6
16.2	13	13	8	1	1	1	7	9	9
1	1	1	100	100	100	100	100	100	100
5	5	13.1	13.3	13.4	13.5	13.7	13.7	14.2	14.4
14.6	14.8	15.3	13	13	7	1	1	1	7
9	9	1	1	1	1	100	100	100	100
100	100	100	4	12.1	12.3	12.4	12.2	12.6	13.1
13.4	13.4	13.7	14.2	14.3	13	15.3	8	1	1
1	7	9	9	1	1	1	1	1	100
100	100	100	100	100	100	11.2	11.2	11.3	11.4
11.3	11.3	11.4	11.6	11.8	12.2	12.4	13	13.2	9
2	2	4	7	6	9	3	2	1	1
1	100	100	100	100	100	100	100	100	100
11.2	11.2	11.3	11.4	11.3	11.3	11.4	11.6	11.8	12.2
12.4	8	3	3	4	7	7	9	6	4
3	2	1	100	100	100	100	100	100	100
100	100	100	1	1	1	1	1	1	1
1	1	1	1	1	1	1	7	9	1
1	1	1	1	1	100	100	100	100	100
100	100	100	100	100	100	100	1	1	1
1	1	1	1	1	1	1	1	1	7

```
9       1       1       1       1       1       1       1       100     100
100     100     100     100     100     100     100     100     100     100
100     1       1       1       1       1       1       1       1       1
1       7       9       1       1       1       1       1       1       1
100     100     100     100     100     100     100     100     100     100
100     100     100     100     100     100     100     100     100     100
100     100     100     100     100     100     100     100     100     100
100     100     100     100     100     100     100     100     100     100
100     100     100     100     100     100     100     100     100     100
100     100     100     100     100     100     100     100     100     100
100     100     100     100     100     100     100     100     100     100
100     100     100     100     100     100     100     100     100     100
100     100     100     100     100     100     100     100     100     100
100     100     100     100     100     100

        PERMJ EQUALSI

        PERMK EQUALSI * 0.7

        **$

**$ Property: Pinchout Array  Max: 1  Min: 1

**$  0 = pinched block, 1 = active block

PINCHOUTARRAY CON           1

        *CPOR     4.0E-6

        *PRPOR    2100.0

MODEL GASWATER_WITH_CONDENSATE

TRES 155

**    pressure   solution  solution       oil     gas        oil      gas

**    psia       GOR       CGR            FVF     FVF        vis,cp   vis,cp

PVTCOND BG 1

**$        p     Rs          Rv     Bo       Bg  viso     visg
```

```
   14.70    0.0         0.0   1.04   0.21015  0.38  0.01268
  515.00   288.7  0.025060e-3  1.172   0.00680  0.28  0.01310
 1015.00   618.7  0.021148e-3  1.362  0.002787  0.21  0.01407
 1515.00   980.1  0.026445e-3  1.607   0.00177  0.18  0.01540
 2015.00  1377.7  0.039146e-3  1.859  0.001306  0.16  0.01753
BWI 0.5
CVW 0.0
CW 3.58E-6
DENSITY OIL 48.56
DENSITY WATER 62.46
REFPW 1875.0
VWI 1.0
DENSITY GAS 0.1109
**$
**$ Property: PVT Type  Max: 1  Min: 1
PTYPE CON          1
*ROCKFLUID
RPT 1
**      SW      KRW           KROW
SWT
**$       Sw         krw        krow  Pcgl
        0.55           0      0.8334
    0.565625  0.000203467      0.6867
```

```
     0.58125   0.00162773     0.558313
    0.596875    0.0054936     0.447017
      0.6125    0.0130219     0.351591
    0.628125    0.0254333     0.270814
     0.64375    0.0439488     0.203467
    0.659375    0.0697891     0.148327
       0.675     0.104175     0.104175
    0.690625     0.148327    0.0697891
     0.70625     0.203467    0.0439488
    0.721875     0.270814    0.0254333
      0.7375     0.351591    0.0130219
    0.753125     0.447017    0.0054936
     0.76875     0.558313   0.00162773
    0.784375       0.6867  0.000203467
         0.8       0.8334            0
**        SL      KRG              KROG
SLT
**$        Sl         krg         krog
        0.75      0.42094            0
    0.753125     0.346844  0.000203467
     0.75625     0.281997   0.00162773
    0.759375     0.225783    0.0054936
      0.7625     0.177584    0.0130219
```

```
    0.765625     0.136785    0.0254333
     0.76875     0.102769    0.0439488
    0.771875    0.0749183    0.0697891
       0.775    0.0526175     0.104175
    0.778125    0.0352496     0.148327
     0.78125     0.022198     0.203467
    0.784375    0.0128461     0.270814
      0.7875   0.00657719     0.351591
    0.790625   0.00277475     0.447017
     0.79375  0.000822148     0.558313
    0.796875  0.000102769       0.6867
         0.8            0       0.8334
*INITIAL
*VERTICAL *DEPTH_AVE *WATER_GAS
REFDEPTH 3500.0
REFPRES 1675.0
DWGC 3900.0
DATUMDEPTH 4200 INITIAL
*PDEW             *CON 800.0
*PDEW *MATRIX      *CON  800.0
*PDEW *FRACTURE    *CON 800.0
*NUMERICAL
   *DTMAX  61.0
```

```
NORM SATUR 0.1

AIM OFF

  *NCUTS  8

SDEGREE 2

*RUN

DATE 2002 3  1.00

**$ Tubing flow table for production wells

PTUBE  CONDENSATE  1

DEPTH    5000.00

OGR      1e-006  2e-006

WGR      5e-007  1e-006

QG       1e+006  2e+006

WHP      1800.  1850.

BHPTC

**$ iogr  iwgr  iqg   bhps

 1   1   1     2200     2200

 2   1   1     2200     2200

 1   2   1     2200     2200

 2   2   1     2200     2200

 1   1   2     2250     2250

 2   1   2     2250     2250

 1   2   2     2250     2250

 2   2   2     2250     2250
```

```
DATE 2002 4  1.00

DATE 2002 5  1.00

WELL  'Well-1'

PRODUCER 'Well-1'

**$             depth  ibhp

PWELLBORE  TABLE  4200.  1

OPERATE  MIN  BHP  500.  SHUTIN

OPERATE  MAX  STG  2.853e+006  SHUTIN

**$          rad  geofac  wfrac  skin

GEOMETRY  K  0.25  0.37  1.  0.

PERF  GEO  'Well-1'

**$ UBA      ff  Status  Connection

   14 16 1  1.  OPEN    FLOW-TO  'SURFACE'

LAYERXYZ  'Well-1'

**$ perf geometric data: UBA, block entry(x,y,z) block exit(x,y,z), length

   14  16  1    5535.000000    6355.000000    3684.711000    5535.000000    6355.000000
3832.415000  148.000000

DATE 2002 6  1.00

DATE 2002 7  1.00

DATE 2002 8  1.00

DATE 2002 9  1.00

**

WELL  'Well-3'
```

```
PRODUCER 'Well-3'

**              depth  ibhp

PWELLBORE  TABLE  4200.  1

OPERATE  MIN  BHP  500.  SHUTIN

OPERATE  MAX  STG  6.1505e+006  CONT

**          rad  geofac  wfrac  skin

GEOMETRY  K  0.25  0.37  1.  0.

PERF  GEO  'Well-3'

**$ UBA      ff  Status  Connection

   17 18 1  1.  OPEN    FLOW-TO  'SURFACE'

DATE 2002 10  1.00

PRODUCER 'Well-1'

**$             depth  ibhp

PWELLBORE  TABLE  4200.  1

OPERATE  MIN  BHP  500.  SHUTIN

OPERATE  MAX  STG  5.44042e+006  SHUTIN

DATE 2002 11  1.00

DATE 2002 12  1.00

DATE 2003 1  1.00

DATE 2003 2  1.00

PRODUCER 'Well-1'

**$             depth  ibhp

PWELLBORE  TABLE  4200.  1
```

```
OPERATE  MIN  BHP  500.  SHUTIN

OPERATE  MAX  STG  3.56456e+006  CONT

DATE 2003 3  1.00

WELL  'Well-4'

PRODUCER 'Well-4'

**$              depth  ibhp

PWELLBORE  TABLE  4200.  1

OPERATE  MIN  BHP  500.  SHUTIN

OPERATE  MAX  STG  1.81588e+006  CONT

**$         rad  geofac  wfrac  skin

GEOMETRY  K  0.25  0.37  1.  0.

PERF  GEO  'Well-4'

**$ UBA      ff  Status  Connection

   15 22 1  1.  OPEN    FLOW-TO  'SURFACE'

DATE 2003 4  1.00

PRODUCER 'Well-3'

**$              depth  ibhp

PWELLBORE  TABLE  4200.  1

OPERATE  MIN  BHP  500.  SHUTIN

OPERATE  MAX  STG  6.22703e+006  CONT

DATE 2003 5  1.00

PRODUCER 'Well-4'

**$              depth  ibhp
```

```
PWELLBORE  TABLE  4200.  1

OPERATE  MIN  BHP  500.  SHUTIN

OPERATE  MAX  STG  3.32892e+006  CONT

DATE 2003 6  1.00

DATE 2003 7  1.00

DATE 2003 8  1.00

WELL  'Well-5'

PRODUCER 'Well-5'

**$              depth  ibhp

PWELLBORE  TABLE  4200.  1

OPERATE  MIN  BHP  500.  SHUTIN

OPERATE  MAX  STG  2.94787e+006  CONT

**$         rad  geofac  wfrac  skin

GEOMETRY  K  0.25  0.37  1.  0.

PERF  GEO  'Well-5'

**$ UBA      ff  Status  Connection

   21 17 1  1.  OPEN    FLOW-TO  'SURFACE'

LAYERXYZ  'Well-5'

**$ perf geometric data: UBA, block entry(x,y,z) block exit(x,y,z), length

   21  17  1    8405.000000    6765.000000    3701.116000    8405.000000    6765.000000
3848.820000  148.000000

PRODUCER 'Well-4'

**$              depth  ibhp
```

```
PWELLBORE  TABLE  4200.  1

OPERATE  MIN  BHP  500.  SHUTIN

OPERATE  MAX  STG  2.6761e+006  CONT

DATE 2003 9  1.00

WELL  'Well-2'

PRODUCER 'Well-2'

**$           depth  ibhp

PWELLBORE  TABLE  4200.  1

OPERATE  MIN  BHP  500.  SHUTIN

OPERATE  MAX  STG  200000.  CONT

**$       rad  geofac  wfrac  skin

GEOMETRY  K  0.25  0.37  1.  0.

PERF  GEO  'Well-2'

**$ UBA     ff  Status  Connection

  13 12 1  1.  OPEN    FLOW-TO  'SURFACE'

DATE 2003 10  1.00

PRODUCER 'Well-3'

**$           depth  ibhp

PWELLBORE  TABLE  4200.  1

OPERATE  MIN  BHP  500.  SHUTIN

OPERATE  MAX  STG  4.58258e+006  CONT

PRODUCER 'Well-1'

**$           depth  ibhp
```

```
PWELLBORE  TABLE  4200.  1

OPERATE  MIN  BHP  500.  SHUTIN

OPERATE  MAX  STG  2.51915e+006  CONT

PRODUCER 'Well-2'

**$              depth  ibhp

PWELLBORE  TABLE  4200.  1

OPERATE  MIN  BHP  500.  SHUTIN

OPERATE  MAX  STG  1.6e+006  CONT

DATE 2003 11  1.00

DATE 2003 12  1.00

PRODUCER 'Well-5'

**$              depth  ibhp

PWELLBORE  TABLE  4200.  1

OPERATE  MIN  BHP  500.  SHUTIN

OPERATE  MAX  STG  1.73619e+006  CONT

PRODUCER 'Well-4'

**$              depth  ibhp

PWELLBORE  TABLE  4200.  1

OPERATE  MIN  BHP  500.  SHUTIN

OPERATE  MAX  STG  2.42302e+006  CONT

PRODUCER 'Well-2'

**$              depth  ibhp

PWELLBORE  TABLE  4200.  1
```

```
OPERATE  MIN  BHP  500.  SHUTIN

OPERATE  MAX  STG  1.2e+006  CONT

DATE 2004 1  1.00

DATE 2004 2  1.00

DATE 2004 3  1.00

PRODUCER 'Well-5'

**$             depth  ibhp

PWELLBORE  TABLE  4200.  1

OPERATE  MIN  BHP  500.  SHUTIN

OPERATE  MAX  STG  519217.  CONT

PRODUCER 'Well-3'

**$             depth  ibhp

PWELLBORE  TABLE  4200.  1

OPERATE  MIN  BHP  500.  SHUTIN

OPERATE  MAX  STG  2.68016e+006  CONT

PRODUCER 'Well-2'

**$             depth  ibhp

PWELLBORE  TABLE  4200.  1

OPERATE  MIN  BHP  500.  SHUTIN

OPERATE  MAX  STG  730000.  CONT

DATE 2004 4  1.00

PRODUCER 'Well-4'

**$             depth  ibhp
```

```
PWELLBORE  TABLE  4200.  1

OPERATE  MIN  BHP  500.  SHUTIN

OPERATE  MAX  STG  437762.  CONT

PRODUCER 'Well-1'

**$              depth  ibhp

PWELLBORE  TABLE  4200.  1

OPERATE  MIN  BHP  500.  SHUTIN

OPERATE  MAX  STG  1.32009e+006  CONT

OPERATE  MIN  WHP IMPLICIT  500.  SHUTIN

DATE 2004 5  1.00

DATE 2004 6  1.00

PRODUCER 'Well-5'

**$              depth  ibhp

PWELLBORE  TABLE  4200.  1

OPERATE  MIN  BHP  500.  SHUTIN

OPERATE  MAX  STG  105934.  CONT

DATE 2004 7  1.00

DATE 2004 8  1.00

PRODUCER 'Well-5'

**$              depth  ibhp

PWELLBORE  TABLE  4200.  1

OPERATE  MIN  BHP  500.  SHUTIN

OPERATE  MAX  STG  596897.  CONT
```

```
PRODUCER 'Well-4'

**$             depth  ibhp

PWELLBORE  TABLE  4200.  1

OPERATE  MIN  BHP  500.  SHUTIN

OPERATE  MAX  STG  1.16996e+006  CONT

OPERATE  MIN  WHP IMPLICIT  500.  SHUTIN

DATE 2004 9  1.00

SHUTIN 'Well-5'

PRODUCER 'Well-3'

**$             depth  ibhp

PWELLBORE  TABLE  4200.  1

OPERATE  MIN  BHP  500.  SHUTIN

OPERATE  MAX  STG  2.11063e+006  CONT

OPERATE  MIN  WHP INITIALIZE  500.  SHUTIN

PRODUCER 'Well-2'

**$             depth  ibhp

PWELLBORE  TABLE  4200.  1

OPERATE  MIN  BHP  500.  SHUTIN

OPERATE  MAX  STG  679000.  CONT

OPERATE  MIN  WHP IMPLICIT  500.  SHUTIN

DATE 2004 10  1.00

DATE 2004 11  1.00

DATE 2004 12  1.00
```

```
DATE 2005 1  1.00

WELL  'Well-7'

PRODUCER 'Well-7'

**$          depth  ibhp

PWELLBORE  TABLE  4200.  1

OPERATE  MIN  WHP IMPLICIT  500.  SHUTIN

OPERATE  MAX  STG  1.1e+006  CONT

**$       rad  geofac  wfrac  skin

GEOMETRY  K  0.25  0.37  1.  0.

PERF  GEO  'Well-7'

**$ UBA    ff  Status  Connection

   8 19 1  1.  OPEN    FLOW-TO  'SURFACE'

LAYERXYZ  'Well-7'

**$ perf geometric data: UBA, block entry(x,y,z) block exit(x,y,z), length

   8  19  1    3075.000000    7585.000000    3766.736000    3075.000000    7585.000000
3914.440000  148.000000

WELL  'Well-6'

PRODUCER 'Well-6'

**$          depth  ibhp

PWELLBORE  TABLE  4200.  1

OPERATE  MIN  WHP IMPLICIT  500.  SHUTIN

OPERATE  MAX  STG  1.1e+006  CONT

**$       rad  geofac  wfrac  skin
```

```
GEOMETRY  K  0.25  0.37  1.  0.

PERF  GEO  'Well-6'

**$ UBA     ff  Status  Connection

   5 15 1  1.  OPEN    FLOW-TO  'SURFACE'

LAYERXYZ  'Well-6'

**$ perf geometric data: UBA, block entry(x,y,z) block exit(x,y,z), length

   5  15  1    1845.000000    5945.000000    3792.984000    1845.000000    5945.000000
3940.688000  148.000000

PRODUCER 'Well-4'

**$             depth  ibhp

PWELLBORE  TABLE  4200.  1

OPERATE  MIN  BHP  500.  SHUTIN

OPERATE  MAX  STG  1.6e+006  CONT

OPERATE  MIN  WHP IMPLICIT  500.  SHUTIN

PRODUCER 'Well-3'

**$             depth  ibhp

PWELLBORE  TABLE  4200.  1

OPERATE  MIN  BHP  500.  SHUTIN

OPERATE  MAX  STG  2.5e+006  CONT

OPERATE  MIN  WHP INITIALIZE  500.  SHUTIN

PRODUCER 'Well-1'

**$             depth  ibhp

PWELLBORE  TABLE  4200.  1
```

```
OPERATE  MIN  BHP  500.  SHUTIN

OPERATE  MAX  STG  2e+006  CONT

OPERATE  MIN  WHP IMPLICIT  500.  SHUTIN

PRODUCER 'Well-2'

**$               depth  ibhp

PWELLBORE  TABLE  4200.  1

OPERATE  MIN  BHP  500.  SHUTIN

OPERATE  MAX  STG  700000.  CONT

OPERATE  MIN  WHP IMPLICIT  500.  SHUTIN

DATE 2005 2  1.00

DATE 2005 3  1.00

DATE 2005 4  1.00

DATE 2005 5  1.00

DATE 2005 6  1.00

DATE 2005 7  1.00

DATE 2005 8  1.00

DATE 2005 9  1.00

DATE 2005 10  1.00

DATE 2005 11  1.00

DATE 2005 12  1.00

DATE 2006 1  1.00

DATE 2006 2  1.00

DATE 2006 3  1.00
```

