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Gas Production Forecasting for a Sudanese field

Case study Fulla North

تنبـــؤ إنتـــاج الـــغـــاز لحقـل ســـوداني
دراســـة حالـــة لحـقل فولــــة الشمالي

PREPARED BY:

- Ahmed Mohamed Ali Mohamed
- Awadallah Mohamed Awadallah
- Mohamed Ahmed Mohamed Omer
- Sofian Mohamed Ahmed Abdullah

SUPERVISOR:

Fatima Khalid

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Prepared by:

1. Awadalah Mohamed Awadalah

2. Mohamed Ahmed Mohamed Omer

3. Sofian Mohamed Ahmed

4. Ahmed Mohamed Ali

This project is approved by college of petroleum engineering and Technology department of petroleum engineering

Internal supervisor

T.Fatima khaled

Singnature :……

Head of petroleum engineering Department :-

Dr.Fatima Eltigani

Singnature:- ……

Dean of College :-

Dr.Tagwa Mousa

Signature:- ………………………………………………………………………………………….

- Date: / / 2106

بسم الله الرحمن الرحيم

(قَالُواْ سُبْحَانَكَ لاَ عِلْمَ لَنَا إِلاَّ مَا عَلَّمْتَنَا إِنَّكَ أَنتَ الْعَلِيمُ الْحَكِيمُ)

سورة البقرة(32)

DEDICATION

We would like you dedicate this research to our beloved families the ones who sheltered love and believe in us and always remain a constant source of inspiration.

Thanks for all things you have done for us.

Also we would like to dedicate this research to the souls of our teacher (Mohamed naeem) who left us to the neighbor o his god

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Thanks firstly and finally for (Allah) and thanks for greatest teacher of the human been our prophet Mohamed.

And we should like to express our deepest gratitude and appreciation to the petroleum engineering department of Sudan University of science and technology (SUST) for this opportunity to undertake this remarkable final year research project.

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التجريد

FN4 هو قطاع من حقل نفط FN هو السودان، الحقل يحتوي أساسا 3 طبقات رئيسية من النفط الخفيف, الثقيل والغاز في طبقة ابوجابرة .وتستخدم العديد من الطرق للتنبؤ الهيدروكربونية الأصلي (H.C) في المكان. تم استخدام مجموعة النمذجة الحاسوبيه (cmg) لإعداد نموذج والتمثيل الافضل من أجل تقديم أدائيه الخزانات كدالة في الزمن. من خلال استخدام مجموعة النمذجة الحاسوبيه الذي يمكننا من التنبؤ بالأداء المستقبلي للخزان كداله في الزمن.

توقع الأداء المستقبلي للخزان يكون في مراحلتين اثنين: الأولى هو التنبؤ بحجم الغاز في الخزان، والمرحلة الثانية من التنبؤ هو معدل الإنتاج السنوي. تم تصميم برنامج مجموعة النمذجة الحاسوبيه صمم لحساب المعاملات التي تشير إلى أداء الإنتاج في المستقبل المكمن. البرنامج هو سهل وسريع، ودقيق. الإخراج من البرنامج يتضمن الرسوم البيانية والجداول.

ABSTRACT

FN4 is a sector from FN oil field is Sudan, the field mainly contains 3 major layers with heavy oil light and gas in abujabra formation. Many methods are used for forecasting original hydrocarbon (H.C) in place. Computer Modeling Group (CMG) was used for the model preparation and optimization in order to provides performance of the reservoirs as a function of time. By CMG Program we enable to predict the future performance of reservoir as a function of time.

The future performance of reservoir is forecasted in the two stages: the first one is to predict volume of gas at reservoir, and the second stage of prediction is the annual production rate. CMG program is designed to calculate the parameters that indicate the reservoir future production performance. Our program is easy, fast, and accurate. The output from our program includes charts and tables

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Chapter one

1.0 Introduction

1.1 General introduction

Natural gas is one of the major global energy sources and its presence in earth is accounts by 42% of total global energy growing up from 19% in 1980, while the dependence on oil in global power generation dropped from 46% in 1980 to 37% in 2006 which means the global demand on the natural gas has more than doubled between 1980 and 2005.

Natural gas is one of the most important pillars of modern industry, whether the petrochemical industry or other substance. That's why it's an interest for all countries in the world to keep a diligent research and exploration to raise their reserves of them.

Natural gas is one of the most environmentally clean energy sources because it contains (after treatment) on a very small amounts of sulfur and free of aromatic substances and materials harmful to human health and the environment compared with oil or fuel, there is also another feature of natural gas on oil and coal is the lack of emission of carbon compounds to the high rate hydrogen in it. All these wonderful qualities of gas and features made powerful countries replace oil with gas in energy production.

Previously no particular report has been published about the deployment of the reservoirs in Sudan, but lately large reserves of natural gas have been discovered in Sudan in each of the Red sea coast , Sennar and South Kurdofan. Strategies and plans should be made for these large quantities of gas reservoirs to develop its production so the local population and the investors could get benefit from it.

In this project we offer a theoretical study and development to calculate the volume of gas found in a number of wells in the Abu Jabra field using the program CMG (computer modeling group). This idea can be generalized to all gas reservoirs in Sudan

1.2 Research Objectives

- Calculate original gas in place OGIP.
- To forecast gas production rate SC.
- Estimate years of production.
- To determine optimum bottomhole pressure BHP.

1.3 Problem statement

The acute shortage of natural gas is one of the more crises faced by the Sudanese economy, where the natural gas import is not in line with the population increase that caused the consumption of gas and reach its peak . As the shortage of gas caused the reduction of the level of Supply in the factories and the deficit in electrical energy in thermal power plants. All of that coincided with a lack of natural gas production in the country, the government and stop sign contracts for gas exploration and production.

1.4 About Area

1.4.1 Background

❖ **Lithological and Electrical Characters of Target Strata in Fula Oilfield**

The oil and gas target zones of Fula Oilfield include Lower Cretaceous Abu Gabra formation, Bentiu formation and Upper Cretaceous Aradeiba formation. Some wells also have revealed Abu Gabra 2 with thin oil/ gas reservoirs.

1. Abu Gabra 2 subdivision was mainly formed in the shallow lake facies sedimentary environment and is mainly composed of shaly sand interbedded with argillaceous siltstone. There are some thin siltstones and fine sandstones with better porosity and permeability and with limited lateral continuity. The sand body maybe the products of delta front's underwater distributary channels or mouth bars developed in argillaceous deposits of the shallow lake. According to the well data, there are 48 wells which have revealed the top of Abu Gabra 2 with different penetration

intervals. The shortest interval is 13 m (well FN-29) and the longest is 748 m (well Fula-5). Abu Gabra 2 has been divided into 10 sublayers by well correlation.

2. Abu Gabra1 subdivision is formed in a delta front subfacies sediment environment and is mainly composed of underwater distributary channel subfacies, underwater interdistributary bay microfacies and mouth bar microfacies. Its total thickness is about 600 m. The sedimentary characteristics are relatively stable in the work area. However, the palaeogeomorphology is raised with shorter sedimentary sections at Fula-4 and Fula-6. Abu Gabra 1 is divided into six layers and 42 sublayers for stratigraphical correlation. Multiple oil and gas reservoirs are found in Abu Gabra 1.

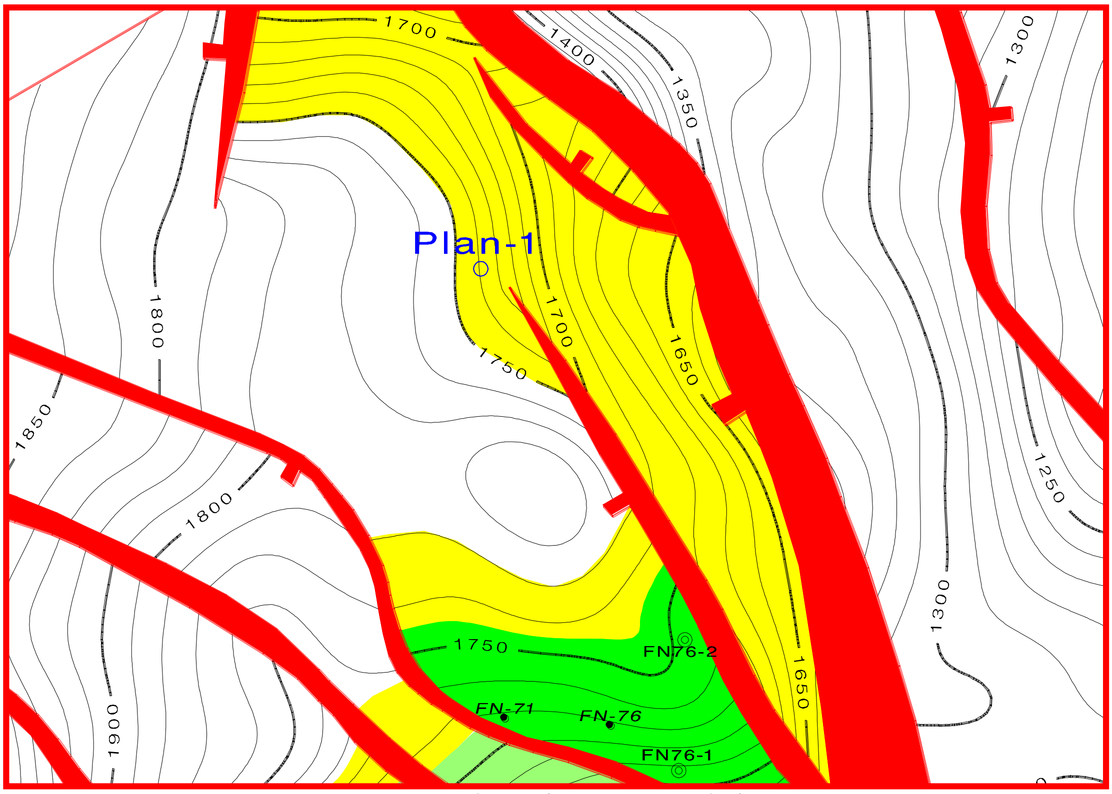


Fig.1.1 AG1d Depth Map around Plan

1.4.2 Reservoir Characteristics

❖ **Reservoir Characteristics of Abu Gabra Formation**

Petrophysical property of reservoir layer varies in a big extent, porosity from 12% to 32%, thickness from 1 to 18 meters, water layer resistivity from 7 to 12 ohmm, oil layer resistivity from 15 to 700 ohmm, oil layer water saturation from 15% to 60%. Water layer water saturation is more than 60%.

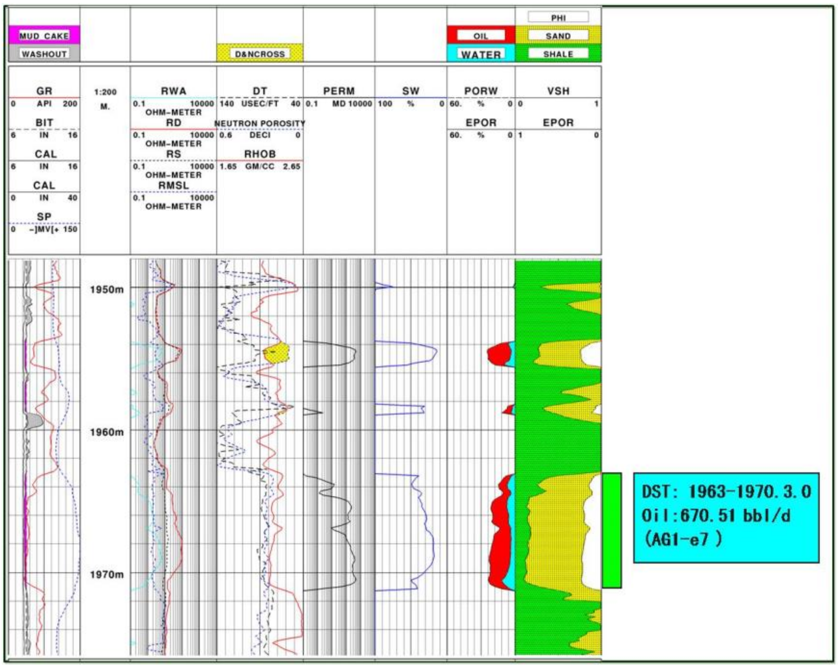


Fig.1.2 Composite log of FN-27 in AG

1.4.3 Fluid Contact Analysis

The following several methods are used to determine the oil -water contact:

(1) The tested oil-water zones or oil bearing water zones;

(2) Obvious oil-water contact from the logging data;

(3) The oil and water zone pressure data acquired from tests reflect oil-water contact;

(4) The oil-water contact inferred based on the oil bottom of the continuous sandstone development section and the adjacent water top depth in the well area;

(5) The four methods mentioned above are used to determine the oil-water contact based on the structural trap conditions.

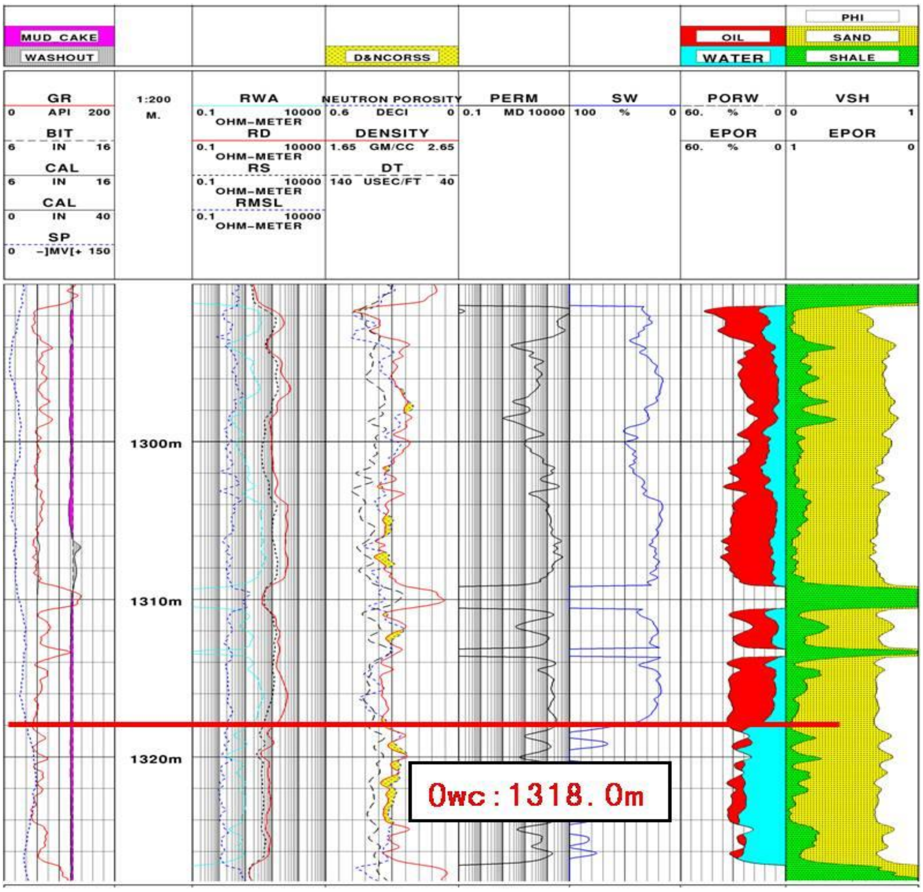


Fig. 1.3 OWC determined by logging curves, well FN-11

Formation	POR (%)	Vsh (%)	Sw (%)	PERM (mD)
Aradeiba	＞17	＜50	＜55	＞10
Bentiu	＞17	＜50	＜55	＞18
AG	＞12	＜50	＜60	＞5

- Apex's petrophysical re-interpretation results have been compared with Petro-Energy's previous results. Twenty seven new oil zones and four new gas zones were identified by the re-interpretation that would be potential layers for further tests.

