RESERVE ESTIMATION AND WELL PERFORMANCE STUDY OF SALDA NADI GAS FIELD

A Thesis
Submitted to the Department of Petroleum & Mineral Resources Engineering
in partial fulfillment of the requirements for the Degree of
MASTER OF ENGINEERING IN PETROLEUM AND MINERAL RESOURCES.

by

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This thesis is dedicated to my eldest brother

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ABSTRACT

Salda Nadi Gas Field is situated about 40 km north of Comilla town. Bangladesh Petroleum Exploration and Production Company Limited (BAPEX) discovered Salda Nadi Gas Field. A total of two wells, one as a duel producer were developed. Gas production started in March 1998. In this study a thorough reservoir engineering investigation has been conducted to get insights into the reservoir and production system.

Reserve estimation is important for the development of a gas field. In this study, volumetric analysis and flowing material balance method have been used to estimate the reserve. Flowing material balance method is helpful to estimate initial gas in place without loss of production.

Pressure transient analysis and deliverability testing give valuable information about reservoir characteristics. Well performance depends upon well and reservoir conditions. The pressure transient analysis determines the wellbore storage, skin factor, permeability etc. of the reservoir.

The overall performance of any well depends upon the combination of well inflow performance, down-hole conduit flow performance and surface flow performance. The production optimization depends upon several parameters i. e. well stimulation, tubing size, flow line size, choke size, separator pressure and average reservoir pressure. The impacts of each parameter have been observed to identify any bottle-neck in the production system. Nodal analysis approach has been followed in conducting the system analysis to optimize production of Salda Nadi Gas Field.

This study reveals that the lower zone of the reservoir may have been damaged during the drilling and/or completion processes. The upper zone of well # 1 is being produced with over-sized tubing. Well # 2 is producing at optimum condition

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NOMENCLATURE

A : Original production area of reservoir

$Ah\phi$: Pore volume of reservoir, acre-ft

B : Formation volume factor, rft^3/sft^3

B_o : Oil formation volume factor, rft^3/sft^3

B_g : Gas formation volume factor, rft^3/sft^3

B_w : Water formation volume factor, rft^3/sft^3

c_t : Total compressibility, 1/psi

c_w : Water isothermal compressibility, psi^{-1}

c_f : Formation isothermal compressibility, psi^{-1}

f : Moody friction factor

G : Initial gas in place

h : Pay zone, ft

k : Permeability, md

N : Initial reservoir oil, stb

N_p : Cumulative produced oil, stb

p_{wf} : Flowing bottom hole pressure, psi

p_{ws} : Shut-in bottom hole pressure, psi

p_i : Initial pressure, psi

p^* : Apparent reservoir pressure, pressure obtained from semi-log plot, psi

$\overline{p}$: Average reservoir pressure, psi

p_{1hr} :Pressure straight-line portion of semi-log plot 1 hour after beginning a transient test , psi

p_{sc} : Pressure at standard condition

q_{sc} : Gas flow rate at standard condition

R_p : Cumulative produced gas-oil ratio

R_s : Solution gas-oil ratio, scf.gas/stb oil

R_{si} : Solution gas-oil ratio at initial reservoir pressure

r_I :Radius of investigation, ft

r_w : Wellbore radius, ft

r_D : Dimensionless radial distance

s_w : Water saturation, fraction

S_{wc} : Connate or irreducible water saturation

T : Temperature

T_{av} : Average temperature

T_{sc} : Temperature at standard condition

Δt : Shut in time, hours

V_w : Connate water volume

W_e : Cumulative water influx from the aquifer in to the reservoir, stb

W_p : Cumulative amount of aquifer water produced, stb

z : Gas compressibility factor

z_{av} : Average gas compressibility factor

μ_o : Oil viscosity, cp

μ_g : Gas viscosity, cp

μ_w : Water viscosity, cp

ϕ : Porosity, fraction

γ_g : Specific gas gravity

ρ : Density

CHAPTER 1

INTRODUCTION

Reserve estimation and well performance study are essential studies in the field of petroleum engineering. Gas or oil recovery depends on well performance. So, a well performance study is important for a production engineer for the depletion of the gas reservoir. Reserve estimation is important to decide whether the reservoir is economically viable or not. If a large amount of gas in place is present and the well performance is also good, then the reservoir is going to be on production.

Salda Nadi gas field is situated about 50 Km south-east of Brahmanbaria Town. SLD # 1 was drilled in 1996 (discovery well). The well was terminated at a depth of 2511m (MD). Two gas zones were discovered out of three zones while conducting DST. Based on DST result the well was completed as dual producer at lower zone interval of 2405-2430m and upper zone interval of 2170-2260m. From SLD # 1, 17100.139 mmscf gas was produced from 29th March 1998 to 3rd May 2001 including two shut-ins. Presently the well is in production.

SLD # 2 is a deviated well and was drilled in 1999 and the total depth is 2458m (MD). Three prospective zones were tested. Only middle zone (i.e. 2300-2365m) produced gas. From SLD # 2, 3465.273 mmscf gas has been produced from 4th May 2001 to 22nd December 2001 and presently the well is in production.

This study will focus on the well test analysis and production simulation of Salda Nadi gas field using a commercial software and reserve estimation by volumetric method and material balance methods. The reservoir characteristics like permeability, porosity, reservoir pressure, wellbore storage, skin factor, pay thickness, wellbore damage and other relevant information may be obtained from the pressure transient analysis. And these data are used in the reserve estimation and production optimization to predict reservoir performance of the gas field.

The pressure transient data supplied by BAPEX will be used to develop log-log, semi-log pressure and pressure derivatives, Horner plot, flow after flow, and simulation plots.

The well deliverability test data and the well completion configuration data will be used to analyze the production scenario by Nodal Analysis method using a commercial software. The analysis is helpful for the prediction of reservoir and well performance of this gas field.

The production and pressure data will be used to calculate gas in place by material balance method. For volumetric calculation the reservoir area, pay thickness, porosity, gas saturation and formation volume factor data from BAPEX will be used.

The study uses core analysis data, PVT properties, production data and pressure data. Well testing and production simulation was conducted to achieve a clear scenario about the well performance and gas in place of the gas field.

CHAPTER 2

LITERATURE REVIEW

2.1 INTRODUCTION

Salda Nadi gas field is situated in Brahmanbaria district. It is about 50 km South-East of Brahmanbaria Town. Bangladesh Petroleum Exploration and Production Company Limited (BAPEX) discovered Salda Nadi gas field in 1996. Directional drilling was used in this field. SLD # 1 drilling was completed as duel producer (Upper gas zone and Lower gas zone). Gas production started in March, 1998.

After the completion of SLD # 1 another well (SLD # 2) was drilled to re-evaluate the hydrocarbon prospect and re-estimate the gas reserve of this field. SLD # 2 was drilled in 1999 and three zones were tested but only from middle zone gas flowed.

2.2 GEOLOGY (BAPEX Report, 2001)

Tectonically the Rukhia Structure lies in the western part of eastern folded belt within Tripura uplift of Tripura State of India. Salda Nadi gas field is located in the northern part of greater Rukhia Structure. Rukhia structure located in the northern culmination, which is known as Shyampur dome and the central part of this dome is situated in the Bangladesh territory. Major part of this structure lies within Indian Territory. So the scope of detail Geological and Geophysical survey in the territory of Bangladesh part is limited.

In general the sediments of Rukhia Structure are poorly fossilized to barren and consist of alternate shale, sandstone, and siltstone in varying proportion. Hydrocarbon entrapment is controlled more by the stratigraphy as compared to structural element because of the depositional condition.

In SLD #1, the Upper Gas Sand is encountered from 2170-2260m. This sand is not encountered in SLD #2. New gas sand was encountered at a depth of 2300-2365m in SLD # 2. About 750m west, one wet gas sand at 2305-2367m depth was observed in SLD # 1. The same sandstone bed extended towards east and encountered at a depth of 2300-2365m in SLD # 2.This sand is gas saturated due to its higher position.

Lower Gas Sand (LGS) was encountered at 2405-2430m in SLD # 1. One sandstone horizon was encountered at a depth of 2425-2451m in SLD # 2, which produced water during DST.

2.3 STRUCTURE AND TECTONICS (Review of BAPEX Report, 2001)

The Salda Nadi structure is exposed on surface and represented by series of hills and valleys in Tripura height of the hill ranges varies between 200m and 500m. In Bangladesh, these elongated and extended hills are low and do not exceed 25m height.

OGDC and BAPEX geologists identified the presence of northern pitch of the dome towards north of Salda Nadi. From seismic data a very gentle southern pitch can be observed.

A fault has been marked on the eastern flank in the time depth contour map on the reflector. Indication of this fault can be observed on topographic map also.

Tectonically the structure lies in the western part of eastern folded belt within Tangail-Tripura high.

2.4 EXPLORATION AND DRILLING HISTORY (BAPEX Report, 2001)

Salda Nadi is a part of greater Rukhia structure of Tripura State of India. Geological Survey of India, Burma Oil Co. prepared photographical map of the entire region i.e. Tripura-Cachar-Mizoram area. This geological survey of this area was conducted between the period 1911 and 1959.

In the Salda Nadi area, Oil and Gas Development Corporation (OGDC) conducted geological survey during 1964-65 field session. The survey confirmed the existence of a closed structure. But this was a younger sediments exposed structure. So the prospect of hydrocarbon was uncertain.

Oil and Natural Gas Corporation (ONGC) of India continued the geological and geophysical survey in Tripura. Their first target location was Rukhia. So they drilled about 37 wells during 1980-83 field session. No faults could be encountered during the session.

BAPEX carried out two multifold seismic lines across and along the anticline during field session 1991-92. And useing on this data structural map was constructed.

SLD # 1 was drilled by BAPEX in 1996. Two gas bearing zones were discovered at a depth between 2405-2430 m and 2170-2260 m. At depth 900 m another sand was tested but there was no gas flow.

SLD # 2 was drilled in 1999. It is a deviated well. Three prospective zones were tested but only one gas-bearing zone was discovered at a depth between 2300-2365m.

2.5 LITHOLOGY

On the basis of geological data and well data of SLD # 1 and SLD # 2 and the seismic data of the following stratigraphic sequence has been stated below in Table: 2.1 (BAPEX Report, 2001)

Table: 2.1: Stratigraphic Sequence of Salda Nadi Gas Field

Depth (m)	Lithological Description	Formation Encountered
Surface-50	Sand dominant with alluvial cover.	Alluvium
50-530	Predominantly Sandstone interbedded with clay and Siltstone and traces of Lignite.	Dupitila
530-1140	Predominantly Sandstone with alternation of	Tipam

	Shale and Siltstone. Sandstone: White, clear, massive, loose, occasionally consolidated, fine to medium grain moderately sorted, dark colors mineral and mica concentrated. Occasionally calcareous.	Sandstone
1140-1300	Shale dominating with alternation of Sandstone and Siltstone. Shale: Light gray to dark gray, thinly laminated, gard and compact, slightly calcareous with silt partings.	Upper Bokabil
1300-2070	Alternation of sandstone and shale predominantly sandstone, white, clear and transparent, fine to medium grain, unconsolidated, sub-rounded, moderately sorted, mica and dark color mineral concentrated, occasionally calcareous.	Middle Bokabil
2070-2395	Predominantly shale, bluish gray, very thinly laminated, moderately hard and compacts, silty in nature, mildly calcareous.	Lower Bokabil
2395-2511	The upper part is alternation of sandstone and shale. Middle part is sand dominated with small shale band and the lower part is Shaley sequence with minor sand stone.	Upper Bhuban

2.6 FLUID COMPOSITION

Two gas samples of Salda Nadi gas field were analyzed by BAPEX using Pye Unicam Series 304 Gas Chromatograph to determine gas composition. Molecular gas composition is presented in the Table2.2 (BAPEX Report, 2001):

Table 2.2: Gas composition of Salda Nadi gas field

Components	SLD # 1	SLD # 2
	Mol. %	Mol. %
Nitrogen(N_2)	0.31	0.31
Carbondioxide (CO_2)	0.68	0.69
Methane (CH_4)	96.06	96.04
Ethane (C_2H_6)	2.26	2.23
Propane (C_3H_8)	0.43	0.48
iso-Butane	0.04	0.05
n-Butane	0.03	0.03
iso-Pentane	0.03	0.03
n-Pentane	0.02	0.02
Hexane	0.02	0.02
Heptane+	0.12	0.11
Specific Gravity of Gas	0.58	0.58
Higher Heating Value of Gas (Btu/scf)	1035.82	1035.62
Lower Heating Value of Gas (Btu/scf)	933.68	933.49

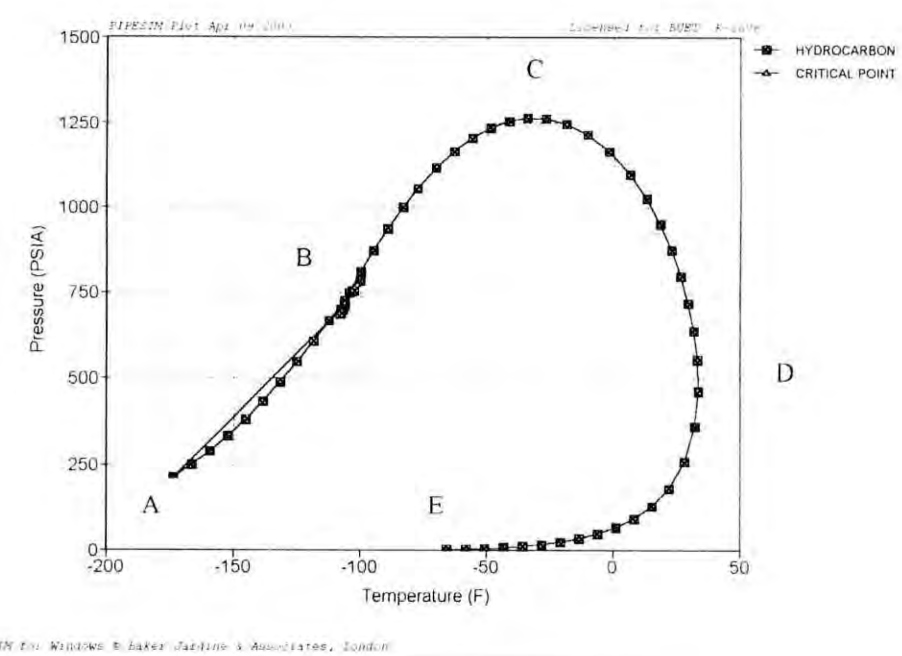
In this table specific gravity of gas and heating value are also included. The analysis shows that the ratio of $C_1/C_{1\text{-}5}$ is 0.9716 that is very similar to the dry gas. The content of carbon dioxide (CO_2) is higher and those of hydrocarbon (C_1-C_5) and nitrogen (N_2) are very similar to the composition of other gases, which are already discovered in the different gas fields of Bangladesh. It can be also mentioned that the specific gravity and calorific value are similar with the presently using gas in the Bangladesh. It is important that the hydrogen sulphide (H_2S) is absent in the Salda Nadi gas field.

2.7 PHASE ENVELOPE

Based on the composition, a phase envelope has been drawn and shown in Fig 2.1. Line AB is bubble point curve and line BE is dew point curve. The critical point, B, is the intersecting point of these two curves. This is located at 777 psia and at -101^0 F. Point C is the criocondenbar, which represent the maximum pressure at which liquid and vapor may exist in equilibrium. Point D is the cricondentherm, the maximum temperature at which liquid and vapor may exist in equilibrium. The cricondenbar is found to be 1263 psia and cricondentherm is found to be 34^0F. The retrograde region is found within BCD region.

Each hydrocarbon reservoir has a characteristic phase diagram. This gives physical and thermodynamic properties. These thermodynamic properties are collectively known as PVT (pressure-volume-temperature) properties. Compositional modeling uses PVT properties in production optimization system.

Figure 2.1: Phase Envelope Plot of Salda Nadi Gas Field



CHAPTER 3

STATEMENT OF THE PROBLEM

3.1 INTRODUCTION

Salda Nadi gas field has been producing gas since March 1998. Volumetric reserve calculation was performed to estimate reserve in the field. But only volumetric method is not sufficient for reserve estimation. For proper reservoir evaluation well flow performance, production simulation and material balance studies should be performed. The reserve of Salda Nadi gas field was estimated when only one well was drilled. Recently, another well has been completed which is now in production. The second well will give additional information to calculate the actual reserve of this field. Well testing and production optimization has been conducted for proper evaluation.

3.2 OBJECTIVES OF THE STUDY

There are several objectives in terms of analysis. They are as follows:

1. Reserve Estimation

i) To calculate initial gas in place of the Salda Nadi gas field by material balance and volumetric studies.

2. Well Test Analysis

i) To determine the initial reservoir pressure, permeability-thickness product and reservoir boundary.

ii) To examine the near well-bore condition (i.e. skin and storage).

3. Production Optimization

i) To determine the flow rate at which an existing gas well will be produced by considering well-bore size and production limitations.

ii) To optimize the system to produce the desirable flow rate most economically and to recognize the way to increase the production rates.

CHAPTER 4

METHODOLOGY OF ANALYSIS

4.1 INTRODUCTION

This study is based on the data of Salda Nadi gas field. Pressure transient analysis, production simulation, and material balance study have been performed to evaluate the reservoir characteristics, production scenario, and determine the initial gas in place of this field.

4.2 GAS IN PLACE ESTIMATION:

4.2.1 VOLUMETRIC METHOD

PVT property and the contour map are used for volumetric method to calculate the gas in place of Salda Nadi gas field.

4.2.2 MATERIAL BALANCE METHOD

Material balance is used to calculate the initial gas in place of Salda Nadi gas field. Z factor is calculated by using the PVT data with the help of 'Correlation Equations for the Standing-Katz Z-factor Chart'. Finally initial gas in place.

4.3 WELL TEST ANALYSIS

Bangladesh Petroleum Exploration and Production Company Limited (BAPEX) recorded the well head pressure data, flow rate data, and other relevant PVT properties of this reservoir by using electronic gauges. Bottom hole pressure data is not available in BAPEX report. For this reason bottom hole pressure has been calculated by using 'Average Temperature and Z-factor Method'. After the calculation of bottom hole pressure, computer aided well testing software (SAPHIR) is used to analysis the well performance and collect the PVT properties of this gas field.

4.4 PRODUCTION OPTIMIZATION

Production simulation is important to forecast the production scenario of present and future of a gas field. It is a useful tool for understanding the reserve performance and production forecasting. The nodal analysis system is used in this study to improve the performance of any well system with the help of PIPESIM, production simulation software. This method is helpful for analyzing any well, which will allow determination of the production capacity for any combination of components. This method may be used to determine locations of excessive flow resistance or pressure drop in any part of the system.

The method consists of selecting a node point in the well and dividing the system at this point. All components upstream of the node is considered as the inflow section, while the outflow section consists of all the components downstream of the node. A relationship between flow rate and pressure drop must be available for each component in the system. The flow rate through the system can be determined once the following requirements are satisfied:

a) flow into the node equals flow out of the node;
b) only one pressure can exist at a node.

CHAPTER 5

GAS IN PLACE ESTIMATION

5.1 INTRODUCTION

Initial gas in place and reserve estimation are the basic requirements for the gas production companies. Reserve evaluation firstly depends on initial gas in place estimation. If the reserve is not economically viable then there is no further work on this field. There are several techniques for initial gas in place calculation such as volumetric method, material balance method, Pressure decline method, and Simulation method. In this study, only volumetric method and material balance method are applied for reserve estimation.

5.2 VOLUMETRIC METHOD

The volumetric method is useful for calculating the gas in place at any time. This method is particularly applicable for newly discovered gas field. The reliability of this method depends on the good data availability. The gas reserve is determined by geological information based on core analysis, electric or radioactive logs, drilling records, drill stem and production test.

The standard cubic feet of gas in place is simply the product of the reservoir pore volume, the initial gas saturation, and initial gas formation volume factor. The standard cubic feet of initial gas in place is given by

$$G = \frac{43560 A h \phi (1 - S_{wi})}{B_{gi}} \quad \text{.......... 5.1}$$

The initial gas formation volume factor is equal to the volume at reservoir temperature and pressure occupied by one standard cubic feet of gas. From gas laws:

$$B_{gi} = \frac{p_b T_i z_i}{p_i T_b z_b} \quad \text{......5.2}$$

For standard condition, we assume p_b=14.7 psia, T_b=60°F, and z_b=1. Then Eq.5.2 can be rearranged as

$$B_{gi} = \frac{(14.7)(T_i z_i)}{p_i(60+460)}$$

$$= 0.0283\frac{T_i z_i}{p_i} \quad \text{......5.3}$$

and gas formation volume factor for any pressure and temperature is defined as below:

$$B = \frac{p_{sc} z T}{p T_{sc}} \quad \text{......5.4}$$

5.3 MATERIAL BALANCE METHOD

Material Balance method is the another process to calculate initial gas in place. The material balance method uses actual reservoir performance data and therefore is generally accepted as the most accurate technique for estimating initial gas in place. Material balance analysis can be performed by the classical method and flowing well methods to estimate both reserves and initials gas in place. The second method is now frequently used and suitable for Bangladesh situation where regular pressure tests are not conducted due to critical demand-supply situation. For newly developed gas field conventional method is not sometimes useful due to lake of data and in this case flowing well method is helpful for reserve estimate.

5.3.1 BASIC THEORY OF MATERIAL BALANCE METHOD

Schilthuis first presented the general form of the material balance equation in 1941. The equation is derived as a volume balance, which equates the cumulative observed production, expressed as an underground withdrawal, to the expansion of the fluids in the reservoir resulting from a finite pressure drop. The general form of the material balance equation (Craft and Hawkins, 1991):

$$N(B_t - B_{ti}) + G(B_g - B_{gi}) + (NB_{ti} + GB_{gi})\left[\frac{c_w S_{wi} + c_f}{1 - S_{wi}}\right]\Delta\bar{p} + W_e = N_p B_t + (G_p - NR_{soi})B_g$$

$$B_w W_p \quad \ldots\ldots\ldots\ldots 5.5$$

For gas reservoirs, there is no initial oil; therefore, N and N_p are equal to zero. The general material balance for a gas reservoir can then be obtained:

$$G(B_g - B_{gi}) + GB_{gi}\frac{c_w S_{wi} + c_f}{1 - S_{wi}}\Delta\bar{p} + W_e = G_p B_g + B_w W_p \quad \ldots\ldots\ldots\ldots 5.6$$

Most of the cases in gas reservoirs, the gas compressibility factor is much greater than the formation and water compressibility, hence the second term on the left-hand side of Eq.5.6 becomes negligible. Therefore Eq.5.6 reduced to

$$G(B_g - B_{gi}) + W_e = G_p B_g + B_w W_p \quad \ldots\ldots\ldots\ldots 5.7$$

In case of no water encroachment and water production from a reservoir, the reservoir is said to be volumetric for a volumetric gas reservoir, Eq.5.7 becomes

$$G(B_g - B_{gi}) = G_p B_g \quad \ldots\ldots\ldots\ldots 5.8$$

By using Eq.5.2 and Eq.5.4 in Eq.5.8, the following is obtained

$$G\left(\frac{p_{sc} z T}{T_{sc} p}\right) - G\left(\frac{p_{sc} z_i T_i}{T_{sc} p_i}\right) = G_p\left(\frac{p_{sc} z T}{T_{sc} p}\right) \quad \ldots\ldots\ldots\ldots 5.9$$

The production is essentially an isothermal process (i.e the reservoir temp. remains constant), then the Eq.5.9 is reduced to

$$G\left(\frac{z}{p}\right)-G\left(\frac{z_i}{p_i}\right)=G_p\left(\frac{z}{p}\right)$$

Therefore

$$\frac{p}{z}=-\frac{p_i}{z_i G}G_p+\frac{p_i}{z_i} \qquad 5.10$$

Since p_i , z_i , and G are constants for a given reservoir, plotting p/z vs. G_p would yield a straight line. If p/z sets equal to zero, which would represent the production of all the gas from a reservoir, than the corresponding G_p equal to G, the initial gas in place.

5.3.2 CLASSICAL MATERIAL BALANCE

The classical material balance expresses a relationship between the average reservoir pressure and the amount of gas produced. When there has been no production, the pressure equals the initial reservoir pressure; when all the gas has been produced, the pressure in the reservoir is zero. In the case where the reservoir acts like a tank and there is no external pressure maintenance, the relationship between pressure and cumulative production is approximately linear. For consideration of compressibility factor z, the material balance plot of p/z vs. cumulative production G_p is a straight line going from the initial pressure, (p_i/z) to the initial gas in place (GIIP). This analysis is fully dependable upon built-up reservoir pressures, collected by shutting in the wells for few days.

The accuracy of reserves calculated from the material balance studies is dependent upon the accuracy of the well's production and pressure data. Unlike the volumetric method, the material balance accounts for reservoir heterogeneity and continuity variations, which occur within the reservoir. The accuracy of the material balance technique for estimating reserves increases with production and pressure decline.

5.3.2.1 Static Bottom-hole Pressure

The static bottom-hole pressure or the reservoir pressure is recorded by down-hole gauge after shut-in the wells for a few days for pressure builds up. This is not often available due to critical demand-supply situation. But different wells of the field were shut-in from time to time because of production problems or any other reason and pressure build up data were recorded in these situations. The recorded shut-in wellhead pressure data was taken from daily records of Salda Nadi Gas Field, and corresponding bottom-hole pressures were calculated. Due to non-availability of bottom-hole pressure, the static bottom-hole pressure is calculated from static well head pressure. The calculated static bottom-hole pressure is, however, not a substitute for the data recorded from a properly designed well test program. In the absence of any well-test program, this technique can be a good alternative. The following technique is used for estimating shut-in bottom-hole pressure from shut-in wellhead pressure.

The general equation for vertical flow calculations is written as follows (Kumar, 1987):

$$\int_2^1 \frac{(zT/p)dp}{1+(6.7393\times10^{-4} fLq_{sc}^2 z^2T^2)/(zp^2d^5)} = 0.01875\gamma_g Z \quad \ldots\ldots 5.11$$

where the units are: p = psia; q_{sc} = MSCFD; d = in.; T = ^{0}R; and L, Z = feet (Z is the vertical elevation difference between the bottom-hole, inlet point1and surface, outlet point 2)

The left integral of Eq.5.11 cannot be evaluated easily because z is a complex function of p and T, and the temperature variation with depth is not easily defined. Some simplifying assumptions made in the evaluation of this integral form are the basis for the different methods that give results of varying degrees of accuracy.

Some methods for vertical flow assume an average temperature, in which case Eq.5.11 becomes:

$$\int_2^1 \frac{(z/p)dp}{1+(6.7393\times10^{-4} fLq_{sc}^2 z^2T^2)/(zp^2d^5)} = \frac{0.01875\gamma_g Z}{T_{av}} \quad \text{............................5.12}$$

For a shut-in well, the flow rate (q or q_{sc}) is equal to zero, and Eq.5.12 simplifies to:

$$\int_{p_{wh}}^{p_{ws}} (zT/p)dp = 0.01875\gamma_g Z \quad \text{............................5.13}$$

Eq.5.13 describes the relationship between the pressure measured at the surface (or wellhead), p_{wh}, and the pressure at the bottom, p_{ws}.

In calculating the static bottom hole pressure of the wells, average temperature and z-factor method (Ikoku, 1992) is used. This method is used to simplify the left-hand side integral in Eq.5.13 as:

$$Z_{av}T_{av} \int_{p_{wh}}^{p_{ws}} (dp/p) = 0.01875\gamma_g Z \quad \text{............................5.14}$$

From integration:

$$\ln\frac{p_{ws}}{p_{wh}} = \frac{0.01875\gamma_g Z}{z_{av}T_{av}} \quad \text{............................5.15}$$

or,

$$p_{ws} = p_{wh}\exp\left[\frac{0.0185\gamma_g Z}{z_{av}T_{av}}\right] \quad \text{............................5.16}$$

Generally this is written as:

$$p_{ws} = p_{wh}\, e^{s/2} \quad \text{............................5.17}$$

where

$$s = (0.0375\gamma_g Z)/(z_{av}T_{av}) \quad \text{............................5.18}$$

To determine the average temperature, the bottom-hole temperature and the surface temperature should be known. For static column of gas, an arithmetic average temperature is satisfactory to use. For calculating z_{av}, the average pressure is required (in addition to average temperature). Thus a trial and error type solution is necessary.

5.3.2.2 Shut-in Wellhead Pressure

In this technique gauge recorded shut-in wellhead pressure are used to build a p/z vs cumulative production (G_p) plot. This technique is based on the assumption, there is no liquid in the wellbore. For the material balance study, p/z term has been calculated by the means of calculating the *z*-factor using Correlation Equations for the Standing-Katz z-factor Chart (Ikoku, 1992).

Since static gas gradient is very small, the plots set for *p/z* using the shut-in wellhead pressure vs cumulative production (G_p) for various sands of Salda Nadi Gas Field should provide quite acceptable results. This method will lead erroneous results for any liquid build up in the tubing.

5.3.3 FLOWING MATERIAL BALANCE METHOD

The flowing material balance method is similar to traditional material balance. The difference is that in this method flowing pressure is used rather than shut-in pressure. Mattar and McNeil (1998) illustrated that original gas in place can be determined from the flowing data (pressure and production). These two authors have proved that it is possible to determine original gas in place with reasonable certainty when shut-in pressures are not available.

5.3.3.1 Flowing Bottom-hole Pressure

This method is based on the pseudo-steady state pressure behavior that is the rate of change of pressure at each location of the reservoir is constant. From the above mentioned assumption for the pseudo-steady state condition the rate of change of the average reservoir pressure is also constant as production continues. This process requires the flowing sand face pressure at the wellbore for plotting p_{wf}/z vs cumulative production (G_p). A straight line drawn through the flowing sand face pressure data and then a parallel line from the initial reservoir pressure gives the initial gas in place.

The method is useful for calculating the reserves of medium and high permeability reservoirs, from flowing pressure data without any loss of valuable production, which is required for classical method. The method is specially suitable for Salda Nadi Gas Field as well as for other gas fields of Bangladesh where routine pressure testing can not be conducted due to critical demand-supply situation.

The flowing bottom-hole pressure is calculated from the daily recorded flowing wellhead pressure and the daily gas flow rate of different wells. The simple form of calculating the flowing bottom hole pressure from Eq.5.12 is given by (Ikoku, 1992):

$$p_{wf}^2 = p_{tf}^2 \exp(s) + \frac{25\gamma_g q_{sc}^2 T_{av} z_{av} f Z[\exp(s)-1]}{sD^5} \qquad 5.16$$

where

q_{sc} = gas flow rate, MMSCFD

D = tubing diameter, inch

f = friction factor which is a function of N_{Re} and e/D

N_{Re} = Reynolds number

e/D = relative roughness

The Reynolds number can be calculated from

$$N_{Re} \approx \frac{20 q_{sc}(Mscfd)\gamma_g}{\mu(cp)D(inch)} \qquad 5.17$$

Friction factor f can be calculated from the Moody friction factor correlation or, for turbulent flow (N_{Re}>2100), by the Jain equation:

$$\frac{1}{\sqrt{f}} = 1.14 - 2\log\left[\frac{e}{D} + \frac{21.25}{N_{Re}^{0.9}}\right] \qquad 5.18$$

The recorded flowing wellhead pressure data was collected from daily records of Salda Nadi Gas Field.