DATE 2006 4 1.00

DATE 2006 5 1.00

DATE 2006 6 1.00

DATE 2006 7 1.00

DATE 2006 8 1.00

DATE 2006 9 1.00

DATE 2006 10 1.00

DATE 2006 11 1.00

DATE 2006 12 1.00

DATE 2007 1 1.00

DATE 2007 2 1.00

DATE 2007 3 1.00

DATE 2007 4 1.00

DATE 2007 5 1.00

DATE 2007 6 1.00

DATE 2007 7 1.00

DATE 2007 8 1.00

DATE 2007 9 1.00

DATE 2007 10 1.00

DATE 2007 11 1.00

DATE 2007 12 1.00

DATE 2008 1 1.00

DATE 2008 2 1.00

DATE 2008 5 1.00

DATE 2008 6 1.00

DATE 2008 7 1.00

DATE 2008 8 1.00

DATE 2008 9 1.00

DATE 2008 10 1.00

DATE 2008 11 1.00

DATE 2008 12 1.00

DATE 2009 1 1.00

DATE 2009 2 1.00

DATE 2009 3 1.00

DATE 2009 4 1.00

DATE 2009 5 1.00

DATE 2009 6 1.00

DATE 2009 7 1.00

DATE 2009 8 1.00

DATE 2009 9 1.00

DATE 2009 10 1.00

DATE 2009 11 1.00

DATE 2009 12 1.00

DATE 2010 1 1.00

STOP

RESULTS WPD END

A2: PRODUCTION DATA FROM THE FIELD

Table A.1. W1 Production Data

Date	Gas Production (MMscf)	Condensate Production (bbl)	WHP (psi)
Jun-02	0	0	1,590
Jul-02	94	691	1,595
Aug-02	164	1,183	1,595
Sep-02	219	1,587	1,595
Oct-02	342	2,491	1,519
Nov-02	508	3,698	1,428
Dec-02	664	4,833	1,390
Jan-03	829	6,021	1,329
Feb-03	995	7,230	1,312
Mar-03	1,089	7,927	1278.0
Apr-03	1,217	8,854	1228.0
May-03	1,334	9,716	1193.0
Jun-03	1,438	10,464	1160.0
Jul-03	1,540	11,204	1120.0
Aug-03	1,646	11,790	1100.0
Sep-03	1,752	12,548	1070.0
Oct-03	1,851	13,254	1050.0
Nov-03	1,932	13,787	1030.0
Dec-03	2,021	14,400	1010.0
Jan-04	2,099	14,946	989.0
Feb-04	2,167	15,408	977.0
Mar-04	2,240	15,940	956.0
Apr-04	2,304	16,417	940.0
May-04	2,356	16,811	918.0
Jun-04	2,414	17,235	879
Jul-04	2,443	17,784	865
Aug-04	2,485	18,003	855
Sep-04	2,504	18,269	843
Oct-04	2,532	18,396	821
Nov-04	2,566	18,609	800
Dec-04	2,621	18,842	781
Jan-05	2,742	19,954	765

Table A.2. W2 Production Data

Month	Gas Production (MMscf)	Condensate Production (bbl)	WHP (psi)
Aug-03	0	0.0	1,030
Sep-03	51	338.8	818
Oct-03	115	765.8	829
Nov-03	159	1,065.4	753
Dec-03	207	1,399.3	840
Jan-04	231	1,565.9	577
Feb-04	254	1,716.4	686
Mar-04	278	1,877.4	706
Apr-04	297	2,005.5	743
May-04	310	2,093.7	705
Jun-04	326	2,192.4	895
Jul-04	343	2,346.2	707
Aug-04	361	2,474.8	687
Sep-04	381	2,608.6	702
Oct-04	392	2,681.1	743
Nov-04	411	2,826.7	703
Dec-04	433	2,974.7	693
Jan-05	451	3,104.0	710

Table A.3 W3 Production Data

Month	Gas Production (MMscf)	Condensate Production (bbl)	WHP (psi)
Oct-02	0	0.0	1,462
Nov-02	195	1,425.9	1,372
Dec-02	390	2,858.8	1,336
Jan-03	566	4,134.2	1,167
Feb-03	760	5,649.7	1,207
Mar-03	895	6,619.9	1,171
Apr-03	1,107	8,155.7	1,104
May-03	1,306	9,598.4	1,075
Jun-03	1,495	10,965.5	1,028
Jul-03	1,673	12,253.5	938
Aug-03	1,858	13,605.9	867
Sep-03	2,054	15,037.4	842
Oct-03	2,228	16,303.0	801
Nov-03	2,364	17,293.5	805
Dec-03	2,532	18,520.6	748
Jan-04	2,667	19,504.8	774
Feb-04	2,787	20,387.5	710
Mar-04	2,915	21,324.8	704
Apr-04	3,009	22,005.2	714
May-04	3,073	22,470.0	714
Jun-04	3,145	22,997.8	701
Jul-04	3,223	23,699.4	747
Aug-04	3,301	24,274.4	756
Sep-04	3,398	24,898.9	712
Oct-04	3,436	25,157.9	702
Nov-04	3,505	25,702.1	722
Dec-04	3,588	26,264.0	706
Jan-05	3,725	27,207.7	696

Table A.4 Production Data

Month	Gas Production (MMscf)	Condensate Production (bbl)	WHP(psi)
Mar-03	0	0.0	1,315
Apr-03	46	290.0	1,242
May-03	109	700.0	1,137
Jun-03	209	1,380.0	1,075
Jul-03	311	1,870.0	1,028
Aug-03	409	2,506.0	992
Sep-03	481	3,010.0	933
Oct-03	554	3,650.0	846
Nov-03	635	4,015.0	796
Dec-03	730	4,765.0	786
Jan-04	805	5,216.0	780
Feb-04	882	5,926.2	797
Mar-04	960	6,134.0	738
Apr-04	1,020	6,343.0	713
May-04	1,045	6,743.0	704
Jun-04	1,056	6,902.0	785
Jul-04	1,057	6,909.4	765
Aug-04	1,073	7,024.4	721
Sep-04	1,117	7,306.3	723
Oct-04	1,135	7,427.7	713
Nov-04	1,170	7,700.8	703
Dec-04	1,213	7,995.7	684
Jan-05	1,287	8,502.0	678

Table A.5 W5 Production Data

Month	Gas Production (MMscf)	Condensate Production (bbl)	WHP (psi)
Jul-03	0	0.0	1,120
Aug-03	81	441.0	1,120
Sep-03	182	987.7	991
Oct-03	265	1,441.3	899
Nov-03	322	1,733.9	822
Dec-03	369	1,967.7	750
Jan-04	382	2,029.3	792
Feb-04	398	2,116.1	775
Mar-04	416	2,214.8	703
Apr-04	425	2,256.8	694
May-04	426	2,261.0	681
Jun-04	426	2,261.0	696
Jul-04	438	2,350.4	766
Aug-04	462	2,502.3	705
Sep-04	462	2,502.3	715
Oct-04	462	2,502.3	682
Nov-04	462	2,502.3	694
Dec-04	462	2,502.3	690
Jan-05	462	2,502.3	690

APPENDIX B: COMMERCIAL SIMULATOR KEYWORDS

B1: Input Output Section Keywords

These keywords must appear in the Input/Output Control keyword group, at the start of the input-data-file.

*__TITLE1:__ is used for project identification.

*__TITLE2:__ is used for project identification. It is used in addition to *TITLE1 to provide a second line for project identification.

*__TITLE3:__ is used for project identification. It is used in addition to *TITLE1 and *TITLE2 to provide a third line for project identification.

*__CASEID:__ is used to identify specific case runs.

Above keywords identify alphanumeric character strings used for project identification. It will appear both in the output file and in the index-results-file

*__INUNIT:__ specifies the input data units.

*__OUTUNIT:__ specifies the output data units

*__FIELD:__ this option specifies FIELD units for input data.

*__WRST:__ controls the frequency of writing restart records to the index-results-file and to either the main-results-file or the re-windable-results-file.

*__REWIND:__ controls the frequency of rewinding the re-windable-results-file.

*__WPRN:__ controls the frequency of writing data to the output file.

*__OUTPRN:__ identifies what information is written to the output file.

***WSRF:** controls the writing of well and/or grid information to the index-results-file and the main-results-file (the SR2 file system).