1.4.4 Geological Study

- Abu Gabra formation

Abu Gabra formation contains oil reservoirs, gas reservoirs and oil-gas reservoirs. Sand zones in Abu Gabra are thin and interbedded with shale, and more faults are found in this formation, thus, oil-water system in Abu Gabra is very complicated, Most reservoirs in AG1 are stratified structural pools with edge water. Oil and gas bearing areas are constructed, based on the structural maps of pay zones, pinch out lines of sandbody and OWC/ODT level.

❖ **Geological Study Summary**

- FN-4 was chosen as typical well for full field stratigraphic division and correlation; There are six geological markers identified for correlation in Fula Oil field;
- 171 available wells were successfully correlated based on the depositional sequences; a total of 68 layers have been divided. The Abu Gabra 2 formation is divided into 10 layers Abu Gabra 1 formation is divided into 7 layers and 42 sublayers; Bentiu formation is divided into 3 layers and Bentiu 1 layer is divided into 5 sublayers further; Aradeiba formation is divided into 6 layers and Aradeiba-D layer is divided into 3 sublayers further;
- Abu Gabra 2 formation deposited in shallow lake environment with thick argillaceous shale and thin fine siltstone. Abu Gabra 1 formation deposited in delta front environment with varying thickness of alternating sand and shale. Bentiu formation deposited in braided river environment with massive sand, Aradeiba formation deposited in meandering river environment with mainly flood plain and point bar;
- In order to better understand the production behaviors of massive sands with bottom water, 28 interbed/barriers in 5 layers of the Bentiu1 layer in the Fula oilfield are identified. In general, the stability of thin barrier beds is poor and the distribution areas of the barriers are relatively small;
- Aradeiba D is stratified structural reservoir with limited edge water; Aradeiba C, E and F is lithological reservoir with sand lenses; Bentiu is massive reservoir with sizable bottom water; AG1a-1e is mainly stratified structural with edge water, and AG1f, AG2 are mainly lithological reservoir;
- The heavy oil reservoirs in Aradeiba and Bentiu have high porosity and permeability. The light oil reservoirs in Abu Gabra have medium to high porosity and permeability;
- 3 prospects were recommended based on the seismic interpretation and integrated study;

- 211 geological calculation units were identified for OOIP and OGIP estimation.

1.4.5 Basic Reservoir Engineering

Table 1.1 PVT Table of AG1a,1b Formation

WELLNAME: FN-4			SAMPLE No. 815908	
Pressure Psi	Rs Scf/STB	Bo	Mo cP	Density g/ml
5000	198.1	1.1493	6	0.819
4000	198.1	1.1541	5.5	0.8155
3000	198.1	1.1612	5	0.8106
2394	198.1	1.1658	4.8	0.8073
2000	198.1	1.1693	4.6	0.805
1680	198.1	1.1723	4.5	0.8029
1571	198.1	1.1735	4.4	0.8021
1000	130.9	1.1476	7	0.8125
500	70.5	1.1258	11.4	0.821
250	38.8	1.1077	16.4	0.8304
150	15.9	1.0825	20	0.8465
75	6.5	1.0649	24.4	0.859
0	0	1.0467	33.7	0.873

Table 1.2 PVT Table of AG1c,1d Formation

WELLNAME: FN-4			SAMPLE No. 815905	
Pressure Psi	Rs Scf/STB	Bo	Mo cP	Density g/ml
5000	324.4	1.1782	7.459	0.7828
4500	324.4	1.182	7.193	0.7803
4000	324.4	1.1872	6.927	0.7769
3500	324.4	1.1901	6.66	0.775
3000	324.4	1.1945	6.37	0.7721
2800	324.4	1.1965		0.7709
2690	324.4	1.1976	6.2	0.7702
2600	324.4	1.1981		0.7698
2500	324.4	1.1986	6.079	0.7695
2364	324.4	1.2001	5.982	0.7686
2000	273	1.182	6.66	0.7748
1500	207.8	1.1571	7.798	0.7849
1000	144.4	1.132	9.276	0.7946
500	80.5	1.1083	10.753	0.8043
200	38.7	1.089	11.673	0.8128
100	22.1	1.0792	12.182	0.8186
0	0	1.0361	13.95	0.8489

1.4.6 Natural Gas

Natural gas mainly existed in Abu Gabra reservoir of Fula North Block. The Methane content ranges from 78.63% to 95.3%, average is 89.76% in 24 gas samples analysis; the density ranges at 0.58 to 0.73 and average is 0.64 (Fig 1.4).

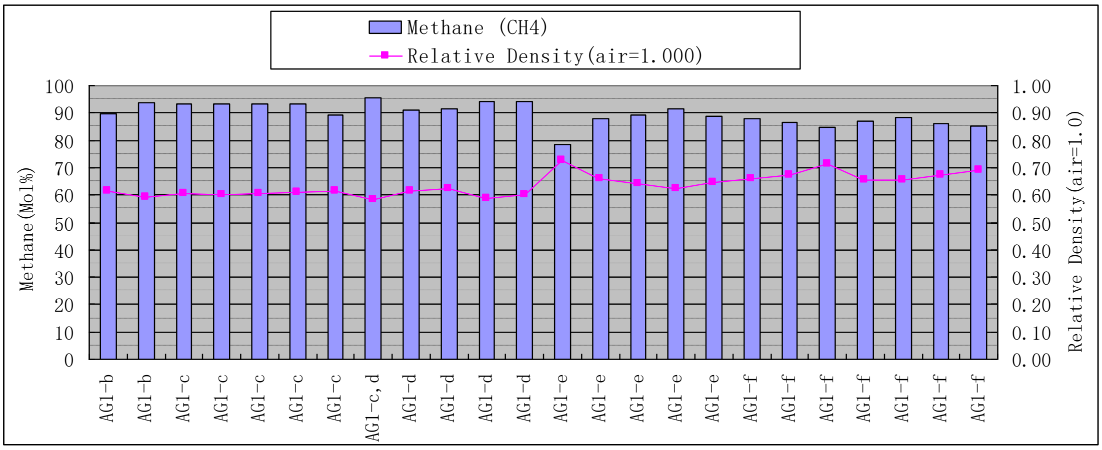


Fig. 1.4 FN Block Natural Gas Properties Analysis Result

1.4.7 Special Core Analysis

Special core analysis was conducted which included relative permeability, capillary pressure, wettability, and pore volume compressibility.

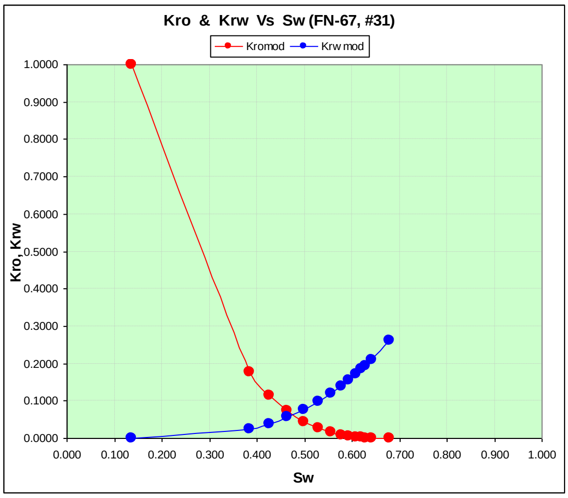


Fig. 1.5 Pseudo Relative Permeability Curves (Abu Gabra)

Table 1.3 SCAL Table for Dynamic Modelling (AG formation)

Sw	Kro	Krw	Pc(psi)
0.264	1.0000	0.0000	85.82
0.403	0.2941	0.0124	57.17
0.448	0.1812	0.0246	50.15
0.490	0.1090	0.0407	44.36
0.526	0.0667	0.0586	39.92
0.551	0.0456	0.0734	37.09
0.565	0.0368	0.0820	35.68
0.585	0.0259	0.0963	33.62
0.608	0.0167	0.1141	31.43
0.623	0.0123	0.1266	30.09
0.637	0.0090	0.1391	28.88
0.654	0.0060	0.1551	27.48
0.667	0.0042	0.1681	26.46
0.680	0.0029	0.1812	25.51
0.822	0.0000	0.3732	16.83

Chapter two

2.0 Literature review and theoretical background

2.0 Theoretical background

2.1 Natural Gas Description

A gas is defined as a homogeneous fluid of low viscosity and density that has no definite volume but expands to completely fill the vessel in which it is placed. Generally, the natural gas is a mixture of hydrocarbon and non-hydrocarbon gases. The hydrocarbon gases that are normally found in a natural gas are methanes, ethanes, propanes, butanes, pentanes, and small amounts of hexanes and heavier. The non-hydrocarbon gases (i.e., impurities) include carbon dioxide, hydrogen sulfide, and nitrogen.(Tareg Ahmed , 2001. "Reservoir Engineering", Hand book, Second edition.)

Researchers have published relevant information on natural gas properties that simplify and ensure safe operation during gas production. This chapter describes most of the important natural gas properties, also define the classification of natural gas and the forecasting gas volume in reservoirs.

2.2 Types of natural gas

The natural gas has categorization depends on the formation processes, conditions in which the gas is found and according to the composition of that particular gas. This can be explained as follows.

According to the natural formation processes of natural gas we have two main types of natural gas which are natural gas formed due to thermogenic processes at great depths and natural gas due to biogenic processes in shallow depth. The natural gas formed by thermogenic processes can also have one of the following natures explained below.

- The gas dissolved in crude oil usually produced from oil reservoirs.
- The gas produced from the top of the crude reservoir.
- The gas that has been produced from gas or condensate reservoirs also called non associated gas.

The conditions which can also classify the natural gas types include the reservoir conditions in which gas is found. In this case we have associated gas and non-associated gas. Non-associated gas is commonly a dry gas with a methane content 90% by volume. It is produced alone without a liquid phase.

Another condition is when gas has left the reservoir and it is in the production well, in a pipe or in processing equipment like a separator. In that case different forms of the gas are classified as:

a. Rich gas from production platform.

b. Dry gas without liquid fraction.

c. Condensate gas which is found between critical temperature and cricondentherm temperature.

2.3 Natural gas Properties

Knowledge of pressure-volume-temperature (PVT) relationships and other physical and chemical properties of gases is essential for solving problems in natural gas reservoir engineering. These properties include:

2.3.1 Gas deviation factor:

The equation of real gas has the following form:

$$PV = znRT \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (2\_1)$$

Where

p = absolute pressure, $psia$

V = volume, ft^3

T = absolute temperature, °R

n = number of moles of gas, lb-mole

R = the universal gas constant which, for the above units, has the value 10.730 psia ft^3/lb-mole °R

Where the gas compressibility factor z is a dimensionless quantity and is defined as the ratio of the actual volume of n-moles of gas at T and p to the ideal volume of the same number of moles at the same T and p:

$$z = \frac{V_{actual}}{V_{ideal}} = \frac{V}{(nRT)/P} \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (2\_2)$$

Studies of the gas compressibility factors for natural gases of various compositions have shown that compressibility factors can be generalized with sufficient accuracies for most engineering purposes when they are expressed in terms of the following two dimensionless properties:

• Pseudo-reduced pressure

• Pseudo-reduced temperature

These dimensionless terms are defined by the following expressions:

$$P_{Pr} = \frac{P}{P_{Pc}} \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (2\_3)$$

$$T_{Pr} = \frac{T}{T_{Pc}} \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (2\_4)$$

Where p = system pressure, Pisa

P_{Pr}= pseudo-reduced pressure, dimensionless

T = system temperature, °R

T_{Pr} = pseudo-reduced temperature, dimensionless

P_{Pc}, T_{Pc} = pseudo-critical pressure and temperature, respectively, and defined by the following relationships:

$$P_{Pc} = \sum_{i=1} y_i P_{ci} \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (2\_5)$$

$$T_{Pc} = \sum_{i=1} y_i T_{ci} \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (2\_6)$$

2.3.2 Apparent Molecular Weight

One of the main gas properties that is frequently of interest to engineers is the apparent molecular weight. If y_i represents the mole fraction of the ith component in a gas mixture, the apparent molecular weight is defined mathematically by the following equation:

$$M_A = \sum_{i=1} y_I M_I \dots\dots\dots\dots\dots\dots\dots\dots\dots (2\_7)$$

Where

Ma = apparent molecular weight of a gas mixture

Mi = molecular weight of the ith component in the mixture

yi = mole fraction of component i in the mixture

2.3.3 Density

The gas density is defined as mass (m) per unit volume (V). It can be calculated from the real gas law:

$$\rho_g = \frac{m}{v} = \frac{P\,M_a}{z\,RT} \dots\dots\dots\dots\dots\dots\dots\dots\dots (2\_8)$$

Where

ρg = density of the gas mixture, $\mathrm{lb/ft^3}$

Ma = apparent molecular weight

2.3.4 Specific Volume

The specific volume is defined as the volume occupied by a unit mass of the gas.

$$v = \frac{V}{m} = \frac{zRT}{PM_a} = \frac{1}{\rho_g} \dots\dots\dots\dots\dots\dots\dots\dots\dots (2\_9)$$

Where v $= \text{specific volume, ft}^3/\text{lb}$

ρ_g = gas density, lb/ft^3

2.3.5 Specific Gravity

The specific gravity is defined as the ratio of the gas density to that of the air. Both densities are measured or expressed at the same pressure and temperature. Commonly, the standard pressure P_{sc} and standard temperature T_{sc} are used in defining the gas specific gravity:

$$\gamma_g = \frac{\rho_g}{\rho_{air}} \dots \dots \dots \dots \dots \dots \dots \dots \dots (2\_10)$$

Assuming that the behavior of both the gas mixture and the air is described by the ideal gas equation, the specific gravity can then be expressed as:

$$\gamma_g = \frac{\frac{P_{sc}M_a}{RT_{sc}}}{\frac{P_{sc}M_{air}}{RT_{sc}}} \dots \dots \dots \dots \dots \dots \dots \dots \dots (2\_11)$$

Or

$$\gamma_g = \frac{M_a}{M_{air}} = \frac{M_a}{28.96} \dots \dots \dots \dots \dots \dots \dots \dots \dots (2\_12)$$

Where

γ_g = gas specific gravity

ρ_{air} = density of the air

M_{air}= apparent molecular weight of the air = 28.96

M_a = apparent molecular weight of the gas

P_{sc} = standard pressure, psia

T_{sc} = standard temperature, °R

2.3.6 Compressibility of natural gas

By definition, the isothermal gas compressibility is the change in volume per unit volume for a unit change in pressure or, in equation form:

$$c_g = -\frac{1}{V}\left(\frac{\partial V}{\partial P}\right)_T \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (2\_13)$$

Where c_g = isothermal gas compressibility , $1/\mathrm{Psi}$.