5.3.3.2 Flowing Wellhead Pressure

Daily flowing wellhead pressure data are used to reserve estimate. The flowing wellhead pressure data was collected from daily records of Salda Nadi Gas Field. Mattar and McNeil explained in the "Flowing" material balance method that the wellhead pressure also has a similar trend of decline as the sand-face pressure. This is true when single-phase gas flows through the well and there is no liquid build up in the tubing. While studying the plots for p/z of FWHP vs cumulative production (G_p), it has been observed that the apparent gas in place figures of the various sands of Salda Nadi Gas Field are lower than those obtained from static bottom-hole pressure and shut-in wellhead pressure methods. This makes sense because flowing wellhead pressure decreases from the shut-in wellhead pressure because of frictional losses. The straight line drawn from the initial reservoir pressure in parallel to the flowing wellhead pressure data gives the initial gas in place.

For newly developed gas field and of critical demand-supply situation, pressure tests are not available in Salda Nadi Gas Field. In the material balance study, due to non-availability of needed pressure surveys only two flowing well method is used in the present study.

Calculation of z factor

Gopal (1977) found straight line fits for the Standing – Kats chart of the form:

$$z = pr\,(ATr + B) + CTr + D$$

Where A, B, C and D are correlation constants. Thirteen equations of this type were found to suitably represent the Standing – Kats chart, with average errors on the order of 0.6% and maximum errors up to 2.5%.

From reduced pressure (pr) and temperature (Tr) correlation equations for the Standing – Katz z– factor chart (Ikoku, 1992)

For $1.2 \leq pr \leq 2.8$ and $1.4 \leq Tr \leq 2.0$

$z = pr\,(-0.0984\,Tr + 0.2053) + 0.0621\,Tr - 0.8580$

For $2.8 \leq pr \leq 5.4$ and $1.4 \leq Tr \leq 2.0$

$z = pr\,(-0.0284\,Tr + 0.0625) + 0.4714\,Tr - 0.0011$

Where pseudo-reduced pressure $p_r = \dfrac{p}{p_c}$, pc = critical pressure

Pseudo – reduced temperature $T_r = \dfrac{T}{T_c}$, Tc = critical temperature.

5.4 CALCULATION DETAILS

5.4.1 VOLUMETRIC METHOD

Relevant data (BAPEX Report, 2001) and Calculated results are shown in Table 5.1.

We know Initial gas in place, $G = \dfrac{43560 A h \phi (1 - S_{wi})}{B_{gi}}$

Figures 5.7 to 5.12 show depth contour and thickness maps of different zones of Salda Nadi Gas Field (APPENDIX-I). These figures have been used to calculate pore volume of different zones.

GIIP Calculation of SLD# 1 (LZ)

$$\text{Proven } G = \frac{43560x555.975x36.122x0.18x0.70}{0.0046397}$$

$= 23757.22$ MMSCF

$= 23.757$ bcf.

$$\text{Probable } G = \frac{43560x502.354x52.234x0.18x0.70}{0.0046397}$$

= 31040.77 MMSCF

= 31.041 bcf.

<u>GIIP Calculation of SLD# 1 (UZ)</u>

$$\text{Proven } G = \frac{43560x303.933x83.69x0.14x0.65}{0.0050281}$$

= 20052.88 MMSCF

= 20.053 bcf.

$$\text{Probable } G = \frac{43560x340.998x86.55x0.14x0.65}{0.0050281}$$

= 23267.21 MMSCF

= 23.267 bcf.

<u>GIIP Calculation of SLD# 2</u>

$$\text{Proven } G = \frac{43560x464.548x97.309x0.155x0.534}{0.0051625}$$

= 31570.71 MMSCF

= 31.570 bcf.

$$\text{Probable } G = \frac{43560x5630388x92.032x0.155x0.534}{0.0051625}$$

= 36211.55 MMSCF

= 36.212 bcf.

5.4.2 MATERIAL BALANCE METHOD

Initial gas in place is calculated by p/z vs. cumulative production method. These results are given in Table 5.2. Flowing material balance analysis results of initial gas in place describes in the Figures 5.1 to 5.6. Corresponding gas in place figures are shown in Table 5.2. The initial gas in place determined by flowing bottom-hole pressure method of SLD # 1 (LZ), SLD # 1 (UZ) and SLD # 2 are found to be 111.427 bcf, 11.97 bcf and 40.7 bcf, respectively and total gas in place is 163.47 bcf. By flowing wellhead pressure method initial gas in place of SLD # 1 (LZ), SLD # 1 (UZ) and SLD # 2 are found to be 102.05 bcf, 13.24 bcf and 38.67 bcf respectively and total gas in place is 153.957 bcf.

5.5 RESULTS AND DISCUSSIONS

In this study the results of volumetric analysis and different flowing material balance approaches have been presented. For all the wells of the different sand gas in place values are estimated from the reservoir data and p/z vs. cumulative production.
There are one dual producer well named SLD # 1 (LZ) and SLD # 1 (UZ) and one single producer well named SLD # 2 is now in production.

Initial gas in place values estimated from the reservoir parameters by volumetric analysis is shown in Table 5.1. This table indicates that proven initial gas in place in SLD # 1(LZ), SLD # 1 (UZ), SLD # 2 be 23.757 bcf, 20.053 bcf, 31.571 bcf respectively and probable initial gas in place in SLD # 1(LZ), SLD # 1 (UZ), SLD # 2 be 31.040 bcf, 23.267 bcf, 36.212 bcf respectively. So the calculated total initial gas in place be 165.900 bcf.

Total gas in place calculated by flowing bottom-hole pressure method is 163.47 bcf and by flowing wellhead pressure method is 153.957 bcf. The reserve calculated by flowing wellhead pressure method is less than that of flowing bottom-hole pressure method except SLD # 1 (UZ). This may due to some frictional losses in pressure. In

SLD # 1 (UZ) the reserve calculated by flowing wellhead pressure method is greater than that of flowing bottom-hole pressure method. This may be due to error in data collection.

Gas in place calculated by volumetric method and material balance method is very close. There is no significant difference in volume of gas.

Table 5.1: Initial Gas In Place of Salda Nadi Gas Field by Volumetric Method

Sand		Area, A (acres)	Net Effective Thickness, h (ft)	Porosity (%)	$S_{gi}=1-S_{wi}$	B_{gi} (rcf/scf)	T res. (°F)	GIIP (BCF)
SLD#1(LZ)	Proven	555.975	36.122	18	0.70	46.397×10^{-4}	194	23.757
	Probable	502.354	52.234					31.040
SLD#1(UZ)	Proven	303.933	83.69	14	0.65	50.281×10^{-4}	185	20.053
	Probable	340.998	86.55					23.267
SLD#2	Proven	464.548	97.309	15.5	0.534	51.625×10^{-4}	193.5	31.571
	Probable	563.388	92.032					36.212
							Total	165.90

Table 5.2: Initial Gas In Place of Salda Nadi Gas Field by "Flowing" Material Balance Method

Well	Flowing Bottom-hole Pressure Method				Flowing Wellhead Pressure Method	
	Initial Res. Press. P_I, psia	Res. Temp. °R	Avg. Compressibility Factor Z	GIIP (BCF)	Initial Wellhead Pressure, psia	GIIP (BCF)
SLD # 1 (LZ)	3650	194	0.915	111.427	3214.7	102.054
SLD # 1 (UZ)	3358	185	0.925	11.973	3014.7	13.240
SLD # 2	3224	193.5	0.90	40.070	2814.7	38.663
Total				163.470		153.957

Figure 5.1: Flowing Bottom-hole Pressure Material Balance of SLD # 1 (LZ)

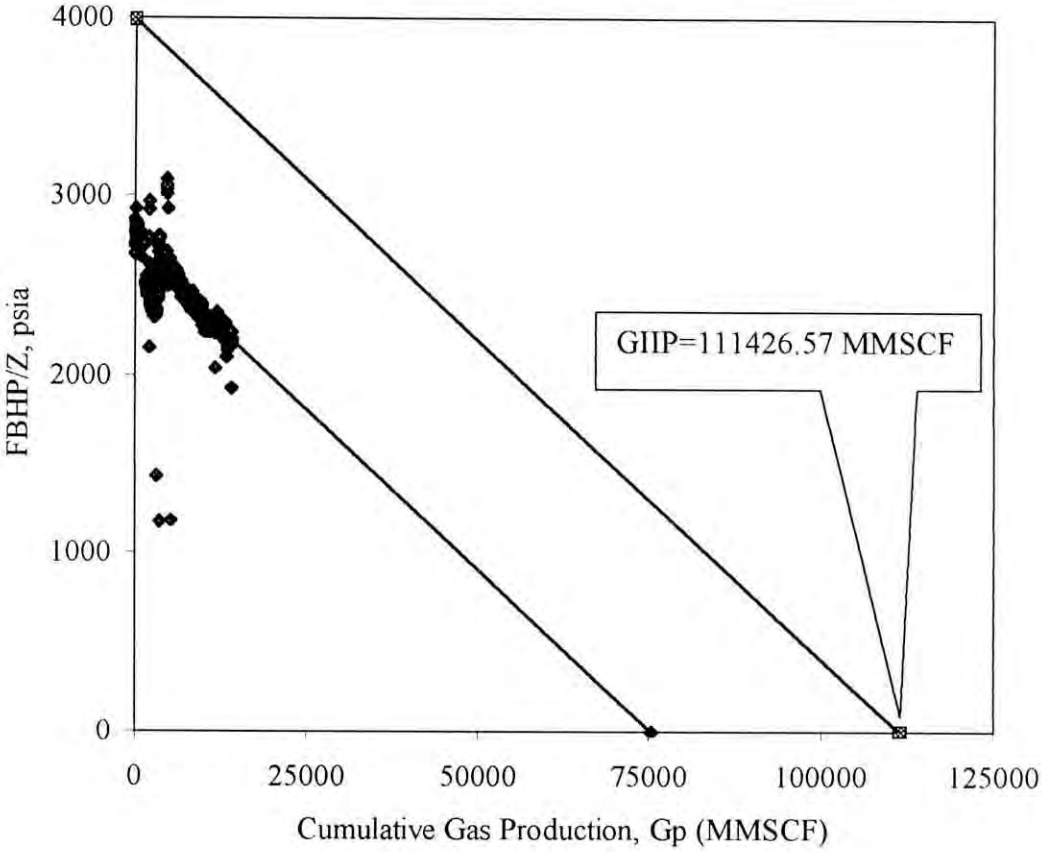


Figure 5.2: Flowing Wellhead Pressure Material Balance of SLD # 1 (LZ)

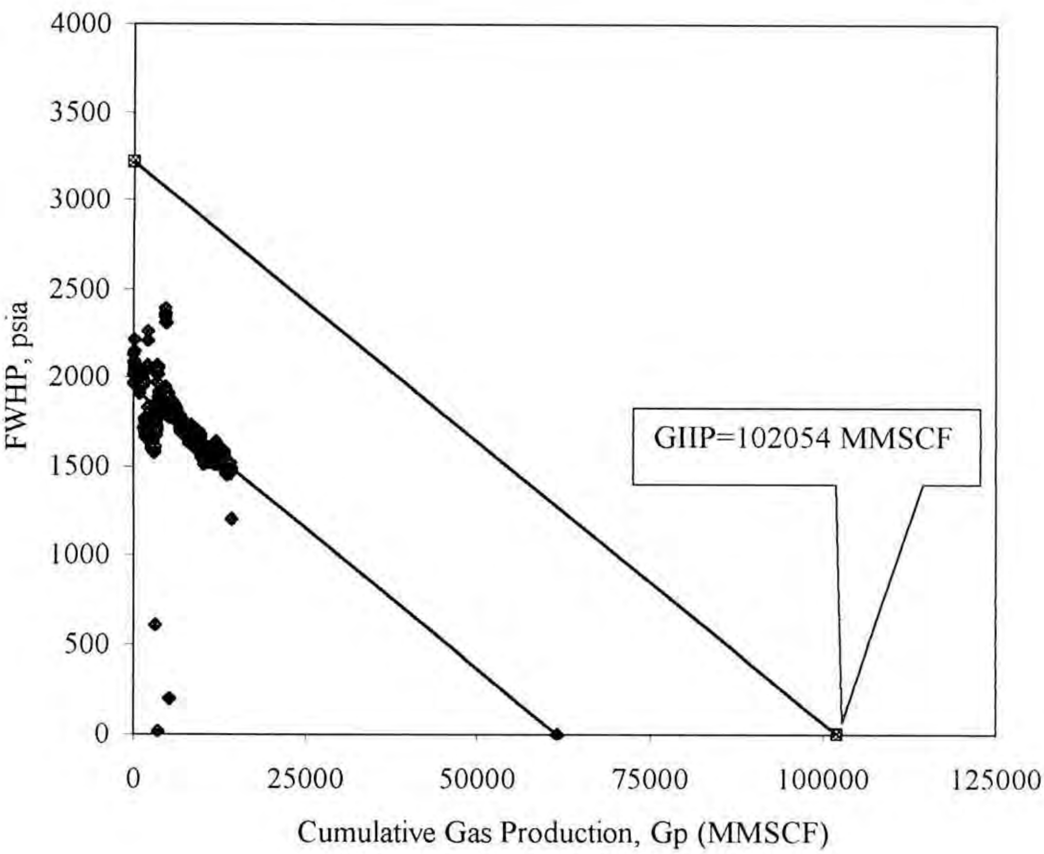


Figure 5.3: Flowing Bottom-hole Pressure Material Balance of SLD # 1 (UZ)

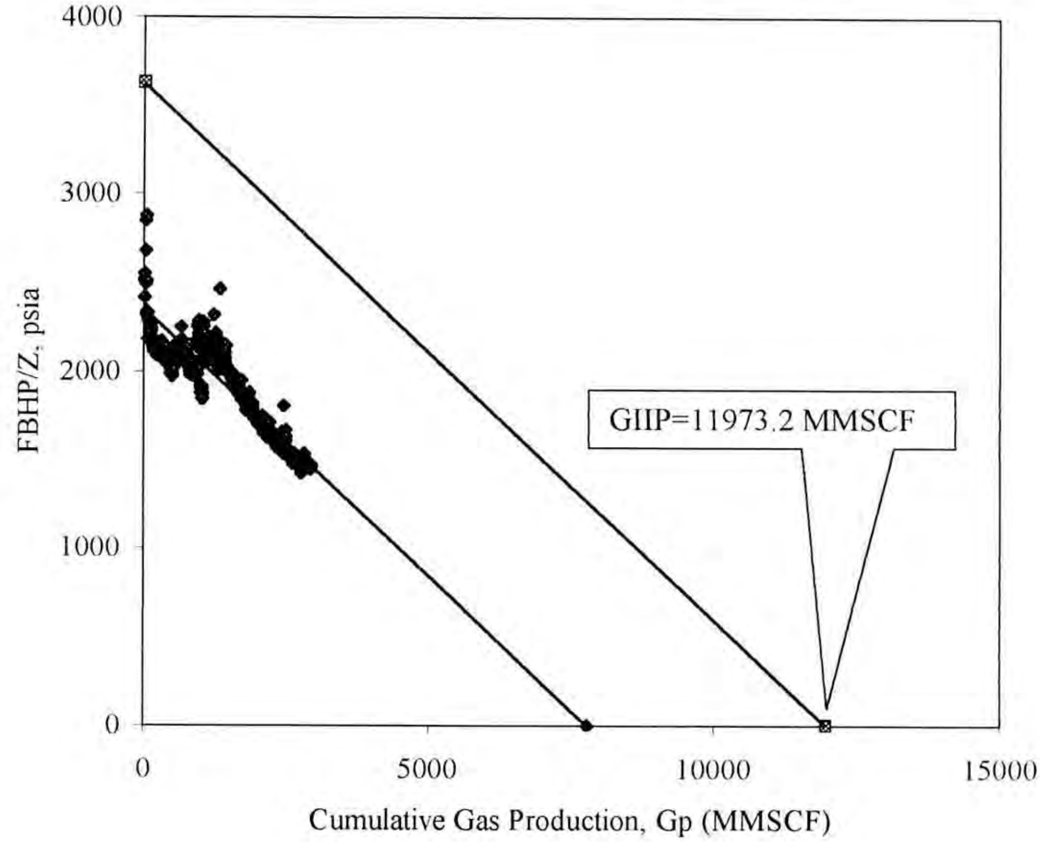


Figure 5.4: Flowing Wellhead Pressure Material Balance of SLD # 1 (UZ)

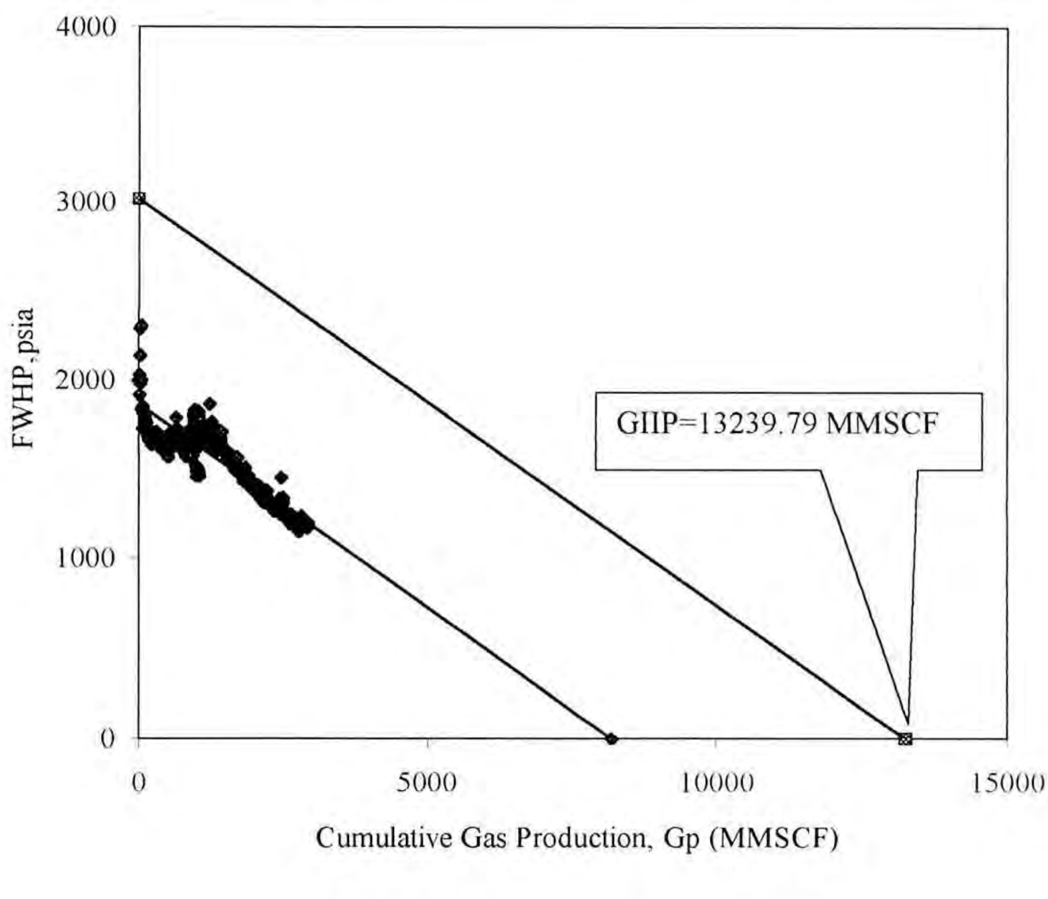


Figure 5.5: Flowing Bottom-hole Pressure Material Balance of SLD # 2

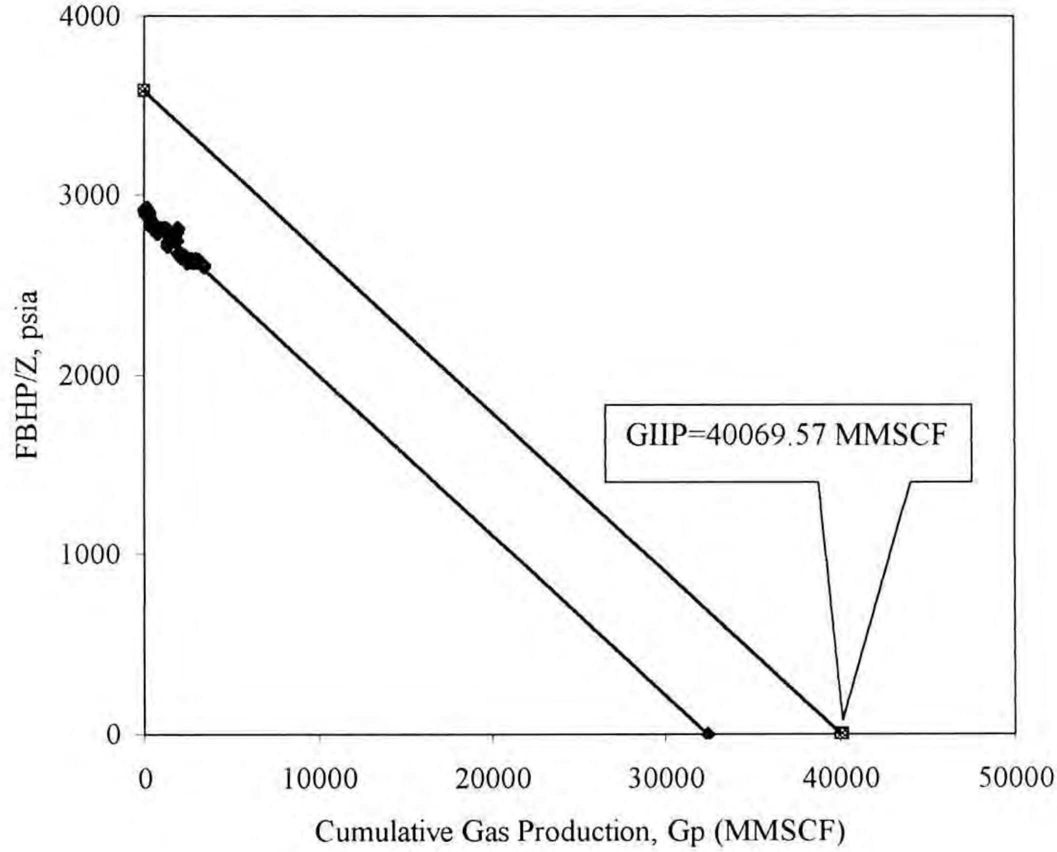
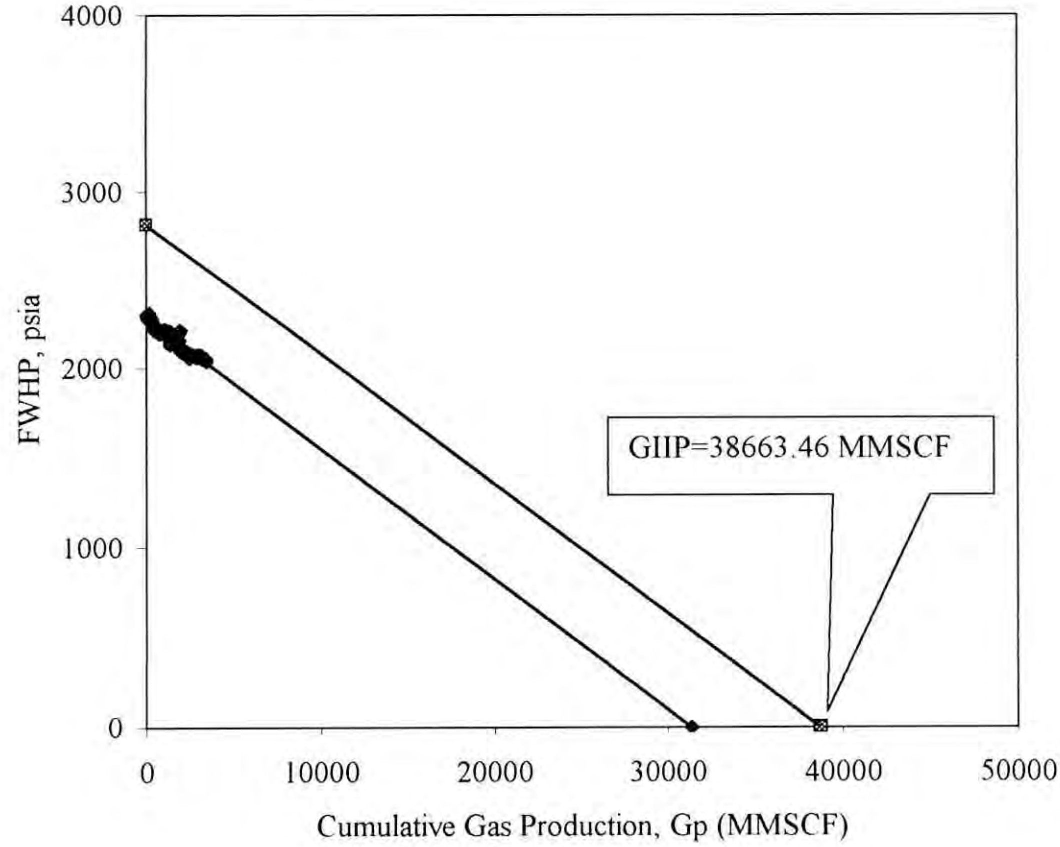


Figure 5.6: Flowing Wellhead Pressure Material Balance of SLD # 2



5.6 CONCLUSIONS

1. Applying the average porosity and water saturation the initial gas in place by volumetric method is determined to be 165.90 bcf.

2. The bottom-hole pressure and wellhead pressure flowing material balance determines the reserve about 163.47 bcf and 153.957 bcf. respectively. Initial gas in place calculated by flowing material balance is very close to that of calculated by volumetric analysis.

5.7 RECOMMENDATIONS

1. 3-D seismic survey is required for all these producing sands of Salda Nadi gas field to properly delineate the reservoir.
2. Some other wells should be drilled to identify the extension of reserve boundary and consequently proper initial gas in place.

CHAPTER 6

WELL TEST ANALYSIS

6.1 INTRODUCTION

The analysis of well test for gas reservoirs is made more complex by the fact that fluid properties are strong functions of pressure, hence the equations governing pressure transmission through fluid in a porous medium are nonlinear. In most cases of well testing, the reservoir response measured is the pressure response. Hence in many cases pressure transient analysis is synonymous with well test analysis. For gas well testing, deliverability testing is specifically useful. During a well test, the response of a reservoir to changing production conditions is monitored. Since the response depends on characteristics of the properties of the reservoir to a greater or lesser degree, it is possible in many cases to infer reservoir properties from the response. In well test interpretation, a mathematical model is used to relate pressure response to flow rate. Well test interpretation is therefore an inverse problem where model parameters are inferred by analyzing model response to a given input.

6.2 BASIC THEORY OF PRESSURE TRANSIENT TEST ANALYSIS

The basic fluid flow equation is the diffusivity equation. It is the combination of the law of conservation of matter, an equation of state, and Darcy's law. The differential equation for fluid flow through porous medium is known as diffusivity equation and is provided below (Earlougher, 1977):

$$\frac{\partial^2 p}{\partial r^2}+\frac{1}{r}\frac{\partial p}{\partial r}=\frac{1}{0.0002637}\frac{\phi\mu c_t}{k}\frac{\partial p}{\partial t} \qquad 6.1$$

Mattews and Russell (Mattews and Russell, 1967) have made some assumptions as: horizontal flow, negligible gravity effects, a homogenous and isotropic porous medium, a single fluid of small and constant compressibility of Darcy's law, and that μ,ϕ, c_t and k are independent of pressure. These assumptions make the Equation 6.1 linear. The linearity of Eq. 6.1 depends on μ,ϕ, c_t or k. If these properties are strong function of pressure, or if varying multiple fluid saturation exist then, this equation must be replaced by a nonlinear form.

The above conception is concerned only with liquid systems, thus it is not applicable to gas system because gas viscosity and density vary significantly with pressure. So it requires some modification. In case of gas system, pseudo-pressure and pseudo-time approach is used to solve the Eq.6.1 to avoid non-linearity problem. The pseudo-pressure or "real gas potential" is defined as:

$$m(p) = 2\int_{p_b}^{p} \frac{p}{\mu(p)z(p)}dp \quad \text{.......} 6.2$$

where p_b is an arbitrary base pressure, $\mu(p)$ is the viscosity, and $z(p)$ is the gas deviation factor at that pressure. When the pseudo-pressure is used Eq. 6.1 essentially retains its form but with $m(p)$ replacing p. In case of very tight formations only pseudo-pressure is not sufficient to linearise the flow equations; because if at the beginning of the test, Δp becomes large, the gas compressibility changes significantly. In this situation it is necessary to replace the time with 'pseudo-time', usually noted t_{pseudo} and defined as:

$$t_{pseudo} = \int_{0}^{t} \frac{d\tau}{\mu c_t}$$, where τ is time of consideration.

6.2.1 PRESSURE BUILD-UP TEST ANALYSIS

The most familiar transient well testing technique is pressure build-up testing. Pressure build-up test requires shut down of producing well. If a well is produced at a rate of q until time t_p, and at zero rate thereafter, the bottom-hole shut-in pressure buildup testing can be presented as below (Earlougher, 1977):

$$p_{ws} = p_i \; \frac{141.2qB\mu}{kh} \{p_D([t_p + \Delta t]_D) - p_D(\Delta t)\} \quad \text{.......} 6.3$$

where p_D and t_d are dimensionless-pressure and dimensionless-time respectively.

And,

$$t_D = \frac{0.0002637kt}{\phi\mu c_t r_w^2} \quad \text{......6.4}$$

For infinite-acting reservoirs and when wellbore storage effects diminish and there is no remarkable induced fracture, p_d can be represented by:

$$p_D = \frac{1}{2}\left(\ln t_D + 0.80907\right) \quad \text{......6.5}$$

This equation is applicable only when t_D >100. Eq.6.3, Eq. 6.4, and Eq. 6.5 yield

$$p_{ws} = p_i - m_x \log\left(\frac{t_p + \Delta t}{\Delta t}\right) \quad \text{......6.6}$$

Eq.6.6 is a straight line equation with intercept p_i and slope $-m_x$, where

$$m_x = \frac{162.6qB\mu}{kh} \quad \text{......6.7}$$

Eq. 6.6 describes that a plot of observed shut-in bottom-hole pressure, p_{ws} vs. $\log[(t_p + \Delta t)/\Delta t]$, known as Horner plot should have a straight line portion with slope –m that can be used to estimate reservoir permeability given as

$$k = \frac{162.6qB\mu}{m_x h} \quad \text{......6.8}$$

Skin factor does not appear in the stated Horner plot. But skin factor affects the shape of the pressure build-up data. Flowing pressure before skin factor and this affect shut-in may be determined from build-up test as expressed below:

$$s = 1.1513\left[\frac{p_{1hr} - p_{wfm}(\Delta t = 0)}{m_x} - \log\left(\frac{k}{\phi\mu c_t r_w^2}\right) + 3.2275\right] \quad \text{......6.9}$$

6.2.2 PRESSURE DRAWDOWN TEST ANALYSIS

A pressure drawdown test is conducted by producing a well, starting ideally with uniform pressure in the reservoir. Flow rate and pressure are recorded as function of time. The objectives of drawdown test are to estimate permeability and skin factor. This test is applicable for new wells and for wells that have been shut-in sufficiently long to allow the pressure to stabilize. In infinite-acting reservoir, when a well producing at a constant rate the pressure for drawdown test can be expressed as below (Earlougher, 1977):

$$p_i - p_{wf} = 1.141.2\frac{qB\mu}{kh}\left[p_D(t_D,...)+s\right] \qquad 6.10$$

For initial reservoir pressure p_i, the dimensionless pressure p_d at the well (r_D=1) is related with dimensionless time by:

$$p_D = \frac{1}{2}\left[\ln(t_D + 0.80907)\right] \qquad 6.11$$

when t_D/r_D^2 >100 and after wellbore storage effects have been diminished. Dimensionless time t_D is same as stated in Eq.6.4.