***WELL *TIME:** write well results to the output file at every time specified by subsequent recurrent *TIME or *DATE keywords in the input-data-file.

***GRID *TIME:** write grid results to the output file at every time specified by subsequent recurrent *TIME or *DATE keywords in the input-data-file.

***WELL:** this sub keyword specifies that well results will be written to the output file.

***GRID:** this sub keyword specifies that grid results will be written to the output file.

***RESERVOIR:** Write a summary of well variables at reservoir conditions to the output file. If available this will also cause voidage replacement information to be printed out at the field and group level

***RES:** This sub keyword specifies that input reservoir properties will be printed at the start of the simulation run. Original volumes in place will always be printed after input reservoir properties unless *RES *NONE is specified.

***ALL:** write all possible variables to the output file. For the *WELL option this means all of *BRIEF, *RESERVOIR and *LAYER

***IMEXMAP:** Implicit / explicit block map

***SW:** Water saturation

***DATUMPRES:** Datum pressure

B2: Reservoir Description Section Keywords

GRID: defines the fundamental (main) grid, and marks the beginning of the reservoir description.

***VARI:** Keyword indicating a rectangular grid allowing variable depth/variable thickness layers.

***KDIR:** controls whether increasing K means going deeper or shallower in the reservoir.

***DOWN:** indicates that the K index increases downward, so larger K means deeper grid blocks.

***DI:** signals input of an array of grid block lengths for the I direction. For rectangular grids, the values are block widths measured in the I direction and for radial-angular cylindrical grids, the values are block widths measured in the radial direction.

***DJ:** signals input of an array of grid block lengths for the J direction. For rectangular grids, the values are block widths measured in the J direction and for radial-angular cylindrical grids, the values are angular extents for portions of the subdivided rings, expressed in degrees.

***DK**: signals input of an array of (gross) grid block thicknesses measured in the K direction.

***CON:** indicates that a constant value is entered for all array elements. The value may be entered on the same line or the next line.

***DTOP:** indicates input of a number of depths that provide the depth to the centre of the top face of each grid block in the top layer of the grid.

***NULL:** indicates the input of an array of null block indicators which can be used to mark individual porosities as non-participating in dual porosity models, or entire blocks as non-participating.

***IJK:** assigns a constant value of a grid property within the region defined by the minimum and maximum block number in each of the three directions.

***POR:** indicates input of porosities, where zero values can be used to mark individual porosities as null (non-participating) in dual porosity models, or entire blocks as null.

***PERMI:** indicates input of an array of I direction permeabilities.

***PERMJ:** indicates input of an array of J direction permeabilities.

***PERMK:** indicates input of an array of K direction permeabilities.

***ALL:** is used to indicate that values vary in most or all the grid blocks. The number of values expected is the number of grid blocks in the grid, including all null or zero-porosity blocks.

***PINCHOUTARRAY:** defines pinch outs using an array input format.

***CPOR:** signals the input of a rock compressibility value that will be used throughout the entire model.

***PRPOR:** signals the input of a reference pressure for the rock compressibility. This pressure is the fluid (pore) pressure at which the values input using

B3: Component Properties Section Keywords

***MODEL** signals the input of the fluid component model to use for the simulation.

***GASWATER_WITH_CONDENSATE** Uses an extension of the *GASWATER option. Oil (as condensate) can initially exist in the gas phase either in a saturated or under-saturated state. Condensate can be produced at surface or can drop out in the reservoir (and possibly be produced as a liquid). Condensate, Gas, and Water equations are solved for simultaneously.

***TRES** indicates the input of reservoir temperature.

***PVTCOND** indicates start of the oil and gas PVTCOND table.

***BG** Keyword indicating that the gas formation volume factor will be used instead of the gas expansion factor.

***BWI** indicates the input of the water formation volume factor (for a PVT region).

***CW** indicates the input of water compressibility (for a PVT region).

***REFPW** indicates the input of reference pressure (for a PVT region).

***VWI** signals the input of Viscosity of water phase at the reference pressure (for a PVT region).

***CVW** signals the input of Pressure dependence of water viscosity (viscosity units/pressure units). (for a PVT region).

***DENSITY** indicates the input of a density (for a PVT region).

B4: Rock-Fluid Properties Section Keywords

ROCKFLUID indicates the start of the rock-fluid data.

***RPT** indicates that this set of relative permeability curves will be defined by table entries.

***SWT** indicates the start of the water-oil relative permeability table. In addition *SWT controls the use of a wide variety of relative permeability regression and optimization functions.

*SLT indicates the start of a liquid-gas relative permeability table dependent on liquid saturation.

B5: Initial Conditions Section Keywords

***INITIAL** indicates the beginning of initial condition values.

***VERTICAL** Indicates that pressures are determined from the hydrostatic equation and saturations from the capillary pressure tables.

***DEPTH_AVE** Sub option of *VERTICAL. Assign block saturations as averages over the depth interval spanned by the grid block.

***WATER_GAS** Perform gravity-capillary equilibrium initialization for reservoirs with only water and gas phases initially present

***REFDEPTH** indicates input of reference depth.

***REFPRES** indicates input of reference pressure

***DWGC** indicates input of water-gas contact depth.

***DATUMDEPTH** specifies the datum depth for pressure printout corrected to datum for each PVT region. A *DATUMDEPTH keyword should be entered for each PVT region. The first *DATUMDEPTH applies to PVT region 1, the second to PVT region 2 and so on.

***PDEW** indicates the input of dew point pressure in array format.

B6: Numerical Control Section Keywords

***NUMERICAL** identifies the beginning of all numerical methods control keywords.

***DTMAX** identifies the maximum time-step size.

***NORM** identifies the typical changes in the basic variables over a time-step.

***SATUR** This sub-keyword identifies saturations (fraction, dimensionless).

***AIM** controls the adaptive implicit switching option.

***OFF** Adaptive implicit option is not used. The problem will be solved with fixed implicitness.

***NCUTS** controls the number of time-step size cuts allowed in a single time-step.

***SDEGREE** controls the maximum degree of fill terms used in the factorization.

B7: Well and Recurrent Data Section Keywords

***RUN** identifies the beginning of all well and recurrent data keywords.

***PTUBE *CONDENSATE** This keyword enables the use of condensate tubing head pressure tables. These tables can be used with the GAS WATER _WITH_ CONDENSATE option.

***DATE** indicates that the well change will occur at a specified date.

***TIME** indicates that the well change will occur at a specified time.

***WELL** is used to identify wells.

***PRODUCER** indicates that the well identified by well number is a producer.

***SHUTIN** indicates that the well identified by wellnum is shut in. A producer or an injector must be fully defined, including the constraints before a well can be shut in.

***PWELLBORE** specifies that the wellbore model will be used for this producer.

***TABLE** This subkeyword specifies that the well-bore hydraulic pressure loss table (input using the *PTUBE) will be used for pressure loss calculations.

Ibhp *PTUBE table number.

Wdepth A real number specifying the well depth of a producer well (m | ft | cm).

Wlength A real number specifying the well length of a producer well (m | ft | cm).

rel_rough A real number specifying the relative well roughness. Dimensionless.

Whtemp A real number specifying the well head temperature (deg. C | deg. F | deg. C).

Bhtemp A real number specifying the reservoir temperature (deg. C | deg. F | deg. C).

Wradius A real number specifying the tubing radius (m | ft | cm).

***OPERATE** defines the well operating constraints, and the remedial action to be taken when a constraint is violated.

***GEOMETRY** specifies the well geometric characteristics to be used by the simulator to calculate the well index internally.

***PERF** specifies the location of the well completion grid blocks.

***LAYERXYZ** allows the user to supply geometric information specifying deviated perforations – perforations in which the wellbore direction is not parallel to one of the local coordinate axes.

***STOP** causes simulation to terminate.

APPENDIX C: RESERVOIR DATA

C1: Porosity Distribution of the field

Table C.1 Porosity Distribution of the Field

Grid No	1	2	3	4	5	6	7	8	9	10
1	30	30	30	30	1	1	1	1	1	30
2	30	30	30	3	1	2	1	2	1	1
3	5	4	3	2	1	1	1	2	3	2
4	2	3	4	4	5	3	2	2	6	3
5	1	5	2	6	6	5	5	5	8	5
6	1	3	1	6	5	4	5	3	8	5
7	2	2	2	3	4	3	5	5	8	5
8	2	3	2	3	3	3	3	5	7	5
9	2	2	1	4	2	2	4	5	10	5
10	3	3	3	3	2	4	5	5	6	7
11	4	4	4	5	3	4	5	7	5	7
12	30	4	3	6	2	4	4	5	5	8
13	30	3	2	3	3	3	5	6	7	8
14	30	30	1	4	5	6	5	8	8	8
15	30	30	4	2	4	3	7	10	10	5
16	30	30	6	2	3	2	7	7	8	5
17	30	30	30	2	5	1	6	6	6	7
18	30	30	30	1	5	2	8	7	7	9
19	30	30	30	30	5	4	7	5	5	5
20	30	30	30	30	30	5	8	10	7	7
21	30	30	30	30	30	30	5	5	6	5
22	30	30	30	30	30	30	30	30	5	6
23	30	30	30	30	30	30	30	30	30	5
24	30	30	30	30	30	30	30	30	30	30
25	30	30	30	30	30	30	30	30	30	30
26	30	30	30	30	30	30	30	30	30	30
27	30	30	30	30	30	30	30	30	30	30
28	30	30	30	30	30	30	30	30	30	30

Table C 1 Porosity Distribution of the Field (continued)

Grid No	12	13	14	15	16	17	18	19	20	21
1	30	30	30	30	30	30	30	30	30	30
2	30	30	30	30	30	30	30	30	30	30
3	3	3	3	30	30	30	30	30	30	30
4	2	3	4	30	30	30	30	30	30	30
5	3	4	2	1	30	30	30	30	30	30
6	5	4	3	2	1	30	30	30	30	30
7	5	5	5	3	3	30	30	30	30	30
8	5	5	5	4	4	30	30	30	30	30
9	5	5	5	5	6	5	30	30	30	30
10	5	5	5	7	7	5	30	30	30	30
11	5	5	5	8	7	8	6	30	30	30
12	11	13	5	9	11	5	5	5	5	7
13	5	5	5	12	12	5	5	5	5	8
14	5	5	5	15	15	15	17	17	17	8
15	5	11	11	11	12	16	13	15	17	8
16	5	19	22	16	15	14	13	12	14	8
17	9	12	12	13	9	13	18	14	15	8
18	13	10	15	14	22	27	19	10	15	12
19	11	11	12	12	11	13	11	10	17	17
20	9	8	10	10	10	10	10	10	17	17
21	5	5	12	16	12	12	12	8	12	12
22	6	5	12	12	12	12	12	8	8	8
23	5	5	11	11	11	11	11	8	8	8
24	5	5	12	12	12	12	12	8	8	8
25	30	30	1	2	3	8	7	4	5	2
26	30	30	30	30	30	30	30	30	30	30
27	30	30	30	30	30	30	30	30	30	30
28	30	30	30	30	30	30	30	30	30	30

Table C 1 Porosity Distribution of the Field (continued)

Grid No	22	23	24	25	26	27	28	29	30	31	32
1	30	30	30	30	30	30	30	30	30	30	30
2	30	30	30	30	30	30	30	30	30	30	30
3	30	30	30	30	30	30	30	30	30	30	30
4	30	30	30	30	30	30	30	30	30	30	30
5	30	30	30	30	30	30	30	30	30	30	30
6	30	30	30	30	30	30	30	30	30	30	30
7	30	30	30	30	30	30	30	30	30	30	30
8	30	30	30	30	30	30	30	30	30	30	30
9	30	30	30	30	30	30	30	30	30	30	30
10	30	30	30	30	30	30	30	30	30	30	30
11	30	30	30	30	30	30	30	30	30	30	30
12	6	8	30	30	30	30	30	30	30	30	30
13	8	8	9	30	30	30	30	30	30	30	30
14	8	7	8	8	8	30	30	30	30	30	30
15	5	6	8	8	8	8	30	30	30	30	30
16	8	8	9	10	7	8	30	30	30	30	30
17	12	12	8	8	8	8	7	30	30	30	30
18	12	12	8	8	8	8	8	30	30	30	30
19	17	17	8	8	8	8	8	8	8	30	30
20	17	4	4	4	4	8	8	8	8	30	30
21	7	4	4	4	4	4	4	4	4	4	30
22	7	4	4	4	4	4	4	4	4	4	30
23	7	4	4	4	4	4	4	4	4	4	30
24	7	4	4	4	4	4	4	4	4	4	4
25	3	6	2	3	1	1	2	2	3	5	4
26	30	30	30	30	30	30	30	30	30	30	30
27	30	30	30	30	30	30	30	30	30	30	30
28	30	30	30	30	30	30	30	30	30	30	30