From the real gas equation-of-state:

$$V = \frac{nRTz}{P} \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (2\_14)$$

Differentiating the above equation with respect to pressure at constant temperature T gives:

$$\left(\frac{\partial V}{\partial P}\right)_T = nRT\left[\frac{1}{P}\left(\frac{\partial z}{\partial P}\right) - \frac{z}{P^2}\right] \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (2\_15)$$

$$c_g = \frac{1}{P} - \frac{1}{z}\left(\frac{\partial z}{\partial p}\right)_T \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (2\_16)$$

For an ideal gas, z = 1 and $\left(\frac{\partial z}{\partial p}\right)_T$ = 0, therefore

$$c_g = \frac{1}{P} \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (2\_17)$$

Equation (2-26) can be conveniently expressed in terms of the pseudo-reduced pressure and temperature by simply replacing p with $(P_{PC}P_{Pr})$, or:

$$c_g = \frac{1}{P_{Pr}P_{Pc}} - \frac{1}{z}\left[\frac{\partial z}{\partial (P_{Pr}P_{Pc})}\right]_{T_{Pr}} \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (2\_18)$$

$$c_g P_{Pc} = c_{Pr} = \frac{1}{P_{Pr}} - \frac{1}{z}\left[\frac{\partial z}{\partial P_{Pr}}\right]_{T_{Pr}} \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (2\_19)$$

The term c_{Pr} is called the isothermal pseudo-reduced compressibility and is defined by the relationship

$$c_{Pr} = c_g P_{Pc} \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (2\_20)$$

Where

c_{Pr} = isothermal pseudo-reduced compressibility

c_g= isothermal gas compressibility, Psi^{-1}

P_{Pc}= pseudo-reduced pressure, psi

Values of $(\partial z/\partial P_{Pr})_{T_{Pr}}$ can be calculated from the slope of theT_{Pr} isotherm on the Standing and Katz z-factor chart.

2.3.7 Gas formation volume factor

The gas formation volume factor is used to relate the volume of gas, as measured at reservoir conditions, to the volume of the gas as measured at standard conditions, i.e., 60°F and 14.7psia. This gas property is then defined as the actual volume occupied by a certain amount of gas at a specified pressure and temperature, divided by the volume occupied by the same amount of gas at standard conditions. In an equation form, the relationship is expressed as:

$$B_g = \frac{V_{P,T}}{V_{SC}} \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (2\_21)$$

Where

Bg = gas formation volume factor, ft^3/scf

Vp, T = volume of gas at pressure p and temperature, T, ft^3

Vsc = volume of gas at standard conditions, scf

Applying the real gas equation-of-state, i.e., Equation (2-1), and substituting for the volume V, gives:

$$B_g = \frac{\frac{znRT}{P}}{\frac{z_{sc}nRT_{SC}}{P_{SC}}} = \frac{P_{SC}}{T_{SC}}\frac{zT}{P} \dots\dots\dots\dots\dots\dots\dots\dots\dots (2\_22)$$

Where

z_{sc} = z_factor at standard conditions = 1.0

P_{SC}, T_{SC} = standard pressure and temperature

Assuming that the standard conditions are represented by P_{SC} =14.7 psia and T_{SC} = 520, the above expression can be reduced to the following relationship:

$$B_g = 0.02827\frac{zT}{P} \dots\dots\dots\dots\dots\dots\dots\dots\dots (2\_23)$$

Where

Bg = gas formation volume factor, ft^3/scf

z = gas compressibility factor

T = temperature, °R

In other field units, the gas formation volume factor can be expressed in bbl/scf, to give:

$$B_g = 0.005035\frac{zT}{P} \dots\dots\dots\dots\dots\dots\dots\dots\dots (2\_24)$$

The reciprocal of the gas formation volume factor is called the gas expansion factor and is designated by the symbol Eg, or:

$$E_g = 35.37\frac{P}{zT} \ , \frac{scf}{ft^3} \dots\dots\dots\dots\dots\dots\dots\dots\dots (2\_25)$$

In other units:

$$E_g = 198.6\frac{P}{zT} \ , \frac{scf}{bbl} \dots\dots\dots\dots\dots\dots\dots\dots\dots (2\_26)$$

2.3.8 Gas viscosity

The viscosity of a fluid is a measure of the internal fluid friction (resistance) to flow. If the friction between layers of the fluid is small, i.e., low viscosity, an applied shearing force will result in a large velocity gradient. As the viscosity increases, each fluid layer exerts a larger frictional drag on the adjacent layers and velocity gradient decreases.

The viscosity of a fluid is generally defined as the ratio of the shear force per unit area to the local velocity gradient. Viscosities are expressed in terms of poises, centipoise, or micropoises .One poise equals a viscosity of 1 dyne-sec/cm2 and can be converted to other field units by the following relationships:

1 poise = 100 centipoises

= $1 * 10^6$ micropoises

= $6.72 * 10^{-2}$ $\mathrm{lb.mass/ft\,.sec}$

= $2.09 * 10^{-3}$ $\mathrm{lb.sec/ft^2}$

Viscosity of a natural gas is completely described by the following function:

$$\mu_g = (P, T, y_i)$$

Where $\mu_g =$ the viscosity of the gas phase . The above relationship simply states that the viscosity is a function of pressure, temperature, and composition

2.4 Calculation of gas volume in reservoir

Reservoirs containing only free gas are termed gas reservoirs. Such a reservoir contains a mixture of hydrocarbons, which exists wholly in the gaseous state. The mixture may be a dry, wet, or condensate gas, depending on the composition of the gas, along with the pressure and temperature at which the accumulation exists.

Gas reservoirs may have water influx from a contiguous water-bearing portion of the formation or may be volumetric (i.e., have no water influx)

Most gas engineering calculations involve the use of gas formation volume factor B_g and gas expansion factor E_g.

This chapter presents two approaches for estimating initial gas in place G, gas reserves, and the gas recovery for volumetric and water-drive mechanisms:

• Volumetric method
• Material balance approach
(Tareg Ahmed , 2001. "Reservoir Engineering", Hand book, Second edition.)

2.4.1 Volumetric Methods:

i. Volumetric Dry-Gas Reservoir:

$$G = \frac{7{,}758 Ah\emptyset(1 - S_{wi})}{B_{gi}} \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (2\_27)$$

Where

G = gas in place, scf

A = area of reservoir, acres

h = average reservoir thickness, ft

ϕ = porosity

S_{wi} = water saturation, and

= gas formation volume factor, $ft^3/scf\, B_{gi}$

Where:

$$B_{gi} = \frac{1000 P_{sc} z_i T}{5.61 P_i z_{sc} T_{SC}} = \frac{5.02 z_i T}{P_i} \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (2\_28)$$

Gas produced = Initial gas – Remaining gas

$$G_p = G - G_a \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (2\_29)$$

$$G_P = \frac{7{,}758Ah\emptyset(1-S_{wi})}{B_{gi}} - \frac{7{,}758Ah\emptyset(1-S_{wi})}{B_{ga}} \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (2\_30)$$

Or:

$$G_P = \frac{7{,}758Ah\emptyset(1-S_{wi})}{B_{gi}}\left(1-\frac{B_{gi}}{B_{ga}}\right) \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (2\_31)$$

Where the gas recovery factor:

$$F = \left(1-\frac{B_{gi}}{B_{ga}}\right) \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (2\_32)$$

ii. Dry-Gas Reservoir with Water Influx:

Assuming volumetric sweep efficiency for gas is 100%,

$$G_P = \frac{7{,}758Ah\emptyset(1-S_{wi})}{B_{gi}} - \frac{7{,}758Ah\emptyset(1-S_{wa})}{B_{ga}} \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (2\_33)$$

In terms of residual gas saturation, $S_{gr}, at\ abandonment$

$$G_P = \frac{7{,}758Ah\emptyset(1-S_{wi})}{B_{gi}} - \frac{7{,}758Ah\emptyset S_{gr}}{B_{ga}} \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (2\_34)$$

Or:

$$G_P = \frac{7{,}758Ah\emptyset(1-S_{wi})}{B_{gi}}\left[1-\frac{B_{gi}S_{gr}}{B_{ga}(1-S_{wi})}\right] \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (2\_35)$$

Introducing a volumetric sweep efficiency,E_v into the volumetric equation

$$G_P = G - [E_v G_a + (1-E_v)G_t] \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (2\_36)$$

$$G_P = \frac{7{,}758Ah\emptyset(1-S_{wi})}{B_{gi}}\left[1-E_v\frac{B_{gi}}{B_{ga}}\left(\frac{S_{gr}}{S_{gi}}+\frac{1-E_v}{E_v}\right)\right] \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (2\_37)$$

Here

$$F = -\left[1 - E_v \frac{B_{gi}}{B_{ga}}\left(\frac{S_{gr}}{S_{gi}} + \frac{1-E_v}{E_v}\right)\right] \dots\dots\dots\dots\dots\dots\dots\dots\dots (2\_38)$$

Because gas often is bypassed and trapped by the encroaching water recovery factors for gas reservoirs with water drive can be significantly lower than for volumetric reservoirs produced by simple gas expansion in addition the presence of reservoir heterogeneities such as low-permeability stringers or layering may reduce gas recovery further .As noted previously ultimate recoveries of 80% to 90%are common in volumetric gas reservoirs while typical recovery factors in water drive gas reservoirs can range from 50% to 70%

iii. Volumetric wet-gas & gas-condensate reservoir:

For a wet-gas reservoir the total initial gas in place G_T which includes gas and the gaseous equivalent of produced liquid hydrocarbons is

$$G_T = \frac{7{,}758Ah\emptyset(1 - S_{wi})}{B_{gi}} \dots\dots\dots\dots\dots\dots\dots\dots\dots (2\_39)$$

Because of condensation some gas at reservoir condition is produced as liquid at the surface. The fraction of the total initial gas in place that will be produced in the gaseous face at the surface is

$$f_g = \frac{R_t}{R_t + \frac{132800\gamma_o}{M_o}} \dots\dots\dots\dots\dots\dots\dots\dots\dots (2\_40)$$

Where

$$M_o = \frac{5954}{\gamma_{API} - 8.811} \dots\dots\dots\dots\dots\dots\dots\dots\dots (2\_41)$$

$$M_0 = \frac{42.43\gamma_o}{1.008 - \gamma_o} \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (2\_42)$$

Where R_t includes gas and condensate production from all separators and stock tank. The fraction of the original total gas in place G_T That will be produced in the gaseous phase is

$$G = f_g G_T \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (2\_43)$$

And the original oil (condensate) in place N is

$$N = \frac{1000 f_g G_T}{R_t} \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (2\_44)$$

Note that this calculation procedure is applicable to gas-condensate reservoir only when the reservoir pressure is above the original dew-point pressure.(Herriot Watt University. "Reservoir Engineering", text book).

2.4.2 Material balance approach

The simplest material balance equation is that applied to gas reservoirs. The compressibility of gas is a very significant drive mechanism in gas reservoirs. Its compressibility compared to that of the reservoir pore volume is considerable. If there is no water drive and change in pore volume with pressure is negligible (which is the case for a gas reservoir), we can write an equation for the volume of gas in the reservoir which remains constant as a function of the reservoir pressure p, the volume of gas produced SCF, the original volume of gas, SCF, and the gas formation volume factor.

A representation of the equation for a gas drive reservoir with no water drive is given below.

i. For a dry gas reservoir - no water drive:

$$GB_{gi} = (G - G_P)B_g \dots \dots \dots \dots \dots \dots \dots \dots \dots (2\_45)$$

B_{gi} - based on z_i, P_i, T_i

B_g - based on z,P,T

ii. For a dry gas reservoir with water drive:

With water drive water will enter pore volume originally occupied by gas and some water may be produced. Figure 2-6

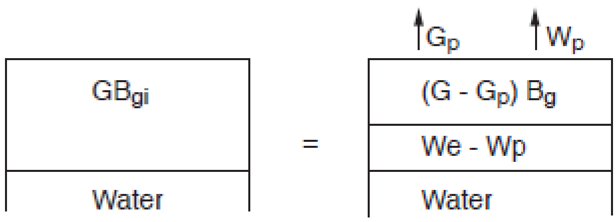


Figure 2-1 Material Balance for a Dry Gas With Water Drive

$$GB_{gi} = (G - G_P)B_g + W_e - W_P \dots \dots \dots \dots \dots \dots \dots \dots \dots (2\_46)$$

iii. Graphical Material Balance:

One can use a graphical form of the material balance equation to analyze a gas reservoir and predict its behavior especially if no water drive is present.

$$GB_{gi} = (G - G_P)B_g \dots \dots \dots \dots \dots \dots \dots \dots \dots (2\_47)$$

Where

$$B_g = \frac{0.00504 z_i T}{P} \dots \dots \dots \dots \dots \dots \dots \dots \dots (2\_48)$$

$$G\left(\frac{0.00504z_iT}{P_i}\right) = (G - G_P)\left(\frac{0.00504zT}{P}\right) \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (2\_49)$$

$$G\frac{z_i}{P_i} = (G - G_P)\frac{z}{P} \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (2\_50)$$

Hence plot of G_P vs. p/z should give a straight line

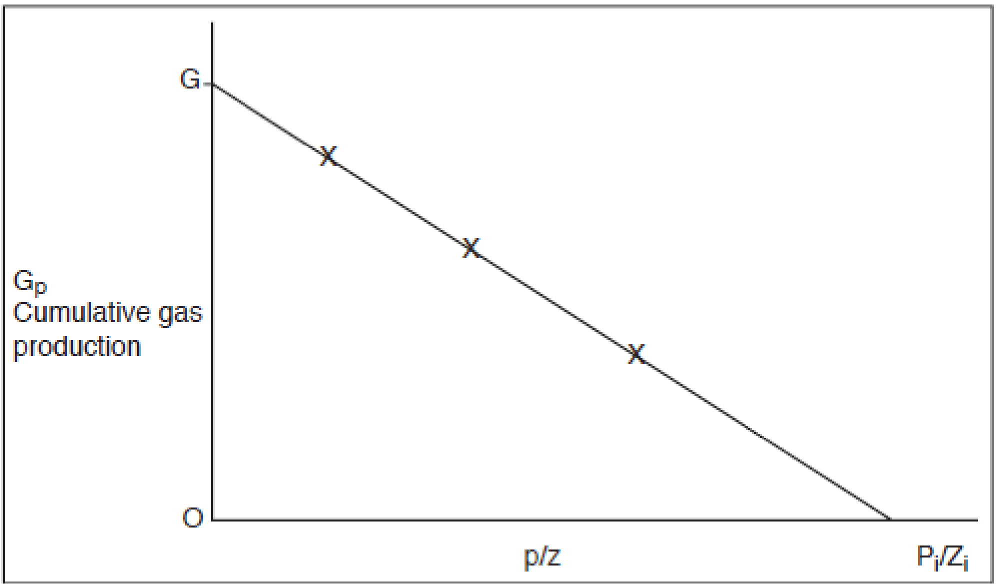


Figure 2-2 G_P vs. p/z

If gas was ideal a plot of G_P vs. p would be a straight line. It is often practice to do this and get a relatively straight line, but caution has to be taken, since deviation from a straight line could indicate additional energy support.