Combining Eq.6.10, Eq.6.11, and Eq. 6.4, a generalized form of the pressure drawdown equation is obtained as below:

$$p_{wf} = p_i - \frac{162.6qB\mu}{kh}\left[\log t + \log\left(\frac{k}{\phi\mu c_t r_w^2}\right) - 3.2275 + 0.86859s\right] \qquad 6.12$$

Eq.6.12 shows a straight-line relationship between p_{wf} and log t, and can be expressed as:

$$p_{wf} = m_x \log t + p_{1hr} \qquad 6.13$$

Theoretically Eq. 6.13 is a semi-log plot (Flowing bottom-hole pressure vs. logarithm of flowing time with slope m and intercept p_{1hr}. The slope of the straight-line from Eq. 6.12 is

$$m_x = \frac{162.6qB\mu}{kh} \qquad 6.14$$

which is similar as in build-up test.

At log t=0, the intercept p_{1hr} can be calculated from Eq.6.12 to be

$$p_{1hr} = p_i + m_x\left[\log\left(\frac{k}{\phi\mu c_t r_w^2}\right) - 3.2275 + 0.86859s\right] \qquad 6.15$$

From Eq. 6.14 we can calculate formation permeability given by

$$k = -\frac{162.6qB\mu}{m_x h} \qquad 6.16$$

and also kh/μ, kh, k/μ.

After rearranging Eq.6.15 skin factor may be estimated as:

$$s = 1.1513\left[\frac{p_{1hr} - p_i}{m_x} - \log\left(\frac{k}{\phi\mu c_t r_w^2}\right) + 3.2275\right] \qquad 6.17$$

p_{1hr} must be from semi-log straight line in any situation to avoid calculating an influenced pressure.

6.3 BASIC THEORY OF DELIVERABILITY TEST ANALYSIS

For slightly compressible liquids in infinite-acting reservoirs, gas flow through porous media is stated below (Lee, 1982):

$$m(p_{wf}) = m(p_i) + 50300\frac{p_{sc}}{T_{sc}}\frac{q_g T}{kh}\left[1.151\log\left(\frac{1688\phi\mu_i c_{ti} r_w^2}{kt}\right) - \left(s + D|q_g|\right)\right] \qquad 6.18$$

where the pseudo-pressure can be defined as:

$$m(p) = 2\int_{p_b}^{p}\frac{p}{\mu(p)z(p)}dp \qquad 6.2$$

The term $D|q_g|$ indicates a non-Darcy flow pressure loss, because Darcy's law is not appropriate to make a relationship between flow rate and pressure drop at high velocities. Here D is a constant and the term $D|q_g|$ is positive in all cases i.e., production or injection, because the absolute value of q_g, $|q_g|$, is positive.

In case of stabilized flow $(r_i \geq r_e)$,

$$m(p_{wf}) = m(p) - 50300\frac{p_{sc}}{T_{sc}}\frac{q_g T}{kh}\left[\log\left(\frac{r_e}{r_w}\right) - 0.75 + \left(s + D|q_g|\right)\right] \qquad 6.19$$

Mainly, gas well test analysis is based on the Eq.6.18 and 6.19.

The generalized form of Eq.6.18 for $\bar{p} \prec p_i$ is given below:

$$m(p_{wf}) = m(\bar{p}) + 50300 \frac{p_{sc}}{T_{sc}} \frac{q_g T}{kh} \left[1.151 \log \left(\frac{1688 \phi \mu_i c_{ti} r_w^2}{kt} \right) - \left(s + D|q_g| \right) \right] \quad 6.20$$

where $p = \bar{p}$ for all r at $t_p = 0$. For most gases, $p < 2000$ psia, $\mu z_g \approx \text{constant} \approx \mu \bar{p} z_{\bar{p}g}$ and then

$$m(p) = \frac{2}{\mu_{\bar{g}} z_{\bar{p}g}} \left(\frac{p^2}{2} - \frac{p_\beta^2}{2} \right)$$

putting into Eq. 6.20,

$$p_{wf}^2 = \bar{p}^2 + 1637 \frac{q_g \mu_{\bar{p}} z_{\bar{p}g} T}{kh} \left[\log \left(\frac{1688 \phi \mu_{\bar{p}} c_{t\bar{p}}}{kt_p} \right) - \left(s + D|q_g| \right) \right] \quad 6.21$$

In case of stabilized flow,

$$p_{wf}^2 = \bar{p}^2 - 1422 \frac{q_g \mu_{\bar{p}} z_{\bar{p}g} T}{kh} \left[\log \left(\frac{r_e}{r_w} \right) - 0.75 + \left(s + D|q_g| \right) \right] \quad 6.22$$

This equation represents the deliverability equation. The gas flow rate q_g can be calculated for a given value of p_{wf} and corresponding backpressure. The equation can be used in the following way:

i) For flow rate q_g until $r_i \geq r_e$ (stabilized flow), the Eq.6.22 can be written as

$$\bar{p}^2 - p_{ef}^2 = a q_g + b q_g^2 \quad 6.23$$

where

$$a = 1422 \frac{\mu_{\bar{p}} z_{\bar{p}g} T}{kh} \left[\log \left(\frac{r_e}{r_w} \right) - 0.75 + s \right] \quad 6.24$$

and

$$b = 1422 \frac{\mu_{\bar{p}} z_{\bar{p}g} T}{kh} D \quad 6.25$$

And these two constants can be determined from flow test.

ii) For flow until $r_i \leq r_e$ (transient flow), we can calculate $kh, s,$ and D from transient tests (drawdown or build-up) by using Eq. 6.21. These parameters with association of $\bar{p}$ and r_e in Eq.6.22 will provide deliverability estimates.

Variations of deliverability tests like flow-after-flow, isochronal and modified isochronal test are used for gas wells.

6.3.1 FLOW- AFTER-FLOW TEST

For this test, a well is allowed to flow at a constant rate until pressure stabilization and then recorded. Again, at another constant flow rate the well is flowed until pressure stabilization. The process is repeated for three to four times. There are two methods to analyze this test.

i) Empirical Method

In general, a plot of $\Delta p^2 = \bar{p}^2 - p_{wf}^2$ vs. q_g on a log-log paper is approximately a straight line for pseudo-steady state at each rate. The equation of the plot is given below:

$$q_g = c\left(\bar{p}^2 - p_{wf}^2\right)^n \quad \text{.......} 6.26$$

Equation 6.26 is an empirical correlation of the field data. The constant c and n used in this equation are not constant exactly. They depend on fluid properties. The absolute open flow potential (AOF) is the theoretical rate at which the well would produce if the flowing wellhead pressure is atmospheric.

ii) Theoretical Method

Equation 6.23 indicates that one can plot $\left(\bar{p}^2 - p_{wf}^2\right)/q_g$ vs. q_g for pseudo-steady state flow. This plot will be a straight line with slope b and intercept a. By extrapolating of this straight-line equation we can determine AOF.

6.3.2 ISOCHRONAL TEST

This technique is used to obtain data to established a deliverability curve for a gas well flowing for a shorter period to achieve stabilized conditions ($r_i \geq r_e$) at each rate. This process is essential for lower-permeability reservoirs, because, it is frequently impractical to achieve $r_i = r_e$ during the test. An isochronal test is carried out by flowing a well at a fixed rate and for certain amount of time, then shutting it until the pressure builds up to a constant pressure, $\bar{p}$. Again the well is allowed for production at a second rate for the same length of time, followed by another shut-in, etc. If possible, the final flow period should be long enough to achieve stabilized flow.

6.3.3 MODIFIED ISOCHRONAL TEST

Basically modified isochronal tests and isochronal tests are same, but the difference is that, in this case, lengthy shut-in period is not required.

In the modified isochronal test method, The same duration of flow periods and shut-in periods are used, The final shut-in p_{ws} before the beginning of a new flow period is used as an approximation to $\bar{p}$ in the analysis procedure. For example, for the first flow period, $(\bar{p}^2 - p_{wf,1}^2)$ is used, $(p_{ws,1}^2 - p_{wf,1}^2)$ is used for the second flow period, is used $(p_{ws,2}^2 - p_{wf,2}^2)$. Otherwise, the analysis procedure is the same as for the "true" isochronal test.

6.4 PRESSURE TRANSIENT ANALYSIS OF SLD # 1(LZ) AND SLD # 2

There are two wells in Salda Nadi Gas Field. Pressure history test data of Salda Nadi Gas Field supplied by Bangladesh Petroleum Exploration and Production Company Limited (A subsidized company of Petrobangla) are used for producing plots of Cartesian or type curve (simulation), semi-log, log-log (pressure vs. pressure derivative profile plot), Horner plot, and flow after flow plot. The collected wellhead pressure data by pressure gauge are converted to bottom hole pressure data by Average-Temperature and z-Factor (Ikuko, 1992) and these bottom hole data are the basis of pressure transient test. Appendix II and Appendix III shows the pressure history data of SLD # 1 (LZ) and SLD # 2 wells respectively.

Different flow rates of both the wells were recorded for different choke sizes. There were six different flow rates in SLD # 1(LZ) and SLD # 2. There are listed below in Table 6.1.

Table 6.1: Different flow rate history of Salda Nadi Gas Field (BAPEX Report, 1996 and 1999).

SLD #1(LZ)		SLD #2	
Duration (hr.)	Rate (mmscfd)	Duration (hr.)	Rate (mmscfd)
32.00	0	3.75	0
3.92	7.174	4.00	8.63
3.50	8.79	4.00	13.26
4.00	10.10	4.00	17.17
3.95	11.10	16.00	18.66
7.97	0	48.00	0

The input reservoir parameters and PVT properties are given below in Table 6.2.

Table 6.2: Reservoir properties and PVT parameters of Salda Nadi Gas Field (BAPEX Report, 1996 and 1999).

Reservoir Parameter	Value	
	SLD #1(LZ)	SLD #2
Porosity , ϕ (%)	18	15.5
Well radius, r_w (ft)	0.3542	0.25
Viscosity, μ (cp)	0.0191932	0.0182191
Total Compressibility, c_t (psi^{-1})	0.000378271	0.000549773
Initial pressure, P_i (psia)	3650	3224
Reservoir temperature, ^0F	194	193.5
Gas gravity, γ_g	0.58	0.58

The matching of the test build up data has been considered with a simple model. The model represents the behavior of a well with wellbore storage and skin in a homogeneous, infinite acting reservoir.

6.5 RESULTS AND DISCUSIONS

The reservoir properties are mainly the pressure response of the reservoir to a given change in the flow rate. Gas viscosity, permeability, compressibility factor, wellbore storage etc are the reservoir properties. The pressure data from all drawdown and build-up periods are carefully examined for the appropriate result. Pseudo-pressure is frequently used in petroleum industries. So pressure is transformed to pseudo-pressure by the given program in SAPHIR (a well testing software).

The bottom-hole pressure data (transformed from wellhead pressure, which are collected by gauge) are plotted in terms of pressure and flow rate difference with time. Buildup and Drawdown profile is shown in Figure 6.3 (for SLD # 1(LZ)) and Figure 6.7 (for SLD #2), which present pressure and production profile with time for drawndown and build-up periods. Figure 6.1 and 6.2 show the actual flow rate and pressure profiles of SLD # 1 (LZ) and SLD # 2, respectively.

Figure 6.4 (for SLD # 1(LZ)) and Figure 6.8 (for SLD #2) show the semi-log plots of pseudo-pressure versus superposition time which have a unit slope of straight line with slope m, which make it possible to estimate the permeability (k), and permeability-thickness product (kh). The unit slope straight line represents wellbore storage and gives the reservoir response. Most of the well test techniques are based on the semi-log approach. Correct semi-log straight line is essential for this analysis and this appears after wellbore damage and storage effects have diminished.

Figure 6.5 (for SLD # 1(LZ)) and Figure 6.9 (for SLD # 2) show the log-log pressure and pressure derivative profile of $dm(p)$ vs. d_t. They show the relationship between pressure and pressure derivative with time for the gas bearing sands. In case of infinite acting radial flow, initially a log-log plot of pressure drop versus time gives a characteristic straight line of unit slope. The initial part of the curve (straight line of unit slope) represents the wellbore storage and skin effect dominated flow period. The "hump" represents the transition period and the last part of the derivative flattens out, indicates the infinite acting radial flow.

Figure 6.6 (for SLD # 1(LZ)) and Figure 6.10 (for SLD # 2) show the Horner plot. A general Horner plot for the build-up period can be set in these figures as p_{ws} versus $\log\left[(t_p + \Delta t)/\Delta t\right]$. The Horner time is useful for semi-log analysis. Horner plot shows that there is a pressure decline with time before build-up period. Decline of pressure starts after diminishing of wellbore storage and skin effect. Hence it can be mentioned that semi-log plot uses early time pressure data and Horner plot uses late time pressure data. Here the slope of semi-log plots are 6.66E6 (for SLD # 1(LZ)) and 1.1E7 (for SLD# 2) and that of Horner plots are −16.2052 (for SLD # 1(LZ)) and −28.84 (for SLD # 2). These tests give some information about reservoir. These are given below in Table 6.3:

Table 6.3: Comparison of Results for Type curve and Build-up of Salda Nadi Gas Field:

Parameters	Result			
	SLD # 1(LZ)		SLD # 2	
	Type curve	Build-up	Type curve	Build-up
Initial Pressure (p_I), psia	3650	3650	3224	3224
Permeability (k), md	22.9	25.5	8.51	8.78
Reservoir Capacity (kh), md.ft	1880	2090	1810	1870
Storage Coefficient, STB/psi	0.0103	0.0103	0.0102	0.0102
Skin Factor (s)	105	121	7.83	8.34
Mobility (k/μ),	1190	1190	467	467
Pressure (p) at dt=0, psia	1850.16	1850.16	2837.99	2837.99
Time match, 1/hr.	2800	-	2890	-
Pressure match, 1/psia	1.82E-7	1.82E-7	1.05E-7	1.04E-7

This analysis gives important phenomena about the reservoir properties. Here the average permeability (k) is 25.5 md (for SLD # 1(LZ)) and 8.78 md (for SLD # 2), reservoir capacity (kh) is 2090 md.ft (for SLD # 1(LZ)) and 1870 md.ft (for SLD # 2), skin factor is +121 (for SLD # 1(LZ)) and +8.34 (for SLD # 2). These values are strongly dependent on the slope of the characteristic straight line. From this analysis, lower permeability is encountered in SLD # 2. Hydraulic fracturing is a stimulating technique. This can be applied for low to moderate- permeability reservoirs. This technique can increase permeability as well as production rate of both well.

The results obtained from different analysis are given below in Table 6.4:

Table 6.4: Comparison of Results from different analysis of SLD # 1(LZ) (SAPHIR):

Properties	Buildup and Drawdown Profile	Semi-Log	Log-Log	Horner
Reservoir	Homogeneous	Homogeneous	Homogeneous	-
Boundary	Infinite	Infinite	Infinite	-
Well	Storage & Skin	Storage & Skin	Storage & Skin	-
Initial Pressure (p_I), psia	3650	3650	3650	3650
Permeability (k), md	22.9	22.9	22.9	25.5
Permeability-thickness product (kh), md.ft	1880	1880	1880	2090
Storage (C), STB/psi	0.0103	0.0103	0.0103	-
Skin factor (s)	105.277	99.79	105.277	120.88
Pressure match, $(psi^2/cp)^{-1}$	1.82E-7	1.82E-7	1.82E-7	-
Investig. R (ft)	-	-	337	-
Mobility, k/μ	1190	1190	1190	-

Table 6.5: Comparison of Results from different analysis of SLD # 2 (SAPHIR):

Properties	Buildup and Drawdown Profile	Semi-Log	Log-Log	Horner
Reservoir	Homogeneous	Homogeneous	Homogeneous	-
Boundary	Infinite	Infinite	Infinite	-
Well	Storage & Skin	Storage & Skin	Storage & Skin	-
Initial Pressure (p_i), psia	3224	3224	3224	3224
Permeability (k), md	8.51	8.51	8.51	8.78
Permeability-thickness product (kh), md.ft	1810	1810	1810	1870
Storage (C), STB/psi	0.0102	0.0102	0.0102	-
Skin factor (s)	7.83	7.78	7.83	8.34
Pressure match, $(psi^2/cp)^{-1}$	1.05E-7	1.04E-7	1.05E-7	-
Investigating R (ft)	-	-	477	-
Mobility, k/μ	467	467	467	

These result show that permeability, reservoir capacity, and skin factor are slightly higher in the Horner plot than that of the Semi-log plot. It can be also mentioned that the above described reservoir properties are similar in case of Type curve and Semi-Log plot.

Analysis shows significant skin factor that represents a formation damage. In case of SLD # 1(LZ), skin factor is abruptly high. One reason of the damage may be due to the mud filtrate invasion and the drilling process. Acidizing generally applied when a well has a high skin effect. So, acidizing can minimize skin factor near wellbore of SLD # 1 (LZ). This technique can significantly enhance the productivity of a well when near wellbore formation damage is present.

Figure 6.11 (SLD # 1(LZ)) and 6.12 (SLD # 2) show the IPR (Flow-After-Flow) $(p_{avg}^2 - p_{wf}^2)$ vs. q_g curves. This test gives useful information about stimulation of the reservoir in terms of back-pressure coefficient, C and back-pressure exponent, n for the prediction of production optimization of the gas field. Deliverability test results of Salda Nadi Gas Field is shown in Table 6.6.

Table 6.6: Results of Flow-After-Flow Tests of the different wells

Parameters	C and n Test Type: Flow after flow	
	SLD # 1(LZ)	SLD # 2
Reservoir Pressure (psia)	3628	3221.88
AOFP (MMSCFD)	12.98	59.7385
C (MMSCFD/psia**2n)	1.60768E-6	7.53718E-5
N	0.970175	0.840625

Flow after flow test results for SLD# 1(LZ) shows lower AOF, which is 12.98 MMSCF. It seems to be very low with production rate. So there is a problem during completion operation. From BAPEX Report (1996) it is clear that SLD# 1 (LZ) was suspended for four months because of operational problem. So there is a chance to formation damage with brine near wellbore. During production test wellbore was not sufficiently clean. For this reason AOF might be very low.

So, to overcome the lower calculated AOF than expected AOF for SLD# 1(LZ), is to flow for longer time during the final flow period. This will ensure at minimum, a single point used for AOF determination from a stabilized flow.

[Note: For operational problem during completion, production tests on SLD # 1 (UZ) was not carried out. So there is no production test data. For this reason, I am unable to do well test analysis on SLD # 1 (UZ).]

Figure 6.1: Flow rate and Presuure Profile of SLD # 1(LZ) using raw data

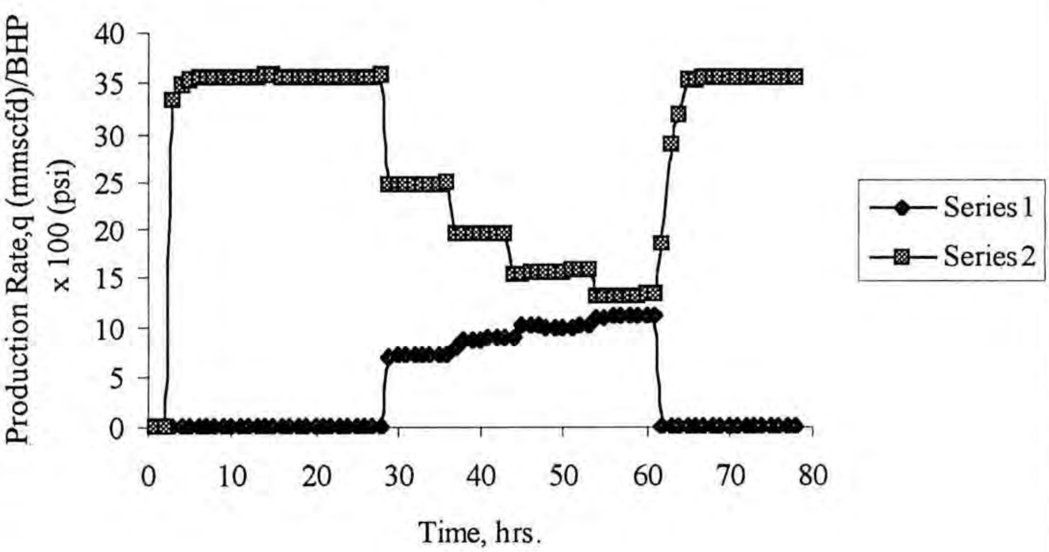


Figure 6.2: Flow rate and Pressure Profile of SLD#2 using raw dara

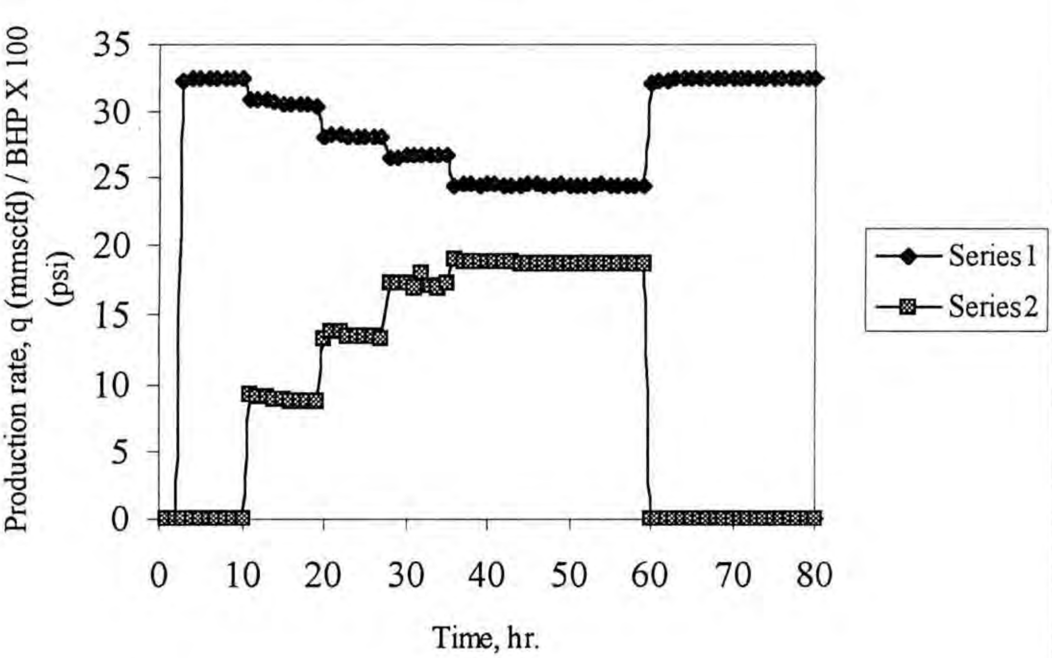
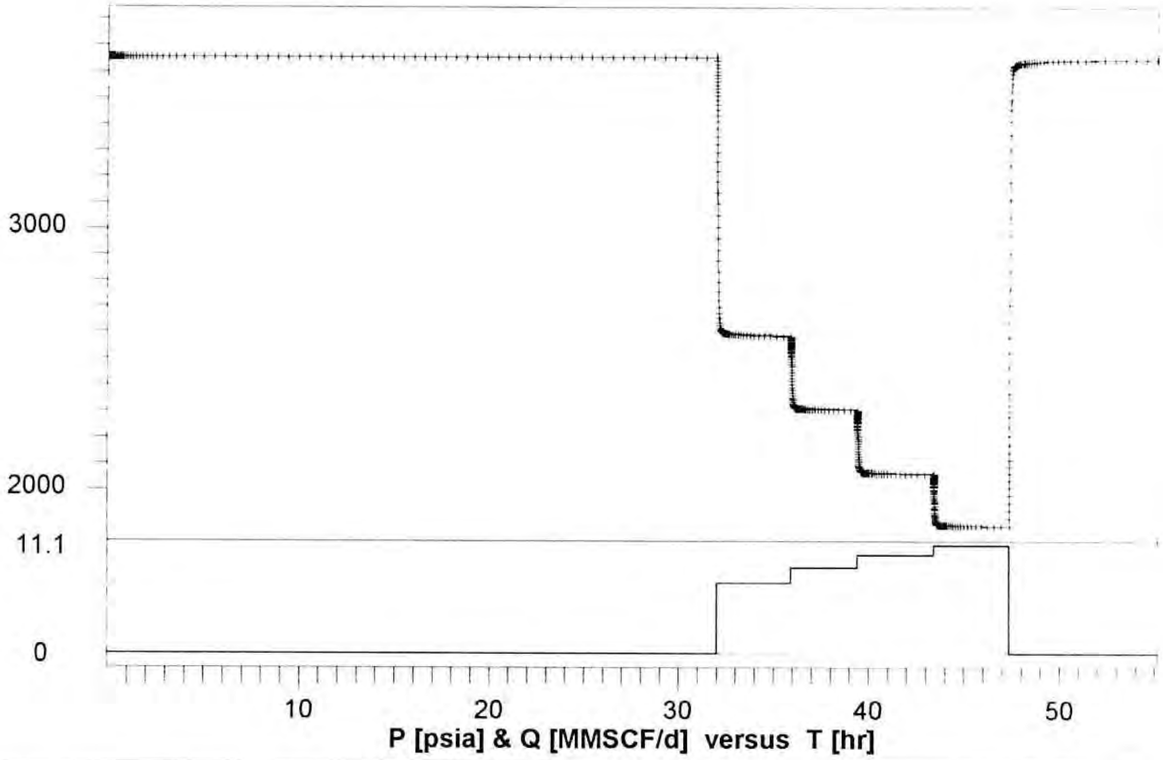


Figure 6.3 Buildup and Drawdown Profile of well SLD# 1(LZ)

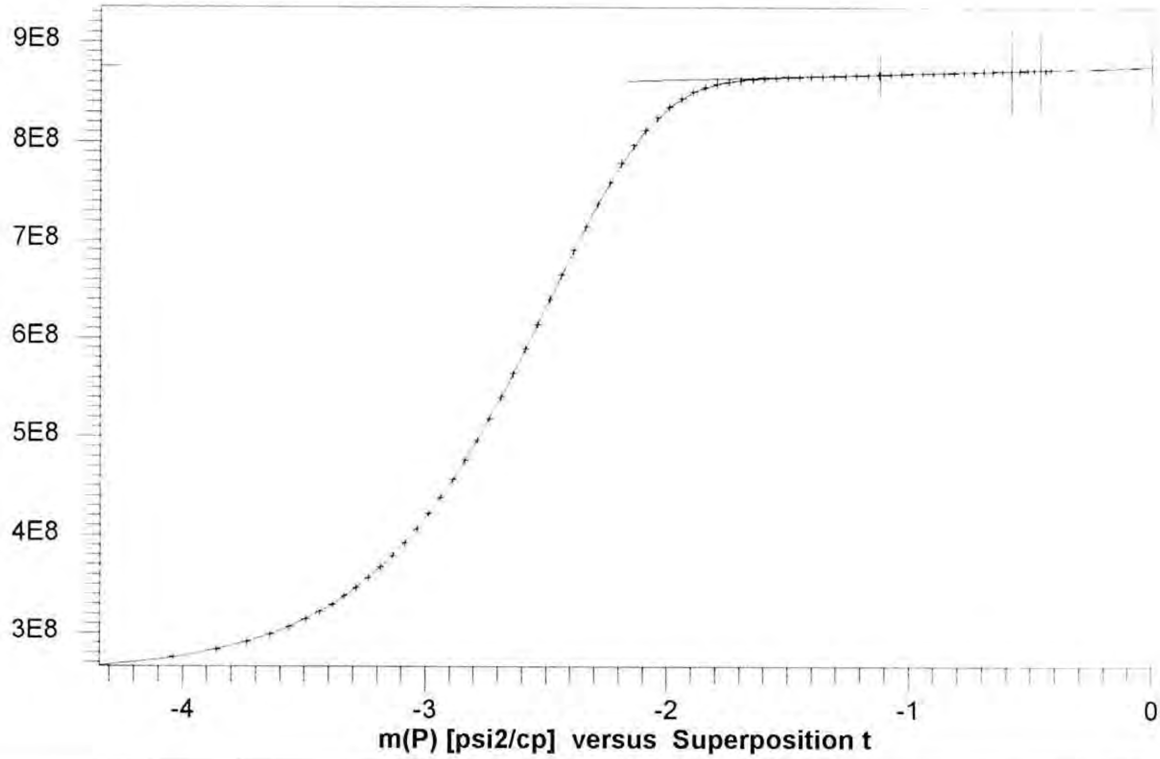
	Simulation		SALDA#1
Company	PMRE, BUET	Test	Production Test
Field	Salda Nadi	Date	November 18, 2001
Well	SLD # 1(LZ)	Gauge	



Flow Period #	6	RESERVOIR	Homogeneous
Rate	0 MMSCF/d	BOUNDARY	Infinite
Rate Change	11.1 MMSCF/d	WELL	Storage & Skin
P at dt=0	1850.16 psia	Storage C	0.0103 STB/psi
Pi	3649.68 psia	Skin factor	105
		Delta P Skin	1659.55 psia
Time Match	2800 (hr)-1		
Pressure Match	1.82E-7 (psi2/cp)-1	kh	1880 md.ft
		k	22.9 md
		Mobility k/mu	1190

Figure 6.4 Semi-log plot of Pressure data with early Time match of well SLD # 1(LZ)