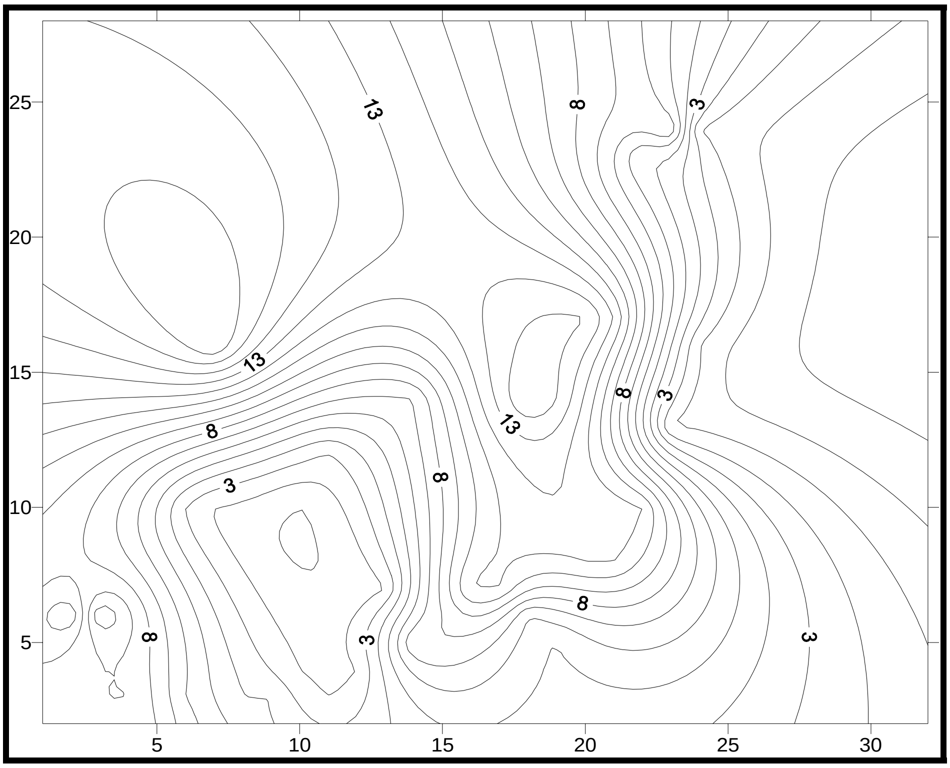

Figure C. 1.Porosity Distribution of the Field (Surfer)

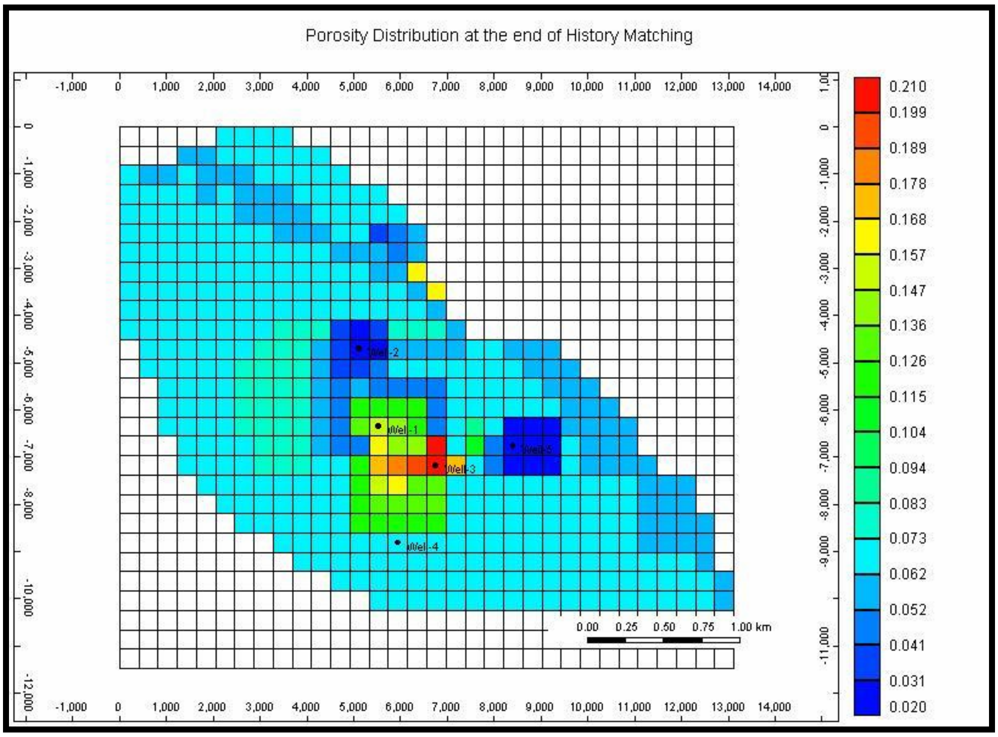

Figure C.2 Porosity Distribution of the field (Simulator)

C2: Permeability Distribution of the Field

Table C.2 Permeability Distribution of the Field

Grid No	1	2	3	4	5	6	7	8	9	10
1	30	30	30	30	30	9	8	6	4	30
2	30	30	30	7.2	7.2	6.2	6.2	5	4	3.1
3	10	11	10	11	10	11	11	11	11	10
4	9.1	9.2	9.3	9.2	9.3	9.3	9.4	9.3	9.4	7
5	8	8	8	7	7	6	6.1	6.1	6.2	5
6	7.2	7.2	6.2	6.2	5	4	3.1	3.1	3.2	3.2
7	6	6.1	5.2	5.2	4	3	2	2	2	2
8	5	4	4	3	3	2	2	1.1	1.2	1
9	5	4	4	3	2	2	1	1	1	1
10	4	3	3	2	2	1	1	1	1	1
11	3	3	2	2	2	1	1	1	1	1
12	30	3	3	2	2	2	1	1	1	1
13	30	10	2	2	2	2	2	2	2	2
14	30	30	8	8	8	8	7	7	7	7
15	30	30	8.2	8.4	8.2	8.1	9	11	9	11
16	30	30	8.2	8.3	8.1	7.3	11	11	9	11
17	30	30	30	7	7.1	7	11	11	9	11
18	30	30	30	6.1	6.2	6.2	11	11	9	11
19	30	30	30	30	5	5	11	11	9	12
20	30	30	30	30	30	4	11	11	9	11
21	30	30	30	30	30	30	11	11	11	11
22	30	30	30	30	30	30	30	30	11	11
23	30	30	30	30	30	30	30	30	30	1
24	30	30	30	30	30	30	30	30	30	30
25	30	30	30	30	30	30	30	30	30	30
26	30	30	30	30	30	30	30	30	30	30
27	30	30	30	30	30	30	30	30	30	30
28	30	30	30	30	30	30	30	30	30	30

Table C.2 Permeability Distribution of the Field (Continued)

Grid No	12	13	14	15	16	16	17	18	19	20
1	30	30	30	30	30	30	30	30	30	30
2	30	30	30	30	30	30	30	30	30	30
3	8	6	4	30	30	30	30	30	30	30
4	6	5	4	30	30	30	30	30	30	30
5	3.1	3.2	2.1	7	30	30	30	30	30	30
6	3.1	3.1	2	7	17	17	30	30	30	30
7	2	2	2	7	17	17	30	30	30	30
8	1	1	1	7	16	16	30	30	30	30
9	1	1	1	7	7	7	7	30	30	30
10	3	3	3	4	6	6	7	30	30	30
11	3	3	4	14	13	13	12	30	30	30
12	2	2	2	1	1	1	1	1	1	1
13	5	2	3	4	3	3	4	4	4	4
14	7	7	7	7	7	7	7	7	8	7
15	11	11	11	11	11	11	11	11	13	9
16	12	12	14	11	12	12	12	13	13	6
17	9	11	11	11	13	13	13	13	13	6
18	11	14.5	15	15	16	16	16	13	13	6
19	10.2	14.2	14	15	15	15	15	13	13	7
20	9.7	13.4	13	14	14	14	14	13	15	8
21	9.6	11.4	12	12	12	12	12	13	13	9
22	10	11.3	11	11	12	12	12	12	12	8
23	1	1	1	1	1	1	1	1	1	1
24	1	1	1	1	1	1	1	1	1	1
25	30	30	1	1	1	1	1	1	1	1
26	30	30	30	30	30	30	30	30	30	30
27	30	30	30	30	30	30	30	30	30	30
28	30	30	30	30	30	30	30	30	30	30

Table C.2 Permeability Distribution of the Field (continued)

Grid No	22	23	24	25	26	27	28	29	30	31	32
1	30	30	30	30	30	30	30	30	30	30	30
2	30	30	30	30	30	30	30	30	30	30	30
3	30	30	30	30	30	30	30	30	30	30	30
4	30	30	30	30	30	30	30	30	30	30	30
5	30	30	30	30	30	30	30	30	30	30	30
6	30	30	30	30	30	30	30	30	30	30	30
7	30	30	30	30	30	30	30	30	30	30	30
8	30	30	30	30	30	30	30	30	30	30	30
9	30	30	30	30	30	30	30	30	30	30	30
10	30	30	30	30	30	30	30	30	30	30	30
11	30	30	30	30	30	30	30	30	30	30	30
12	1	1	30	30	30	30	30	30	30	30	30
13	2	4	2	30	30	30	30	30	30	30	30
14	3	7	7	7	9	30	30	30	30	30	30
15	2	4	7	7	9	9	30	30	30	30	30
16	6	3	7	9	9	1	30	30	30	30	30
17	6	6	7	9	9	1	1	30	30	30	30
18	6	6	7	9	9	1	1	30	30	30	30
19	6	6	7	9	9	1	1	1	1	30	30
20	1	1	7	9	9	1	1	1	1	30	30
21	2	4	7	6	9	3	2	1	1	1	30
22	3	4	7	7	9	6	4	3	2	1	30
23	1	1	7	9	1	1	1	1	1	1	30
24	1	1	7	9	1	1	1	1	1	1	1
25	1	1	7	9	1	1	1	1	1	1	1
26	30	30	30	30	30	30	30	30	30	30	30
27	30	30	30	30	30	30	30	30	30	30	30
28	30	30	30	30	30	30	30	30	30	30	30

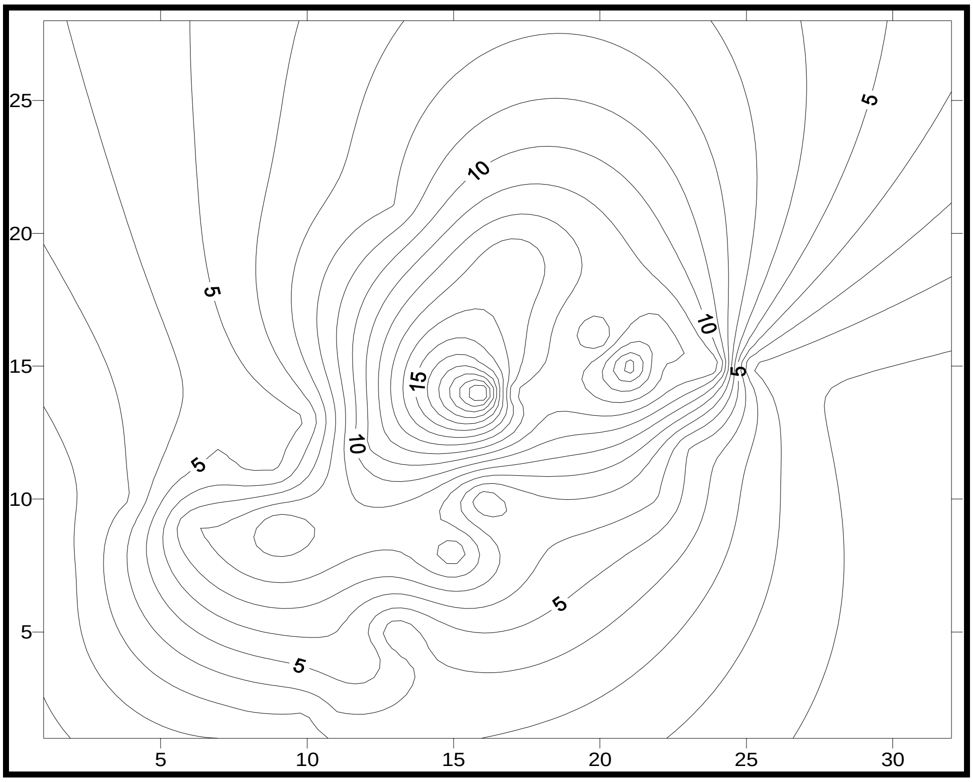

Figure C. 3. Permeability Distribution of the Field (Surfer)