When $P/z = 0$ $G_P =$ G the original gas in place

When $G_P = 0$ $P/z = P_i/z_i$

This procedure is often used in predicting gas reserves. Often the influence of water drive is ignored resulting in a serious error in reserves.

This simple analysis method for gas reservoirs has gained wide acceptance in the industry as a history matching tool, to determine for example an estimate of initial gas reserves based on production data. This figure, (figure 2-2), can then be compared to estimates from exploration methods. It can also give indications of gas to be produced at abandonment pressures.

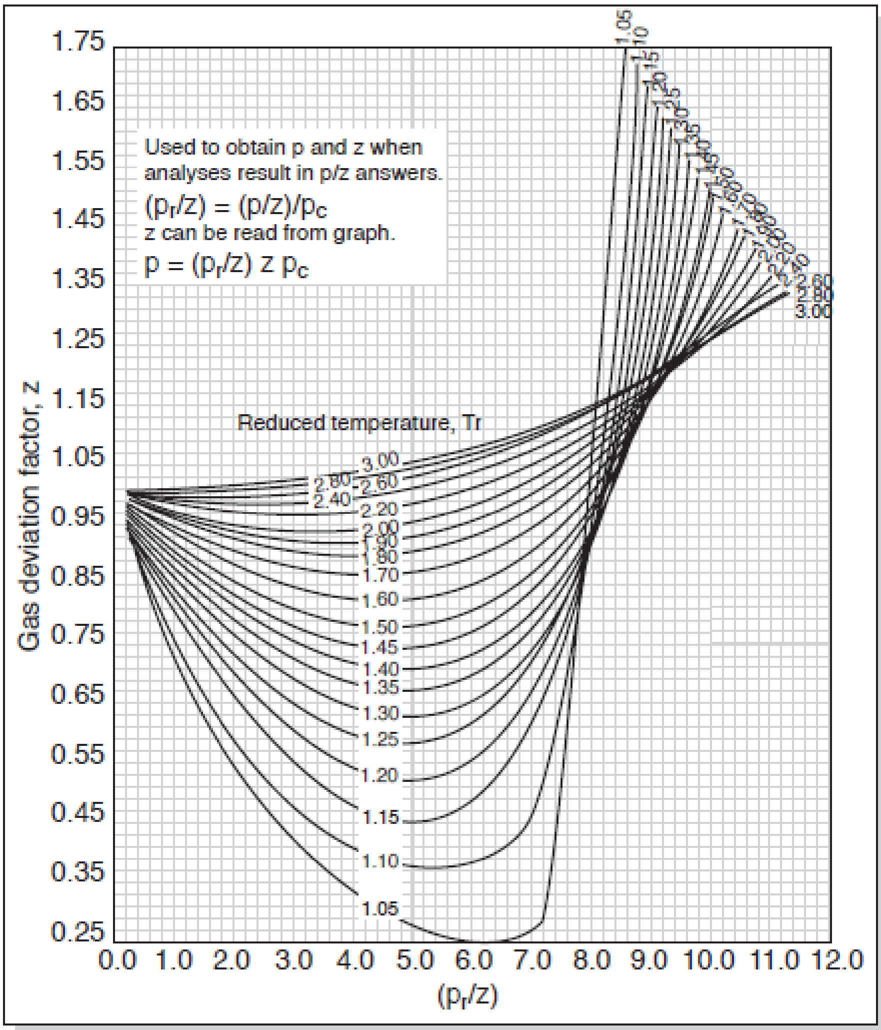


Figure 2-3 Gas Deviation Factor z vs. P_r/z (Slider2)

Great caution has to be taken when using this method. Water drive is considered to be zero, that is the gas is being solely produced as a result of gas compressibility .If water drive exists this will contribute to pressure support .If a plot of G_P vs. P/z deviates from linearity than that gives evidence of water drive support. Figure 2-4 from Dake illustrates this deviation. If a straight line is fitted to this data assuming no pressure support from water then gas reserves are enhanced, beyond what they are in actuality.

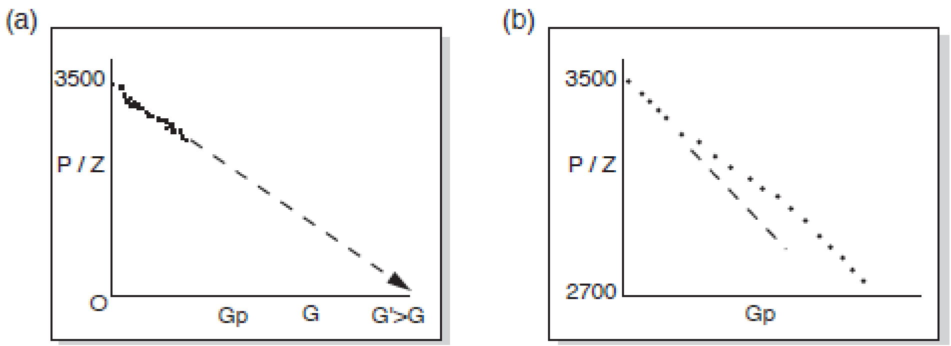


Figure 2-4 p/z Plots for a Water Drive Gas Reservoir

We will consider this topic later if there is water drive then the equation applies.

$$GB_{gi} = (G - G_P)B_g + W_e - W_w B_w \dots\dots\dots\dots\dots\dots\dots\dots\dots (2\_51)$$

iv. Wet Gas Reservoirs

Another aspect that needs to be considered with gas reservoirs is the treatment of wet gas reservoirs. In these reservoirs production also includes liquids as well as gas, although in the reservoir the liquids were in a gaseous state, figure 2-5. In the application of the material balance equation to these reservoirs it is important to convert oil production to gas equivalent figures to add to the gas production figures.

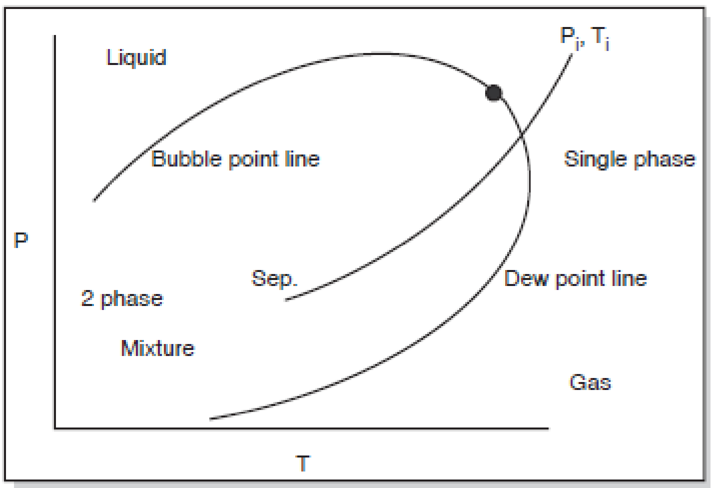


Figure 2-5 Phase Diagram for a Wet Gas System

The equation already produced assumed that the formation of liquid condensate causes insignificant error in the quality.

For condensate systems the G_P produced should include the produced condensate and the produced water (originally dissolved in gas).

The volume of 1 STB of condensate of molecular weight M_o and specific gravity γ_o follows from equation.

$$V = \frac{znRT}{P} \dots\dots\dots\dots\dots\dots\dots\dots\dots (2\_52)$$

Z=1at P=14.7psia and T=520 ˚R , $(\text{Density of water} = 62.4 \quad \text{Ib/ft}^3)$

$$V = 133{,}000 \frac{\gamma_o}{M_o} \frac{\text{ScF}}{\text{STB}} \dots\dots\dots\dots\dots\dots\dots\dots\dots (2\_53)$$

v. Gas Cap Expansion

If a gas reservoir is attached to an oil reservoir (figure 2-6), a similar equation to

(2_61):

$$GB_{gi} = (G - G_P)B_g$$

Can be written to describe the change in gas cap volume due to oil production and production of gas . In this case it is suggested that some gas has been produced from the gas cap G_{Pc} . (Herriot Watt University. "Reservoir Engineering ", text book).

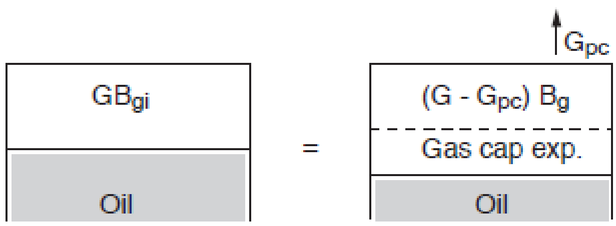


Figure 2-6 Gas Cap expansion

Change in gas cap volume is:

$$(G - G_P)B_g - GB_{gi}$$

2.5 Literature Review

K. Hahn et al (1983) describes a computer model for production forecasting of oil and gas. It was developed and used in selecting the ratio of gas to oil produced by each gas-oil separator (GOSP) in produced by each gas-oil separator (GOSP) in a series of oil fields in order to maximize/ minimize either the gas or the oil production. The model has succeeded in integrating physical constraints of surface facilities, reservoir restrictions, and scheduled equipment shutdowns. Linear Programming (LP) was used to determine optional production values. Forecasts can be obtained instantaneously, new managers are no longer entirely dependent on years of experience, and a 4% improvement in production can be expected.

S.Ameri et al discusses the development and application of three sets of production type curves for: (a) single-phase gas flow ;(b) two-phase flow of gas and water ;and (c) single-phase gas flow in horizontal wells. The influence of important factors such as the pressure dependency of gas properties ,non-Darcy flow, drainage area shape , horizontal well penetration and relative permeability have also been discussed. The type curves have been evaluated against both simulated and actual gas well production history data and found to be very reliable. The type curves can be utilized, through graphical history matching techniques, for predicting gas reservoir production performance under a variety of conditions and for evaluating the key reservoir parameters

A.Sadeghi Boogara presents the treatment of a modern method of production data analysis (single-phase flow) to analyze the production data of a gas condensate reservoir (two-phase flow). For this purpose, a single-phase production model is presented. Using a compositional reservoir simulator, long-term production data is generated over a wide range of gas condensate reservoir parameters. Next, a comparison is made between the simulator results (gas condensate) and the corresponding single-phase gas reservoir, using a modern production analysis method. The error for each case is analyzed, and a correlation for treatment of the single-phase analysis method is developed. Our results show that the methodology developed here can be successfully applied for analysis of the production data of a gas condensate reservoir

Result of the paper

1. Due to condensate dropout and the two-phase flow nature of gas condensate reservoirs, analysis of the production data of gas condensate reservoirs by available modern methods creates significant error (up to 50%) on estimation of the original gas-in-place.
2. Results indicate that CGR and critical oil saturation have further effects on the magnitude of the error. This error increases as the richness of the gas condensate reservoir increases.
3. Using correlations developed in this study, a reasonable reserve-estimate for a gas condensate reservoir can be obtained with the available single-phase technique.

Morteza Bagherpour1 et al evaluated several types of neural networks for forecasting of underground gas storage. The best fitness has been occurred with MLP (Multi Layer Perceptron) neural network. Also, by incorporating a time series analysis and embedding with the fitted neural network model, prediction has been appropriately performed. Statistical analysis and p-value approved our hypothesis indicating the model is well fitted. This approach would be significantly beneficial for forecasting of working gas in UGS. Further research can be made on applying simulation based optimization through neural network modeling to tune the network architecture. Additionally, economic evaluation of the developed scenarios can be further elaborated.

And the results show a 99 percent of accuracy which demonstrate superiority of the proposed approach over existing traditional models.

Chapter three

3.0 Methodology

3.1 Introduction

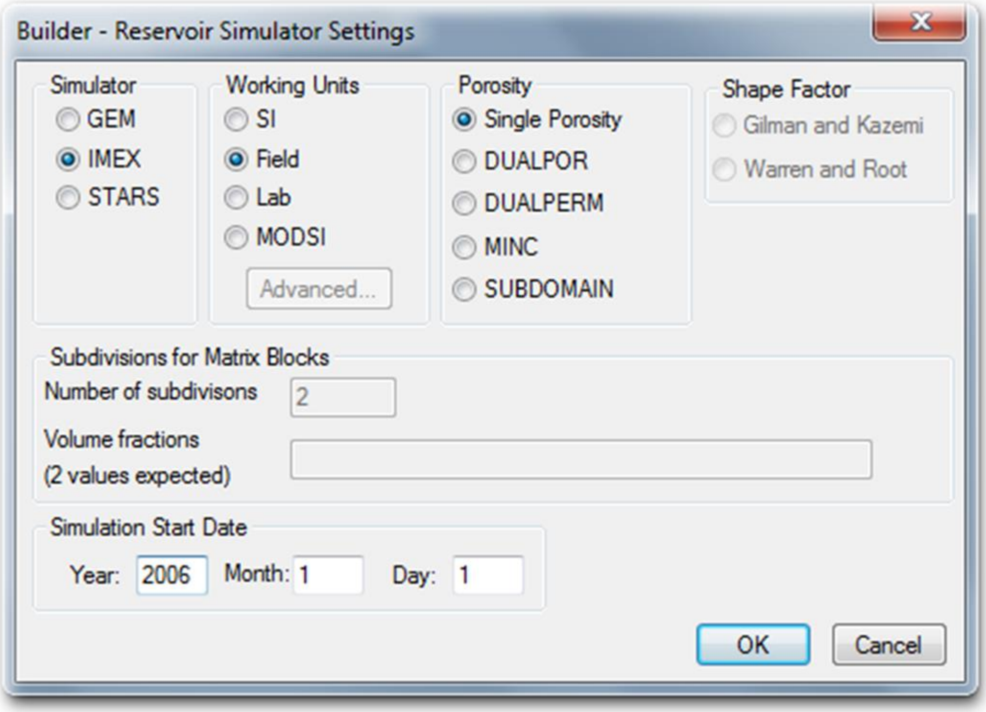
Simulation input files (datasets) for CMG simulators. All three CMG simulators – IMEX, GEM Builder is a Microsoft Windows based software tool that you can use to create and STARS – are supported by Builder. Builder covers all areas of data input, including creating and importing grids and grid properties, locating wells, importing well production data, importing or creating fluid models, rock-fluid properties, and initial conditions. Builder contains a number of tools for data manipulation, creating tables from correlations, and data checking. It allows you to visualize and check your data before running a simulation.

3.1.1 Starting Builder

Prior to starting Builder, you should set up a project directory within the CMG Technologies Launcher. If you need to convert any contour map or mesh map files, this should also be done prior to starting Builder.

To start Builder from CMG Technologies Launcher for a new case:

1. In the CMG Technologies Launcher, double-click the Builder icon. Builder starts then the **Reservoir Simulator Settings** dialog box is displayed.