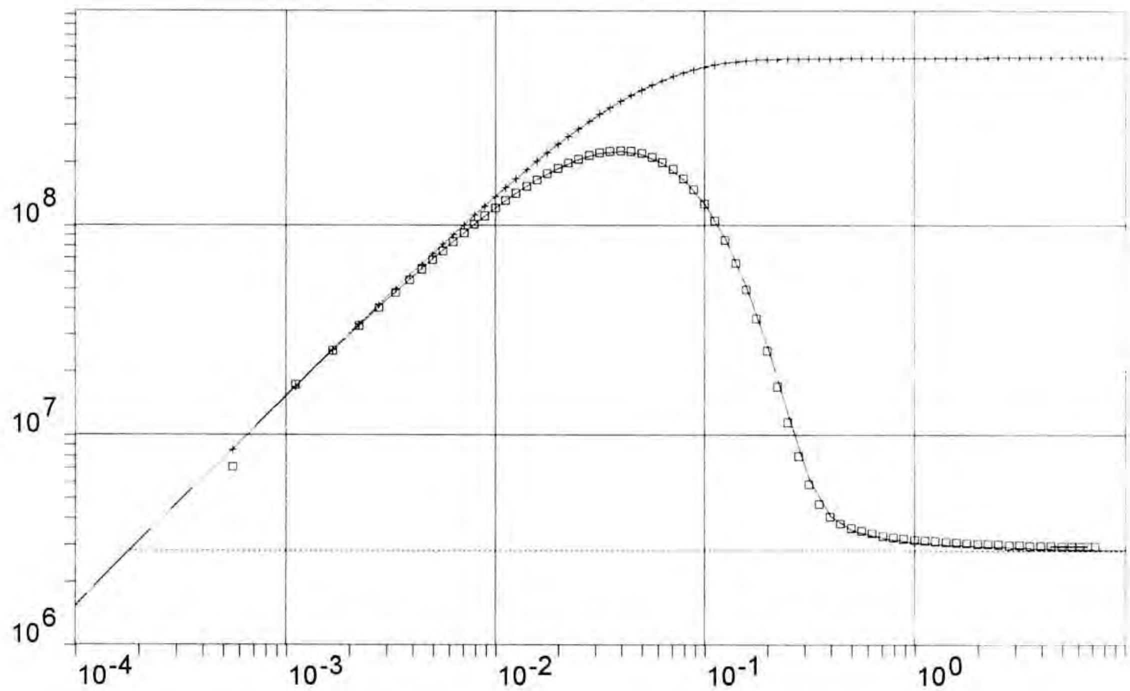
	Semi-Log		SALDA#1
Company	PMRE, BUET	Test	Production Test
Field	Salda Nadi	Date	November 18, 2001
Well	SLD # 1(LZ)	Gauge	



Flow Period #	6	RESERVOIR	Homogeneous
Rate	0 MMSCF/d	BOUNDARY	Infinite
Rate Change	11.1 MMSCF/d	WELL	Storage & Skin
P at dt=0	1850.16 psia	Storage C	0.0103 STB/psi
Pi	3649.68 psia	Skin factor	105
		Delta P Skin	1659.55 psia
STRAIGHT	LINE		
		kh	1880 md.ft
From	4.42 hr	k	22.9 md
To	6.62 hr	Mobility k/mu	1190
Slope	6.66E6 psi2/cp		
Intercept	8.73627E8 psi2/cp		
value at dt=1hr	8.66177E8 psi2/cp		
-> m*	8.73627E8 psi2/cp		
-> p*	3650.09 psia		
->PMatch	1.73E-7 (psi2/cp)-1		
-> k.h	1780 md.ft		
-> k	21.8 md		
-> Skin	99.8		
Time Match	2800 (hr)-1		
Pressure Match	1.82E-7 (psi2/cp)-1		

Figure 6.5 Log-log plot of Pressure Derivative of well SLD # 1(LZ)

Log-Log			**SALDA#1**	
Company	PMRE, BUET		Test	Production Test
Field	Salda Nadi		Date	November 18, 2001
Well	SLD # 1(LZ)		Gauge	

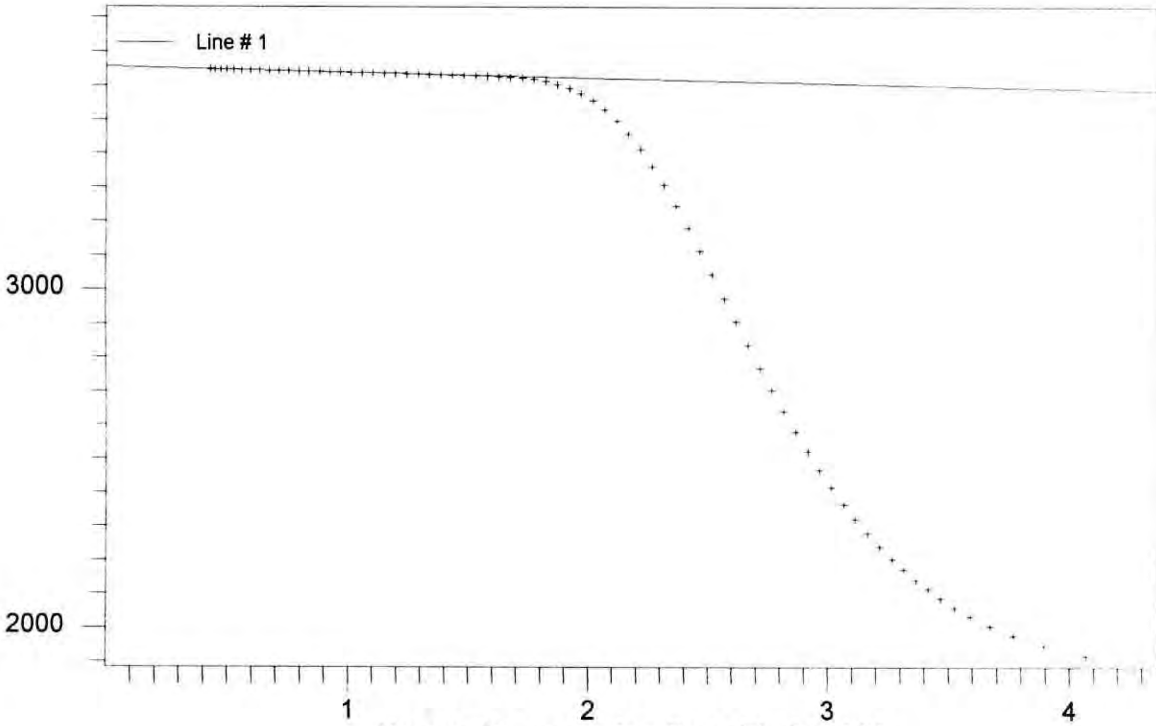


dm(P) [psi2/cp] versus dt [hr]

Flow Period #	6	RESERVOIR	Homogeneous
Rate	0 MMSCF/d	BOUNDARY	Infinite
Rate Change	11.1 MMSCF/d	WELL	Storage & Skin
P at dt=0	1850.16 psia	Storage C	0.0103 STB/psi
Smoothing	0.1	Skin factor	105
Pi	3649.68 psia	Delta P Skin	1659.55 psia
Time Match	2800 (hr)-1	kh	1880 md.ft
Pressure Match	1.82E-7 (psi2/cp)-1	k	22.9 md
		Mobility k/mu	1190
		Investig. R	337 ft

Figure 6.6 Horner plot of Pressure data with early Time match of well SLD# 1(LZ)

	Flexible		SALDA#1
Company	PMRE, BUET	Test	Production Test
Field	Salda Nadi	Date	November 18, 2001
Well	SLD # 1(LZ)	Gauge	

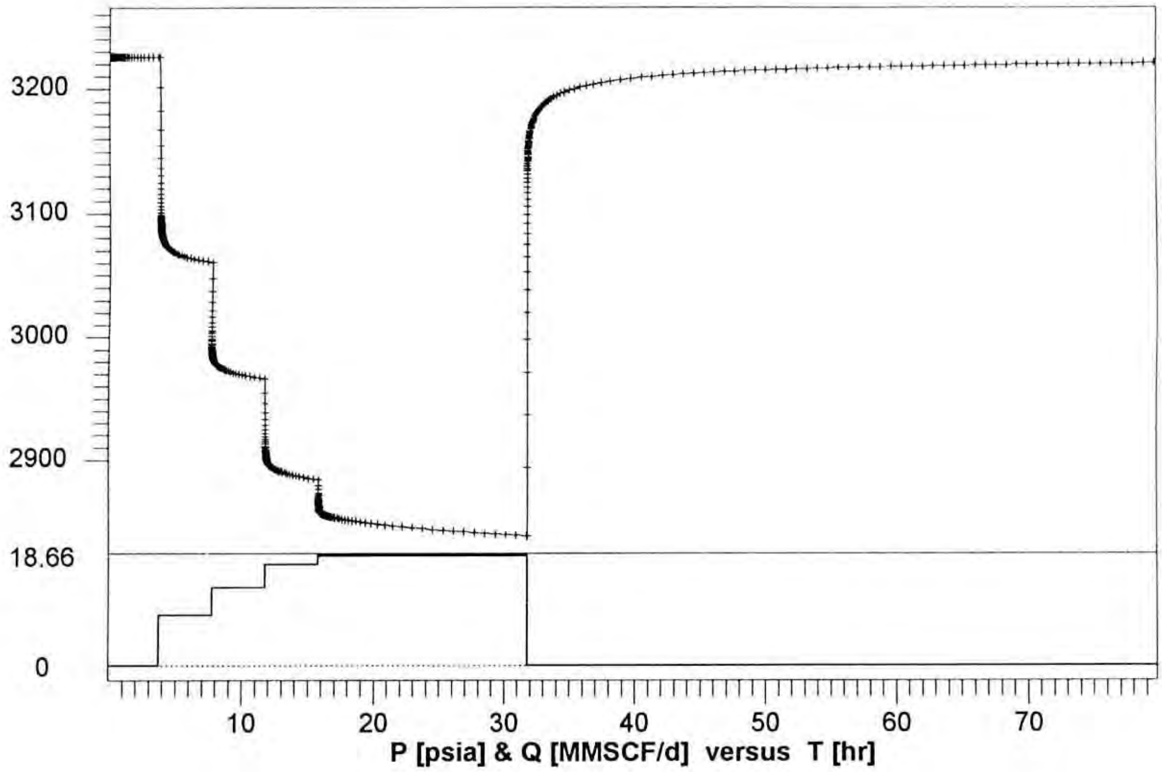


Flow Period #	6
Rate	0 MMSCF/d
Rate Change	11.1 MMSCF/d
P at dt=0	1850.16 psia
Pi	3649.68 psia

Flexible line #	1
P vs	Log(dt), BU
Slope	-16.2052
Intercept	3650.04
kh	2090 md.ft
k	25.5 md
Skin factor	121

Figure 6.7 Buildup and Drawdown Profile of well SLD # 2

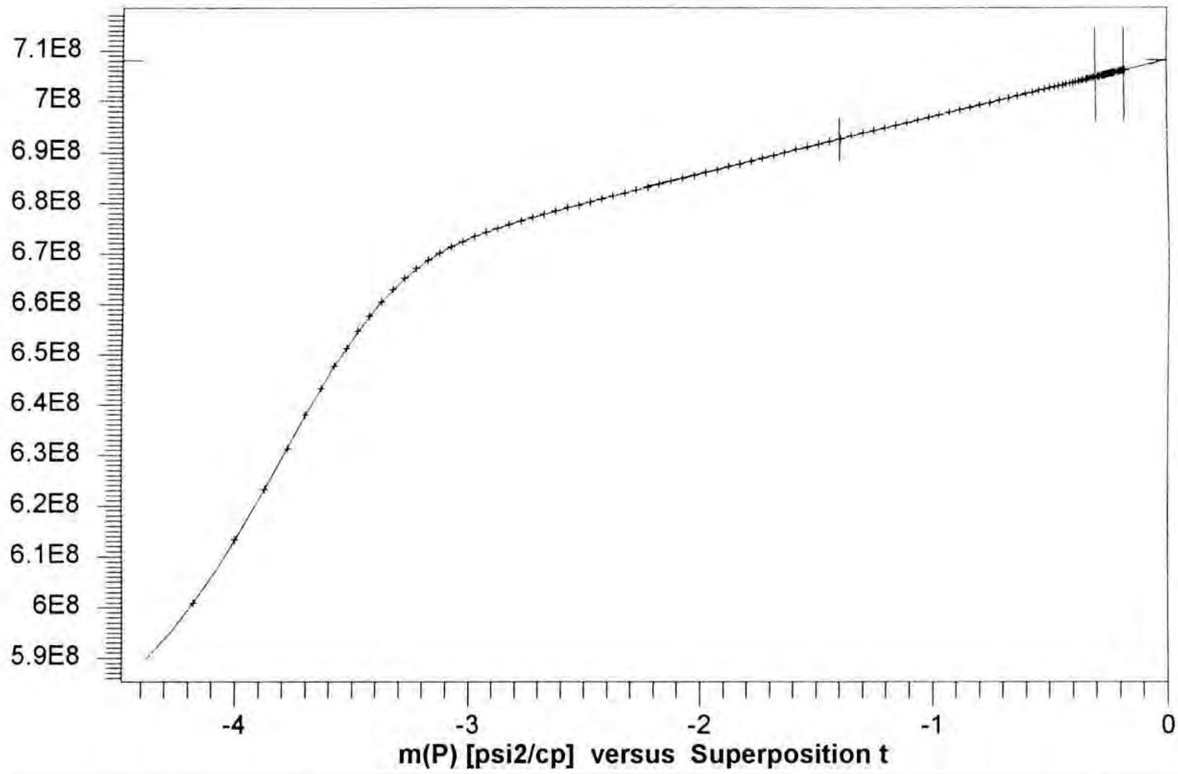
	Simulation		SALDA#2
	Company PMRE, BUET	Test	Production Test
	Field Salda Nadi	Date	November 20, 2001
	Well SLD # 2	Gauge	



Flow Period #	6	RESERVOIR	Homogeneous
Rate	0 MMSCF/d	BOUNDARY	Infinite
Rate Change	18.66 MMSCF/d	WELL	Storage & Skin
P at dt=0	2837.99 psia	Storage C	0.0102 STB/psi
Pi	3223.98 psia	Skin factor	7.83
		Delta P Skin	200.199 psia
Time Match	2890 (hr)-1		
Pressure Match	1.05E-7 (psi2/cp)-1	kh	1810 md.ft
		k	8.51 md
		Mobility k/mu	467

Figure 6.8 Semi-log plot of Pressure data with early Time match of well SLD # 2

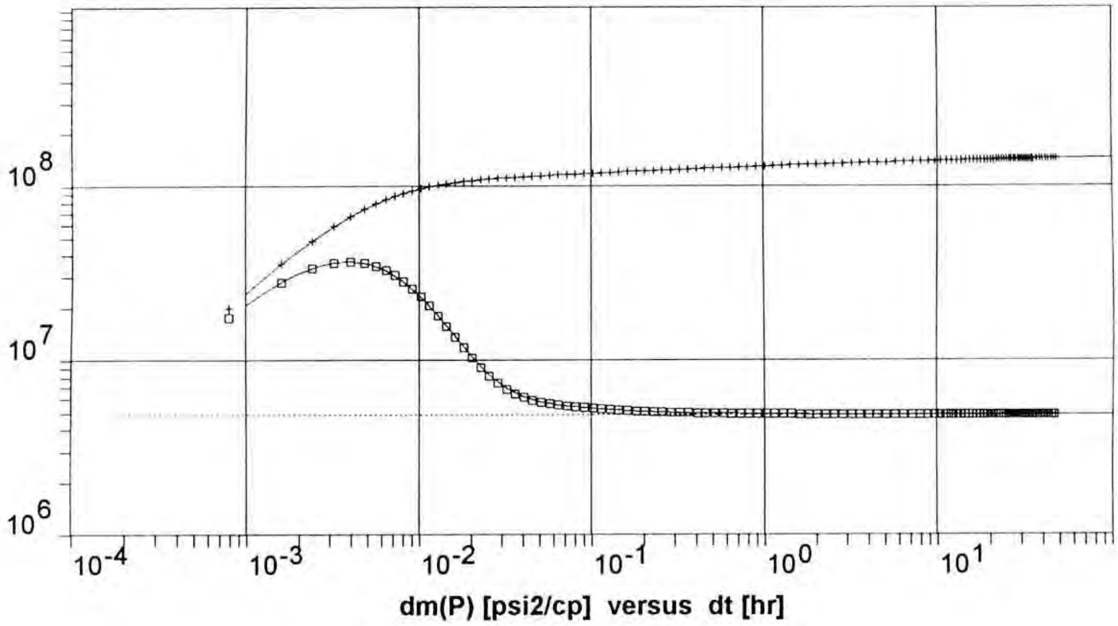
	Semi-Log			SALDA#2
	Company	PMRE, BUET	Test	Production Test
	Field	Salda Nadi	Date	November 20, 2001
	Well	SLD # 2	Gauge	



Flow Period #	6	RESERVOIR	Homogeneous
Rate	0 MMSCF/d	BOUNDARY	Infinite
Rate Change	18.66 MMSCF/d	WELL	Storage & Skin
P at dt=0	2837.99 psia	Storage C	0.0102 STB/psi
Pi	3223.98 psia	Skin factor	7.83
		Delta P Skin	200.199 psia
STRAIGHT	LINE		
		kh	1810 md.ft
From	23.9 hr	k	8.51 md
To	46.3 hr	Mobility k/mu	467
Slope	1.1E7 psi2/cp		
Intercept	7.07685E8 psi2/cp		
value at dt=1hr	6.92269E8 psi2/cp		
-> m*	7.07685E8 psi2/cp		
-> p*	3224 psia		
->PMatch	1.04E-7 (psi2/cp)-1		
-> k.h	1810 md.ft		
-> k	8.49 md		
-> Skin	7.76		
Time Match	2890 (hr)-1		
Pressure Match	1.05E-7 (psi2/cp)-1		

Figure 6.9 Log-log plot of Pressure Derivative of well SLD # 2

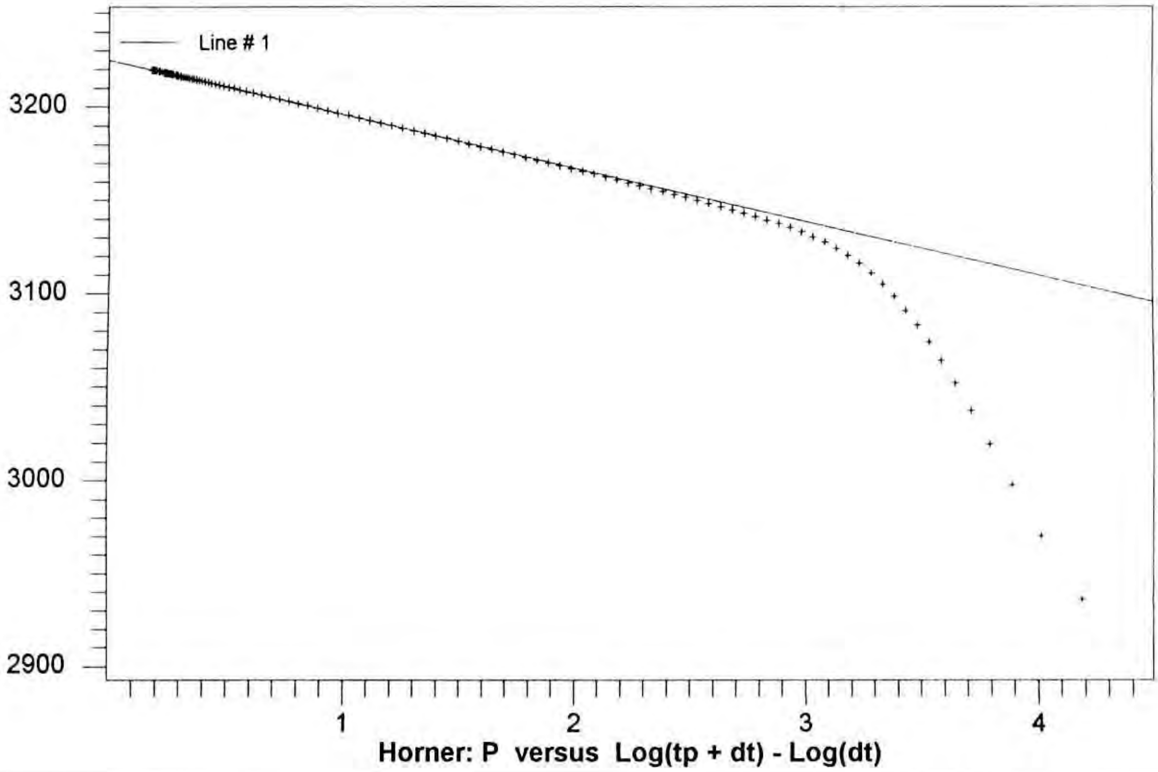
Log-Log			**SALDA#2**
Company	PMRE, BUET	Test	Production Test
Field	Salda Nadi	Date	November 20, 2001
Well	SLD # 2	Gauge	



Flow Period #	6	RESERVOIR	Homogeneous
Rate	0 MMSCF/d	BOUNDARY	Infinite
Rate Change	18.66 MMSCF/d	WELL	Storage & Skin
P at dt=0	2837.99 psia	Storage C	0.0102 STB/psi
Smoothing	0.1	Skin factor	7.83
Pi	3223.98 psia	Delta P Skin	200.199 psia
Time Match	2890 (hr)-1	kh	1810 md.ft
Pressure Match	1.05E-7 (psi2/cp)-1	k	8.51 md
		Mobility k/mu	467
		Investig. R	477 ft

Figure 6.10 Horner plot of Pressure data with early Time match of well SLD# 2

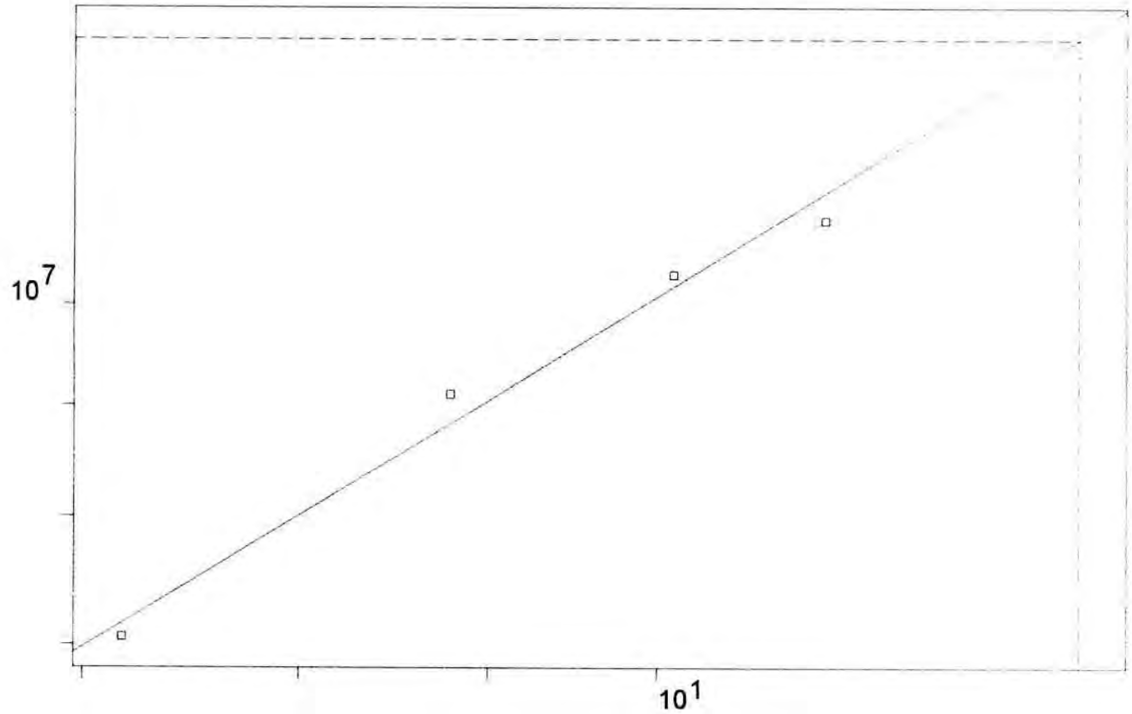
Flexible				**SALDA#2**
Company	PMRE, BUET		Test	Production Test
Field	Salda Nadi		Date	November 20, 2001
Well	SLD # 2		Gauge	



Flow Period #	6
Rate	0 MMSCF/d
Rate Change	18.66 MMSCF/d
P at dt=0	2837.99 psia
Pi	3223.98 psia
Flexible line #	1
P vs	Log(dt), BU
Slope	-28.84
Intercept	3223.98
kh	1870 md.ft
k	8.78 md
Skin factor	8.34

Figure 6.11 IPR Curve of Flow-After-Flow Test of well SLD # 1(LZ)

	IPR			SALDA#1
	Company	PMRE, BUET	Test	Production Test
	Field	Salda Nadi	Date	November 18, 2001
	Well	SLD # 1(LZ)	Gauge	

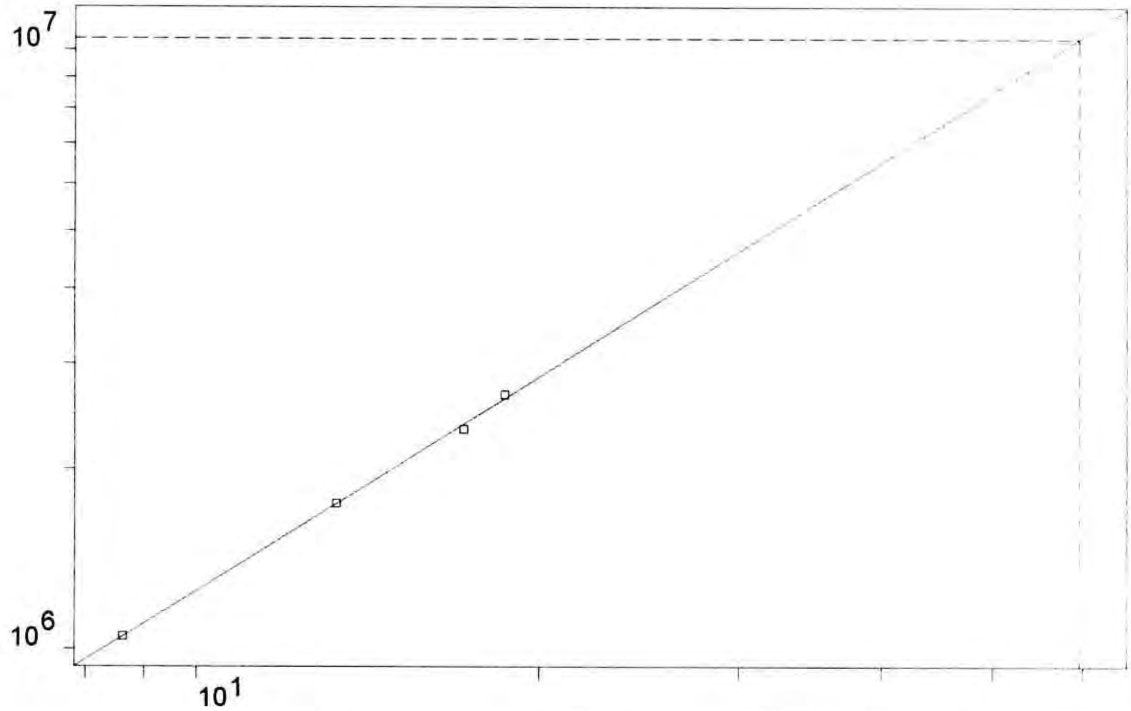


(Pavg²-Pwf²) [psia2] versus Qg [MMSCF/d]

C and n	I.P.R.
Test type	Flow after flow
Reservoir Pressure	3628.35 psia
AOFP	12.98 MMSCF/d
C	1.60768E-6, MMSCF/d/psia**2n
n	0.970175
Test points	4

Figure 6.12 IPR Curve of Flow-After-Flow Test of well SLD # 2

	IPR	SALDA#2
	Company PMRE, BUET Field Salda Nadi Well SLD # 2	Test Production Test Date November 20, 2001 Gauge



(Pavg²-Pwf²) [psia2] versus Qg [MMSCF/d]

C and n	I.P.R.
Test type	Flow after flow
Reservoir Pressure	3221 psia
AOFP	59.5677 MMSCF/d
C	7.53718E-5, MMSCF/d/psia**2n
n	0.840625
Test points	4

6.6 CONCLUSIONS

1. In SLD # 1 (LZ) AOF is very low (12.98 MMSCF) and skin factor (105) is very high. This indicates severe wellbore damage. During completion operation this well was suspended for four months and in this time pores were plugged by fine material of brine. Another cause of this problem is that this zone was partially perforated.

2. Permeability (k) of SLD # 1 (LZ) and SLD # 2 are 25.5 md and 8.78 md, respectively. Lower permeability is encountered in SLD # 2. Permeability-thickness product (kh) of SLD # 1 (LZ) and SLD # 2 are 2090 md.ft and 1870 md.ft, respectively.

3. For proper evaluation of the well inflow performance and reservoir behavior characteristics the pressure transient test as well as deliverability test on the upper zone, SLD # 1(UZ) is required.

6.7 RECOMMENDATIONS

1. It is recommended that the drilling program for all new wells in the field include provisions for the individual DST evaluation of each gas-bearing zone in the wellbore prior to final completion.

2. Isochronal or modified isochronal deliverability test is required to properly define the inflow performance of the wells completed in the different gas bearing zones.

3. The proposed solution to overcome the lower calculated AOF than expected AOF for SLD# 1(LZ), is to flow for longer time during the final flow period. This will ensure at minimum, a single point used for AOF determination from a stabilized flow.

4. Acidizing is recommended to increase the well productivity.

CHAPTER 7

PRODUCTION OPTIMIZATION

7.1 INTRODUCTION

Well is drilled and completed to transfer the gas or oil from the reservoir to the stock tank or sales line. Frictional losses are associated with the transportation. So energy is required to overcome friction losses in the system. The schematic diagram shown in Figure 7.1 illustrates the total production system with different types of losses in the production system components (i.e., porous medium, vertical conduit, and horizontal pipe). Every component in the system has an effect in the production rate of a well.

Gas production operation system is closely inter-related with reservoir performance and piping system performance. The flow rate of gas through a well from the reservoir depends on the reservoir pressure and pressure drop in the piping system. For this reason, the whole production operation must be analyzed as a single system.

7.2 NODAL ANALYSIS

Gilbert (1954) first introduced this method. This method is helpful for analyzing any well, which will allow determination of the producing capacity for any combination of components. This method may be used to determine locations of excessive flow resistance or pressure drop in any part of the system.