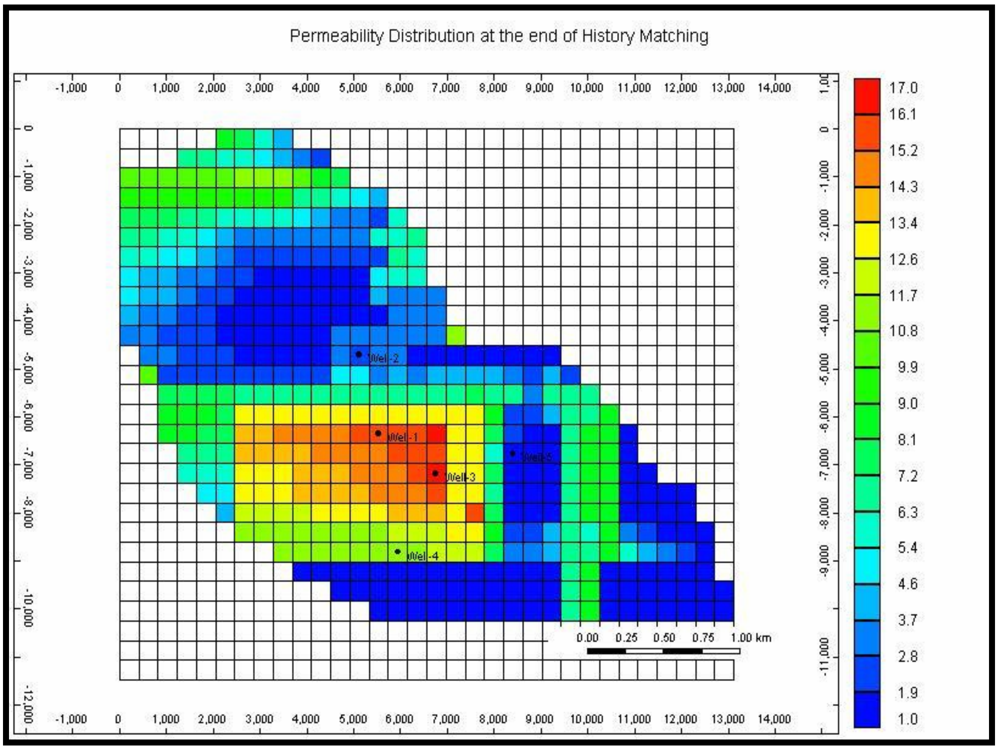

Figure C.4 Permeability Distribution of the Field (Simulator)

C3: Grid Top Map of the Field

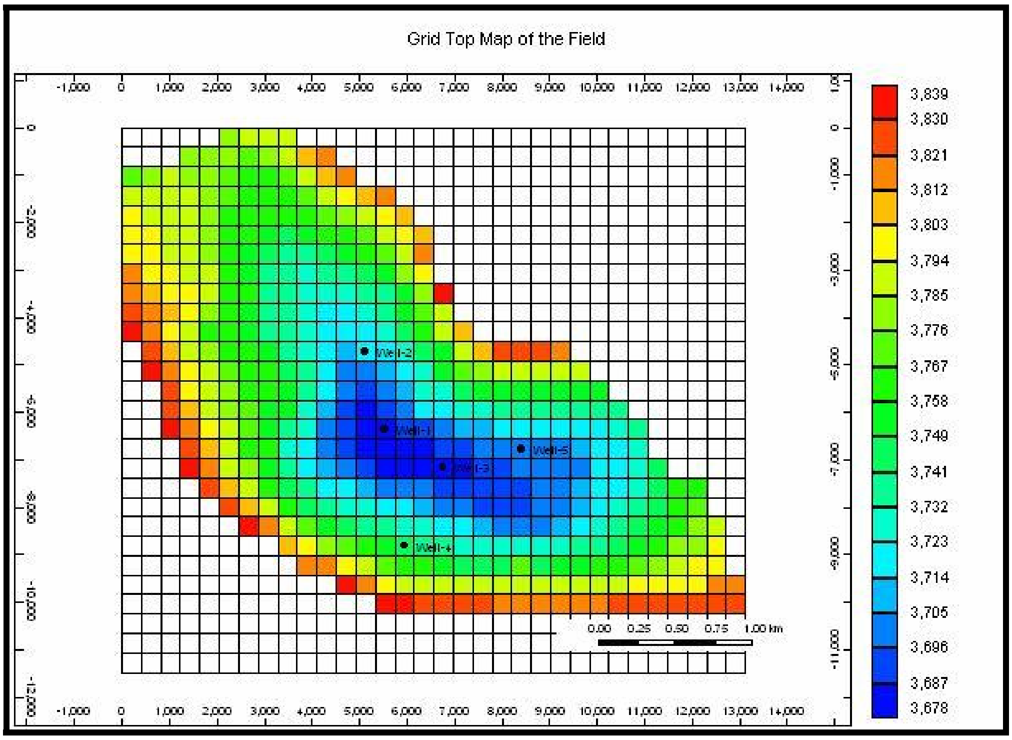

Figure C. 5. Grid Top Map of the Field (Areal)

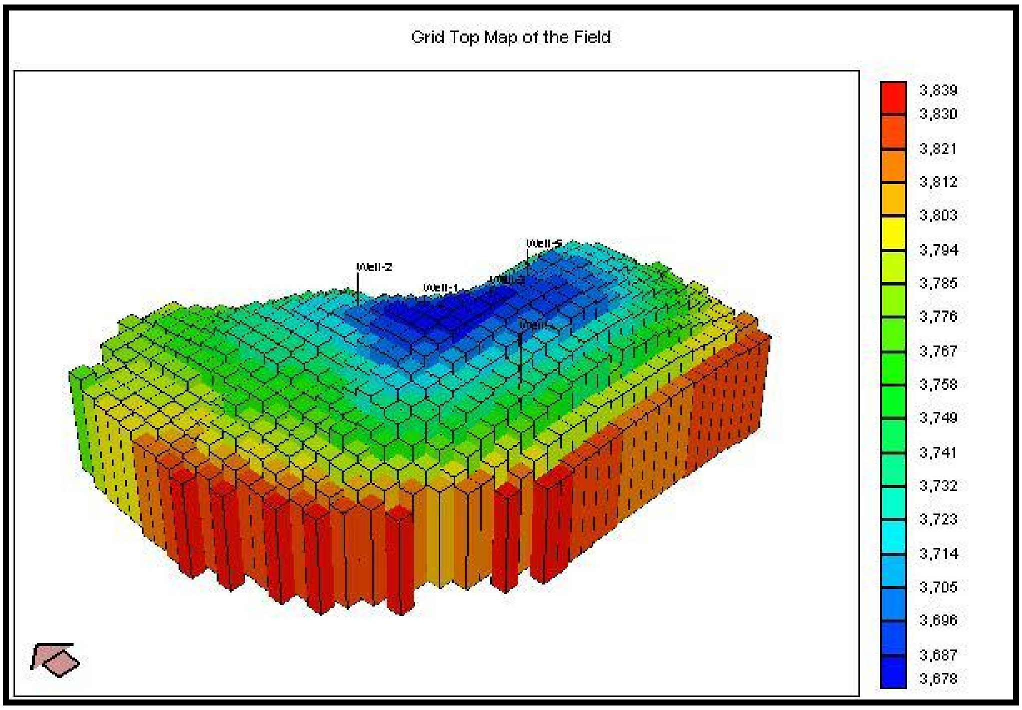

Figure C.6 Grid Top Map of the Field (3-D)

C4: PVT Table Calculations Empirical Formulas

Solution Gas/Oil Ratio (24)

$$Rs = Yg * \left(\frac{Pb}{18} * \frac{10^{0.0125*°API}}{10^{0.00091*T(°F)}} \right)^{1.2048}$$

Formation Volume Factor (24)

$$Bo = 0.972 * 0.000147 * F^{1.175}$$

$$F = Rs * \left(\frac{Yg}{Yo} \right)^{0.5} + 1.25 * T$$

Where

Yg : Specific Gravity Gas

Yo : Specific Gravity Oil

T : Bottom-Hole Temperature, °F

Pb : Bubble-Point Pressure, psi

Viscosity values of crude oils and crude oils containing dissolved natural gas are required in various petroleum engineering calculations. In evaluation of fluid flow in a reservoir, the viscosity of the liquid is required at various values of reservoir values of reservoir pressure and at reservoir temperature. This information can be obtained from a standard laboratory PVT analysis that is run at reservoir temperature. The most common situation requiring viscosities at various pressures and temperatures occurs in the calculation of two phases, gas liquid flowing pressure traverses. Calculation of these traverses is required in tubing-string design, gas-lift design, and pipeline design. Calculation of these traverses involves dividing the flow string into a number length increments and calculating the pressure gradient at average conditions of pressure and temperature in the increment. Calculation of pressure gradients requires knowledge of oil viscosity (25)

$$\mu_{OD} = 10^{X} - 1$$

$$X = y * T^{-1.163}$$

$$Z = 3.0324 - 0.02023 * {}^{\circ}API$$

$$\mu_{O} = A * \mu_{OD}{}^{B}$$

$$A = 10.715 * (Rs + 100)^{-0.515}$$

$$B = 5.44 * (Rs + 150)^{-0.338}$$

μ_{OD} : Dead oil viscosity, cp

μ_{o} : Live oil viscosity,cp

R_{S} : Solution Gas/Oil Ratio , scf/STB

API : API Gravity of oil

T : Bottom-hole Temperature ºF

C5: Relative Permeability Calculations Empirical Formulas

Knopp developed below equations experimentally from Venezuelan core samples. Comparison of Knopp's correlation with experimental values is more promising when the geometric mean of the suite of k_{rg}/k_{ro} curves for a given reservoir or sample group is compared with the corresponding most probable curves for the correlation

$$krw = 1.5814 * \left(\frac{Sw - Swi}{1 - Swi}\right)^{2.9} - 0.58617 * \frac{Sw - Sorw}{1 - Swi - Sorw} * \left(Sw - Swi\right) -$$
$$1.2484 * \Phi * (1 - Swi) * (Sw - Swi)$$

For intermediately wet (26)

$$Krow = 0.76067 * \left[\frac{\left(\frac{So}{1 - Swi}\right) - Sor}{1 - Sorw}\right]^{1.8} * \left[\frac{So - Sorw}{1 - Swi - Sorw}\right]^{2.0} +$$
$$2.6318 * \Phi * (1 - Sorw) * (So - Sorw)$$

For any Wettability (26)

$$Krog = 0.98372 * \left(\frac{So}{1 - Swi}\right)^{4} * \left[\frac{So - Sorg}{1 - Swi - Sorg}\right]^{2}$$

For any Wettability (26)

$$krg = 1.1072 * \left(\frac{Sg - Sgc}{1 - Swi}\right)^{2} * krg(Sorg) + 2.7794 * \frac{Sorg * (Sg - Sgc)}{(1 - Swi)} * krg(Sorg)$$

For any Wettability (26)

Where:

krg	:	Gas relative permeability, oil and gas system fraction
Krg(Sorg)	:	Gas relative permeability at residual oil saturation, fraction
krow	:	Oil relative permeability, water and oil system fraction
krw	:	Water relative permeability, water and oil system, fraction
krog	:	Oil relative permeability, oil and gas system, fraction
Sg	:	Gas saturation, fraction
Sgc	:	Critical gas saturation, fraction
So	:	Oil saturation, fraction
Sorg	:	Residual oil saturation to gas, fraction
Sorw	:	Residual oil saturation to water, fraction
Sw	:	Water saturation, fraction
Swi	:	Irreducible water saturation, fraction
Φ	:	Porosity, fraction

C6: Dew Point Determination

The experimental determination of dewpoint pressure at reservoir temperature for gas condensate reservoir relatively timed consuming, expensive and sometimes subjected to many errors. Thus, there is need for simple accurate method of predicting dewpoint pressure for gas condensate reservoirs. Gas condensate reservoirs have two dewpoint pressures. The lower dewpoint pressure is , usually below the reservoir abandonment pressure. Therefore it is much important to calculate the upper dewpoint pressure, which can be calculated with equation of state or correlations. Even though all the detailed information required for the equation of state is entered, there is no guarantee that the predicted dewpoint is accurate. Correlation methods rely on calculation of K-values which is performed by trial and error method.(27)

Vleflash Software is used to figure out dew point determination (28)

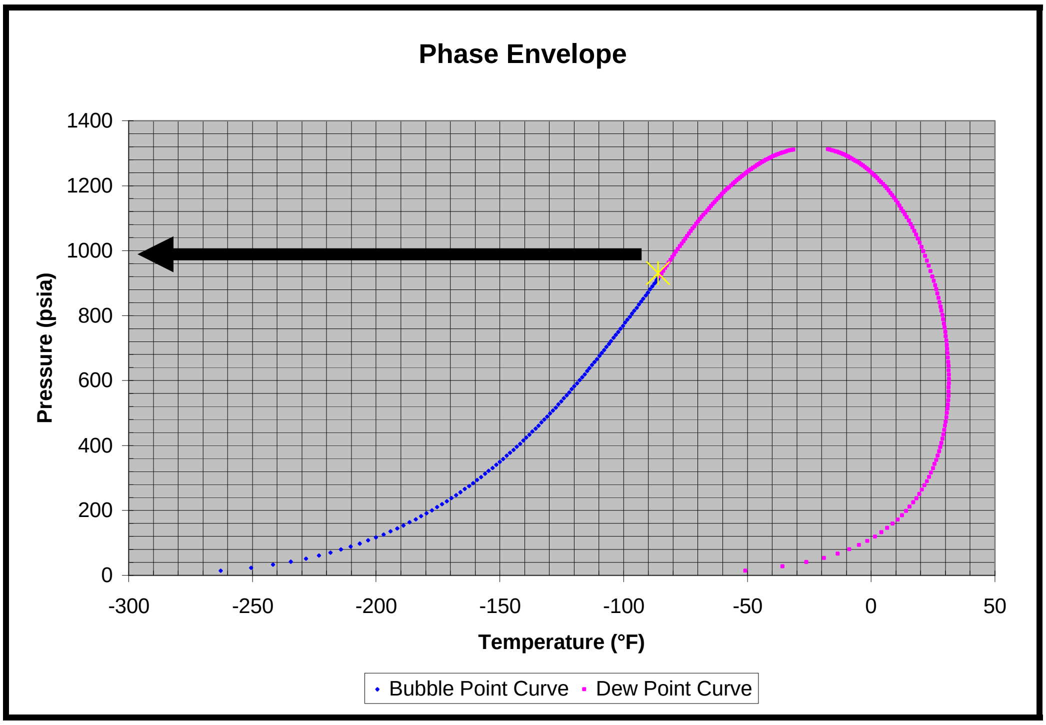

Figure C.4 Phase Envelope Diagram

C7: Calculations for Preparing IPR Curves

Jones, Blount and Glaze prepared form of Darcy's Law is used for the calculations.