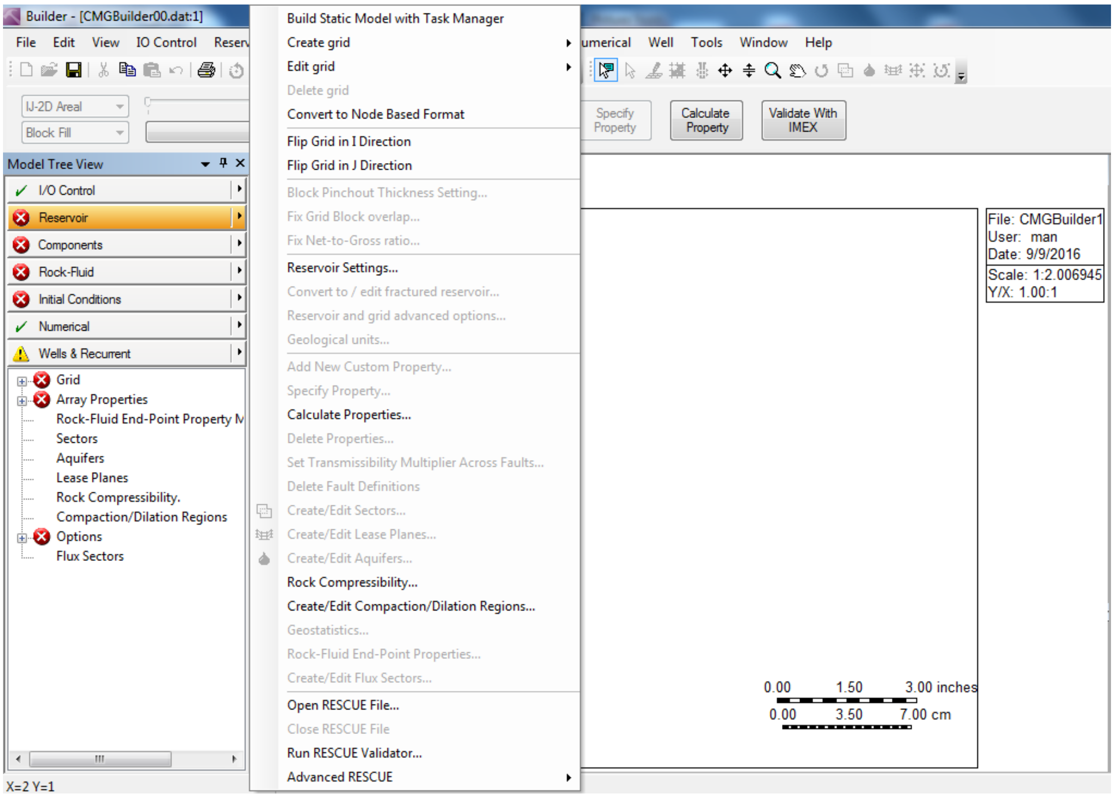
2. Under **Simulator**, select the simulator that you will be using
3. Under **Working Units**, select the unit system to use.
4. Under **Porosity**, select Single Porosity, or one of the dual porosity options. Some of the dual porosity options will enable input of **Shape Factor** or **Subdivisions for Matrix Blocks** input.
5. Enter the **Simulation Start Date**. This is usually the date of the start of production or injection in the earliest well.
6. Click **OK** to apply your settings.

3.2 Reservoir Description

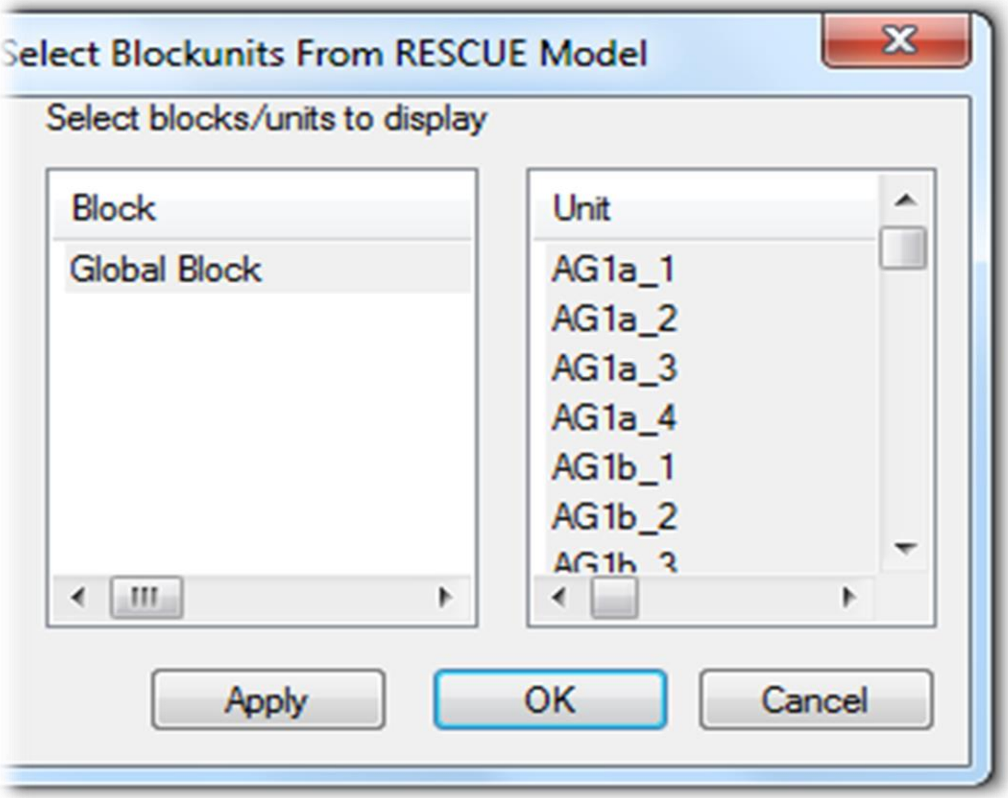
3.2.1Creating a Simulation Grid Using 3D Surfaces from RESCUE Model

To construct a simulation grid in volumes represented by RESCUE block units:

1. Start Builder for a new case as explained in **Starting Builder**.
2. Select **Open RESCUE File** from the **Reservoir** menu. Select and open the file from the **Open RESCUE File** dialog box.



3. The **Select Block Units from RESCUE Model** dialog box is displayed. Select the blocks and units you want to work with, and then click **OK**.
4. The **Grid creation options** dialog box is displayed. Make your selection and then click **OK** or click **Cancel** to select action later from menu.



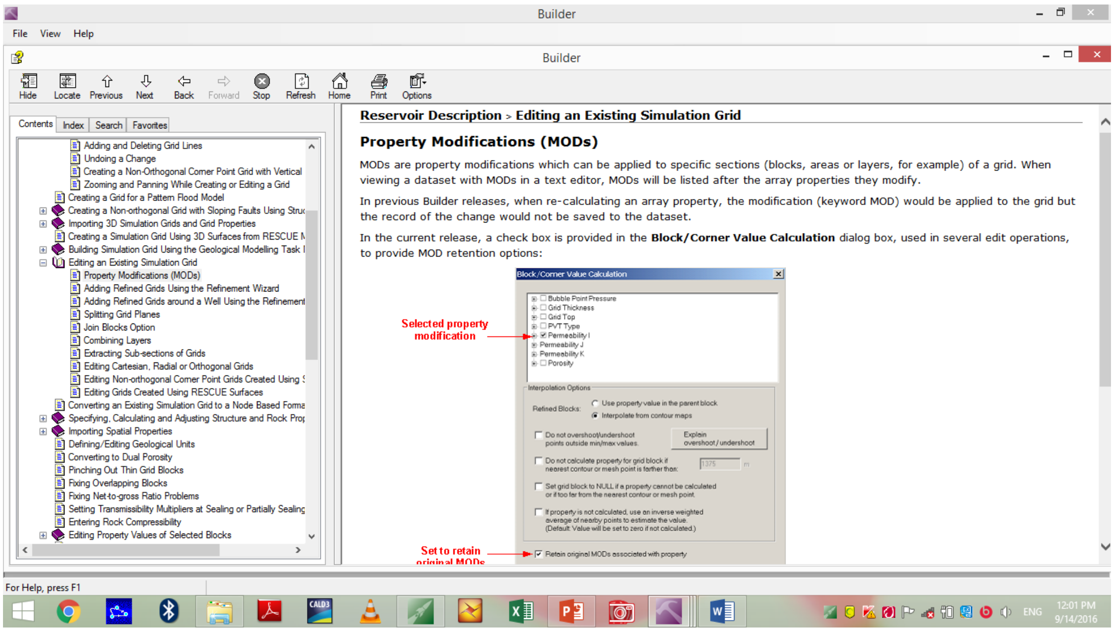
3.2.2 Editing an Existing Simulation Grid

Property Modifications (MODs

MODs are property modifications which can be applied to specific sections (blocks, areas or layers, for example) of a grid. When viewing a dataset with MODs in a text editor, MODs will be listed after the array properties they modify.

In previous Builder releases, when re-calculating an array property, the modification (keyword MOD) would be applied to the grid but the record of the change would not be saved to the dataset.

In the current release, a check box is provided in the **Block/Corner Value Calculation** dialog box, used in several edit operations, to provide MOD retention options.

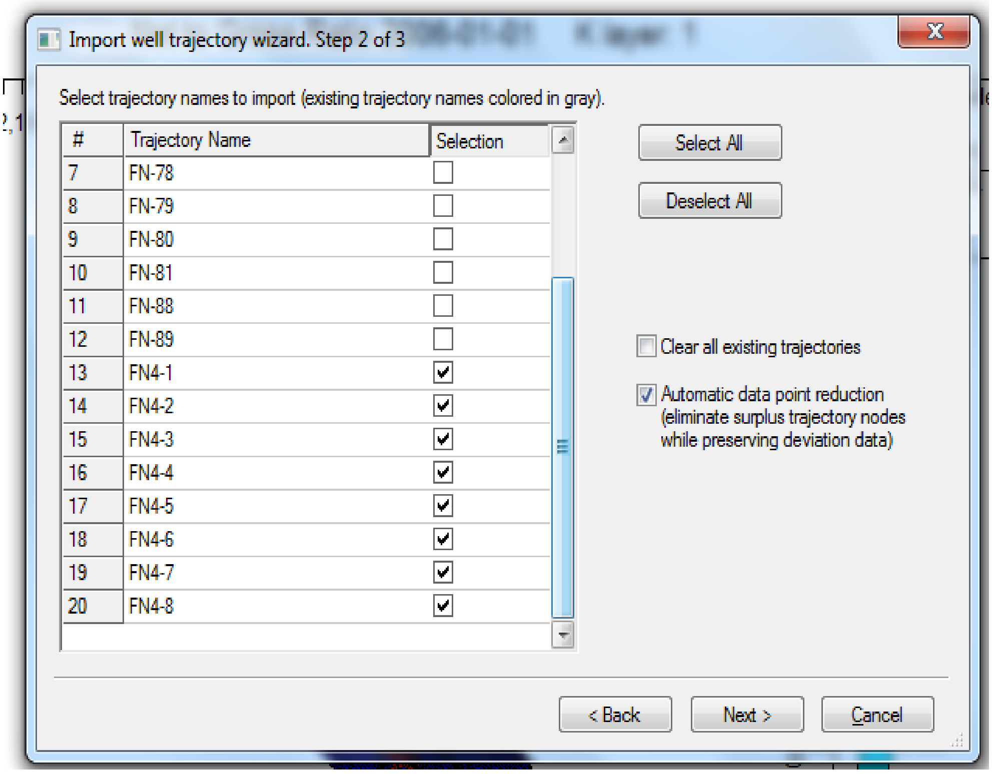


3.2.3 Adding Refined Grids around a Well Using the Refinement Wizard

Note: For information about the processing of property modifications.

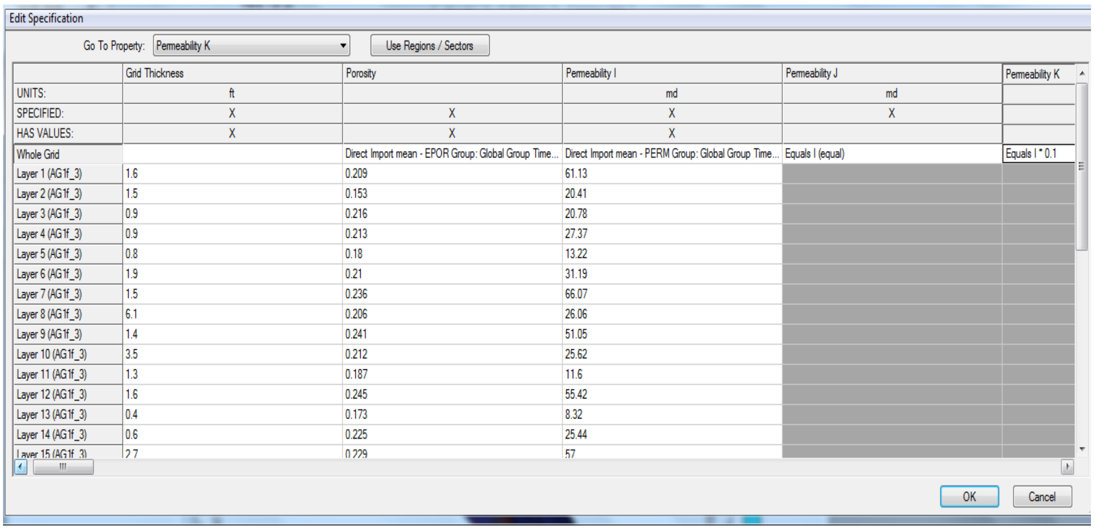
To add refined grids around a well:

1. You must be in **Edit Grid** mode to perform this operation. To enter **Edit Grid** mode, click the **Edit Grid** button on the modes toolbar, or right-click to pop up the context menu and click **Edit Grid**.
2. If you want to refine blocks around a well or several wells, you will be presented with a **Refinement 9 well from fn4 to fn4-8**



To specify a property calculation:

1. You must be in **Probe Mode** to perform this operation. To enter Probe Mode, select **Probe Mode** from the mode selection box, or right-click to display the context menu then click **Probe Mode**.
2. Select **Specify Property** from the **Reservoir** menu, or click the **Specify Property** button. The **General Property Specification** dialog box is displayed