Firstly, the system analysis procedure requires a selection of node point in the well. This node point divides the whole system as upstream and downstream. All components upstream of the node are considered as the inflow section, while all the components downstream of the node are as the outflow section. There is a relationship

Figure 7.1: Possible Pressure Losses in Complete System (Beggs, 1984)

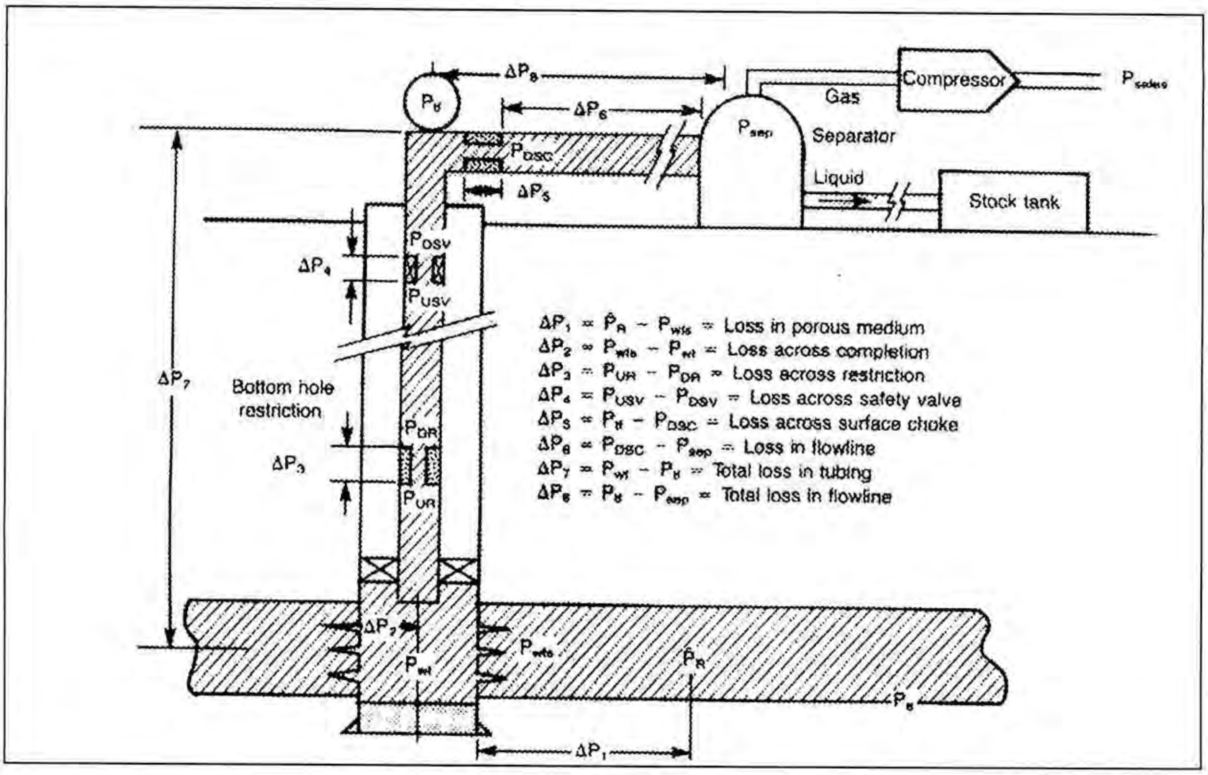
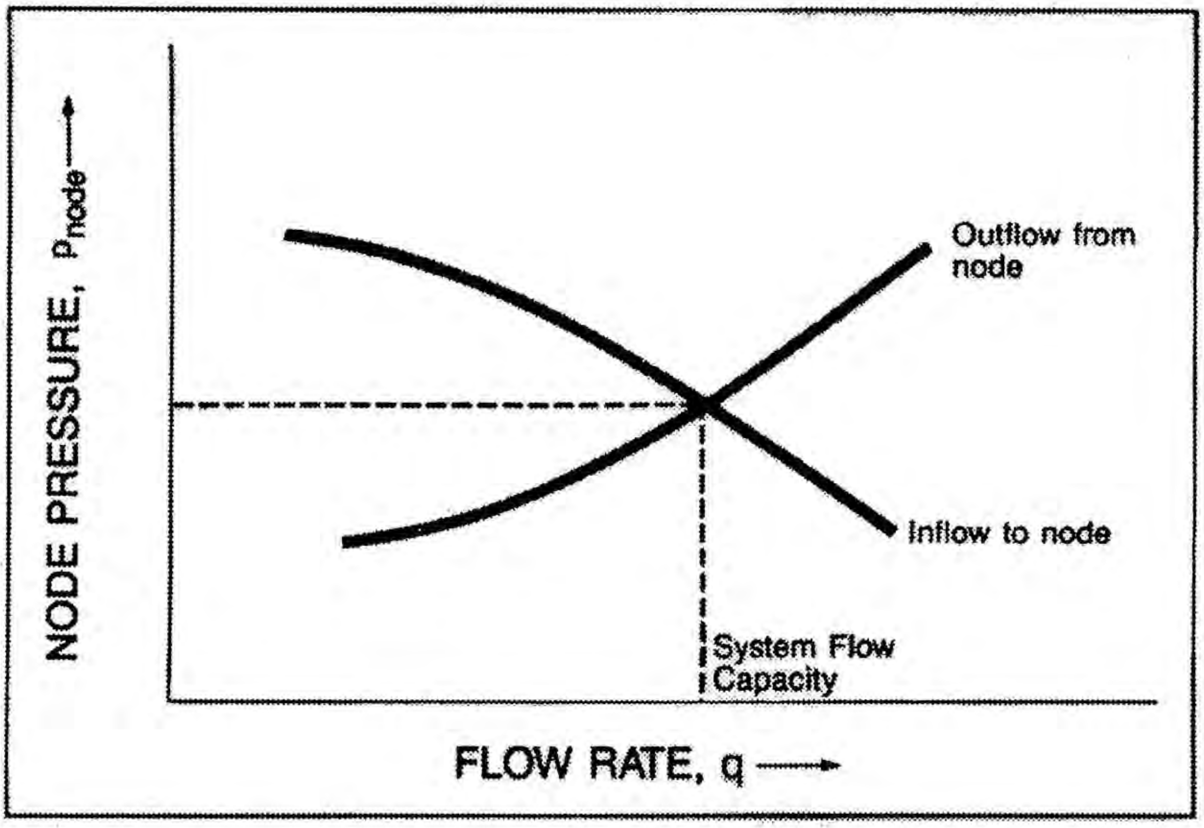


Figure 7.2: Determination of flow capacity (Beggs, 1984)



between flow rate and pressure drop for each component in the system. The production optimization system is started with two constant pressures. One is the average pressure $\overline{p}_R$ and the other is the system outlet pressure, means separator pressure p_{sep}.

The expressions for the flow into the node and for the flow out of the node can be expressed as:

Inflow:

$\overline{p}_R - \Delta p$ (upstream components)= p_{node}

Outflow:

$p_{sep} + \Delta p$ (downstream components)= p_{node}

The pressure drop, ΔP, in any component varies with flow rate, q. The flow rate through the system can be determined once the following requirements are satisfied:

a) Flow into the node equals flow out of the node;
b) Only one pressure can exist at a node.

Therefore the intersection of inflow and outflow curves determine the natural flow rate at a particular pressure. The schematic diagram shown in the Figure 7.2 illustrated the process graphically.

The effect of changing any parameters should be reflected on the inflow and outflow curve of node pressure versus flow rate. So it will be regenerated and recalculated for a new scenario. Any change in inflow curve will not affect the outflow curve, only intersection point will be shifted.

In this study, bottom-hole point is selected as nodal analysis point.

The nodal analysis method has wide variety of applications. A particular list of possible application is given below (Beggs, 1991):

i) Selecting tubing size.
ii) Selecting flowing size.
iii) Surface choke sizing.
iv) Subsurface safety valve sizing.
v) Well stimulation evaluation.
vi) Predicting the effect of depletion on producing capacity.

The success of Nodal Analysis method, however, depends on the use of appropriate correlation and equations while analyzing IPR and OPR.

7.3 NECESSARY CORRELATIONS

Production forecasting depends upon some correlation through the different components of the production system.

7.3.1 BACK PRESSURE EQUATION

In all cases, oil-well back-pressure curves were found to follow the same general form as that used to express inflow relationship for a gas well. This equation is as below:

$$q_g = C\left(\bar{p}^2 - p_{wf}^2\right)^n \qquad 7.1$$

where

q_g = gas flow rate

$\bar{p}$ = average reservoir pressure,

p_{wf} = flowing wellbore pressure,

C = flow coefficient

n = exponent depending on flow characteristics

For high-permeability reservoirs the performance of a well over the life of the field can be predicted from a single backpressure curve. The value of C and n can be evaluated from pressure test data.

7.3.2 CHOKE CORRELATION

Choke is a flow restriction device that is placed at the wellhead in the flow line. For various purposes it is desirable to restrict the production rate from a flowing well, including the prevention of coning or sand production, satisfying production rate limits as required by authority and design pressure of the plant equipment.

When gas flows through a choke, the fluid may be accelerated sufficiently to reach sonic velocity in the throat of choke. When this condition occurs, the flow is called "critical" and changes in the pressure downstream of the choke do not affect the flow rate, because pressure disturbances cannot travel upstream faster than the sonic velocity.

For isotropic flow of an ideal gas through a choke, the rate is related to the pressure ratio P_2/P_1 (Economides, et al., 1994),

$$q_g = \frac{\left(\pi D_2^2 p_1 T_{sc} \alpha\right)}{4 p_{sc} \sqrt{\left[\left(2 g_c R / 28.97 \gamma_g T_1\right)\left(\gamma / (\gamma - 1)\right)\left\{\left(p_2 / p_1\right)^{2/\gamma} - \left(p_2 / p_1\right)^{(\gamma+1)/\gamma}\right\}\right]}} \qquad \text{..............7.2}$$

where,

q_g = gas flow rate, MSCFD;

D = choke diameter, inch;

T_1 = temperature upstream of the choke, ^{0}R;

p_1 and p_2 = upstream and downstream pressure, psia;

γ = heat capacity ratio, C_p/C_V;

α = flow coefficient of the choke;

γ_g = gas gravity;

T_{sc} = standard temperature, ^{o}R

p_{sc} = standard pressure, psia;

7.3.3 SEPARATOR GAS CAPACITY CALCULATION

Separators operate basically upon the principle of pressure reduction to separate gas and liquid from an inlet stream. The separator pressure, temperature, and the composition of the fluid feed to the separator affect gas liquid separation. Generally, the gas capacity of the separator increases with increasing pressure, due to the effect of pressure on gas and liquid densities, actual flowing volume, and the allowable velocity through the separator. But for increasing temperature, the separator capacity usually decreases due to the effect of temperature on gas and liquid densities, actual flowing volume. Separation is based on the principle of gravity settling and impingement. The effectiveness of separators can be calculated from Souders-Brown equation (Kumar, 1987):

$$q_g = \frac{\pi h L\left[4 g d_d\left(\rho_l - \rho_g\right)\right]^{0.5}}{4\left(3 C_d \rho_g\right)^{0.5}} \quad \text{.......... 7.3}$$

where

q_g = gas flow rate

h= height of the separator

L= length of the separator

ρ_l, ρ_g = liquid and gas density, respectively

d_p = smallest particle size that can be separated

C_d = drag coefficient

7.4 MODEL LAYOUT

First step of the production optimization operation using Pipesim by nodal analysis is required to buildup a model. In this study the model consist of vertical completion, well tubing, choke and separator. This model is built by selecting standard component objects from the toolbox and placing them into the model window to create the system model. After creating the model relevant data is used to generate responses by varying different parameters to get a clear production scenario of the production operation. Figure: 7.3 describe the simulation model.

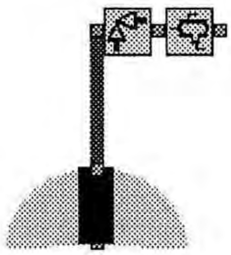


Figure 7.3: Production Optimization Model Configuration.

7.4.1 COMPLETION PERFORMANCE MODELS

There are different well inflow performance models available in PIPESIM for Windows. These are:

a) Well Productivity Index (oil and gas)
b) Vogel's Equation
c) Fetkovich's Equation
d) Jones's Equation
e) Pseudo Steady State Equation
f) Back Pressure Equation.

In this study back pressure equation is used to simulate different models.

7.4.2 FLUID MODEL

There are two fluid models available in PIPESIM for Windows. These are:

Black Oil model
Compositional model

Compositional fluid modeling is used in this study.

7.4.2.1 COMPOSITIONAL MODELING

Compositional fluid modeling is more accurate than black oil fluid modeling. For volatile fluids, rigorous heat transfer calculation is essential, which is more convenient in compositional modeling than black oil modeling. An external fluid property table is generated to obtain the physical properties at the required temperature and pressure in PIPESIM for Windows package. This is an additional advantage that this table can be used for other PIPESIM models. The compositional interface within PIPESIM allows:

Compositions to be specified
PVT tables generated
Phase envelopes generated for mixture
Compositions to be exported and
Composition to be imported.

Table 7.1 Input Well Completion data (BAPEX Report, 1996 and 1999):

Well Completion Data	SLD# 1 (LZ)	SLD# 1 (UZ)	SLD# 2
Reservoir Data:			
Static press. (psia)	3624	1701	2572
Temp. (^{o}F)	194	185	193.5
C	1.60768 e-06	1.16041 e-06	7.53714 e-05
n	0.970175	0.99918	0.840625
Tubing Details:			
Well head TVD (ft)	0	0	0
SSSV (ft)	181.89	139.6	152.654

Kick off (ft)	0	0	1223.75
Ambient Temp. (°F)	77	77	77
Mid. Perforated (ft)	7911.75	7157	7652.93
Tubing Configuration:			
Inner diameter (inch)	2.75	2.75	2.687
Wall thickness (inch)	0.625	0.625	0.410
Casing ID (inch)	7	9.625	7
SSSV data:			
Length (ft)	2.47	2.13	2.47
Inner diameter (inch)	2.562	2.31	1.38
Choke Details:			
Bean size (inch)	0.381	0.2366	0.453

7.5 RESULTS AND DISCUSSIONS

7.5.1 Well SLD # 1 (LZ)

Average reservoir pressure : 3624 psia

Average reservoir temperature : 194^0F

Bake pressure equation coefficient, C: 1.60768E-06

Bake pressure equation exponent, n : 0.970175

Figure 7.4 shows the variation of flow rate with average reservoir pressure for a tubing inner diameter of 2.75 inches. For reservoir pressure of 3624 psia, the flow rate was about 6.3 MMSCFD at well bore pressure of 2644 psia. For a lower reservoir pressure of 2800 psia, the flow rate will be as low as 4.2 MMSCFD at well bore pressure of 1894 psia, assuming all other parameters remain constant. This plot verifies past and present well performances. This simulation is helpful for prediction of flow rate with pressure drop.

Figure 7.5 presents the effect of back pressure co-efficient on production rate. The backpressure coefficient C indicates the well stimulation. For present value of C=1.60768E-06, production rate is 6.3 MMSCFD. For a low C value of 1.55E-06, production rate is only 6.2 MMSCFD. To a higher C value of 3.0768E-06, production rate will increase to 7.3 MMSCFD, and for C equals to 4.0768E-05, production rate is 7.6 MMSCF. Present production rate is low. This may be for formation damage. The formation damage can be overcome by acidizing, a well stimulation technique. Well stimulation can increase the value of C and significantly enhance the productivity of a well.

Back pressure exponent, n varies with C. So, an increase in well stimulation also changes the value of n. Figure7.6 shows that, for n equals to 0.93, a very large pressure drop occur along the reservoir and a low flow rate of 4.7 MMSCFD is obtained because of turbulent flow. With an increase in n, flow rate increases drastically. This abrupt change is between 0.94 and 0.96, and increases in flow rate from 5.2 MMSCFD to 6.0 MMSCFD. But the change is less steep between n equals to 0.970175 and 0.99. For present value of n equals to 0.970175 flow rate is 6.3 MMSCFD. The significant production rate is at n equals to 0.98. The turbulent flow is not desired in the reservoir. So, it should be avoidable and for optimum flow the value of exponent should be kept around 0.98.

The choke size has a great influence in the flow rate. The simple way of increasing the flow rate is to increase the bean size of the choke. When choke size increases from 0.425 inches to 0.5625 inches, it increases the flow rate from 7.2MMSCFD to 9 MMSCFD shown in Figure 7.7. The well is presently produces 6.3 MMSCFD at a bean size of 0.381 inches.

Figure 7.8 represents the variation of flow rate with different size of tubing. For a lower tubing inner diameter the flow rate is also low. For a tubing inner diameter of 2.31 inches a flow rate is 6.1 MMSCFD and out flow performance relationship curve is very steep which indicate a large pressure drop. But for an increase of only 0.19 inches, the flow rate increases to almost 6.2 MMSCFD and for the next 0.25 inches increment, flow rates almost 6.3 MMSCFD. The present tubing inner diameter of 2.75 inches, the production rate is 6.3 MMSCFD. Figure 7.5 also shows that up to an optimum tubing size the production rate increases significantly from this figure. We can also taken a decision that for the present flow rate the tubing size can be 2.75 inches.

Figure 7.9 shows the effect of separator pressure. At a high separator pressure of 1600 psia, the flow rate is 5.7 MMSCFD and at 1000 the flow rate is 6.3 MMSCFD. As separator pressure is decreased, gas velocity increases that also increase the gas friction.

7.5.2 Well SLD # 1 (UZ)

Average reservoir pressure: 1701 psia

Average reservoir temperature: 185 ^{0}F

Back Pressure equation coefficient C=1.16041E-06

Back Pressure equation exponent n=0.99918

[Note: Due to unavailability of production test data of this well, DST data is used to calculate back pressure equation coefficient C and exponent n.]

Flow rate depends upon reservoir pressure. With the declination of reservoir pressure, gas flow rate decreases sequentially. Figure 7.10 shows the relationship of flow rate and pressure. For present reservoir pressure of 1701 psia, the flow rate is about 1.0 MMSCFD at well bore pressure 1428 psia. Analysis shows that for a lower reservoir pressure of 1300 psia, the flow will be as low as 0.3 MMSCFD at well bore pressure 1191 psia, assuming all other parameters remain the same.

Effect of the coefficient C on flow rate shows that for a C value of 5.0E-06, production rate is 0.6 MMSCFD, which increases to 1.2 MMSCFD when C increases to 2.2E-06. For the present value of C=1.16041E-06, production rate is 1 MMSCFD shown in Figure 7.11. Present production rate is low. This may be for formation damage. The formation damage can be overcome by acidizing, a well stimulation technique. Well stimulation can increase the value of C and significantly enhance the productivity of a well.

Figure 7.12 shows the effect of the exponent n on flow rate. For the value of n equals to 0.90, a low flow rate of 0.4 MMSCFD is obtainable. The flow rate increases to 0.6 MMSCFD and 1 MMSCFD as n is increased to 0.94 and 0.99918, respectively.

Figure 7.13 shows that the flow rate increases from 1 MMSCFD to 1.7 MMSCFD as bean size is increased from 0.2366 inches to 0.725 inches. The well produces 1 MMSCFD at a choke size of 0.2366 inches.

Effect of the tubing size on the flow rate is shown in Figure 7.14. For a tubing inner diameter of 2.0 inches a flow rate of only 1 MMSCFD is possible. For a tubing size beyond 2.5 inch, the flow rate does not increase significantly. An increase in the current tubing size of 2.75 inches will not increase the flow rate further.

Separator pressure plays an important role on the flow rate as the average reservoir pressure gets lower. Figure 7.15 represents the effect of separator pressure. At high separator pressure of 1400 psia, flow rate is 0.3 MMSCFD and at 1000 psia, the flow rate is increases to 1 MMSCFD, the current value.

7.5.3 Well SLD # 2

Average reservoir pressure: 2572 psia

Average reservoir temperature: 193.5 ^{0}F

Back Pressure equation coefficient C=7.53718E-05

Back Pressure equation exponent n=0.840625

Figure 7.16 describes the variation of flow with average reservoir pressure for a tubing size 2.687 inches. For reservoir pressure of 2572 psia, the flow rate is about 7.8 MMSCFD at wellbore pressure 2386 psia. For a low reservoir pressure of 2050 psia, the flow will be as low as 5.7 MMSCFD at well bore pressure 1885 psia, assuming all other parameters remain the same.

Effect of the coefficient C on flow rate shown in Figure 7.17. This figure describes that for a C value of 0.00006, production rate is 7.6 MMSCFD, which increases to 8.3 MMSCFD when C is 0.000753718. For the present value of C 0.0000753718 the production rate is 7.8 MMSCFD. Present production rate is low. This may be for formation damage. The formation damage can be overcome by acidizing, a well stimulation technique. Well stimulation can increase the value of C and significantly enhance the productivity of a well.

Figure 7.18 represents the effect of the exponent n on flow rate. It shows that when n is 0.75, a very low flow rate of 5.6 MMSCFD is obtained because of highly turbulent flow. The flow rate increases to 7.4 MMSCFD and 8.1 MMSCFD as n is increased to 0.80 and 0.88 respectively. For present C value of 0.840625 flow rate is 7.8. Beyond the value of n=0.88, an increase in n will not increase the production rate significantly.

Choke size has a great effect on the flow rate. Figure 7.19 shows flow rate increases from 5.6 MMSCFD to 15.8 MMSCFD as bean size is increased from 0.375 inches to 0.90 inches. The well now produces at 7.8 MMSCFD at a choke size of 0.453 inches.

Figure 7.20 shows the effect of different tubing size on the flow rate. For a tubing inner diameter of 2.0 inches a flow rate of only 6.7 MMSCFD is possible. For a tubing size of 2.5 and 2.687 inches, the flow rate increases to almost 7.6 MMSCFD and 7.8 MMSCFD. It means that increasing the current tubing size of 2.687 inch, there will be no further increase in flow rate.

At high separator pressure of 1400 psia, flow rate is 6.9 MMSCFD and at 1000 psia, the flow rate is 7.8 MMSCFD as shown in Figure 7.21. For a separator pressure of

1000 psia and below, the choke is in critical range. As a result, decreasing the separator pressure below 1000 psia will have no positive effect on the flow rate.

Different optimum tubing and separator pressure of wells in the Salda Nadi gas field is shown below in Table 7.2.

Table 7.2: Existing and Recommended Tubing Size and Separator Pressure

Well	Tubing Size, inch		Separator Pressure, psia	
	Existing	Recommended	Existing	Recommended
SLD #1 (LZ)	2.75	2.75	1000	1000
SLD #1 (UZ)	2.75	2.5	1000	1000
SLD #2	2.687	2.687	1000	1000

Figure 7.4: Effect of Average Reservoir Pressure on the Performance of Well SLD # 1(LZ)

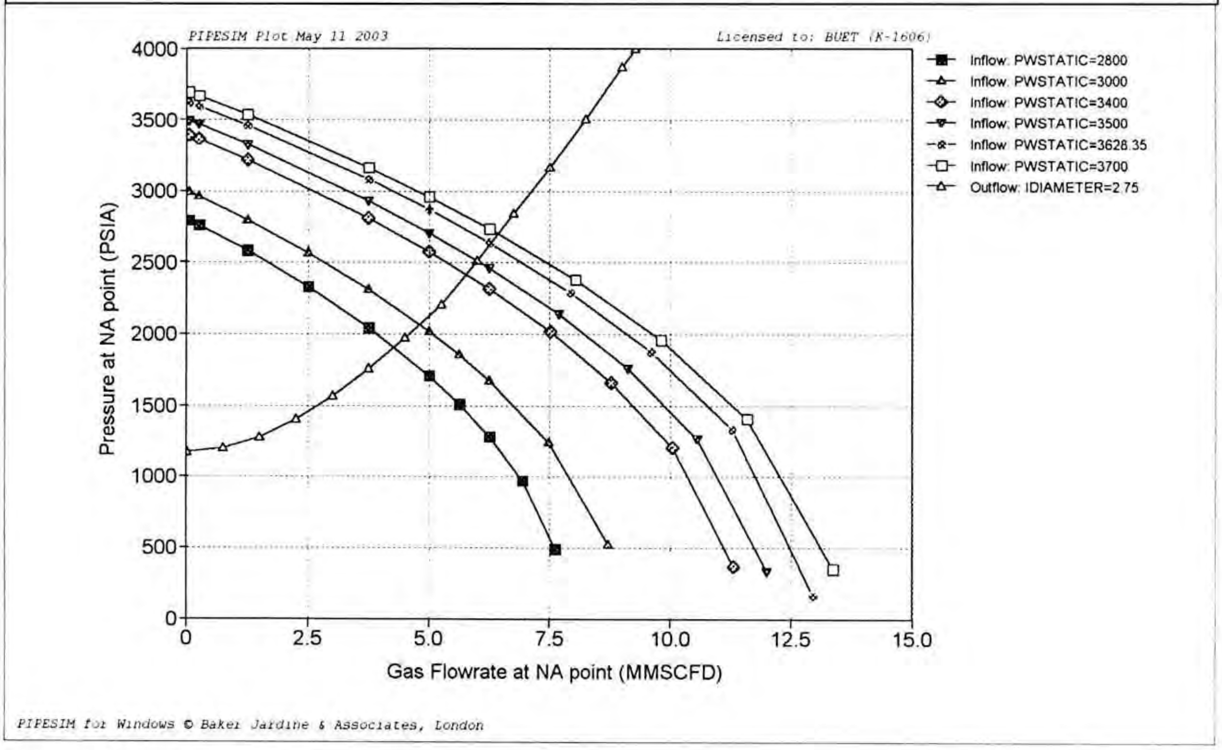


Figure 7.5: Effect of Back Pressure Coefficient on the Performance of Well SLD # 1(LZ)

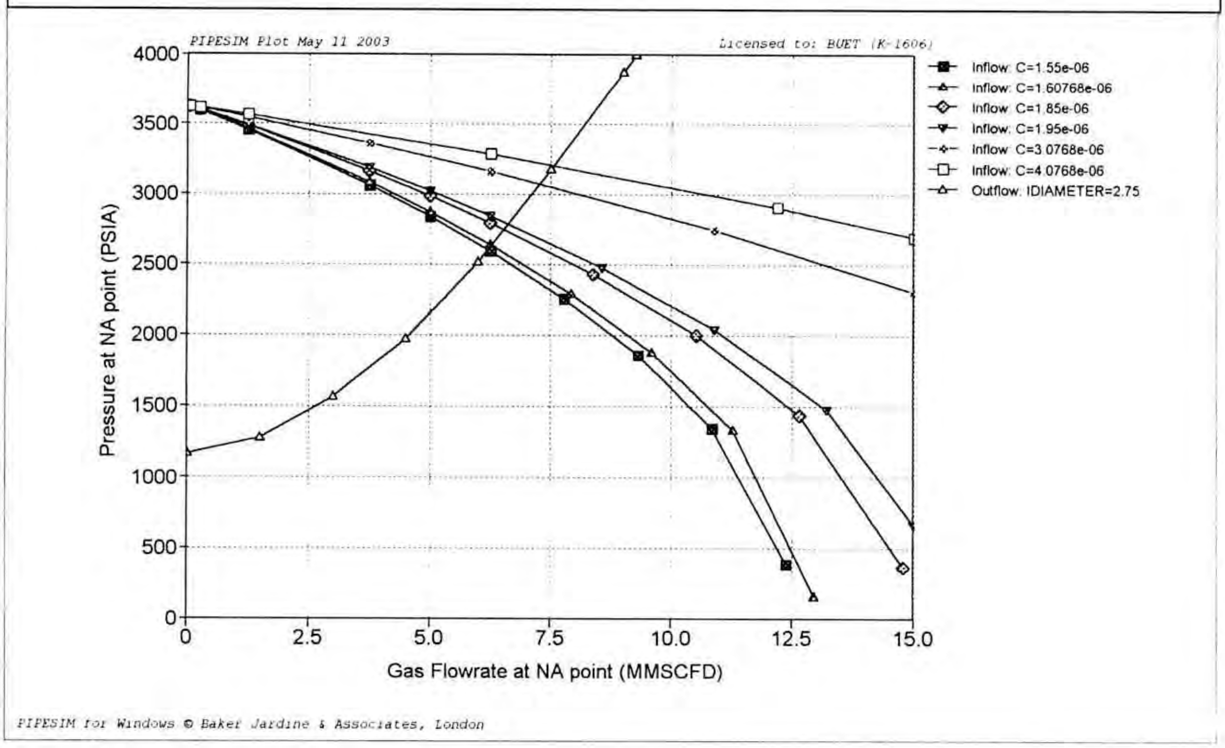


Figure 7.6: Effect of Back Pressure Exponent on the Performance of Well SLD # 1 (LZ)

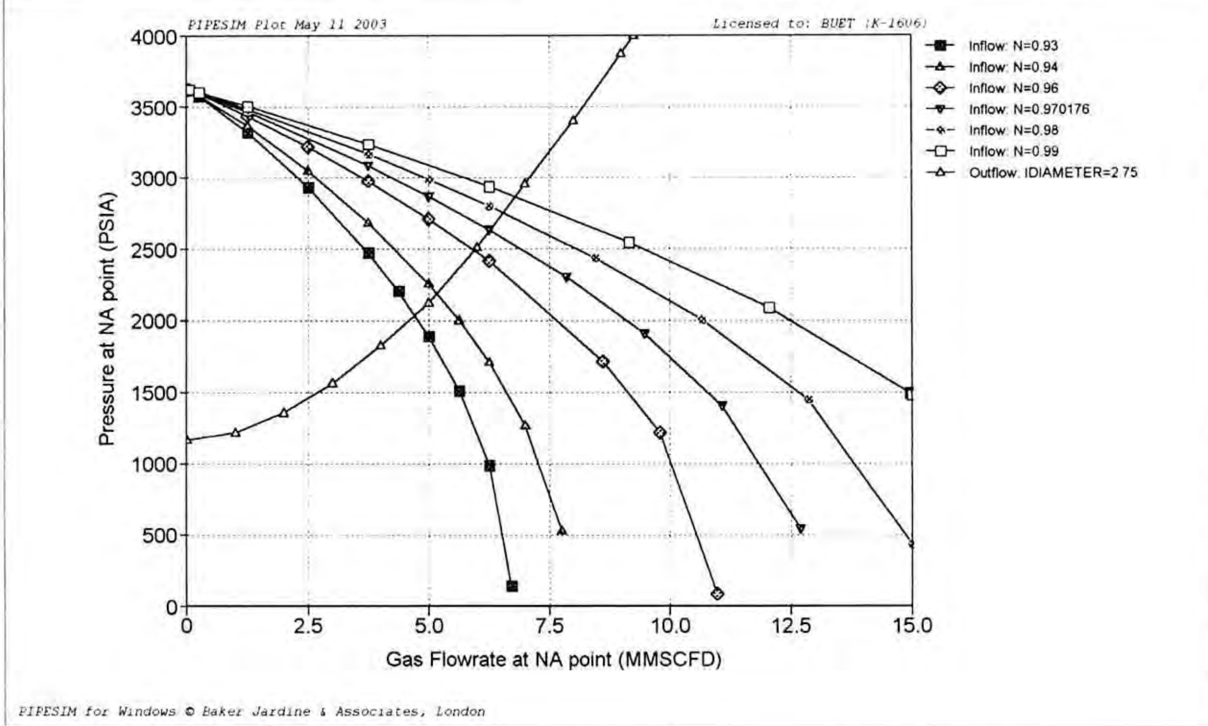


Figure 7.7: Effect of Choke Size on the Performance of Well SLD # 1 (LZ)

