Thesis Report

Title: Optimization of a Saldanadi gas field of Bangladesh

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By

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Key Abbreviation & Notation

CGR:	Condensate Gas Ratio.
WGR:	Water Gas Ratio.
IPR :	Inflow Performance Ratio.
VLP:	Vertical Lift Performance.
BHP:	Bottom Hole Pressure.
WHP:	Well Head Pressure.
MD:	Measured Depth.
TVD:	True Vertical Depth.
AOF:	Absolute Open Flow.
S.S:	Short string.
L.S:	Long String.
BCF:	Billion Cubic Feet.
MMSCFD:	Million Standard Cubic Feed Day.
Gp:	Cumulative Gas Production.

Abstract:

In this study, three software (MBAL, PROSPER & GAP) are used to calculate different important parameters for "Saldanadi gas field optimization study". A systematic reservoir engineering investigation which is extremely important for the development of a gas field is conducted to get insight information of the reservoir and production system. In the present work, MBAL software calculation is used to estimate the total gas in place of Saldanadi gas field which is 114.96 BCF. In October 2010, the cumulative production of the field is 62.321 BCF. Thus the overall gas in place recovery of the field is 54%. PROSPER is most common software for the petroleum industry which can assist the production or reservoir engineer to predict tubing and pipeline hydraulics and temperatures with accuracy and speed that is also used to compare the measured gas rate. In the case, it is found that the measured gas rate and software calculated gas rate are almost similar and the result variations are less than 7%. The production optimization depends upon several parameters such as well stimulation, tubing size, flow line size, chock size, separator pressure and average reservoir pressure. The impacts of each parameter are also observed to identify any bottle-neck in the production system. GAP analysis approach has been followed in conducting the system analysis to optimize production of Saldanadi Gas Field. Different separator pressure is also investigated because it has a great influence in the flow period and flow rate. From the study, it is found that with the increase of separator pressure the flow period decreases i.e. the recovery of gas decreases. Various types of production tubing inner diameter is also used to find the great influence on the flow period and flow rate of gas. In this case, when production tubing inner diameter decreases then the gas flow rate also decreases but flow period of gas production increases i.e. recovery of gas increases.

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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.

Saldanadi Gas Field is situated about 50 Km south east of Brahmanbaria town. Saldanadi Gas Field well # 1 was drilled in 1996 (discovery well). The well was terminated at a depth of 2511 m (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 2405-2430 m and upper zone interval of 2170-2260 m. From Saldanadi Gas Field well #1 lower zone, 29.907 BCF and well #1 upper zone 5.841 BCF gas was produced from 29th march 1998 to October 2010 including two shut-ins period. Presently these well are production.

Saldanadi Gas Field well #2 is a deviated well and was drilled in 1999 and the total depth is 2458 m (MD). Three prospective zones were tested. Only middle zone (2300-2365 m) produced gas. From Saldanadi Gas Field well # 2 26.573 BCF gas has been produced from 4th May 2001 to October 2010 and presently the well is in production.

This study will focus on the well test analysis and production simulation of Saldanadi Gas Field using a commercial software and reserve estimation by MBAL software. The reservoir characteristics like permeability, porosity, reservoir pressure, well bore storage, skin factor, pay thickness, well bore damage and other relevant information may be obtained and these data are used in the reserve estimation and production optimization to predict reservoir performance of the gas field.

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

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

Chapter 2

Literature Overview:

Inflow performance of a well:

The ability of a well to lift up the fluid represents its inflow performance. Success of a design for lifting fluids depends upon the accuracy of predicting a fluid flow into the well bore from the reservoir.

Inflow performance of a well with the flowing well pressure Pwf above bubble point pressure can be easily evaluated using the Dupuit's solution for a single well located in a center of a drainage area which produces at a steady state conditions (often called Darcy's equation):

$q=2\pi kh(Pe-Pwf)/\mu B \ln (re/rw)+S$……………………………………(1)

According to which the productivity index PI has a constant value:

$PI= q/Pe-Pwf=2\pi kh/\mu B.\ 1/ \ln (re/rw)+S$ ……………………….(2)

As follows from (2), PI depends on the reservoir / fluid properties and therefore is one of important characteristics of a well's inflow performance.

If Pi is known, then evaluation of the expected production rate under specified flowing well pressure Pwf is straightforward:

$q = PI. (Pe- Pwf)$

In case of a single phase flow, the relation between the production rate q and the pressure drop ΔP, which is called the inflow performance ratio, or IPR – curve is a straight line. As follows slope of the IPR curve is inversely proportional to the PI value, i.e.

Slope = 1/PI

Following the straight line to the point corresponding to the zero value of the bottom hole flowing well pressure Pwf =0, we can evaluate a theoretical limit of flow called absolute open flow(AOF).

IPR- curve : Generalized form.

Here we will consider a more general case when the reservoir pressure is higher than the bubble point pressure while the flowing well pressure can take any value (i.e. above or below the point pressure).

Due to the fact that the reservoir pressure is higher than bubble point pressure and IPR curve will consist of 2 parts i.e.

- Linear part for Pwf > Pb
- Curved (Vogel's type curve) part for Pwf < Pb

Note that both parts coincide at Pwf = Pb and q0 =q*, where q* is unknown.

Moreover, at this point both parts should have the same productivity index which means that derivatives to both parts at this point should have the same value.

Constructing IPR-curve:

In performing a system analysis on a well, it is necessary to have a good test data on the well so that the reservoir capability can be predicted. In order to construct the IPR-curve, a well test data consisting of the measured average reservoir pressure, the flowing well pressure and the corresponding production rate are needed.