Edit Specification

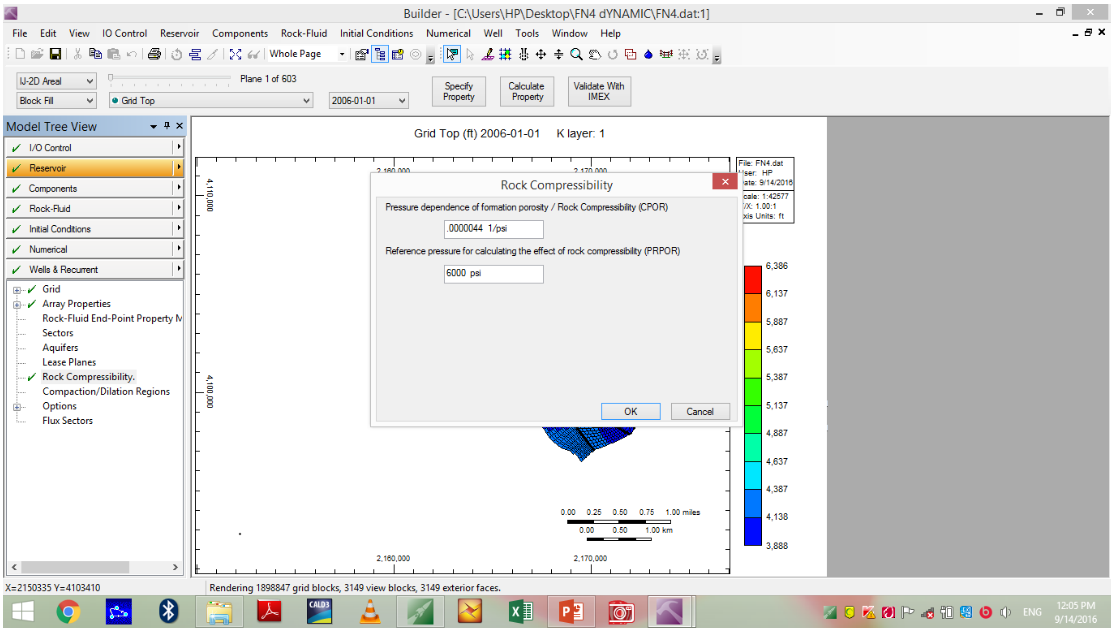
Go To Property: Permeability K | Use Regions / Sectors

	Grid Thickness	Porosity	Permeability I	Permeability J	Permeability K
UNITS:	ft		md	md	
SPECIFIED:	X	X	X	X	
HAS VALUES:	X	X	X		
Whole Grid		Direct Import mean - EPOR Group: Global Group Time...	Direct Import mean - PERM Group: Global Group Time...	Equals I (equal)	Equals I * 0.1
Layer 1 (AG1f_3)	1.6	0.209	61.13		
Layer 2 (AG1f_3)	1.5	0.153	20.41		
Layer 3 (AG1f_3)	0.9	0.216	20.78		
Layer 4 (AG1f_3)	0.9	0.213	27.37		
Layer 5 (AG1f_3)	0.8	0.18	13.22		
Layer 6 (AG1f_3)	1.9	0.21	31.19		
Layer 7 (AG1f_3)	1.5	0.236	66.07		
Layer 8 (AG1f_3)	6.1	0.206	26.06		
Layer 9 (AG1f_3)	1.4	0.241	51.05		
Layer 10 (AG1f_3)	3.5	0.212	25.62		
Layer 11 (AG1f_3)	1.3	0.187	11.6		
Layer 12 (AG1f_3)	1.6	0.245	55.42		
Layer 13 (AG1f_3)	0.4	0.173	8.32		
Layer 14 (AG1f_3)	0.6	0.225	25.44		
Layer 15 (AG1f_3)	2.7	0.229	57		

OK Cancel

3.2.4 Entering Rock Compressibility

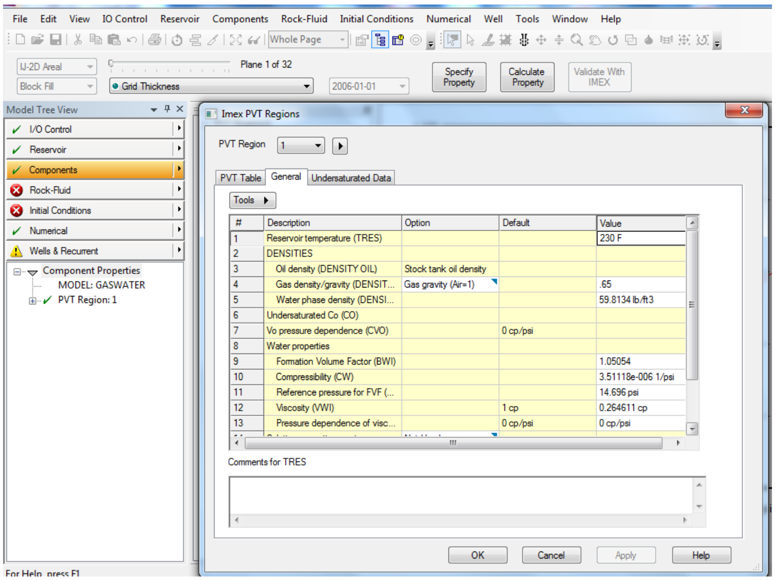
To specify rock compressibility, select **Rock Compressibility** from the **Reservoir** menu. Fill in the required values, and then click **OK**.



3.3 Fluid Model – IMEX

3.3.1 Entering Other PVT Region Properties

These are entered on the **General** tab of the **Imex PVT Regions** dialog box

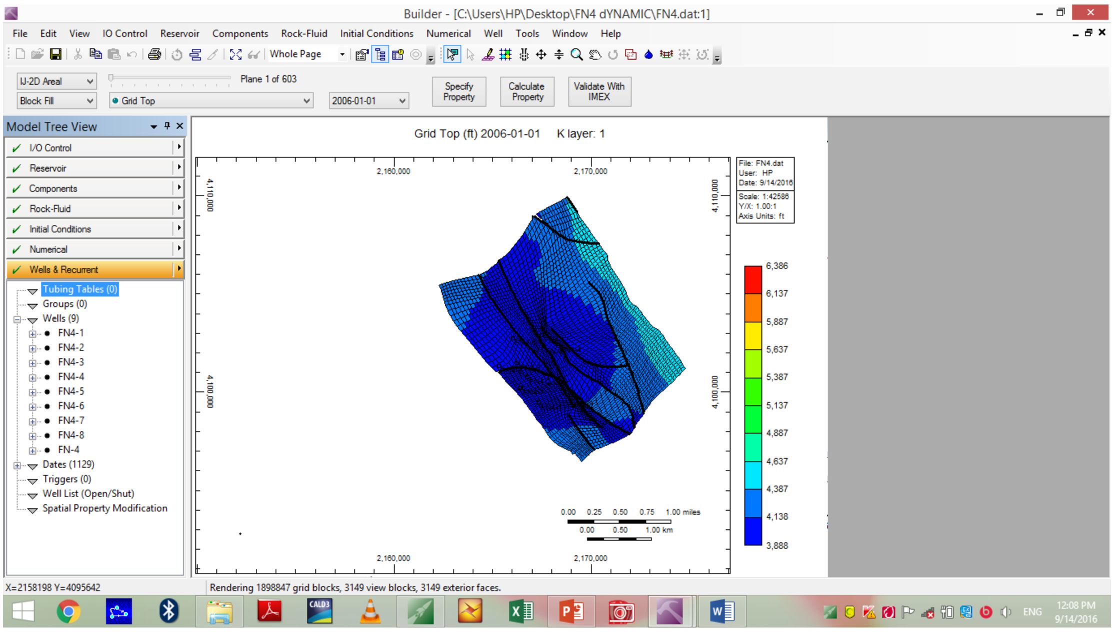


3.4 Well and Group Control

Overview

Through the **Well and Recurrent** data section you can:

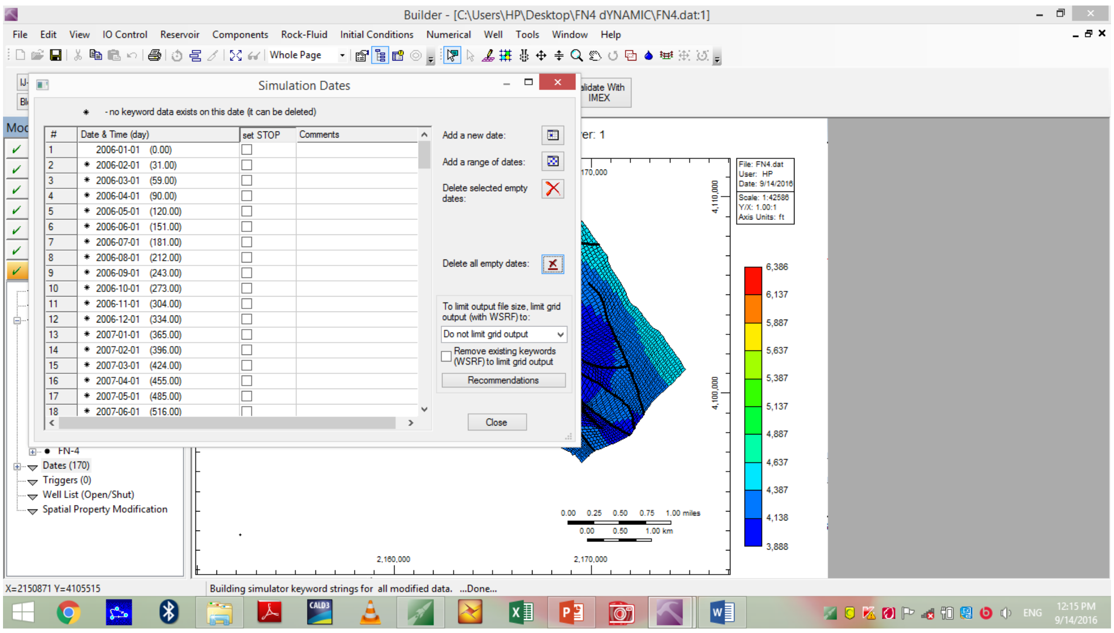
- Define wells and groups
- Set production/ injection constraints
- Define well completions and other properties as a function of time



3.4.1 Date/Time Information

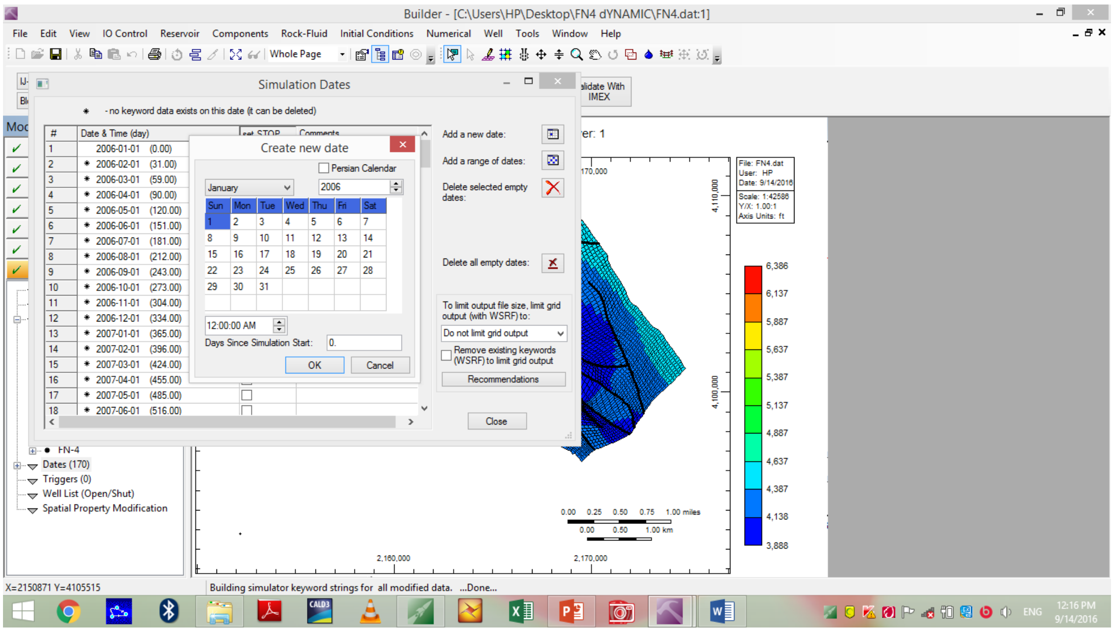
The simulators will use a default starting date if one is not found in this section. Given a start date, subsequent recurrent data is set by entering a new date or time and then entering the simulation information for that date or time.

Simulation Dates dialog box shows all dates that exist in the dataset. Through this dialog box, you can set simulation STOP dates, and enter comments for each date.

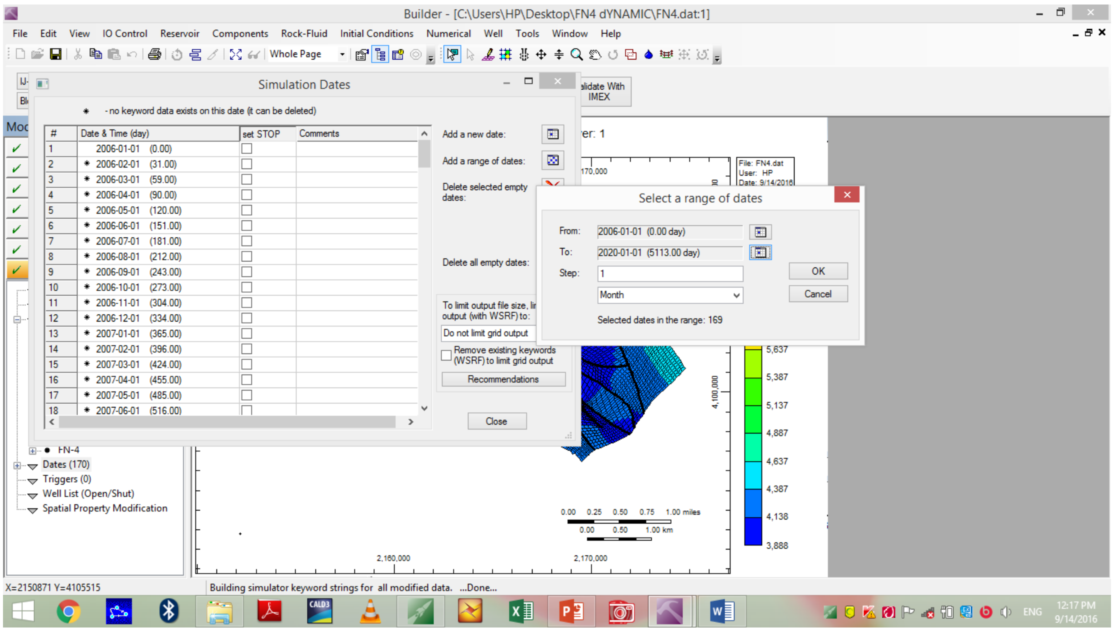


Adding Dates

Open the **Simulation Dates** dialog box. Press the **Add a new date** button to open a calendar dialog box through which you can enter a new date or time from the simulation start. The dialog box checks that the new date will not repeat an existing one.