$$P_r^{\,2} - P_{wf}^{\,2} = a*q^2 + b*q \quad (29)$$

Where

$$a = 1.424*10^{-6}*\beta*\gamma_g*Z*T/\left(h_p^{\,2}*r_w\right)$$
$$b = 1.424*10^{6}*\mu*Z*T*\left(\ln\left(r_e/r_w\right)-3/4+S\right)/\left(k*h\right)$$
$$\beta = \frac{2.33*10^{10}}{k^{1.201}}$$

q	=	Flow rate, MMscf
H	=	Thickness of zone , ft
h_p	=	Perforated interval, ft
r_w	=	Radius of wellbore, ft
r_e	=	Radius of drainage, ft
µ	=	Viscosity, cp
K	=	Permeability md
P_r	=	Initial Reservoir Pressure, psi
P_{wf}	=	Flowing Well Head Pressure,psi
D	=	Depth, ft
d_g	=	Density of gas
T	=	Reservoir temperature, °F
Tu , OD	=	Tubing Outside Diameter, in
Tu, ID	=	Tubing Inside Diameter, in

C8: Vertical Flowing Gas Gradients

The separator pressure of 1000 psi is used to find out the Vertical Gas Gradients (29)

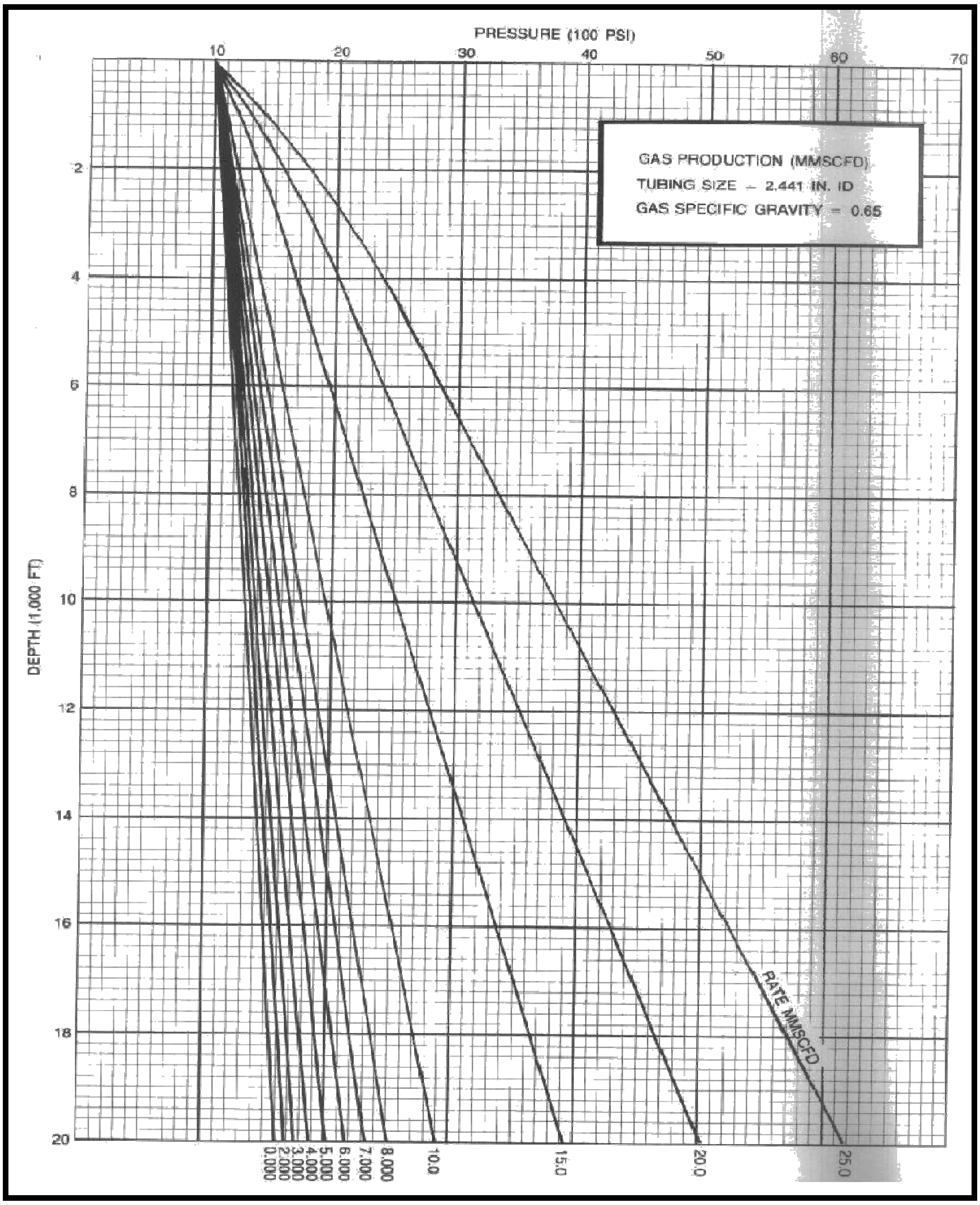

Figure C.5 Vertical Flowing Gas Gradients

C9: Peng Robinson Equation of State

$$P = \frac{R*T}{V_m - b} - \frac{a*\alpha}{V_m{}^2 + 2*b*V_m - b^2}$$

$$a = \frac{0.45724*R^2*T_c{}^2}{P_c}$$

$$b = \frac{0.07780*R*T_c}{P_c}$$

$$\alpha = (1 + (0.37464 + 1.54226*\omega - 0.26992*\omega^2)*(1 - T_r{}^{0.5}))^2$$

$$T_r = \frac{T}{T_c}$$

R = Ideal Gas constant (8.31451 J/mol·K)

P = Pressure

V_m = Molar volume, the volume of 1 mole of gas or liquid

T = Temperature (K)

Tc= Critical Temperature (K)

ω = acentric factor for the species.

The Peng-Robinson Equation (30) was developed in 1976 in order to satisfy the following goals:

- The parameters should be expressible in terms of the critical properties and the acentric factor.
- The model should provide reasonable accuracy near the critical point, particularly for calculations of the Compressibility factor and liquid density.

- The mixing rules should not employ more than a single binary interaction parameter, which should be independent of temperature pressure and composition.

- The equation should be applicable to all calculations of all fluid properties in natural gas processes.

C10: Water Content of Natural Gas

This figure was developed by Katz for the calculation of water content of natural gas (31)

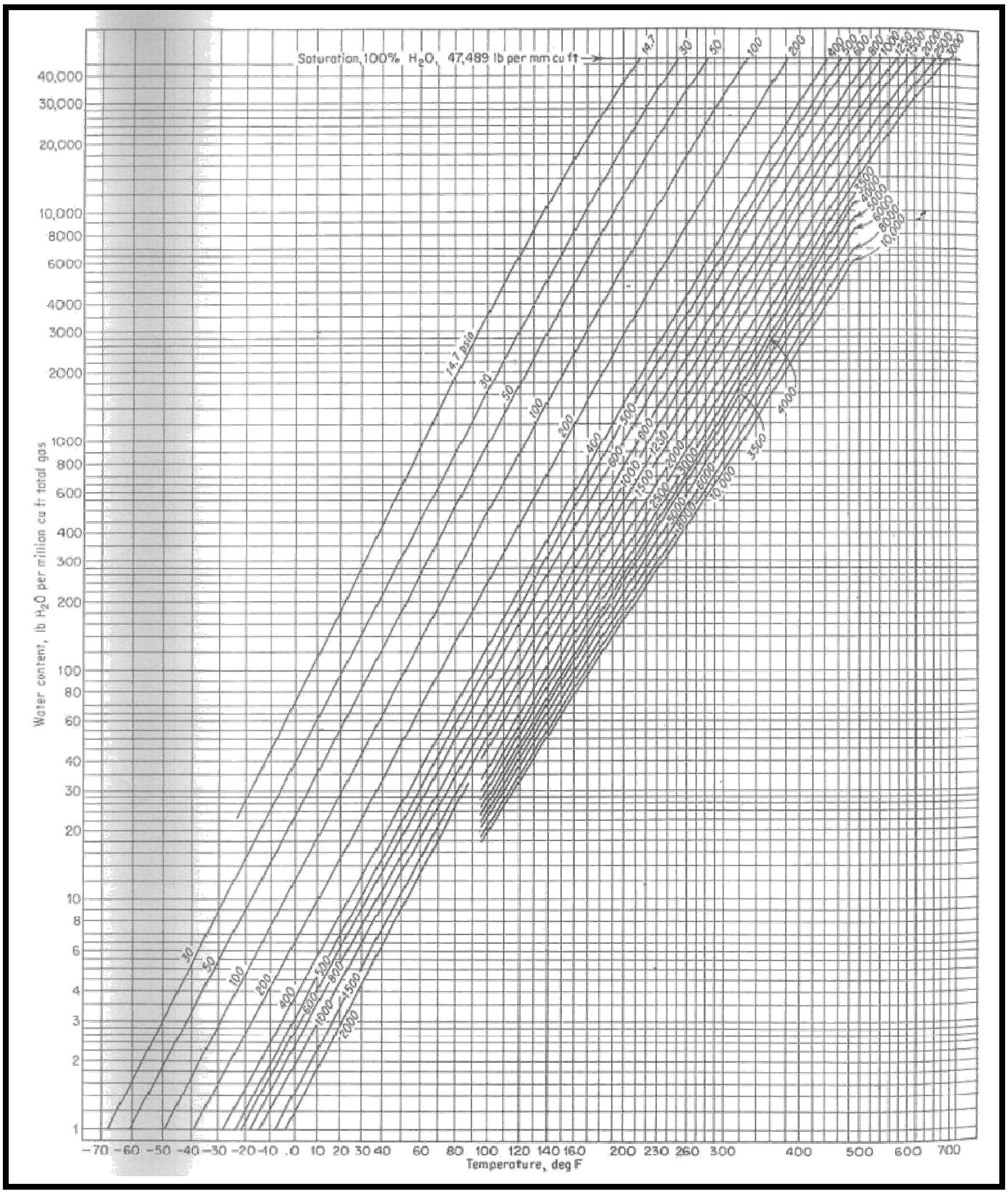

Figure C.6 Water Content of natural gas in equilibrium with water

Table C.3 Water Production Calculations

Date	Pave	A	B	GAS MMscf	WATER scf	Water Katz,bbl	Water Field,bbl
May-02	1600	156.90	2.51	0.0	0.0	0.0	0.0
Jun-02	1600	156.90	2.51	99.2	249.4	44.4	44.8
Jul-02	1591	157.20	2.52	195.2	491.8	87.6	79.8
Aug-02	1584	157.60	2.53	294.4	743.5	132.4	105.7
Sep-02	1578	157.70	2.53	539.3	1,362.9	242.7	163.1
Oct-02	1506	160.70	2.58	776.3	1,999.2	356.1	259.0
Nov-02	1431	164.70	2.64	1,021.2	2,695.4	480.0	346.5
Dec-02	1402	167.00	2.68	1,258.2	3,367.3	599.7	438.2
Jan-03	1376	169.60	2.72	1,518.6	4,127.5	735.1	517.3
Feb-03	1375	169.60	2.72	1,749.6	4,755.2	846.9	584.5
Mar-03	1366	170.40	2.73	2,017.0	5,507.8	980.9	683.9
Apr-03	1350	172.90	2.77	2,313.0	6,408.9	1,141.4	774.2
May-03	1350	172.90	2.77	2,598.0	7,198.6	1,282.0	872.2
Jun-03	1299	175.80	2.82	2,898.7	8,166.5	1,454.4	966.0
Jul-03	1273	177.90	2.85	3,179.2	9,064.0	1,614.2	1,045.1
Aug-03	1260	179.02	2.87	3,497.0	10,032.6	1,786.7	1,288.7
Sep-03	1244	180.36	2.89	3,799.2	10,981.4	1,955.7	1,575.0
Oct-03	1210	183.12	2.93	4,051.8	11,890.3	2,117.6	1,834.7
Nov-03	1173	186.26	2.98	4,312.8	12,873.3	2,292.7	2,090.9
Dec-03	1164	186.99	3.00	4,565.4	13,681.2	2,436.5	2,308.6
Jan-04	1156	187.64	3.01	4,826.4	14,513.0	2,584.7	2,550.1
Feb-04	1146	188.49	3.02	5,094.0	15,387.2	2,740.4	2,812.6
Mar-04	1128	189.93	3.04	5,344.2	16,266.4	2,896.9	3,040.8
Apr-04	1168	186.65	2.99	5,649.0	16,897.6	3,009.4	3,245.9
May-04	1207	183.41	2.94	5,943.9	17,471.0	3,111.5	3,453.1
Jun-04	1205	183.54	2.94	6,233.9	18,335.9	3,265.5	3,553.3
Jul-04	1203	183.73	2.94	6,511.5	19,172.6	3,414.5	3,605.3
Aug-04	1200	184.00	2.95	6,798.4	20,046.5	3,570.2	3,623.3
Sep-04	1176	185.99	2.98	7,107.0	21,183.2	3,772.6	3,636.3
Oct-04	1179	185.74	2.98	7,404.5	22,040.5	3,925.3	3,653.3
Nov-04	1173	186.21	2.98	7,711.9	23,013.0	4,098.5	3,724.3
Dec-04	1167	186.69	2.99	8,009.3	23,962.0	4,267.5	3,876.4
Jan-05	1161	185.10	2.97	8,316.7	24,670.1	4,393.6	4,001.6