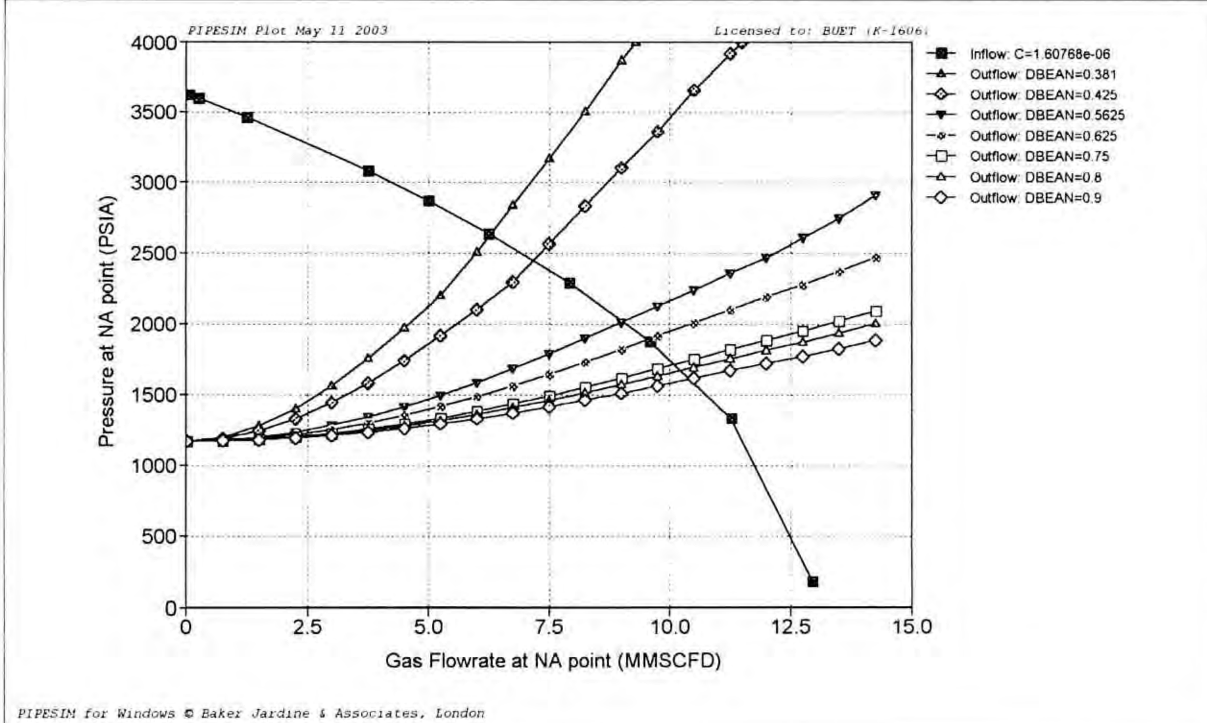


Figure 7.8: Effect of Tubing Inner Diameter on the Performance of Well SLD # 1 (LZ)

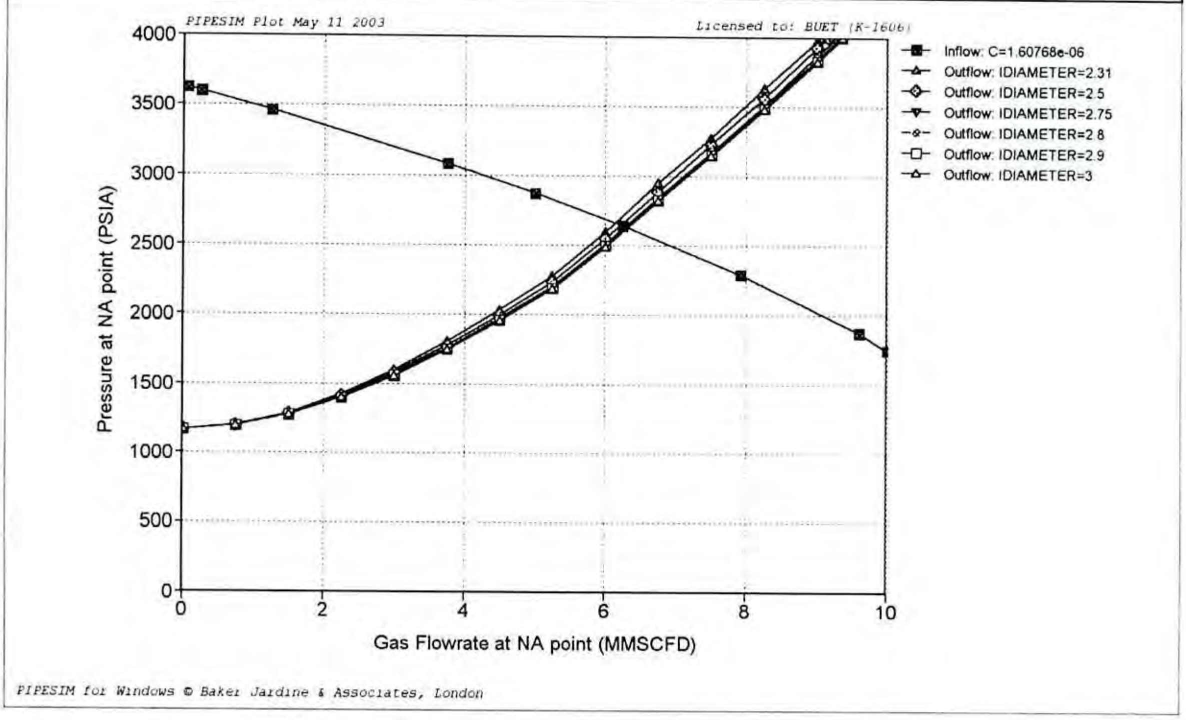


Figure 7.9: Effect of Separator Pressure on the Performance of Well SLD # 1 (LZ)

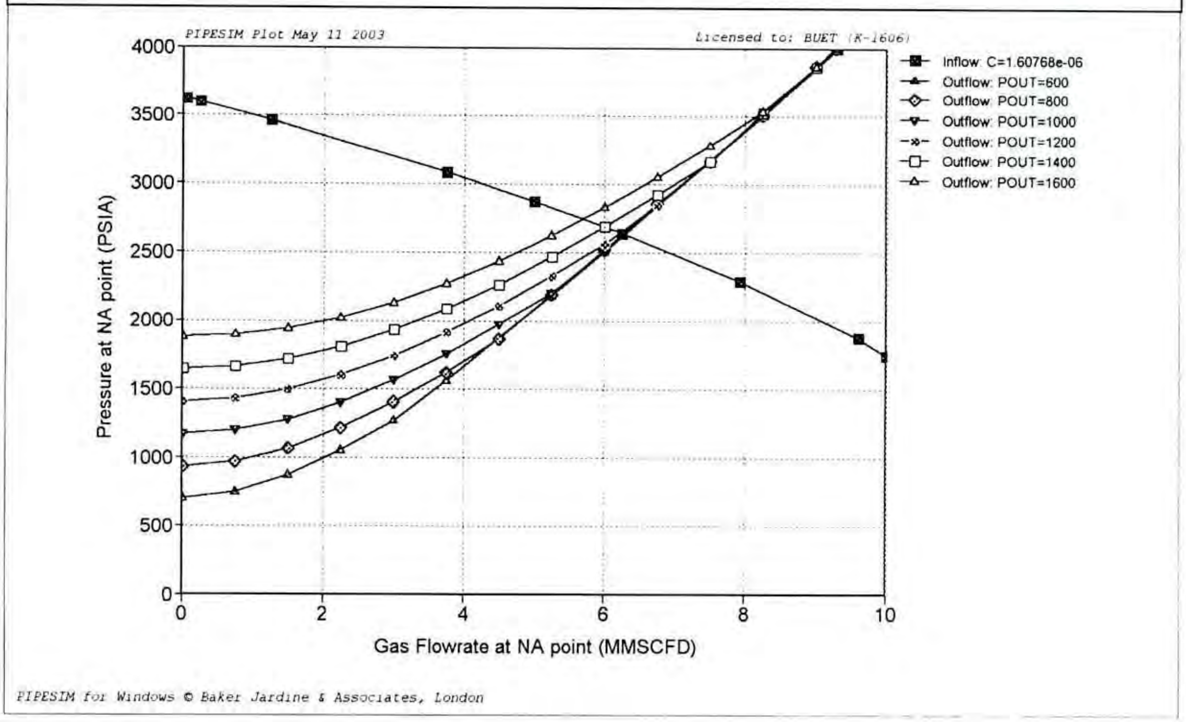


Figure 7.10: Effect of Averages Reservoir Pressure on Performance of Well SLD # 1(UZ)

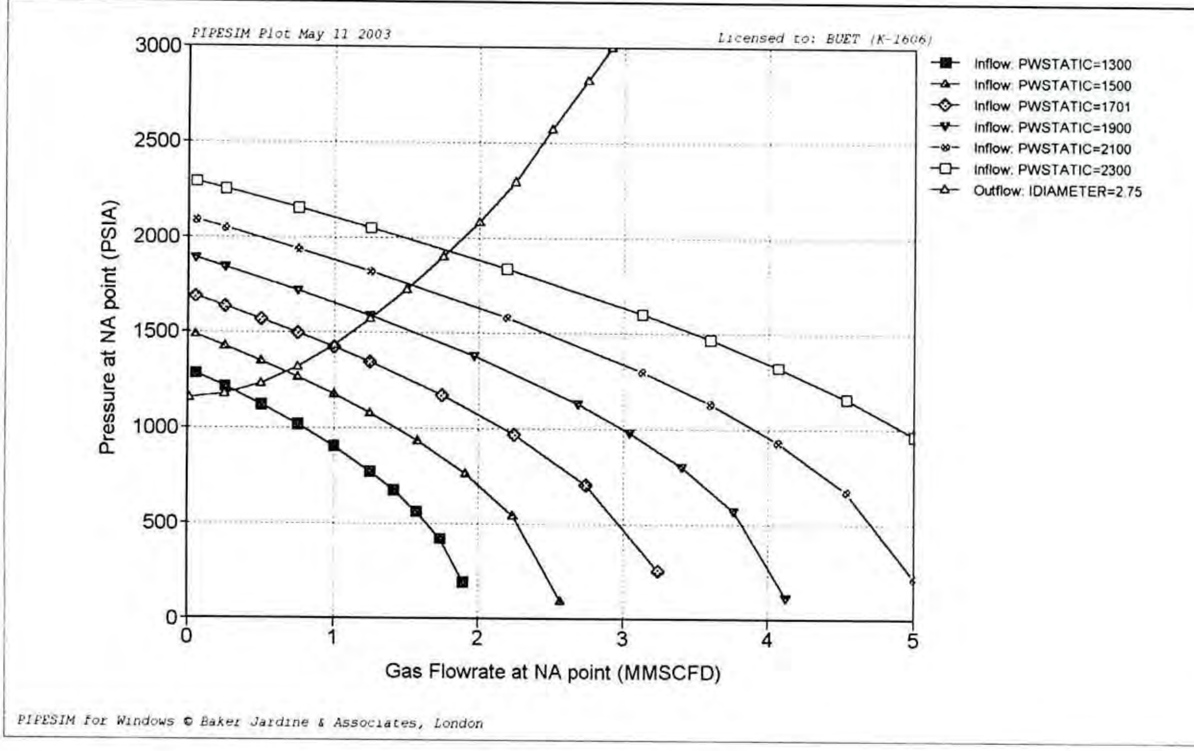


Figure 7.11: Effect of Back Pressure Coefficient on Performance of Well SLD # 1 (UZ)

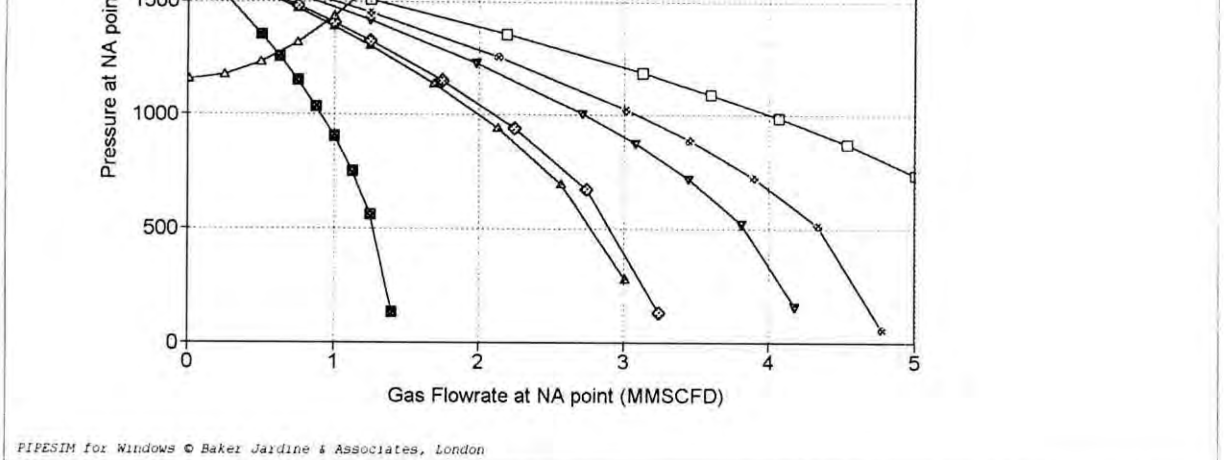


Figure 7.12: Effect of Back Pressure Exponent on the Performance of SLD # 1 (UZ)

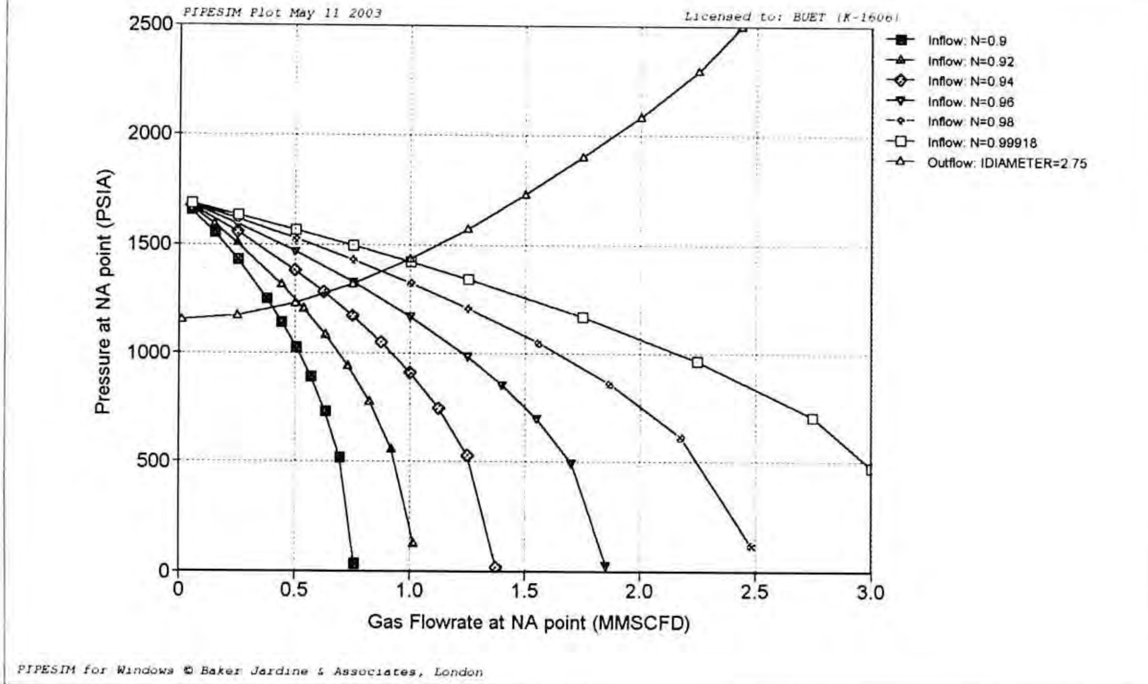


Figure 7.13: Effect of Choke Size on the Performance of SLD # 1 (UZ)

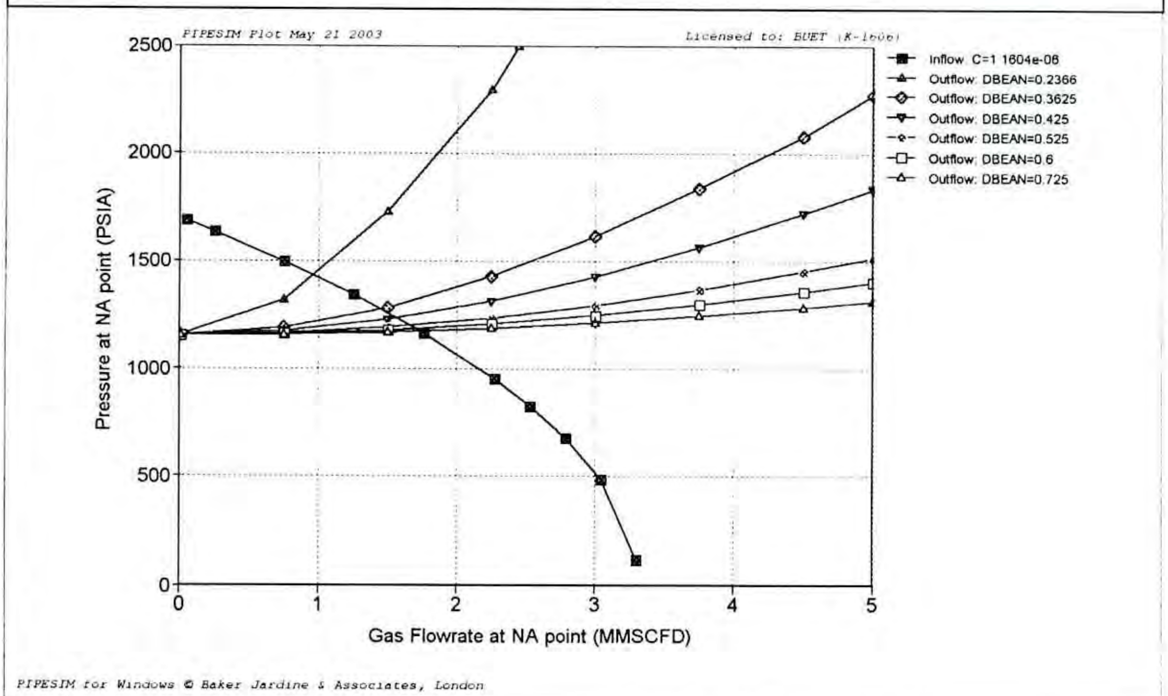


Figure 7.14: Effect of Tubing Inner Diameter on the Performance of Well SLD# 1 (UZ)

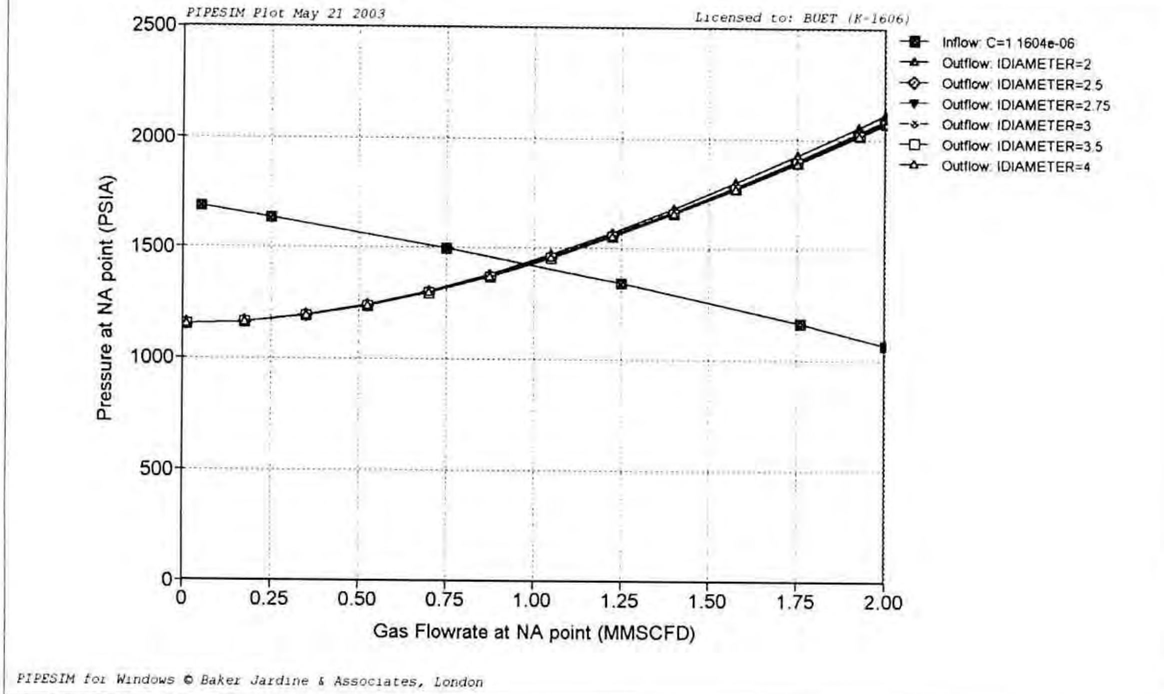


Figure 7.15: Effect of Seperator Pressure on the Performance of Well SLD # 1 (UZ)

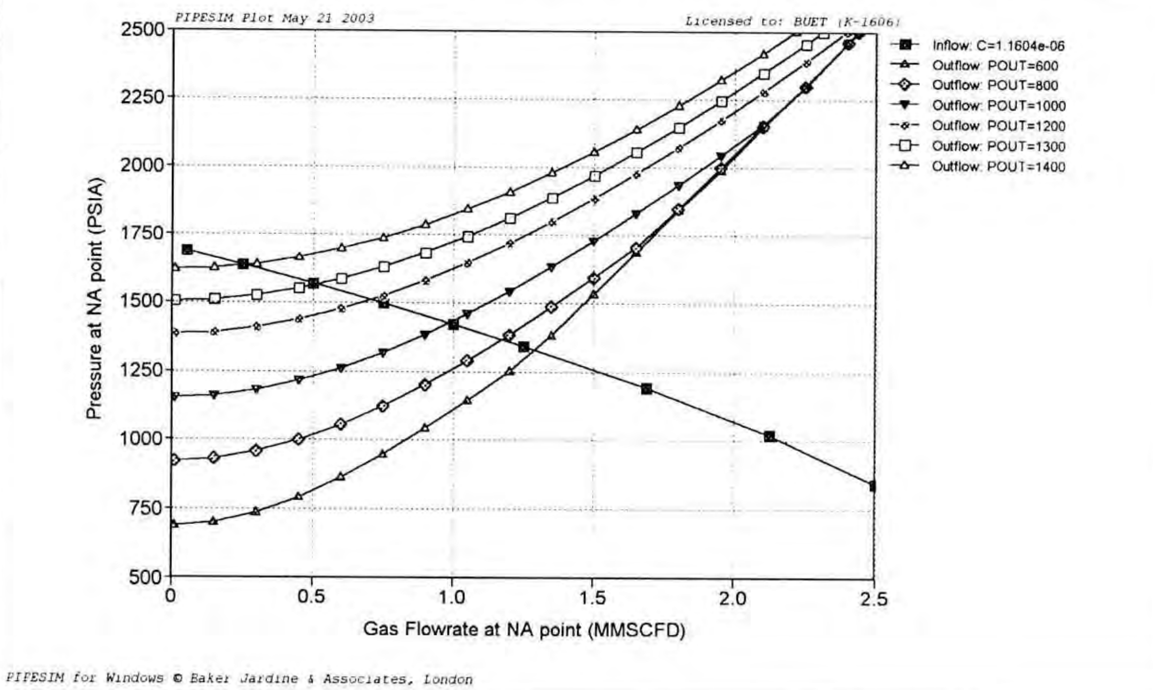


Figure7.16: Effect of Average Reservoir Pressure on the Performance of Well SLD # 2