In the **Simulation Dates** dialog box, click **Add a range of dates** to open the **Select a range of dates** dialog box, through which you can create a range of new dates with a selected step



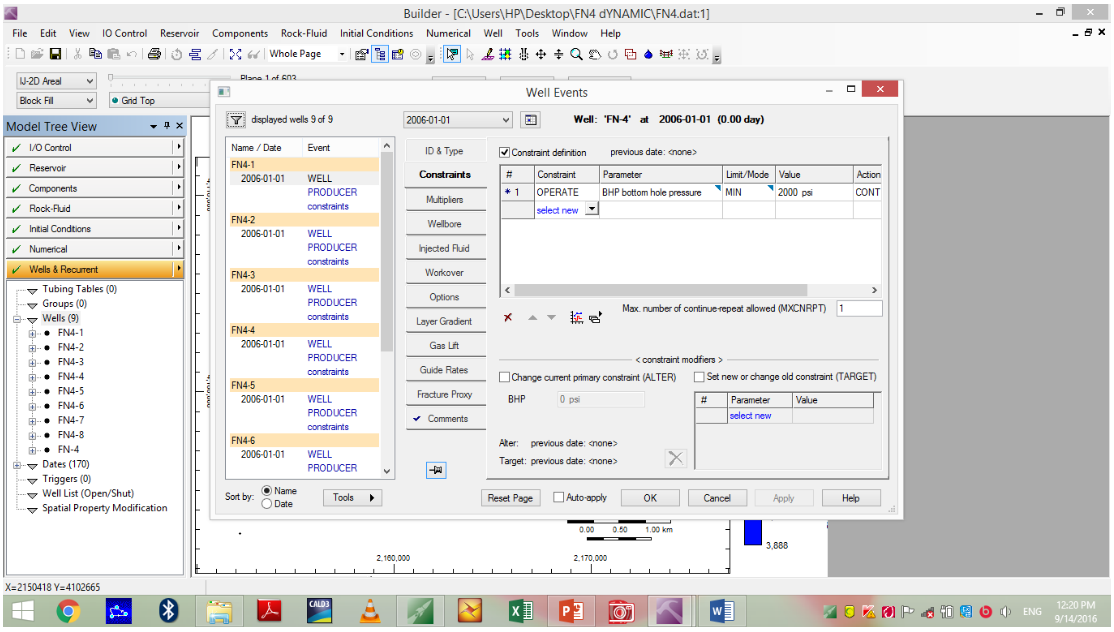
3.4.2 Well Data

The well data is found on the section tree-view under the root item Wells(#). Each well is defined with:

- Unique name with 1 to 40 characters (except * and ?).
- Type PRODUCER or INJECTOR (constant in time).
- Group affiliation (optional).
- Trajectory data (optional) that may have one main branch and several multilateral legs. Each trajectory branch may have perforation intervals on various dates.
- Completions, also called model wells or PERF cards.
- Events that set constraints and other properties in chronological order.

List of Well Constraints

The list of well constraints must have one or more operate constraints and any number (including zero) of monitor and penalty constraints. The first operate constraint is called primary. To add a new entry in the constraint list, select a constraint type from the drop-down box “**select new**” at the end of the list. Fill in the other parameters on the new line.

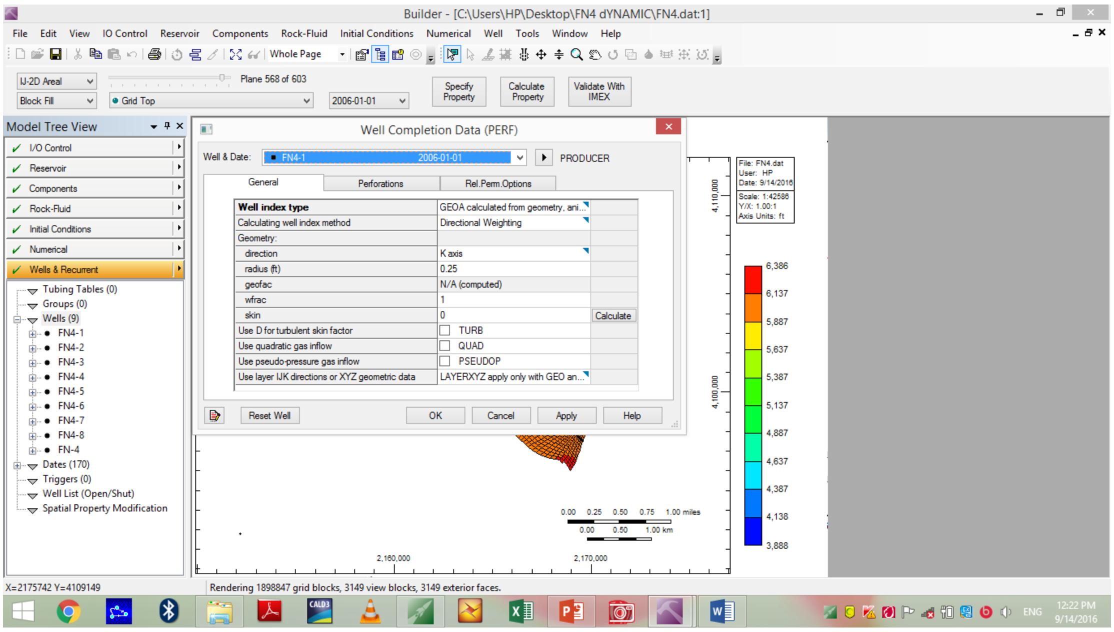


3.4.3 Well Completions (PERF)

Well completions define well locations and flow connections to the grid blocks in the simulation grid. At least one completion is required for each well. Well completions include data used in several dataset keywords: GEOMETRY, PERF, LAYERXYZ, LAYERIJK and KRPERF. Well completion data can also be referred to as PERF cards or model wells.

To open the **Well Completion Data (PERF)** dialog box, use one of:

- Select **Well Completions (PERF)** from the **Well** menu.
- Double-click on a completion item on the tree-view.
- Right-click a completion item on the tree-view then select **Properties** from the context menu



3.5 Input data

Fula North-4

ZONE SUMMATION DATA

MIN PORE: 0.17

Net Pay cut-offs

Max S_w : 0.50

MAX VSH: 0.30

Net Reservoir						Net Pay									
NO	Interval (m)	Thick (m)	AvgPor	por* thick (m)	Avg vsh	Interval	Thick (m)	Por* thick (m)	Avg por	Avg perm (md)	perm* thick	sw	sw*h	Avg VSH	Result
39	1965. 2 – 1966. 5	1.3	0. 187	0. 262	0. 240	1965. 2 – 1966. 5	1. 3	0. 262	0. 187	11. 600	16. 240	0. 533	0. 746	0. 240	Prob. Oil
41	2004. 8 – 2006. 4	1.6	0. 245	0. 368	0. 173	2004. 8 – 2006. 4	1. 6	0. 368	0. 245	55. 420	83. 130	0. 444	0. 666	0. 173	Gas
42	2007. 0 – 2007. 4	0.4	0. 173	0. 087	0. 251	2007. 0 – 2007. 4	0. 4	0. 087	0. 173	8. 320	4. 160	0. 507	0. 254	0. 251	Gas
43	2008. 5 – 2009. 1	0.6	0. 225	0. 135	0. 293	2008. 5 – 2009. 1	0. 6	0. 135	0. 225	25. 440	15. 264	0. 527	0. 316	0. 293	Gas
44	2010. 5 – 2013. 2	2.7	0. 229	0. 617	0. 080	2010. 5 – 2013. 2	2. 7	0. 617	0. 229	57. 000	153. 900	0. 513	1. 386	0. 080	Gas
45	2013. 3 – 2015. 0	1.7	0. 257	0. 437	0. 131	2013. 3 – 2015. 0	1. 7	0. 437	0. 257	97. 510	165. 767	0. 440	0. 747	0. 131	Gas
46	2015. 5 – 2017. 6	2.1	0. 229	0. 480	0. 138	2015. 5 – 2017. 6	2. 1	0. 480	0. 229	58. 310	122. 451	0. 508	1. 067	0. 138	Gas
47	2028. 1 – 2030. 1	2	0. 213	0. 425	0. 155	2028. 1 – 2030. 1	2	0. 425	0. 213	27. 070	54. 140	0. 463	0. 926	0. 155	Gas
48	2032. 2 – 2033. 3	1.1	0. 183	0. 202	0. 304	2032. 2 – 2033. 3	1. 1	0. 202	0. 183	11. 130	12. 243	0. 519	0. 571	0. 304	Gas
49	2034. 0 – 2034. 8	0.8	0. 206	0. 165	0. 206	2034. 0 – 2034. 8	0. 8	0. 165	0. 206	19. 490	15. 592	0. 504	0. 403	0. 206	Gas
50	2048. 5 – 2052. 0	3.5	0. 242	0. 846	0. 046	2048. 5 – 2052. 0	3. 5	0. 846	0. 242	76. 640	268. 240	0. 585	2. 047	0. 046	Gas

25	1784.3 - 1788.2	3.9	0.242	0.969	0.109	1784.3 - 1788.2	3.9	0.969	0.242	56.610	226.440	0.363	1.450	0.109	Oil
26	1788.5 - 1793.1	4.6	0.233	1.073	0.091										transition
28	1817.5 – 1819.1	1.6	0.209	0.336	0.081	1817.5 – 1819.1	1.6	0.336	0.209	61.130	98.420	0.453	0.730	0.081	Gas
29	1819.6 – 1821.1	1.5	0.153	0.230	0.098	1819.6 – 1821.1	1.5	0.230	0.153	20.410	30.620	0.626	0.940	0.098	Gas
31	1851.3 - 1852.2	0.9	0.216	0.194	0.320	1851.3 - 1852.2	0.9	0.194	0.216	20.780	18.702	0.510	0.459	0.320	Gas
32	1856.0 - 1856.9	0.9	0.213	0.191	0.190	1856.0 - 1856.9	0.9	0.191	0.213	27.370	24.633	0.416	0.374	0.190	Gas
33	1862.4 - 1863.2	0.8	0.180	0.144	0.140	1862.4 - 1863.2	0.8	0.144	0.180	13.220	10.576	0.415	0.332	0.140	Prob.Oil
34	1864.2 - 1866.1	1.9	0.210	0.378	0.164	1864.2 - 1866.1	1.9	0.378	0.210	31.190	56.142	0.416	0.750	0.164	Prob.Oil
35	1866.8 - 1868.3	1.5	0.236	0.354	0.155	1866.8 - 1868.3	1.5	0.354	0.236	66.070	99.105	0.420	0.630	0.155	Prob.Oil
36	1925.2 - 1931.3	6.1	0.206	1.256	0.141	1925.2 - 1931.3	6.1	1.256	0.206	26.060	158.966	0.405	2.471	0.141	Gas6
37	1936.6 - 1938.0	1.4	0.241	0.338	0.162	1936.6 - 1938.0	1.4	0.338	0.241	51.050	71.470	0.486	0.680	0.162	Gas
38	1953.0 - 1956.5	3.5	0.212	0.740	0.196	1953.0 - 1956.5	3.5	0.740	0.212	25.620	89.670	0.487	1.704	0.196	Prob.Oil

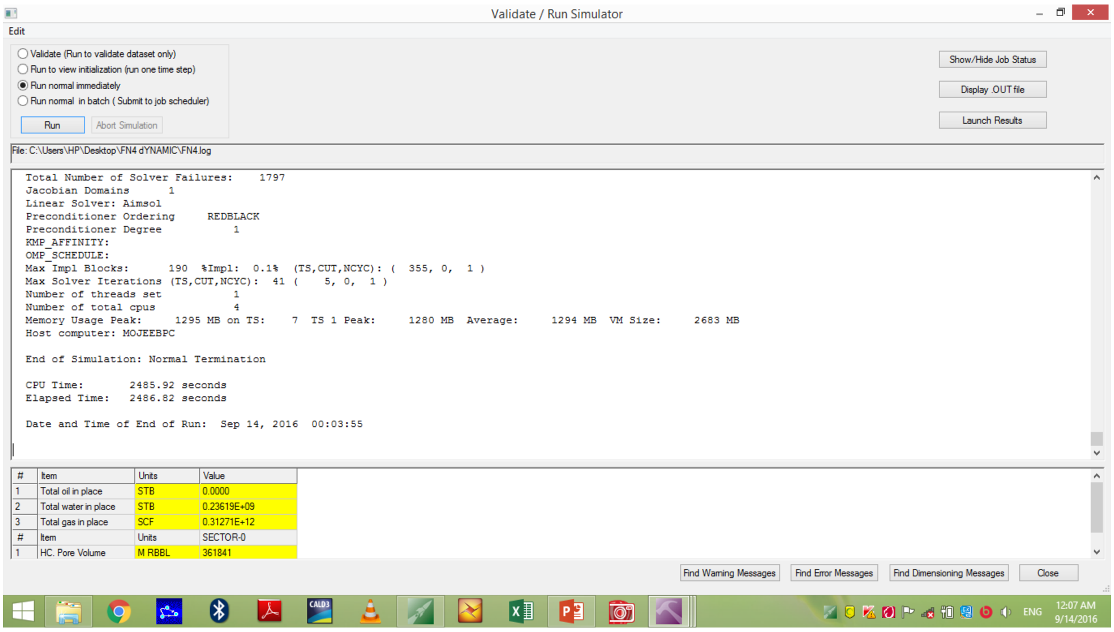
Chapter four

4.0 Result and Discussion

Result & Discussion

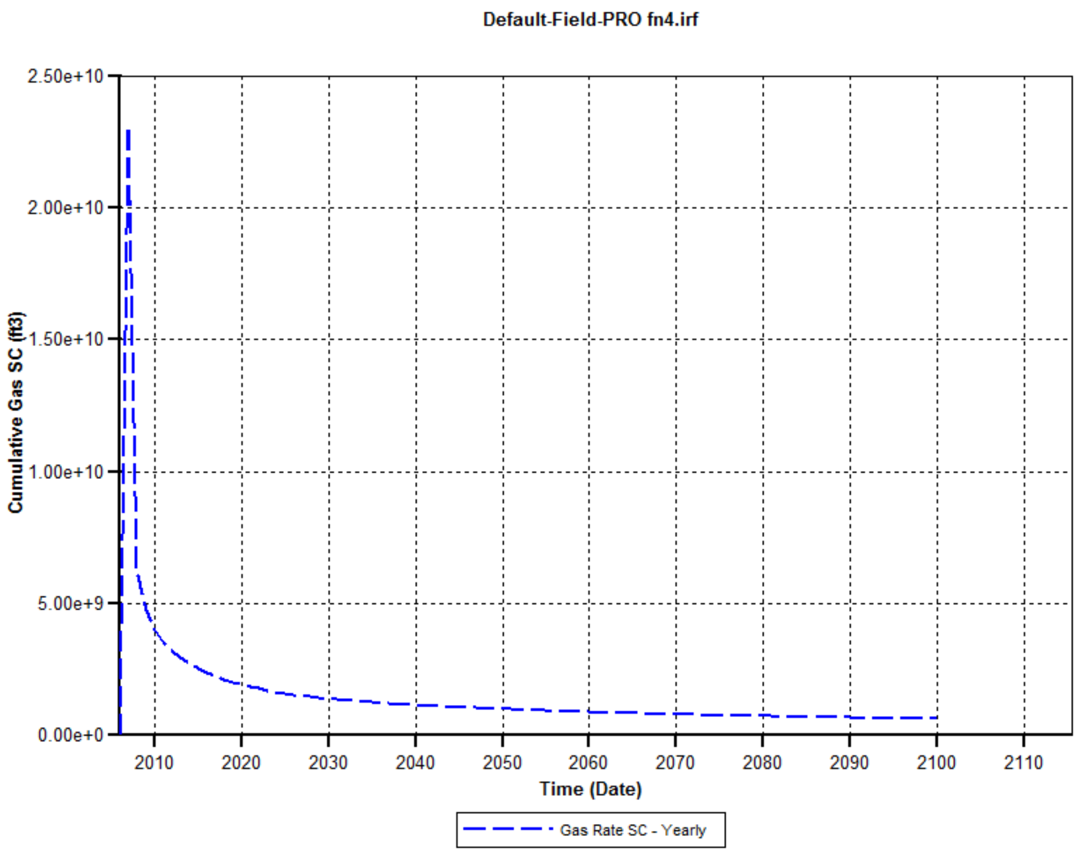
The model was run for five scenarios , each one is different bottom hole presser (1000,2000,2500)psi and end of simulate time to 2020 and 2100.Results were obtained as shown in figures below :