C11 Root Mean Square Error (RMSE) Calculations

RMSE is defined as,

$$\mathrm{RMSE} = \frac{\sqrt{\sum \left(\mathrm{P_{simulator}} - \mathrm{P_{field}}\right)^2}}{\mathrm{N}}$$

Where;

N=Number of data

Table C.4 RMSE Calculation for W1

Date	WHP Simulator	WHP Field	RMSE
Jun-02	1161.56	1,590	-428
Jul-02	1152.65	1,595	-442
Aug-02	1145.56	1,595	-449
Sep-02	1139.31	1,595	-456
Oct-02	1118.7	1,519	-400
Nov-02	990.642	1,428	-437
Dec-02	962.6	1,390	-427
Jan-03	936.831	1,329	-392
Feb-03	912.504	1,312	-399
Mar-03	968.205	1278.0	-310
Apr-03	950.62	1228.0	-277
May-03	931.058	1193.0	-262
Jun-03	908.508	1160.0	-251
Jul-03	886.04	1120.0	-234
Aug-03	863.031	1100.0	-237
Sep-03	839.082	1070.0	-231
Oct-03	811.27	1050.0	-239
Nov-03	840.999	1030.0	-189
Dec-03	823.392	1010.0	-187
Jan-04	807.222	989.0	-182
Feb-04	791.124	977.0	-186
Mar-04	775.709	956.0	-180
Apr-04	765.176	940.0	-175
May-04	852.202	958.0	-106
Jun-04	851.091	973	-122
Jul-04	849.185	972	-123
Aug-04	846.494	971	-125
Sep-04	841.806	965	-123
Oct-04	837.84	945	-107
Nov-04	833.719	940	-106
Dec-04	829.382	943	-114

Average: 255

Table C.5 RMSE Calculation for W2

Date	WHP Simulator	WHP Field	RMSE
Aug-03	1054.92	1,030	25
Sep-03	621.401	818	-197
Oct-03	591.103	710	-119
Nov-03	695.247	753	-58
Dec-03	676.679	740	-63
Jan-04	658.423	725	-67
Feb-04	791.937	686	106
Mar-04	785.934	706	80
Apr-04	779.668	743	37
May-04	773.543	705	69
Jun-04	767.442	725	42
Jul-04	760.695	707	53
Aug-04	769.98	687	83
Sep-04	763.904	702	62
Oct-04	757.755	720	38
Nov-04	751.236	703	48
Dec-04	791.908	740	52
Jan-05	785.633	735	51

Average: 13

Table C.6 RMSE Calculation for W3

Date	WHP Simulator	WHP Field	RMSE
Oct-02	1002	1462	-460.231
Nov-02	966	1372	-406.354
Dec-02	938	1336	-398.097
Jan-03	911	1167	-256.429
Feb-03	885	1207	-321.292
Mar-03	868	1171	-303.425
Apr-03	845	1104	-258.737
May-03	820	1075	-254.581
Jun-03	794	1028	-233.868
Jul-03	769	938	-169.818
Aug-03	743	867	-123.677
Sep-03	714	842	-128.183
Oct-03	685	801	-115.913
Nov-03	730	805	-74.7457
Dec-03	713	748	-34.7586
Jan-04	695	774	-79.2566
Feb-04	677	710	-33.3273
Mar-04	660	704	-43.735
Apr-04	740	720	19.536
May-04	741	745	-4.004
Jun-04	741	750	-8.885
Jul-04	741	760	-19.072
Aug-04	739	756	-16.729
Sep-04	734	745	-11.499
Oct-04	765	720	45.136
Nov-04	762	740	22.092
Dec-04	758	740	18.202

Average: 129

Table C.7 RMSE Calculation for W4

Date	WHP Simulator	WHP Field	RMSE
Mar-03	1250	1315	-65.4643
Apr-03	1022	1242	-219.439
May-03	998	1137	-139.251
Jun-03	857	1075	-217.81
Jul-03	829	1028	-198.366
Aug-03	803	992	-188.477
Sep-03	822	933	-110.743
Oct-03	798	846	-47.7973
Nov-03	778	796	-18.6307
Dec-03	759	786	-27.4855
Jan-04	760	780	-20.333
Feb-04	742	797	-54.3634
Mar-04	726	738	-12.402
Apr-04	713	713	0.195571
May-04	900	704	196.3494
Jun-04	902	785	117.3887
Jul-04	902	765	137.1871
Aug-04	900	721	178.7692
Sep-04	829	723	106.0773
Oct-04	823	713	110.6348
Nov-04	819	703	116.0913
Dec-04	814	684	129.9416

Average: 10

Table C.8 RMSE Calculation for W5

Date	WHP Simulator	WHP Field	RMSE
Sep-03	1010.22	991.4603	18.76
Oct-03	919.0029	898.7929	20.21
Nov-03	841.9563	821.9563	20
Dec-03	771.1464	749.8464	21.3
Jan-04	809.3357	791.8357	17.5
Feb-04	797.4339	775.1339	22.3
Mar-04	723.4881	703.4881	20
Apr-04	671.257	693.75	-22.493
May-04	670.467	680.9643	-10.4973
Jun-04	666.493	695.5278	-29.0348
Jul-04	893.844	766	128.244
Aug-04	892.258	705	186.8709
Sep-04	609.674	715	-105.626

Average: 22

APPENDIX D: ECONOMICAL EVALUATION

D1: Economical Comparison of Scenario 1 and Scenario 4

Scenario ID	DE ($)	EFE ($)	EGSI ($)	Total ($)
Scenario 1	2,000,000	18,371		2,018,371
Scenario 4			4,133,693	4,133,693

DE: Drilling Expenditure ($). Hence this value has a negative effect on the scenario 4; it is shown as a positive effect on Scenario 1

EFE: Extra Production Facility Expenditure ($) Hence this value has an negative effect on scenario 4, it is shown as a positive effect on Scenario 1

EGSI: Extra Gas Sales Income ($) Scenario 4 has more gas sales than Scenario 1, so it is shown as positive value in Scenario 4

DE= 1,000,000 $ /well (assumed)

EFE = EGP*0.0008 (ref)

EGP = (Total Gas Produced in Scenario 4) – (Total Gas Produced in Scenario 1), MMscf

EGSI = EGP* 0.18

EGP =16,404 - 15,593= 811 MMscf

EGP (Extra Gas Produced) =22,964,962 scm

EGSI=22,964,962*0.18 =4,133,693 $

EFE=22,964,962*0.0008= 18,371$

D.2: Economical Comparison of Scenario 3 and Scenario 4

Scenario ID	DE ($)	EFE ($)	EGSI ($)	Total ($)
Scenario 3	1,000,000	8,427		1,008,427
Scenario 4			1,896,096	1,896,096

Where:

DE: Drilling Expenditure ($). Hence this value has a negative effect on the scenario 4; it is shown as a positive effect on Scenario 3

EFE: Extra Production Facility Expenditure ($) Hence this value has an negative effect on scenario 4, it is shown as a positive effect on Scenario 3

EGP: Extra Gas Produced (scm)

EGSI: Extra Gas Sales Income ($) Scenario 4 has more gas sales than Scenario 3, so it is shown as positive value in Scenario 4

DE= 1,000,000 $ /well (assumed)

EFE = EGP*0.0008 (ref)

EGP = (Total Gas Produced in Scenario 4) – (Total Gas Produced in Scenario 3), MMscf