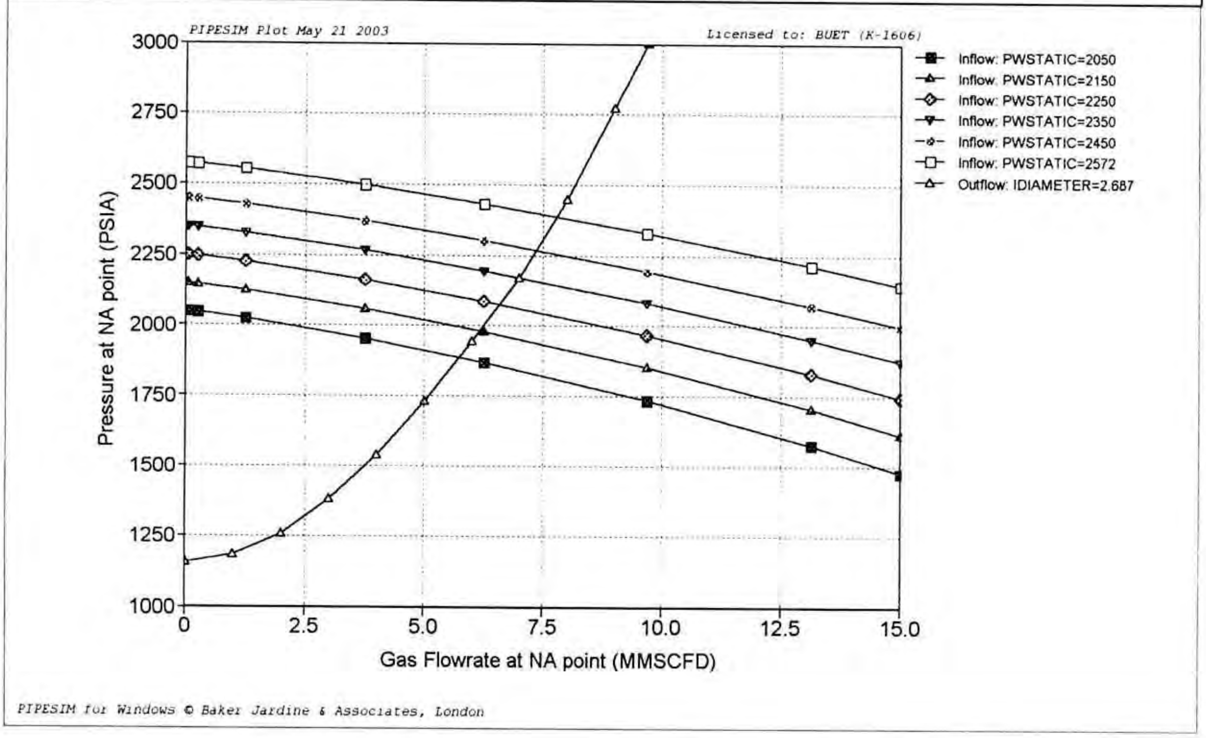


Figure7.17: Back Pressure Coefficient on the Performance of Well SLD # 2

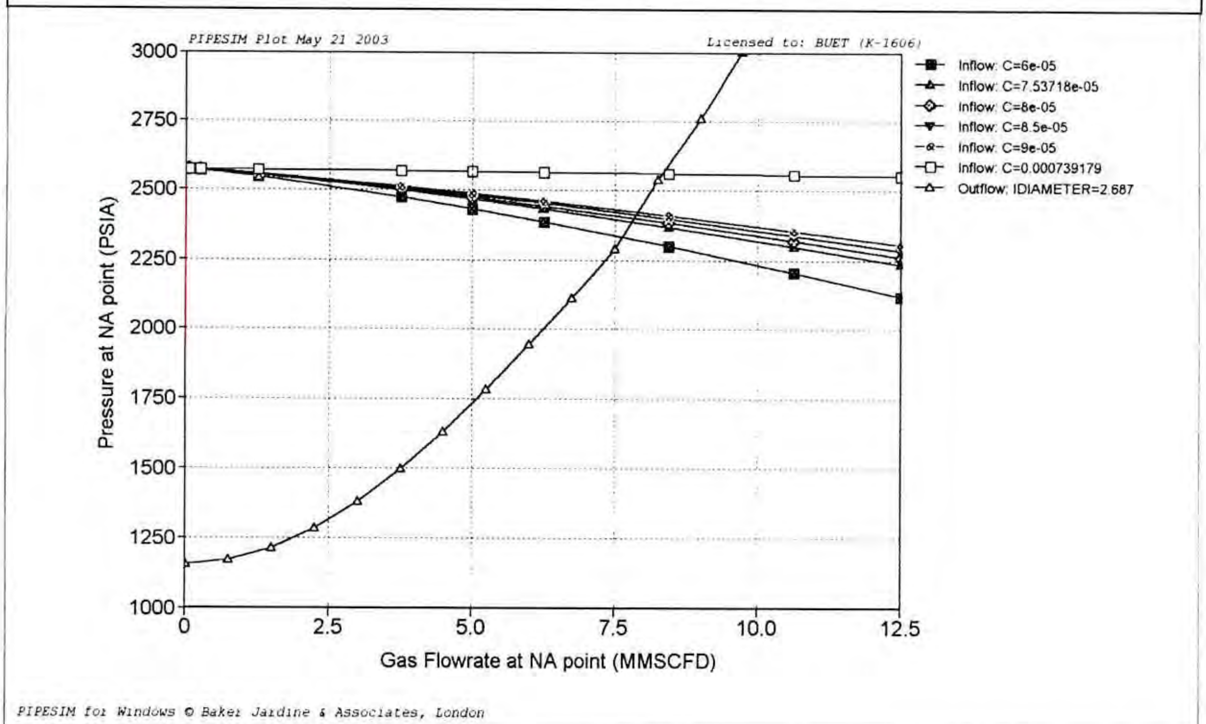


Figure7.18: Effect of Back Pressure Exponent on the Performance of Well SLD # 2

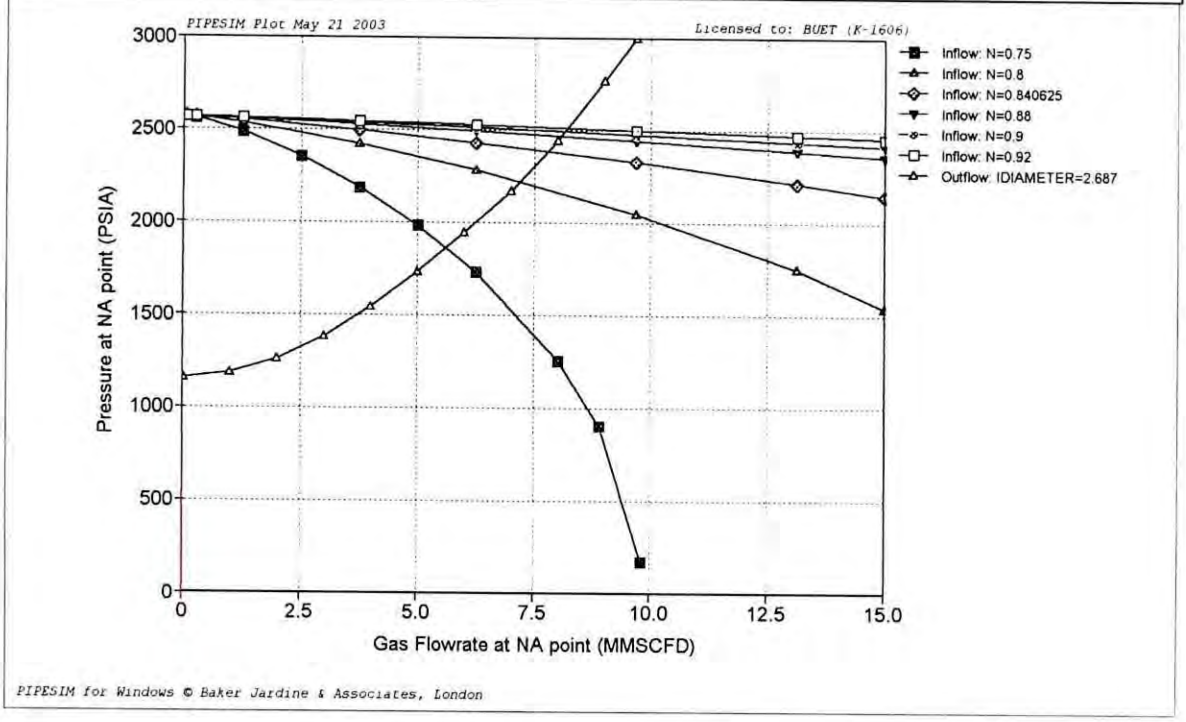


Figure7.19: Effect of Choke Size on the Performance of Well SLD # 2

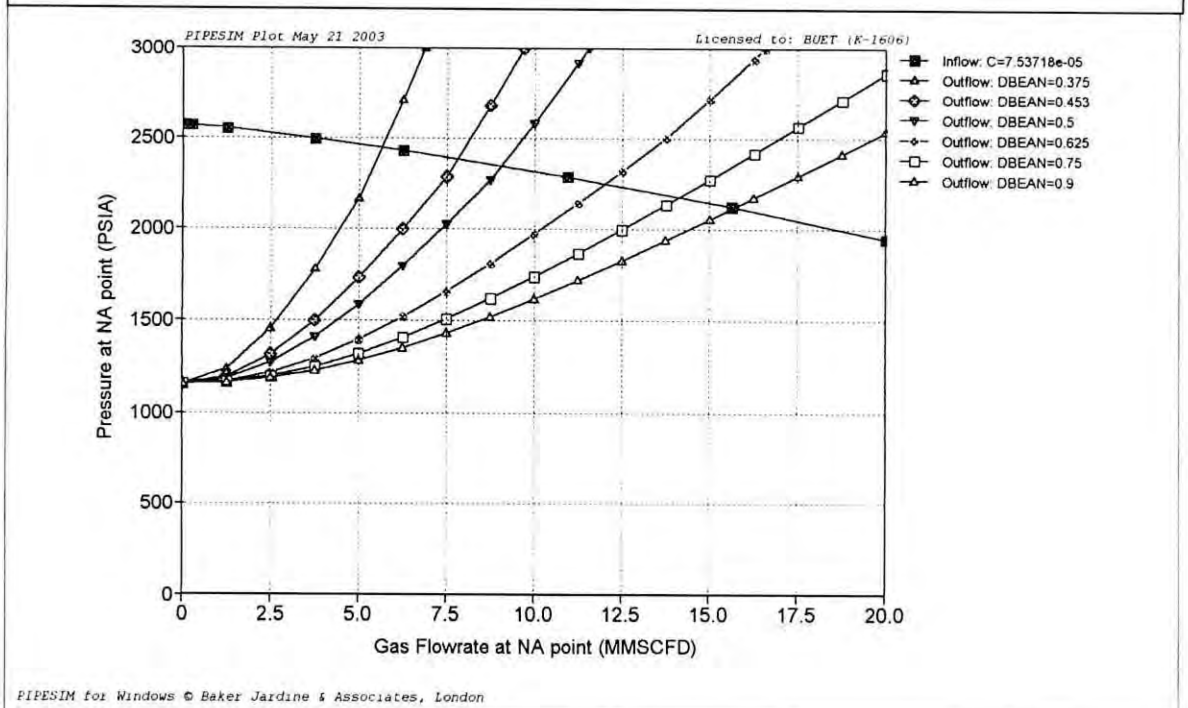


Figure 7.20: Effect of Tubing Inner Diameter on the Performance of Well SLD # 2

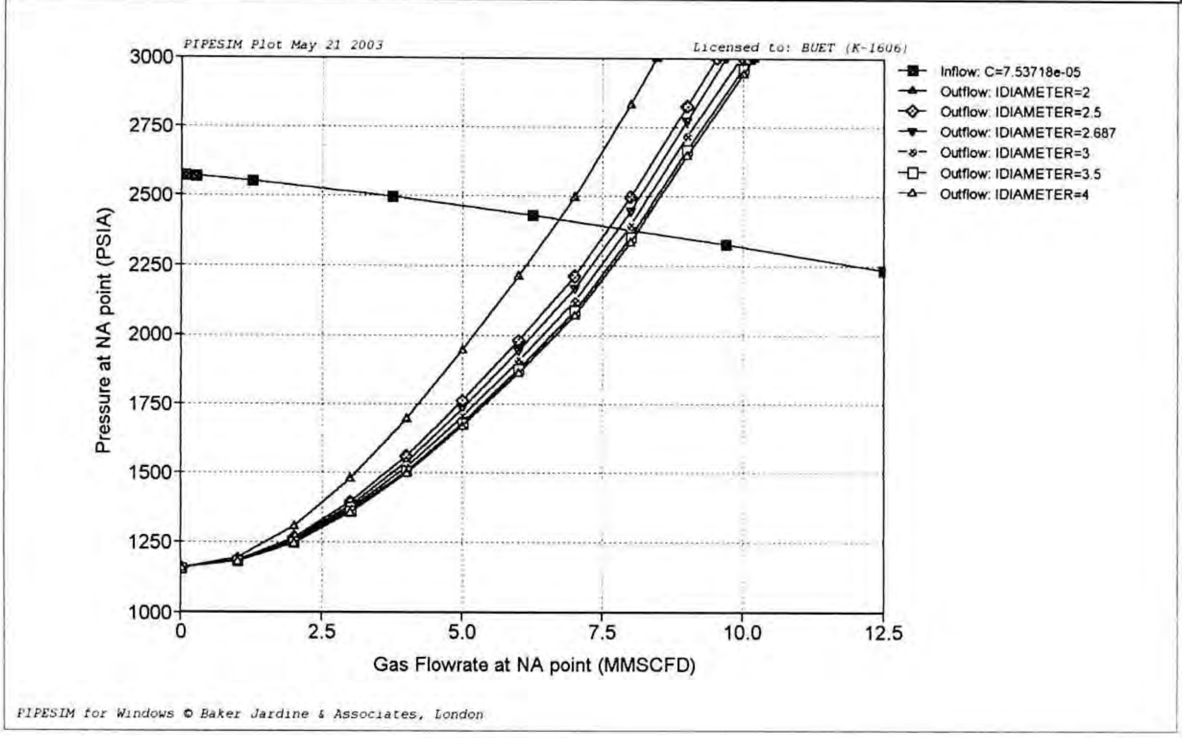
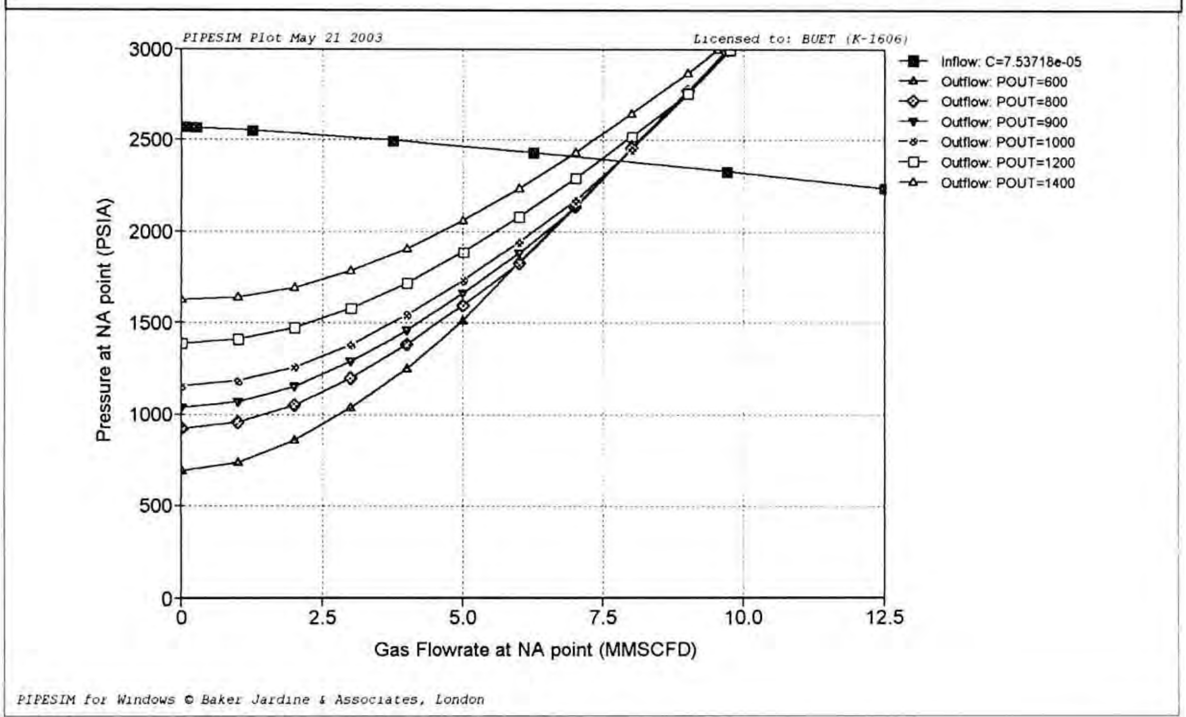


Figure 7.21: Effect of Separator Pressure on the Performance of Well SLD # 2



7.6 CONCLUSIONS

Production optimization analysis gives some important conclusion as given below:

1. Stimulation of the wells can significantly increase the flow rate up to a certain range for the entire wells.

2. Changing the choke size of any well effects the flow rate. And in general, flow rate increases with increasing choke size.

3. Tubing size for SLD # 1(LZ) and SLD # 2 wells seem to be the right size for maintain the present production rate but that for SLD # 1(UZ) tubing is oversized and the same flow rate can be achieved with a smaller tubing size.

4. At present condition, optimum production rate is 6.3 MMSCFD, 1 MMSCFD and 7.8 MMSCFD for SLD # 1 (LZ), SLD # 1 (UZ) and SLD # 2 respectively.

5. Lowering the separator pressure will not increase the flow from the wells at present condition.

7.7 RECOMMENDATIONS

1. Comprehensive pressure survey test should be conducted in each well to find out up to date values of reservoir parameters.

2. In Well SLD # 1 (UZ), the tubing size is oversized and the recommended size is 2.5 inch.

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APPENDIX- I

Depth Contour and Thickness Maps on different zones of salda Nadi Gas Field

Figure 5.7 Depth Contour Map on top of lower gas zone of SLD# 1 (LZ)

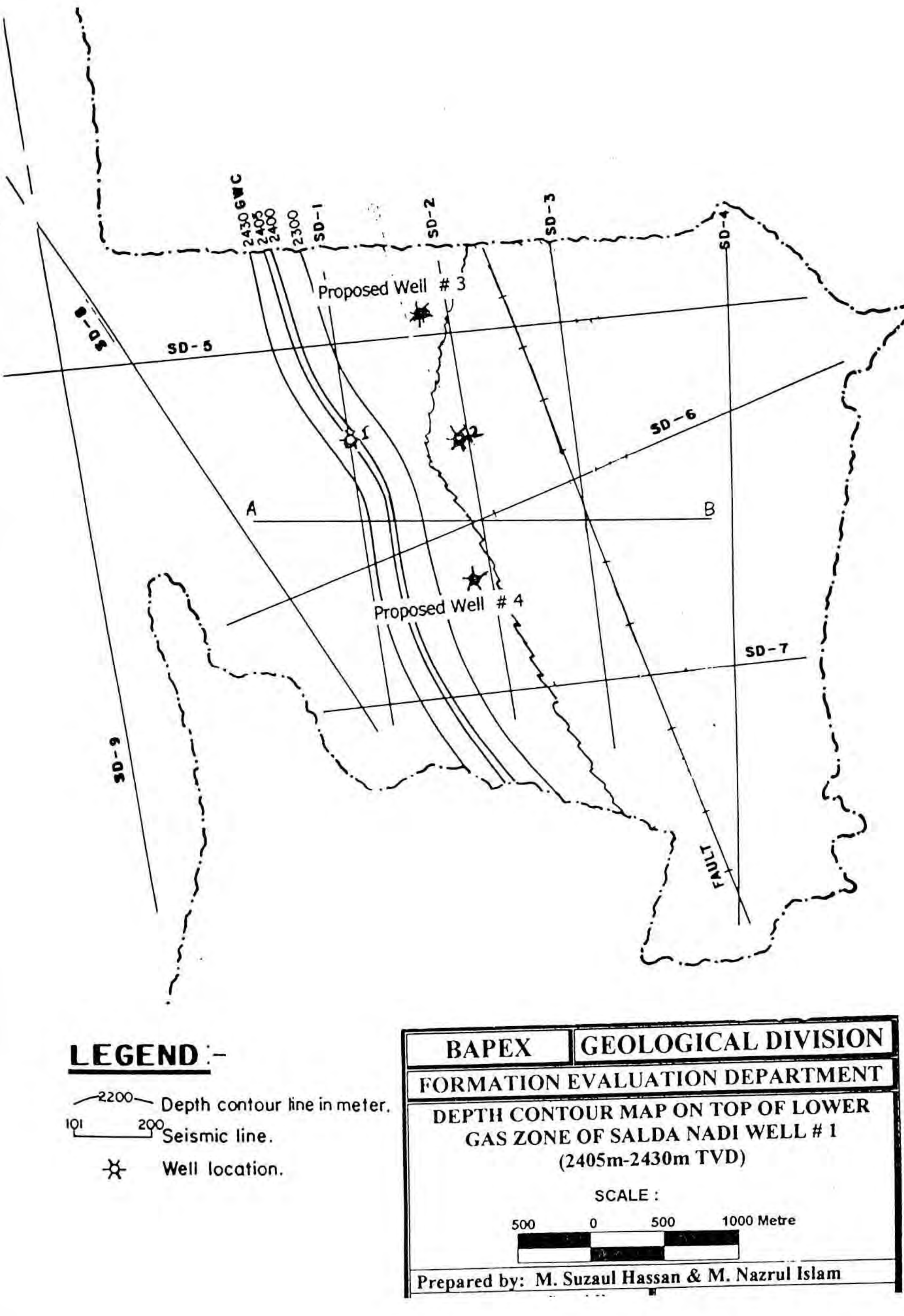
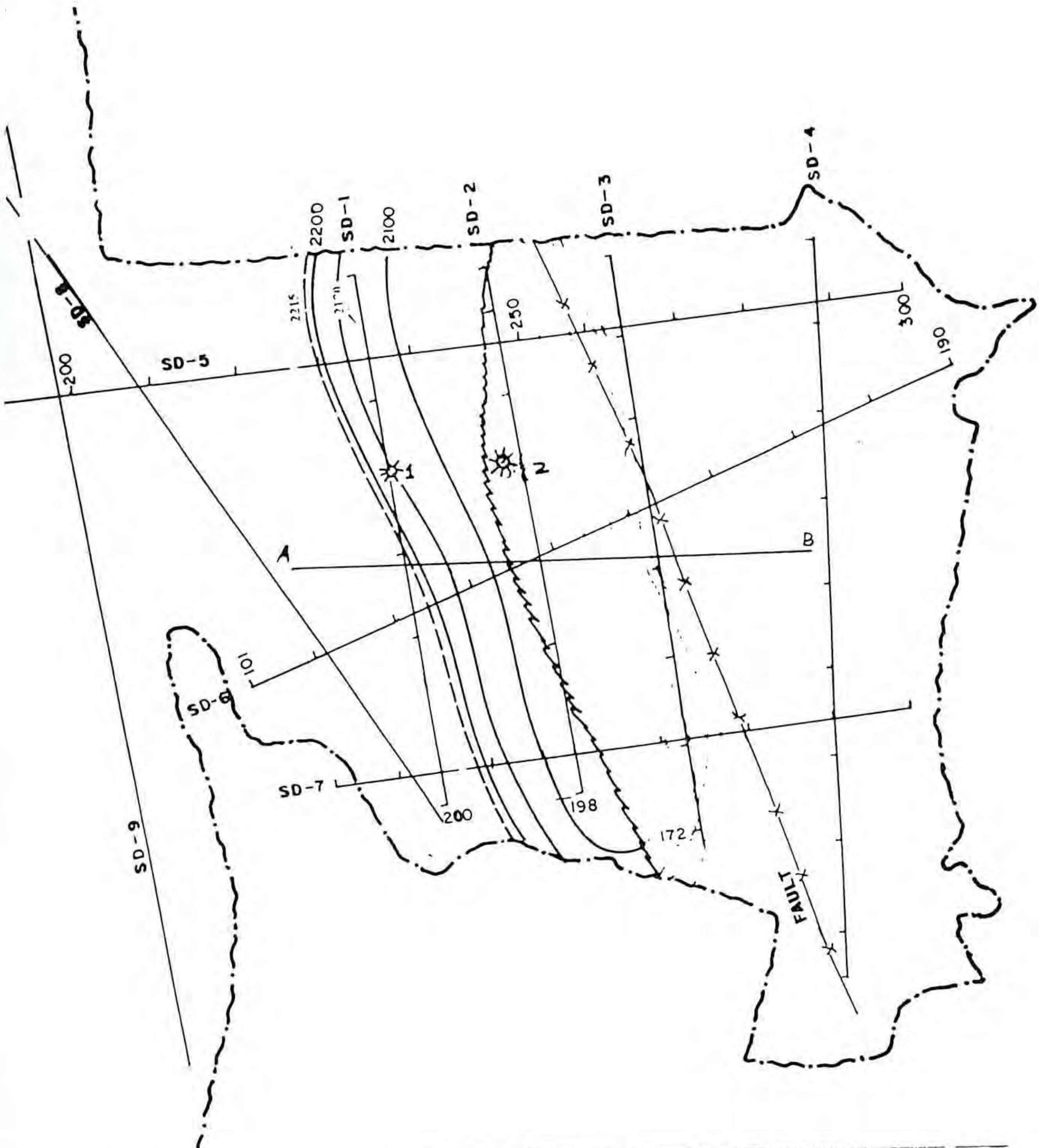


Figure 5.8 Depth Contour Map on top of lower gas zone of SLD# 1 (UZ)



LEGEND :-

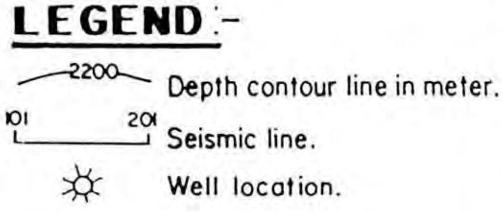
2200 — Depth contour line in meter.

101 — 200 Seismic line.

☼ Well location.

BAPEX	GEOLOGICAL DIVISION
FORMATION EVALUATION DEPARTMENT	
DEPTH CONTOUR MAP ON TOP OF UPPER GAS ZONE OF SALDA NADI WELL # 1 (2170m-2215m TVD)	
SCALE : 500 0 500 1000 Metre	
Prepared by: M. Suzaul Hassan & M. Nazrul Islam	

Figure 5.9 Depth Contour Map on top of lower gas zone of SLD# 2



BAPEX	GEOLOGICAL DIVISION
FORMATION EVALUATION DEPARTMENT	
DEPTH CONTOUR MAP ON TOP OF MIDDLE GAS ZONE OF SALDA NADI WELL # 2 (2165m-2230m TVD) SCALE : 500 0 500 1000 Metre	
Prepared by: M. Suzaul Hassan & M. Nazrul Islam	
Draftsmen : Hafiz uddin	

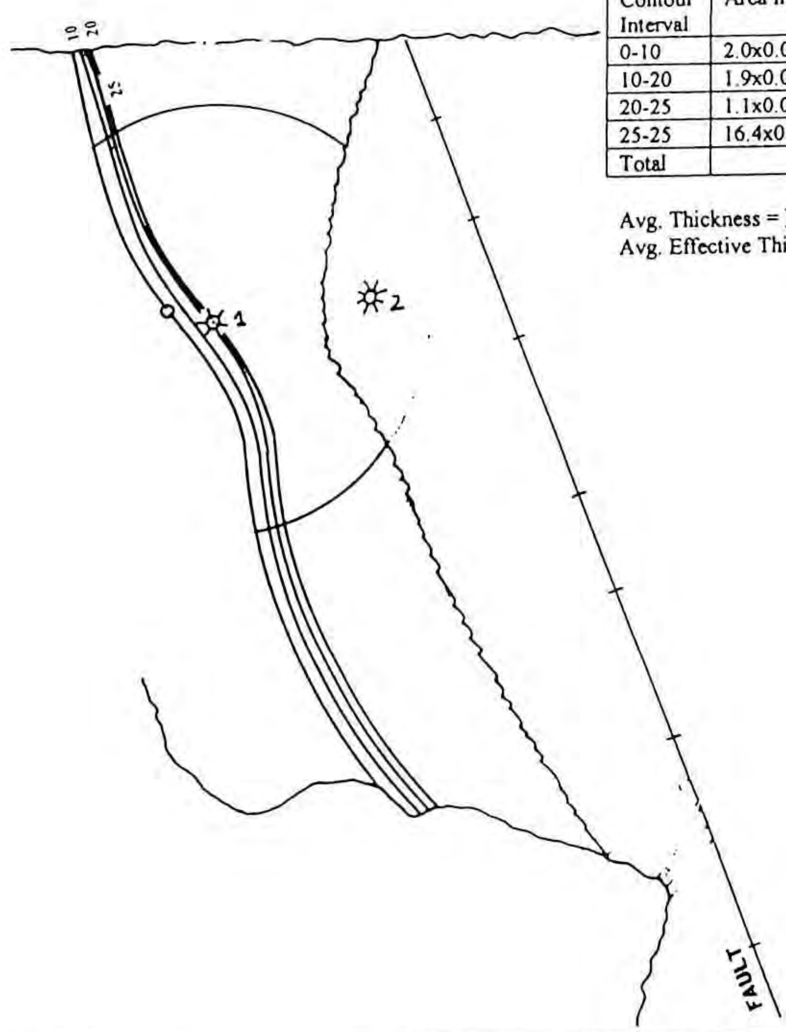
Figure 5.10 Thickness Map on top of lower gas zone of SLD# 1 (LZ)

Proven of Lower Gas Zone of Salda Well # 1			
Contour Interval	Area in Sq. Km(s)	Thickness in Meter (h)	sxh
0-10	1.4x0.095=0.1330	5	0.6650
10-20	2.0x0.095=0.190	15	2.850
20-25	0.8x0.095=0.760	22.5	1.710
25-25	12.3x0.095=1.168	25	29.2125
Total	=2.251		34.4375

Avg. Thickness = Σs/h\s = 34.4375/2.251 = 15.2953m
Avg. Effective Thickness = 15.2953x0.72 = 11.01m

Probable of Lower Gas Zone of Salda Well # 1			
Contour Interval	Area in Sq. Km(s)	Thickness in Meter (h)	sxh
0-10	2.0x0.095=0.190	5	0.950
10-20	1.9x0.095=0.1805	15	2.7075
20-25	1.1x0.095=0.1045	22.5	2.3512
25-25	16.4x0.095=1.558	25	38.950
Total	=2.033		44.9587

Avg. Thickness = Σs/h\s = 44.9587/2.033 = 22.1144m
Avg. Effective Thickness = 22.1144x0.72 = 15.92m



LEGEND :-

—20— Thickness line in meter.
——— Boundary
☼ Well # I

BAPEX	GEOLOGICAL DIVISION
FORMATION EVALUATION DEPARTMENT	
THICKNESS MAP ON TOP OF LOWER GAS ZONE OF SALDA NADI WELL # 1 (2405m-2430m TVD)	
SCALE : 500 0 500 1000 Metre	
Prepared by: M. Suzaul Hassan & M. Nazrul Islam	
Draftsmen : Hafiz uddin	

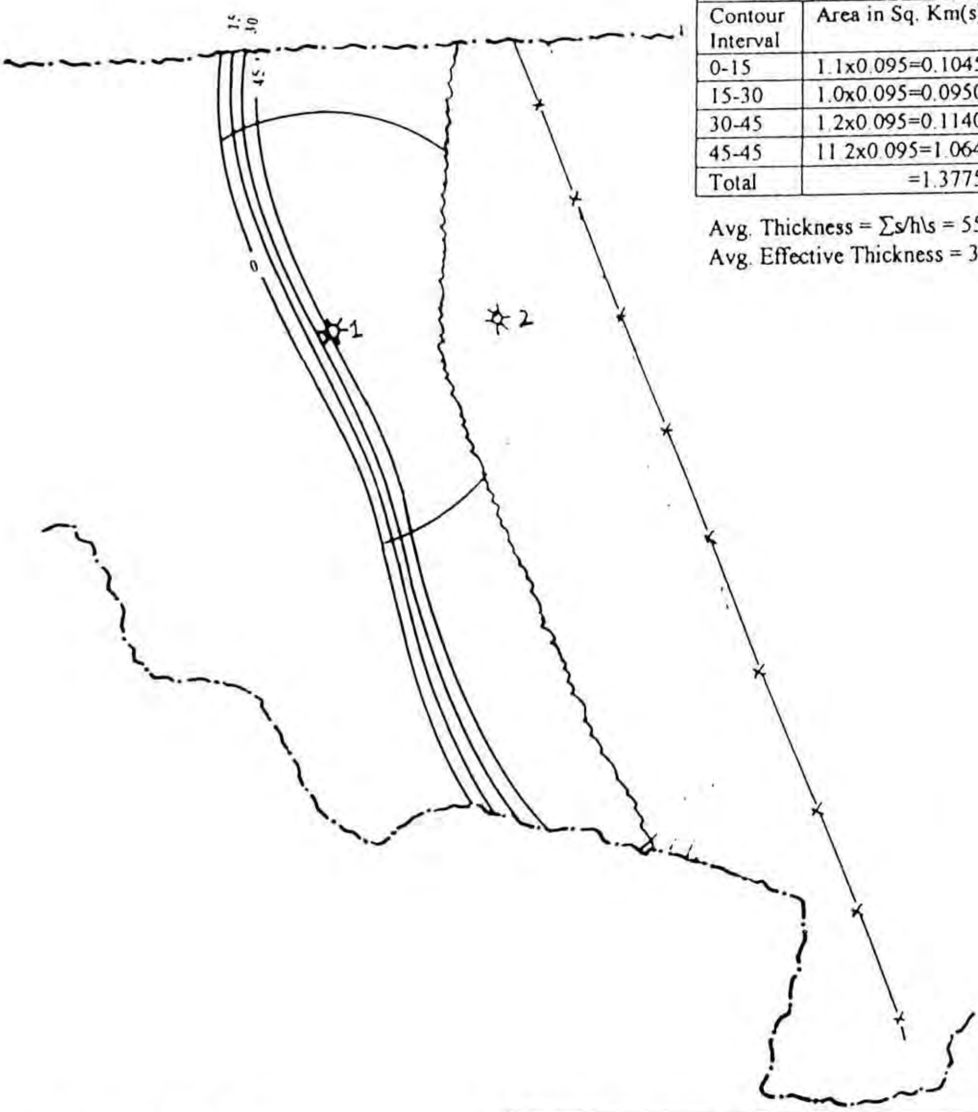
Figure 5.11 Thickness Map on top of lower gas zone of SLD# 1 (UZ)

Proven of Upper Gas Zone of Salda Well # 1			
Contour Interval	Area in Sq. Km(s)	Thickness in Meter (h)	sxh
0-15	1.2x0.095=0.1140	7.5	0.8550
15-30	1.3x0.095=0.1235	22.5	2.7787
30-45	1.0x0.095=0.0950	37.5	3.5625
45-45	9.4x0.095=0.8930	45	40.1850
Total	=1.2255		47.3812

Avg. Thickness = Σs/h\s = 47.3812/1.2255 = 38.66m
Avg. Effective Thickness = 38.66x0.66 = 25.51m

Probable of Upper Gas Zone of Salda Well # 1			
Contour Interval	Area in Sq. Km(s)	Thickness in Meter (h)	sxh
0-15	1.1x0.095=0.1045	7.5	0.7837
15-30	1.0x0.095=0.0950	22.5	2.1375
30-45	1.2x0.095=0.1140	37.5	4.2750
45-45	11.2x0.095=1.064	45	47.880
Total	=1.3775		55.0762

Avg. Thickness = Σs/h\s = 55.0762/1.3775 = 39.98m
Avg. Effective Thickness = 39.98x0.66 = 26.38m



LEGEND :-

15 Thickness line in meter.
Boundary.
Well # I

BAPEX	GEOLOGICAL DIVISION
FORMATION EVALUATION DEPARTMENT	
THICKNESS MAP ON TOP OF UPPER GAS ZONE OF SALDA NADI WELL # 1 (2170m-2215m TVD) SCALE : 500 0 500 1000 Metre	
Prepared by: M. Suzaul Hassan & M. Nazrul Islam	
Draftsmen : Hafiz uddin	

Figure 5.12 Thickness Map on top of lower gas zone of SLD# 2

Contour Interval	Area In Sq. Km (S)	Thickness In Metre (h)	Sxh
PROVEN			
0 – 20	0.422	10	4.22
20 – 40	0.399	30 .	11.97
40 – 60	0.3325	50	16.62
60 – 65	0.1472	62.5	9.20
65 – 65	0.5795	65	37.66
Total	1.8802		79.67
PROBABLE			
0 – 20	0.4892	10	4.89
20 – 40	0.4275	30	12.82
40 – 60	0.4655	50	23.27
60 – 65	0.247	62.5	15.43
65 – 65	0.5415	65	35.19
Total	2.28		91.40

Proven

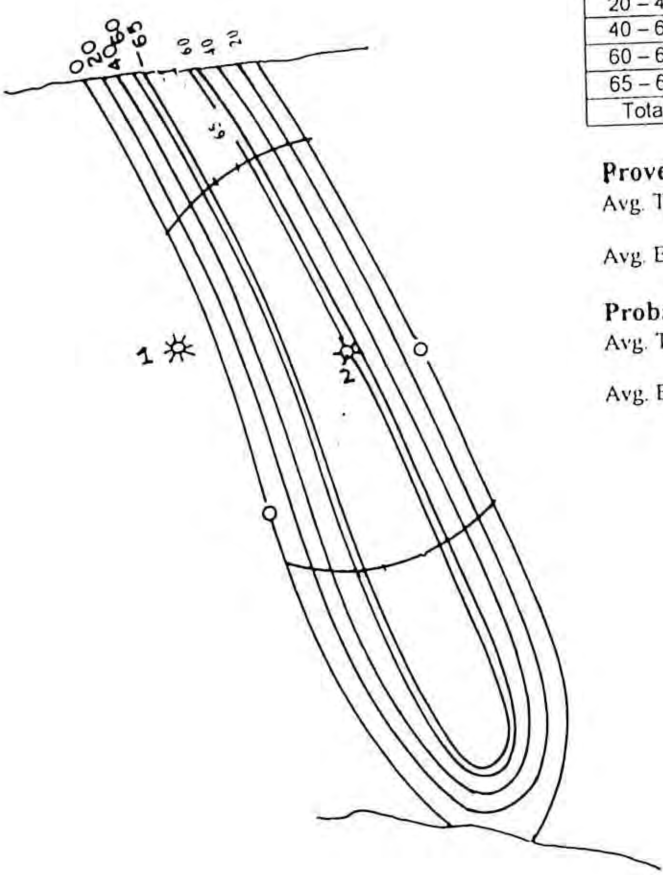
Avg. Thickness = Σ (sxh)/ Σs = 79.67/1.8802 = 42.37 m.