Total gas in place (OGIP) :-



The result show the total gas in place is 0.313 E+12 SCF and there is no oil in place

Yearly Productions until 2100 Years:-

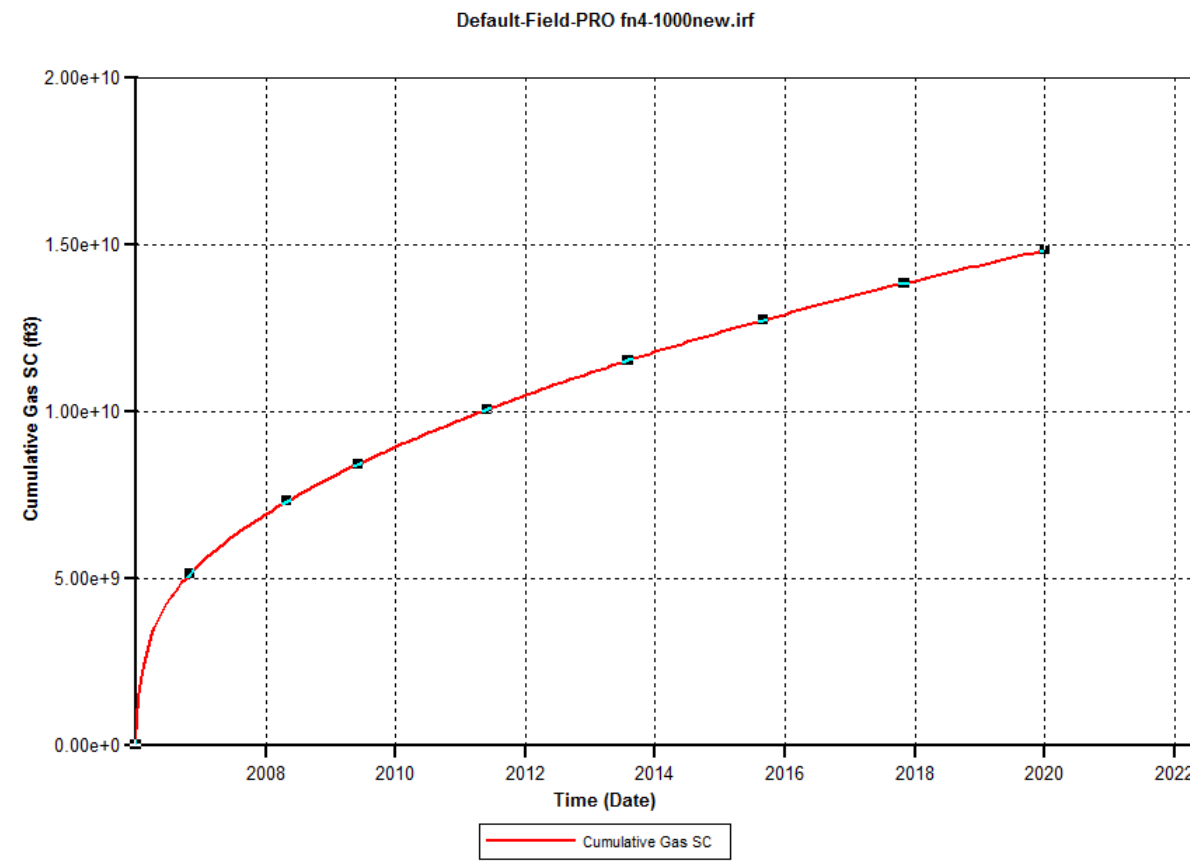


The result shows production gas rate to year 2100, production rate decrease with time until its finish in year 2100.

Optimum bottomhole presser selection:-

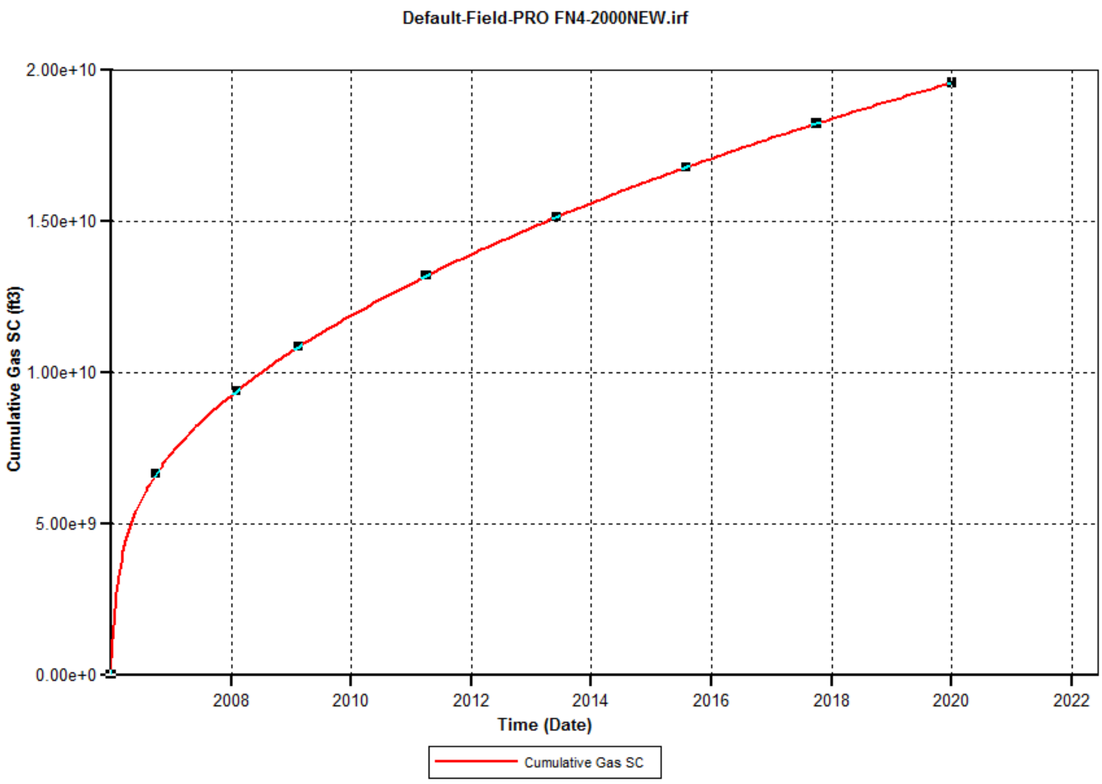
The model was run for five scenarios , each one is different bottom hole presser (1000,2000,2500)psi and end of simulate to 2020 and 2100.Results were obtained as shown in figures below :

Bottm hole presser 1000 psi :-



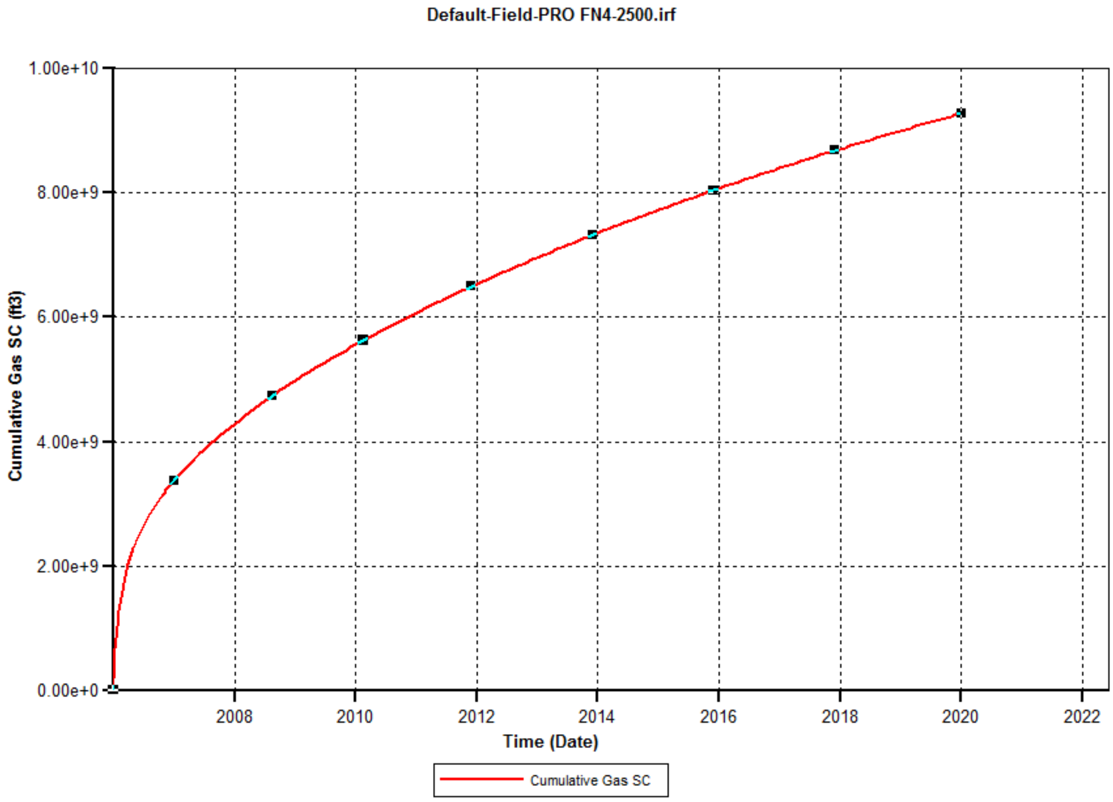
The first result shows the cumulative gas production for 14 years, the cumulative gas productions is 1.5 e^{+10} ft^3

Bottom hole 2000 psi :-



The result shows the cumulative gas production for 14 years, the cumulative gas production is 1.98 e^{+10} ft^3 and this better than bottomhole presser (1000 psi).

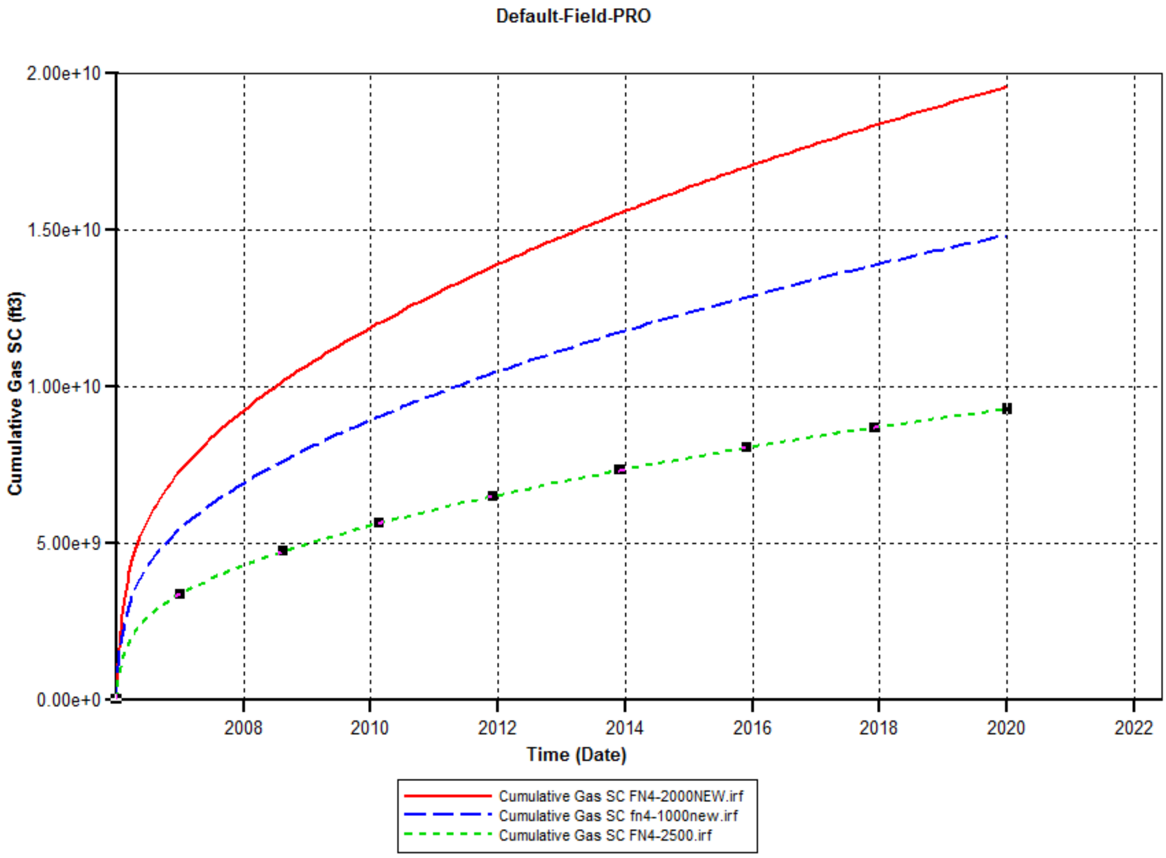
Bottom hole 2500 psi:-



The result shows the cumulative gas production for 14 years, the cumulative gas productions is 9.2 $e^{+9}\ ft^3$ and this less than bottomhole presser (1000,2000) psi.

Summary:-

This figure below changing cumulative gas with changing in bottom hole presser.



From the figure optimum bottom hole presser to produce gas is 2000 psi, and cumulative is 1.98 E+10 ft^3, and cumulative gas decrease with 1000 and 2500 psi to (1.5E+10 and 9.2E+9).

Chapter five

5.0 Recommendation

5.1 Conclusions

- forecasting gas production and ultimate gas recovery by CMG method.
- solution gas, and reservoir properties, for producing tables and charts, which can be used to forecast gas production for any data to depletion drive reservoir
- Combination between Computer Program Group (CMG) and Real production, we can easily to forecasting years of production.

5.2 Recommendation

- The accuracy of the results in one way or another has been affected by the data used because we do not have enough information for the field under discussion. The idea was to get an understanding of how to predict some information about the field before the production activities start.

- This project can be improved when all important information is published and hence a real performance of the wellbore and the reservoir can be assessed. Further research is necessary because more gas will be discovered and need to be analyzed in technical aspects.

- With continuing exploration in sudan more gas might be discovered and hence the production profile may change with the number of wells. Therefore, this study may be considered as a base case for another analysis since it will not consume much time.

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