EGSI = EGP* 0.18

EGP =16,404 - 16,032= 372 MMscf

EGP=10,533,866 scm

EGSI=10,533,866*0.18 =1,896,096 $

EFE=10,533,866*0.0008= 8,427$

APPENDIX E: WELL DIAGRAMS

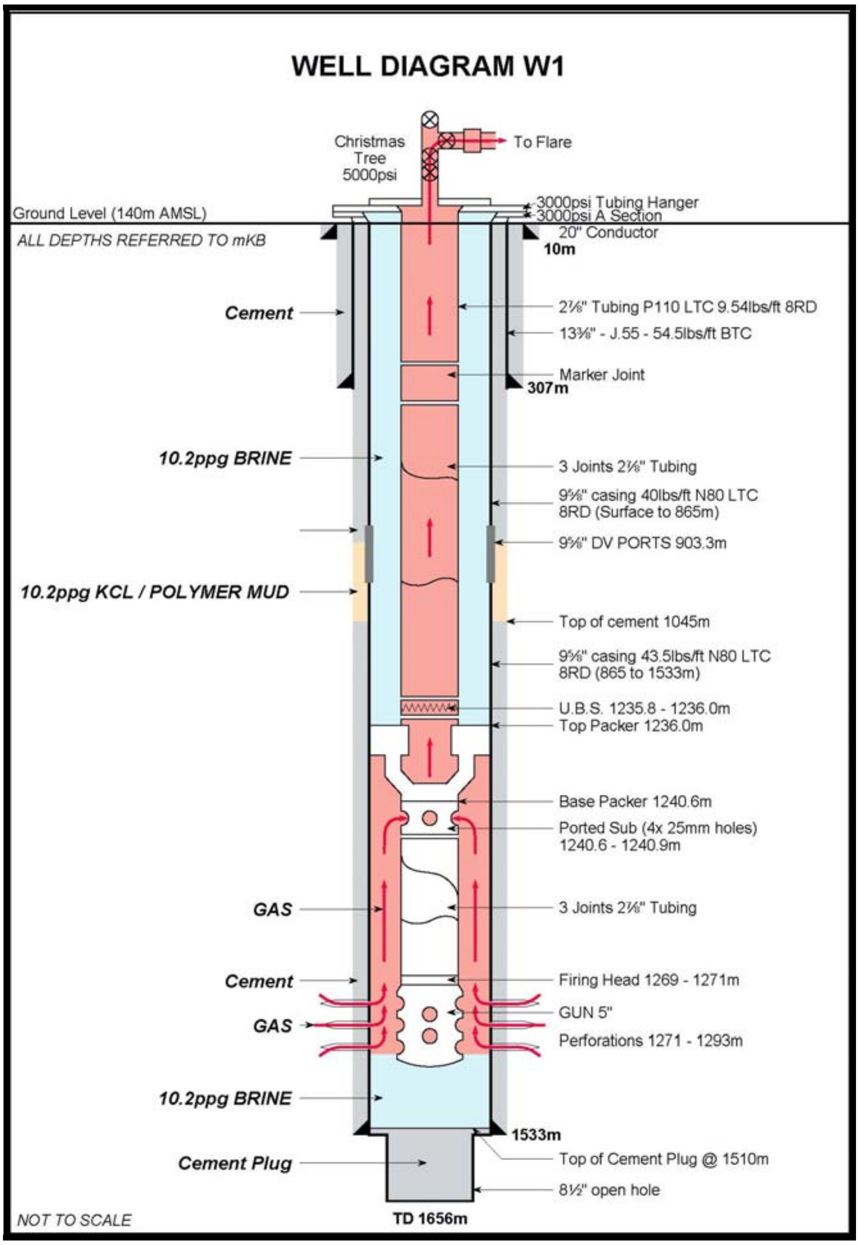

Figure E. 1. Well Diagram of W1

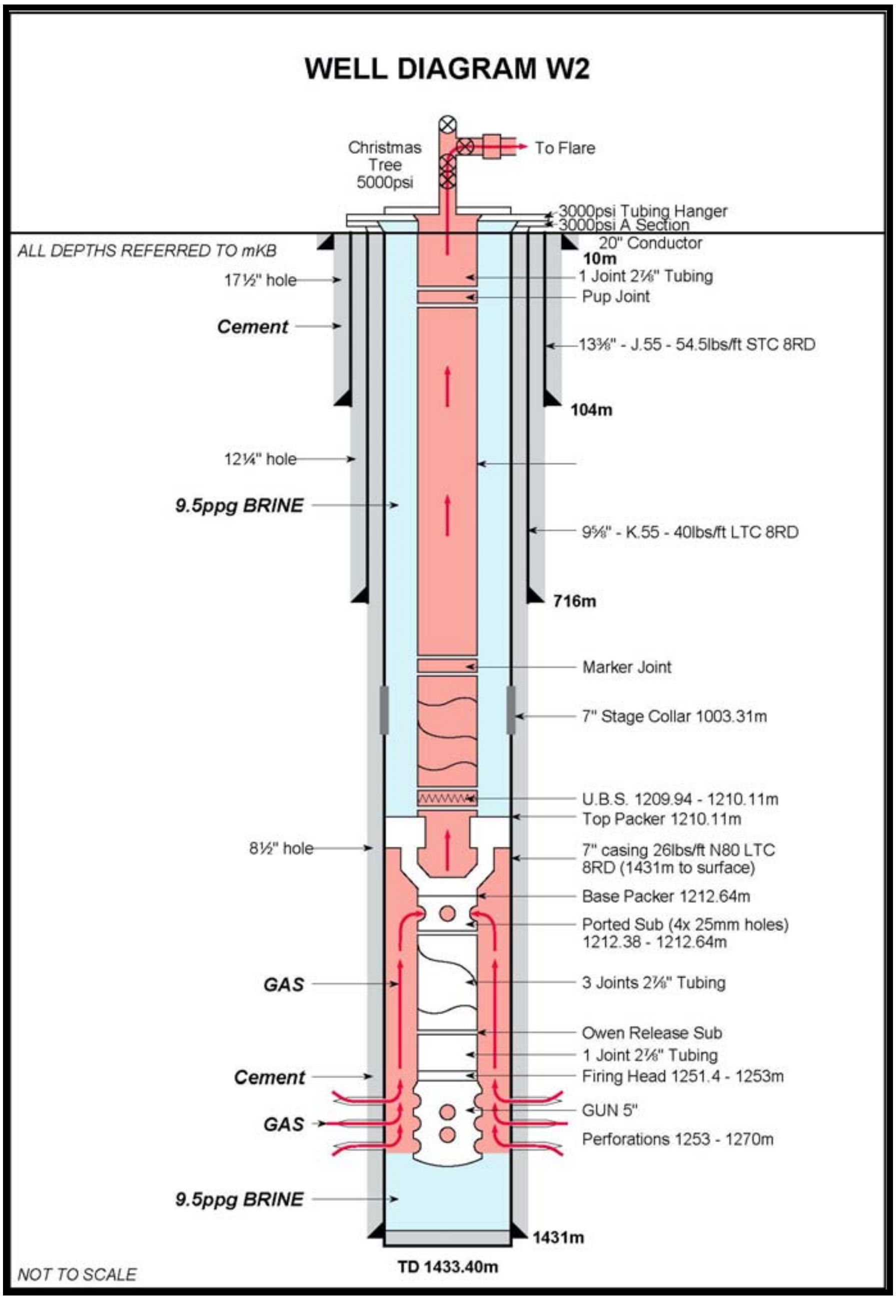

Figure E. 2. Well Diagram of W2

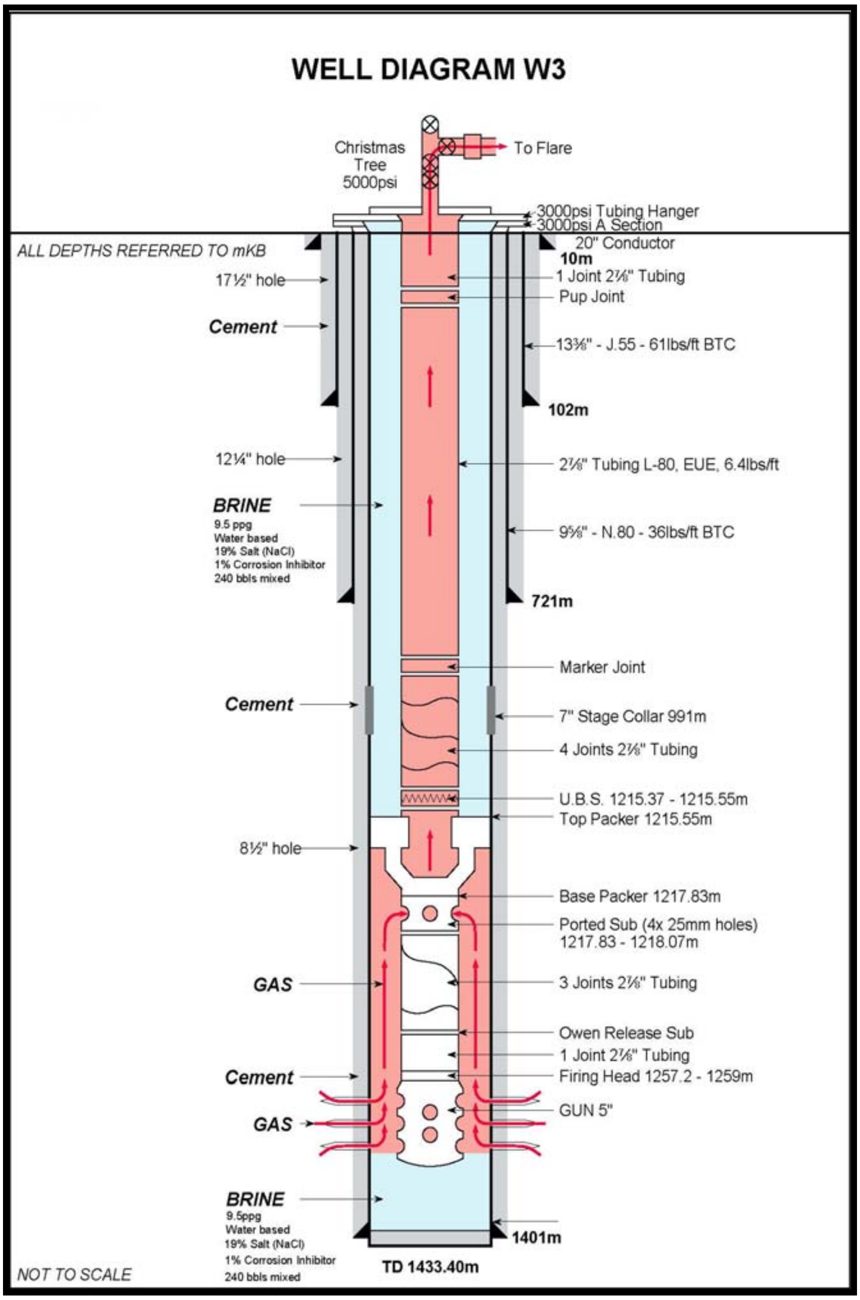

Figure E. 3. Well Diagram of W3

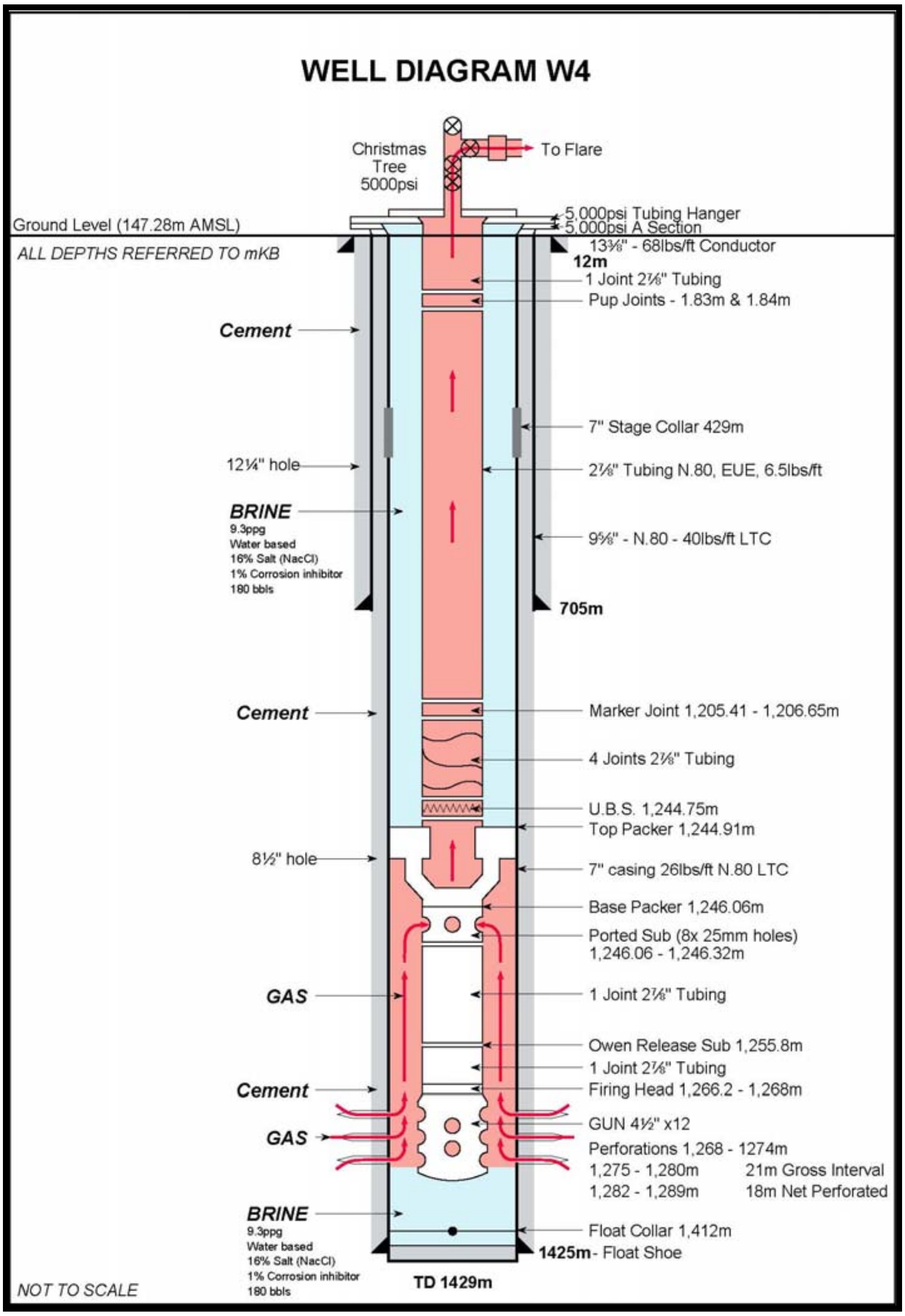

Figure E. 4. Well Diagram of W4

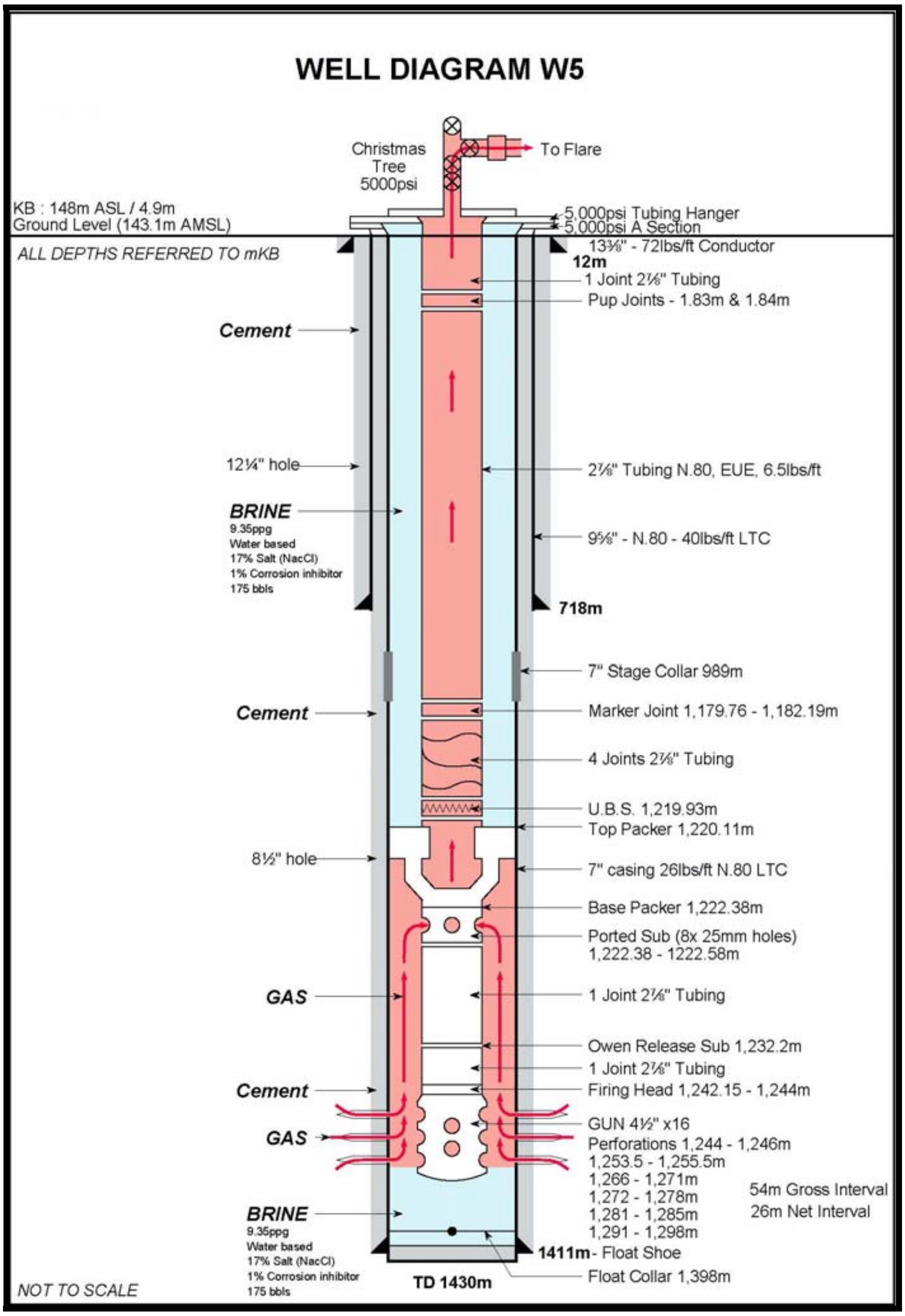

Figure E. 5. Well Diagram of W5