Avg. Effect. Thickness = Avg. Thickness x Sand Factor
= 42.37 x 0.70 = 29.66 m.

Probable

Avg. Thickness = Σ (sxh)/ Σs = 91.40/2.28 = 40.08 m.

Avg. Effect. Thickness = Avg. Thickness x Sand Factor
= 40.08 x 0.70 = 28.05 m.



LEGEND:-

20 — Thickness line in meter.

— Boundary.

☼ Well # 2

BAPEX	GEOLOGICAL DIVISION
FORMATION EVALUATION DEPARTMENT	
THICKNESS MAP ON TOP OF MIDDLE GAS ZONE OF SALDA NADI WELL # 2 (2165m-2230m TVD)	
SCALE : 500 0 500 1000 Metre	
Prepared by: M. Suzaul Hassan & M. Nazrul Islam	
Draftsmen : Hafiz uddin	

APPENDIX- II

Pressure History data of well SLD # 1 (LZ)

History Listings	SALDA#1

Company PMRE, BUET
Field Salda Nadi
Well SLD # 1(LZ)
Test Production Test
Date November 18, 2001
Gauge
Depth 2375.5M

Formation interval 2405-2430M
Perforated interval 2408.5-2414.5M

Date	Time	Pressure psia	Date	Time	Pressure psia	Date	Time	Pressure psia
31/01/92	00:00:00	3650.00	31/01/92	00:03:44	3650.00	31/01/92	02:13:03	3650.00
	00:00:01	3650.00		00:04:12	3650.00		02:29:17	3650.00
	00:00:03	3650.00		00:04:43	3650.00		02:47:30	3650.00
	00:00:05	3650.00		00:05:17	3650.00		03:07:56	3650.00
	00:00:07	3650.00		00:05:56	3650.00		03:30:52	3650.00
	00:00:09	3650.00		00:06:40	3650.00		03:56:36	3650.00
	00:00:11	3650.00		00:07:28	3650.00		04:25:28	3650.00
	00:00:13	3650.00		00:08:23	3650.00		04:57:51	3650.00
	00:00:15	3650.00		00:09:25	3650.00		05:30:57	3650.00
	00:00:17	3650.00		00:10:34	3650.00		06:04:03	3650.00
	00:00:20	3650.00		00:11:51	3650.00		06:37:09	3650.00
	00:00:22	3650.00		00:13:18	3650.00		07:10:14	3650.00
	00:00:25	3650.00		00:14:55	3650.00		07:43:20	3650.00
	00:00:28	3650.00		00:16:45	3650.00		08:16:26	3650.00
	00:00:31	3650.00		00:18:47	3650.00		08:49:32	3650.00
	00:00:35	3650.00		00:21:05	3650.00		09:22:37	3650.00
	00:00:40	3650.00		00:23:39	3650.00		09:55:43	3650.00
	00:00:44	3650.00		00:26:32	3650.00		10:28:49	3650.00
	00:00:50	3650.00		00:29:47	3650.00		11:01:55	3650.00
	00:00:56	3650.00		00:33:25	3650.00		11:35:00	3650.00
	00:01:03	3650.00		00:37:29	3650.00		12:08:06	3650.00
	00:01:11	3650.00		00:42:04	3650.00		12:41:12	3650.00
	00:01:19	3650.00		00:47:12	3650.00		13:14:18	3650.00
	00:01:29	3650.00		00:52:58	3650.00		13:47:23	3650.00
	00:01:40	3650.00		00:59:25	3650.00		14:20:29	3650.00
	00:01:52	3650.00		01:06:41	3650.00		14:53:35	3650.00
	00:02:06	3650.00		01:14:49	3650.00		15:26:41	3650.00
	00:02:21	3650.00		01:23:56	3650.00		15:59:47	3650.00
	00:02:39	3650.00		01:34:11	3650.00		16:32:52	3650.00
	00:02:58	3650.00		01:45:41	3650.00		17:05:58	3650.00
	00:03:20	3650.00		01:58:34	3650.00		17:39:04	3650.00

	History Listings	SALDA#1

Company	PMRE, BUET	Formation interval	2405-2430M
Field	Salda Nadi	Perforated interval	2408.5-2414.5M
Well	SLD # 1(LZ)		
Test	Production Test		
Date	November 18, 2001		
Gauge			
Depth	2375.5M		

Date	Time	Pressure psia	Date	Time	Pressure psia	Date	Time	Pressure psia
31/01/92	18:12:10	3650.00	01/02/92	08:00:09	3582.27	01/02/92	08:06:40	2664.82
	18:45:15	3650.00		08:00:11	3569.26		08:07:28	2644.99
	19:18:21	3650.00		08:00:13	3556.43		08:08:23	2629.27
	19:51:27	3650.00		08:00:15	3543.75		08:09:25	2617.28
	20:24:33	3650.00		08:00:17	3531.22		08:10:34	2608.51
	20:57:38	3650.00		08:00:20	3517.67		08:11:51	2602.33
	21:30:44	3650.00		08:00:22	3502.71		08:13:18	2598.04
	22:03:50	3650.00		08:00:25	3486.17		08:14:55	2595.17
	22:36:56	3650.00		08:00:28	3467.98		08:16:45	2593.18
	23:10:01	3650.00		08:00:31	3448.03		08:18:47	2591.80
	23:43:07	3650.00		08:00:35	3426.13		08:21:05	2590.70
01/02/92	00:16:13	3650.00		08:00:40	3402.27		08:23:39	2589.80
	00:49:19	3650.00		08:00:44	3376.24		08:26:32	2588.97
	01:22:24	3650.00		08:00:50	3348.07		08:29:47	2588.19
	01:55:30	3650.00		08:00:56	3317.60		08:33:25	2587.44
	02:28:36	3650.00		08:01:03	3284.86		08:37:29	2586.71
	03:01:42	3650.00		08:01:11	3249.91		08:42:04	2585.99
	03:34:47	3650.00		08:01:19	3212.67		08:47:12	2585.30
	04:07:53	3650.00		08:01:29	3173.41		08:52:58	2584.61
	04:40:59	3650.00		08:01:40	3132.25		08:59:25	2583.93
	05:14:05	3650.00		08:01:52	3089.53		09:06:41	2583.26
	05:47:11	3650.00		08:02:06	3045.54		09:14:49	2582.60
	06:20:16	3650.00		08:02:21	3000.79		09:23:56	2581.94
	06:53:22	3650.00		08:02:39	2955.73		09:34:11	2581.28
	07:26:28	3650.00		08:02:58	2911.06		09:45:41	2580.63
	07:59:34	3650.00		08:03:20	2867.44		09:58:34	2579.98
	08:00:00	3650.00		08:03:45	2825.57		10:13:03	2579.33
	08:00:01	3636.08		08:04:12	2786.23		10:29:17	2578.69
	08:00:03	3622.36		08:04:43	2749.98		10:47:30	2578.05
	08:00:05	3608.83		08:05:17	2717.42		11:07:56	2577.41
	08:00:07	3595.48		08:05:56	2688.92		11:30:52	2576.78

	History Listings	SALDA#1

Company	PMRE, BUET	Formation interval	2405-2430M
Field	Salda Nadi	Perforated interval	2408.5-2414.5M
Well	SLD # 1(LZ)		
Test	Production Test		
Date	November 18, 2001		
Gauge			
Depth	2375.5M		

Date	Time	Pressure psia	Date	Time	Pressure psia	Date	Time	Pressure psia
01/02/92	11:55:11	2576.18	01/02/92	11:58:56	2362.32	01/02/92	14:08:15	2299.05
	11:55:13	2572.49		11:59:24	2352.51		14:24:29	2298.63
	11:55:15	2568.86		11:59:55	2343.44		14:42:42	2298.20
	11:55:17	2565.28		12:00:29	2335.33		15:03:08	2297.76
	11:55:19	2561.75		12:01:08	2328.25		15:25:11	2297.31
	11:55:21	2558.28		12:01:52	2322.30		15:25:13	2294.07
	11:55:23	2554.85		12:02:40	2317.42		15:25:15	2290.88
	11:55:25	2551.47		12:03:35	2313.57		15:25:17	2287.74
	11:55:27	2548.12		12:04:37	2310.63		15:25:19	2284.64
	11:55:29	2544.79		12:05:46	2308.47		15:25:21	2281.59
	11:55:32	2541.20		12:07:03	2306.93		15:25:23	2278.58
	11:55:34	2537.23		12:08:30	2305.86		15:25:25	2275.61
	11:55:37	2532.87		12:10:07	2305.13		15:25:27	2272.68
	11:55:40	2528.07		12:11:57	2304.61		15:25:29	2269.80
	11:55:43	2522.81		12:13:59	2304.23		15:25:32	2266.68
	11:55:47	2517.06		12:16:17	2303.91		15:25:34	2263.24
	11:55:52	2510.80		12:18:51	2303.64		15:25:37	2259.45
	11:55:56	2504.01		12:21:44	2303.37		15:25:40	2255.29
	11:56:02	2496.63		12:24:59	2303.11		15:25:43	2250.73
	11:56:08	2488.63		12:28:37	2302.85		15:25:47	2245.68
	11:56:15	2480.06		12:32:41	2302.59		15:25:52	2240.17
	11:56:23	2470.94		12:37:16	2302.32		15:25:56	2234.18
	11:56:31	2461.29		12:42:24	2302.04		15:26:02	2227.72
	11:56:41	2451.16		12:48:10	2301.76		15:26:08	2220.76
	11:56:52	2440.48		12:54:37	2301.47		15:26:15	2213.31
	11:57:04	2429.43		13:01:53	2301.17		15:26:23	2205.38
	11:57:18	2418.13		13:10:01	2300.85		15:26:31	2196.93
	11:57:33	2406.72		13:19:08	2300.52		15:26:41	2187.99
	11:57:51	2395.25		13:29:23	2300.18		15:26:52	2178.65
	11:58:10	2383.87		13:40:53	2299.82		15:27:04	2169.02
	11:58:32	2372.84		13:53:46	2299.44		15:27:18	2159.17

History Listings	SALDA#1

Company	PMRE, BUET	Formation interval	2405-2430M
Field	Salda Nadi	Perforated interval	2408.5-2414.5M
Well	SLD # 1(LZ)		
Test	Production Test		
Date	November 18, 2001		
Gauge			
Depth	2375.5M		

Date	Time	Pressure psia	Date	Time	Pressure psia	Date	Time	Pressure psia
01/02/92	15:27:33	2149.20	01/02/92	16:49:08	2056.14	01/02/92	19:26:23	1976.69
	15:27:51	2139.09		16:59:23	2055.83		19:26:31	1969.71
	15:28:10	2129.14		17:10:53	2055.51		19:26:41	1962.38
	15:28:32	2119.50		17:23:46	2055.17		19:26:52	1954.74
	15:28:56	2110.31		17:38:15	2054.81		19:27:04	1946.79
	15:29:24	2101.73		17:54:29	2054.44		19:27:18	1938.56
	15:29:55	2093.77		18:12:42	2054.04		19:27:33	1930.25
	15:30:29	2086.66		18:33:08	2053.63		19:27:51	1921.94
	15:31:08	2080.46		18:56:04	2053.19		19:28:10	1913.76
	15:31:52	2075.24		19:21:48	2052.73		19:28:32	1905.83
	15:32:40	2070.96		19:25:11	2052.67		19:28:56	1898.24
	15:33:35	2067.59		19:25:13	2050.04		19:29:24	1891.04
	15:34:37	2065.01		19:25:15	2047.40		19:29:55	1884.45
	15:35:46	2063.11		19:25:17	2044.79		19:30:29	1878.58
	15:37:03	2061.77		19:25:19	2042.23		19:31:08	1873.46
	15:38:30	2060.83		19:25:21	2039.70		19:31:52	1869.15
	15:40:07	2060.19		19:25:23	2037.21		19:32:40	1865.62
	15:41:57	2059.73		19:25:25	2034.75		19:33:35	1862.83
	15:43:59	2059.40		19:25:27	2032.33		19:34:37	1860.70
	15:46:17	2059.12		19:25:29	2029.94		19:35:46	1859.14
	15:48:51	2058.88		19:25:32	2027.35		19:37:03	1858.03
	15:51:44	2058.65		19:25:34	2024.50		19:38:30	1857.25
	15:54:59	2058.43		19:25:37	2021.37		19:40:07	1856.72
	15:58:37	2058.20		19:25:40	2017.92		19:41:57	1856.34
	16:02:41	2057.97		19:25:43	2014.14		19:43:59	1856.07
	16:07:16	2057.73		19:25:47	2010.01		19:46:17	1855.83
	16:12:24	2057.49		19:25:52	2005.51		19:48:51	1855.63
	16:18:10	2057.24		19:25:56	2000.63		19:51:44	1855.44
	16:24:37	2056.98		19:26:02	1995.26		19:54:59	1855.25
	16:31:53	2056.71		19:26:08	1989.48		19:58:37	1855.05
	16:40:01	2056.43		19:26:15	1983.28		20:02:41	1854.85

	History Listings	SALDA#1

Company	PMRE, BUET	Formation interval	2405-2430M
Field	Salda Nadi	Perforated interval	2408.5-2414.5M
Well	SLD # 1(LZ)		
Test	Production Test		
Date	November 18, 2001		
Gauge			
Depth	2375.5M		

Date	Time	Pressure psia	Date	Time	Pressure psia	Date	Time	Pressure psia
01/02/92	20:07:16	1854.65	01/02/92	23:22:47	2315.38	01/02/92	23:43:17	3622.56
	20:12:24	1854.45		23:22:52	2360.57		23:45:51	3623.72
	20:18:10	1854.23		23:22:56	2408.95		23:48:44	3624.79
	20:24:37	1854.01		23:23:02	2460.55		23:51:59	3625.78
	20:31:53	1853.77		23:23:08	2515.28		23:55:37	3626.74
	20:40:01	1853.53		23:23:15	2573.10		23:59:41	3627.66
	20:49:08	1853.27		23:23:23	2633.77	02/02/92	00:04:16	3628.55
	20:59:23	1853.00		23:23:31	2697.13		00:09:24	3629.42
	21:10:53	1852.71		23:23:41	2762.65		00:15:10	3630.26
	21:23:46	1852.41		23:23:52	2830.14		00:21:37	3631.09
	21:38:15	1852.09		23:24:04	2898.98		00:28:53	3631.90
	21:54:29	1851.75		23:24:18	2968.49		00:37:01	3632.70
	22:12:42	1851.39		23:24:33	3037.97		00:46:08	3633.48
	22:33:08	1851.01		23:24:51	3106.65		00:56:23	3634.25
	22:56:04	1850.60		23:25:10	3173.54		01:07:53	3635.00
	23:21:48	1850.17		23:25:32	3237.81		01:20:46	3635.74
	23:22:11	1850.16		23:25:56	3298.56		01:35:15	3636.46
	23:22:13	1881.75		23:26:24	3354.79		01:51:29	3637.17
	23:22:15	1912.62		23:26:55	3405.94		02:09:42	3637.86
	23:22:17	1942.67		23:27:29	3451.23		02:30:08	3638.53
	23:22:19	1971.84		23:28:08	3490.48		02:53:04	3639.19
	23:22:21	2000.44		23:28:52	3523.34		03:18:48	3639.82
	23:22:23	2028.11		23:29:40	3550.26		03:47:40	3640.44
	23:22:25	2055.29		23:30:35	3571.30		04:20:03	3641.03
	23:22:27	2081.70		23:31:37	3587.35		04:53:09	3641.56
	23:22:29	2107.60		23:32:46	3599.08		05:26:15	3642.03
	23:22:32	2135.29		23:34:03	3607.31		05:59:21	3642.43
	23:22:34	2165.59		23:35:30	3612.98		06:32:26	3642.80
	23:22:37	2198.69		23:37:07	3616.74		07:05:32	3643.13
	23:22:40	2234.51		23:38:57	3619.35			
	23:22:43	2273.39		23:40:59	3621.14			

APPENDIX- III

Pressure History data of well SLD # 2

History Listings

SALDA#2

Company	PMRE, BUET	Formation interval	2300-2365M
Field	Salda Nadi	Perforated interval	2299-2342M
Well	SLD # 2		
Test	Production Test		
Date	November 20, 2001		
Gauge			
Depth	2230M		

Date	Time	Pressure psia	Date	Time	Pressure psia	Date	Time	Pressure psia
28/02/99	00:00:00	3224.00	28/02/99	00:05:25	3224.00	28/02/99	03:12:21	3224.00
	00:00:02	3224.00		00:06:04	3224.00		03:35:50	3224.00
	00:00:05	3224.00		00:06:49	3224.00		03:45:00	3224.00
	00:00:08	3224.00		00:07:39	3224.00		03:45:02	3200.15
	00:00:11	3224.00		00:08:35	3224.00		03:45:05	3181.15
	00:00:14	3224.00		00:09:38	3224.00		03:45:08	3165.92
	00:00:17	3224.00		00:10:49	3224.00		03:45:11	3153.66
	00:00:20	3224.00		00:12:08	3224.00		03:45:14	3143.68
	00:00:22	3224.00		00:13:37	3224.00		03:45:17	3135.54
	00:00:25	3224.00		00:15:16	3224.00		03:45:20	3128.89
	00:00:28	3224.00		00:17:08	3224.00		03:45:22	3123.41
	00:00:32	3224.00		00:19:14	3224.00		03:45:25	3118.87
	00:00:36	3224.00		00:21:35	3224.00		03:45:28	3114.75
	00:00:40	3224.00		00:24:13	3224.00		03:45:32	3110.98
	00:00:45	3224.00		00:27:10	3224.00		03:45:36	3107.57
	00:00:51	3224.00		00:30:29	3224.00		03:45:40	3104.53
	00:00:57	3224.00		00:34:12	3224.00		03:45:45	3101.85
	00:01:04	3224.00		00:38:22	3224.00		03:45:51	3099.51
	00:01:12	3224.00		00:43:03	3224.00		03:45:57	3097.46
	00:01:21	3224.00		00:48:19	3224.00		03:46:04	3095.68
	00:01:31	3224.00		00:54:12	3224.00		03:46:12	3094.14
	00:01:42	3224.00		01:00:49	3224.00		03:46:21	3092.78
	00:01:55	3224.00		01:08:15	3224.00		03:46:31	3091.58
	00:02:09	3224.00		01:16:34	3224.00		03:46:42	3090.50
	00:02:25	3224.00		01:25:55	3224.00		03:46:55	3089.50
	00:02:43	3224.00		01:36:24	3224.00		03:47:09	3088.58
	00:03:02	3224.00		01:48:10	3224.00		03:47:25	3087.70
	00:03:25	3224.00		02:01:22	3224.00		03:47:43	3086.86
	00:03:50	3224.00		02:16:11	3224.00		03:48:02	3086.04
	00:04:18	3224.00		02:32:48	3224.00		03:48:25	3085.24
	00:04:49	3224.00		02:51:26	3224.00		03:48:50	3084.46

	History Listings	SALDA#2

Company	PMRE, BUET	Formation interval	2300-2365M
Field	Salda Nadi	Perforated interval	2299-2342M
Well	SLD # 2		
Test	Production Test		
Date	November 20, 2001		
Gauge			
Depth	2230M		

Date	Time	Pressure psia	Date	Time	Pressure psia	Date	Time	Pressure psia
28/02/99	03:49:18	3083.69	28/02/99	06:17:48	3061.76	28/02/99	07:48:25	2983.03
	03:49:49	3082.92		06:36:26	3061.07		07:48:50	2982.59
	03:50:25	3082.17		06:57:21	3060.39		07:49:18	2982.16
	03:51:04	3081.42		07:20:50	3059.70		07:49:49	2981.73
	03:51:49	3080.68		07:45:00	3059.07		07:50:25	2981.31
	03:52:39	3079.95		07:45:02	3045.97		07:51:04	2980.88
	03:53:35	3079.22		07:45:05	3035.54		07:51:49	2980.46
	03:54:38	3078.49		07:45:08	3027.19		07:52:39	2980.04
	03:55:49	3077.77		07:45:11	3020.46		07:53:35	2979.62
	03:57:08	3077.05		07:45:14	3015.01		07:54:38	2979.20
	03:58:37	3076.34		07:45:17	3010.58		07:55:49	2978.78
	04:00:16	3075.63		07:45:20	3006.95		07:57:08	2978.35
	04:02:08	3074.92		07:45:22	3003.97		07:58:37	2977.93
	04:04:14	3074.22		07:45:25	3001.49		08:00:16	2977.50
	04:06:35	3073.52		07:45:28	2999.24		08:02:08	2977.07
	04:09:13	3072.82		07:45:32	2997.17		08:04:14	2976.64
	04:12:10	3072.12		07:45:36	2995.30		08:06:35	2976.20
	04:15:29	3071.42		07:45:40	2993.63		08:09:13	2975.76
	04:19:12	3070.73		07:45:45	2992.15		08:12:10	2975.31
	04:23:22	3070.03		07:45:51	2990.87		08:15:29	2974.86
	04:28:03	3069.34		07:45:57	2989.75		08:19:12	2974.40
	04:33:19	3068.64		07:46:04	2988.78		08:23:22	2973.93
	04:39:12	3067.95		07:46:12	2987.93		08:28:03	2973.45
	04:45:49	3067.26		07:46:21	2987.19		08:33:19	2972.96
	04:53:15	3066.57		07:46:31	2986.53		08:39:12	2972.46
	05:01:34	3065.88		07:46:42	2985.93		08:45:49	2971.95
	05:10:55	3065.19		07:46:55	2985.39		08:53:15	2971.43
	05:21:24	3064.50		07:47:09	2984.88		09:01:34	2970.89
	05:33:10	3063.82		07:47:25	2984.39		09:10:55	2970.34
	05:46:22	3063.13		07:47:43	2983.93		09:21:24	2969.77
	06:01:11	3062.44		07:48:02	2983.47		09:33:10	2969.19

	History Listings	SALDA#2

Company	PMRE, BUET	Formation interval	2300-2365M
Field	Salda Nadi	Perforated interval	2299-2342M
Well	SLD # 2		
Test	Production Test		
Date	November 20, 2001		
Gauge			
Depth	2230M		

Date	Time	Pressure psia	Date	Time	Pressure psia	Date	Time	Pressure psia
28/02/99	09:46:22	2968.59	28/02/99	11:47:43	2900.32	28/02/99	13:21:24	2887.69
	10:01:11	2967.97		11:48:02	2899.93		13:33:10	2887.13
	10:17:48	2967.33		11:48:25	2899.55		13:46:22	2886.55
	10:36:26	2966.68		11:48:50	2899.17		14:01:11	2885.95
	10:57:21	2966.01		11:49:18	2898.80		14:17:48	2885.32
	11:20:50	2965.31		11:49:49	2898.43		14:36:26	2884.67
	11:45:00	2964.66		11:50:25	2898.06		14:57:21	2883.99
	11:45:02	2953.44		11:51:04	2897.69		15:20:50	2883.28
	11:45:05	2944.52		11:51:49	2897.32		15:45:00	2882.60
	11:45:08	2937.35		11:52:39	2896.96		15:45:02	2878.26
	11:45:11	2931.58		11:53:35	2896.59		15:45:05	2874.82
	11:45:14	2926.90		11:54:38	2896.23		15:45:08	2872.06
	11:45:17	2923.10		11:55:49	2895.86		15:45:11	2869.84
	11:45:20	2919.98		11:57:08	2895.49		15:45:14	2868.04
	11:45:22	2917.42		11:58:37	2895.12		15:45:17	2866.58
	11:45:25	2915.30		12:00:16	2894.74		15:45:20	2865.38
	11:45:28	2913.37		12:02:08	2894.37		15:45:22	2864.39
	11:45:32	2911.61		12:04:14	2893.98		15:45:25	2863.58
	11:45:36	2910.01		12:06:35	2893.60		15:45:28	2862.84
	11:45:40	2908.59		12:09:13	2893.20		15:45:32	2862.16
	11:45:45	2907.33		12:12:10	2892.80		15:45:36	2861.54
	11:45:51	2906.24		12:15:29	2892.40		15:45:40	2860.99
	11:45:57	2905.28		12:19:12	2891.98		15:45:45	2860.51
	11:46:04	2904.46		12:23:22	2891.56		15:45:51	2860.09
	11:46:12	2903.74		12:28:03	2891.12		15:45:57	2859.72
	11:46:21	2903.10		12:33:19	2890.67		15:46:04	2859.40
	11:46:31	2902.54		12:39:12	2890.22		15:46:12	2859.12
	11:46:42	2902.03		12:45:49	2889.74		15:46:21	2858.88
	11:46:55	2901.57		12:53:15	2889.26		15:46:31	2858.66
	11:47:09	2901.13		13:01:34	2888.75		15:46:42	2858.46
	11:47:25	2900.72		13:10:55	2888.23		15:46:55	2858.27

	History Listings	SALDA#2

Company	PMRE, BUET	Formation interval	2300-2365M
Field	Salda Nadi	Perforated interval	2299-2342M
Well	SLD # 2		
Test	Production Test		
Date	November 20, 2001		
Gauge			
Depth	2230M		

Date	Time	Pressure psia	Date	Time	Pressure psia	Date	Time	Pressure psia
28/02/99	15:47:09	2858.10	28/02/99	17:01:34	2852.23	01/03/99	07:45:11	2996.65
	15:47:25	2857.94		17:10:55	2851.90		07:45:14	3018.62
	15:47:43	2857.78		17:21:24	2851.55		07:45:17	3036.48
	15:48:02	2857.63		17:33:10	2851.18		07:45:20	3051.09
	15:48:25	2857.47		17:46:22	2850.78		07:45:22	3063.02
	15:48:50	2857.32		18:01:11	2850.36		07:45:25	3072.91
	15:49:18	2857.17		18:17:48	2849.91		07:45:28	3081.88
	15:49:49	2857.02		18:36:26	2849.42		07:45:32	3090.10
	15:50:25	2856.87		18:57:21	2848.91		07:45:36	3097.52
	15:51:04	2856.72		19:20:50	2848.37		07:45:40	3104.11
	15:51:49	2856.57		19:47:10	2847.79		07:45:45	3109.90
	15:52:39	2856.42		20:16:43	2847.18		07:45:51	3114.96
	15:53:35	2856.26		20:49:52	2846.53		07:45:57	3119.36
	15:54:38	2856.11		21:27:04	2845.84		07:46:04	3123.17
	15:55:49	2855.95		22:08:49	2845.12		07:46:12	3126.48
	15:57:08	2855.78		22:55:38	2844.36		07:46:21	3129.39
	15:58:37	2855.62		23:43:30	2843.63		07:46:31	3131.97
	16:00:16	2855.45	01/03/99	00:31:20	2842.94		07:46:42	3134.29
	16:02:08	2855.27		01:19:11	2842.29		07:46:55	3136.43
	16:04:14	2855.09		02:07:03	2841.67		07:47:09	3138.41
	16:06:35	2854.91		02:54:54	2841.08		07:47:25	3140.29
	16:09:13	2854.72		03:42:44	2840.51		07:47:43	3142.10
	16:12:10	2854.52		04:30:36	2839.97		07:48:02	3143.85
	16:15:29	2854.31		05:18:27	2839.46		07:48:25	3145.56
	16:19:12	2854.09		06:06:17	2838.96		07:48:50	3147.23
	16:23:22	2853.87		06:54:09	2838.48		07:49:18	3148.89
	16:28:03	2853.63		07:42:00	2838.02		07:49:49	3150.51
	16:33:19	2853.38		07:45:00	2837.99		07:50:25	3152.12
	16:39:12	2853.12		07:45:02	2892.50		07:51:04	3153.70
	16:45:49	2852.84		07:45:05	2935.27		07:51:49	3155.27
	16:53:15	2852.54		07:45:08	2969.31		07:52:39	3156.83

	History Listings	SALDA#2

Company PMRE, BUET
Field Salda Nadi
Well SLD # 2
Test Production Test
Date November 20, 2001
Gauge
Depth 2230M

Formation interval 2300-2365M
Perforated interval 2299-2342M

Date	Time	Pressure psia	Date	Time	Pressure psia	Date	Time	Pressure psia
01/03/99	07:53:35	3158.38	01/03/99	12:49:52	3201.96	02/03/99	13:15:26	3216.44
	07:54:38	3159.92		13:27:04	3203.14		14:03:18	3216.59
	07:55:49	3161.44		14:08:49	3204.30		14:51:09	3216.74
	07:57:08	3162.96		14:55:39	3205.43		15:39:00	3216.87
	07:58:37	3164.46		15:43:29	3206.44		16:26:51	3217.01
	08:00:16	3165.96		16:31:20	3207.33		17:14:42	3217.13
	08:02:08	3167.45		17:19:11	3208.12		18:02:33	3217.26
	08:04:14	3168.94		18:07:03	3208.84		18:50:23	3217.38
	08:06:35	3170.41		18:54:54	3209.48		19:38:14	3217.49
	08:09:13	3171.88		19:42:45	3210.07		20:26:05	3217.60
	08:12:10	3173.34		20:30:35	3210.60		21:13:56	3217.71
	08:15:29	3174.80		21:18:26	3211.10		22:01:47	3217.81
	08:19:12	3176.25		22:06:17	3211.55		22:49:38	3217.91
	08:23:22	3177.70		22:54:09	3211.97		23:37:30	3218.01
	08:28:03	3179.13		23:42:00	3212.37	03/03/99	00:25:21	3218.10
	08:33:19	3180.56	02/03/99	00:29:51	3212.73		01:13:12	3218.19
	08:39:12	3181.99		01:17:41	3213.07		02:01:03	3218.28
	08:45:49	3183.40		02:05:32	3213.40		02:48:54	3218.37
	08:53:15	3184.81		02:53:23	3213.70		03:36:45	3218.45
	09:01:34	3186.21		03:41:15	3213.98		04:24:36	3218.53
	09:10:55	3187.60		04:29:06	3214.25		05:12:26	3218.61
	09:21:24	3188.98		05:16:57	3214.50		06:00:17	3218.68
	09:33:10	3190.35		06:04:48	3214.74		06:48:08	3218.76
	09:46:22	3191.70		06:52:38	3214.97		07:35:59	3218.83
	10:01:11	3193.04		07:40:29	3215.18			
	10:17:48	3194.37		08:28:20	3215.39			
	10:36:26	3195.68		09:16:12	3215.59			
	10:57:21	3196.98		10:04:03	3215.77			
	11:20:50	3198.26		10:51:54	3215.95			
	11:47:10	3199.52		11:39:44	3216.12			
	12:16:43	3200.75		12:27:35	3216.28			