Back pressure IPR-curve:

Another technique for evaluating the non-linear IPR curve at two-phase flow is based on so called back pressure equation:

q=C.(Pr*2 – Pwf*2)*n

which can be used for both gas and saturated oil wells.

Here n usually takes value:

0.5 < n < 1.0

Fetkovich:

The fetkovich equation is modified from the Darcy equation which allows for the two phase flow below the bubble point. The Fetkovich equation can be expressed as

Q = J (Pr - Pb) + J' (Pr*2 – Pwf*2)

Multi-rate Fetkovich

This method uses a non-linear regression to fit the Fetkovich model for up to 10 test point. The model is expressed as

Q = C ((Pr*2 – Pwf*2)/1000)*n

In Prosper, the fit values of C and n are posted on the IPR plot.

Multi-rate Jones

This method uses a non-linear regression to fit for up to 10 test point for the Jones model

(Pr – Pwf) = aQ*2 + bQ*2

Chapter 3

Gas Field Overview:

Saldanadi is situated about 40 km north of Comilla town. Its location is in Eastern part of Bangladesh between 23°39 N and 23°42 N Latitude and 91°10 E and 91°12 E Longitude.
It is located in the central part of the Rukhia Anticline. The anticline is a gently folded, doubly plugging, NNW-SSE trending one. Northern and Southern part of the anticline lies in India. The structure is about 40 km long and possesses two culminations. Structurally northern culmination, known as Skyampur dome, which is about 500 m higher than the southern one. The southern culmination is known as Jalangi dome. Titas and Bakhrabad is about 40 km north and 30 km west of Saldanadi respectively. Most of the Rukhia anticline lies within the territory of the Indian state of Tripura. About 15 sq. km area of the crestal part of the structure i.e. Shyampur Dome is in Bangladesh.

Saldanadi is a part of greater Rukhia anticline which is located in the western part of broad zone of Neogene folds having a general N-S trend. The hill range system constitutes a serried of symmetrical anticlines and relatively broader and nearly symmetrical synclines (Zutshi 1993).

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

From Landsat map (Ganguly 1983) it appears that the structure is about 40 km long and 6 km wide. In the Landsat map both Jalangi and Shyampur Dome are well pronounced. Three lineaments were drawn within the Shyampur Dome by the Indian authors. In the geological map (Ganguly 1983) no faults could be observed. OGDC and BAPEX geologists identified the presence of northern pitch of the dome towards north of Saldanadi. From seismic data a very gentle southern pitch can be observed.

A fault has been marked on the eastern flank in the time and depth contour maps. Indication of this fault can be observed on topographic map also. The course of the Saldanadi could be an

indication of an E-W fault.
Tectonically the structure lies in the western part of eastern folded belt (Assam Arakan frontal folded Belt) and can be placed within Tangail-Tripura high.

In general the sediments of Rukhia structure are poorly fossiliferous to barren and consist of alternate shale, sandstone and siltstone in varying proportion. According to Patel and Sing (1993), the Upper and Middle Bhuban sediments in konaban field (India) are characterized by seven alternate arenaceous and argillaceous sequences indicating different cycles of deposition. A study of sedimentary depositional environment on the basis of log, core and sand shale ratio indicate that Bhuban sediments were deposited in near shore environment with frequent shallow marine environment. Konaban and Saldanadi are both part of Rukhia Anticline.

Another study by Mane (2001) indicated that the sediments belonging to Bhuban and Bokabil Formations were deposited during Middle to Late Miocene in a deltaic environment which was the result of fluctuating sea level. The study used well datafrom wells in Rukhia and Agartala Dome (India). The later is located about 25 km east of Saldanadi. This study has placed Oligocene-Miocene boundary at 4275 m in Rukhia well # 1.

In Saldanadi well # 1 the Upper Gas Sand is encountered at 2170-2260 m but the gas water contact (GWC) was observed at 2215 m (From wire line logs). Presence of this sand sequence in well # 2 is doubtful. However, this could be confirmed when DST is conducted at this interval in well # 2 in future. In well # 2 new gas sand was encountered at a depth of 2300-2365m (2165-2230 m TVD). About 768 m west, in well # 1 one wet sand at 2305-2367 m depth can be correlated with this gas sand. However correlation is rather difficult due to discontinuous character of the sand bodies. Lower gas sand was encountered at 2405-2430 m in well #1. One sandstone horizon was encountered at a depth of 2425-2451 m (2316-2349 m TVD) in the well # 2 and could be considered as equivalent to the Lower gas sand but this zone produced water during DST. Test result confirmed that the LGS of well #1 has been watered out at well # 2.

Table-1, GAS RESERVE BASED ON VOLUMETRIC ESTIMATE:

	LOWER ZONE	MIDDLE ZONE	UPPER ZONE	TOTAL
GIIP (BCF)	52.410	70.680	42.710	165.80
Recoverable Reserve(BCF) Recovery Factor 0.7	36.680	49.470	29.880	116.03
Cumulative Production as on october 2010 (BCF)	29.908	26.573	5.841	62.322
Remaining Recoverable Reserve (BCF)	6.772	22.897	24.039	53.708

Based on BAPEX Report (2001): Re-Evaluation of Reserve of Salda Nadi Gas Field.

Cumulative gas and condensate production from October 2010.

Gas Production: 62.322 BCF.

Condensate production: 48,325 BBLs.

Saldanadi gas field well # 1 & well # 2 subsurface views:

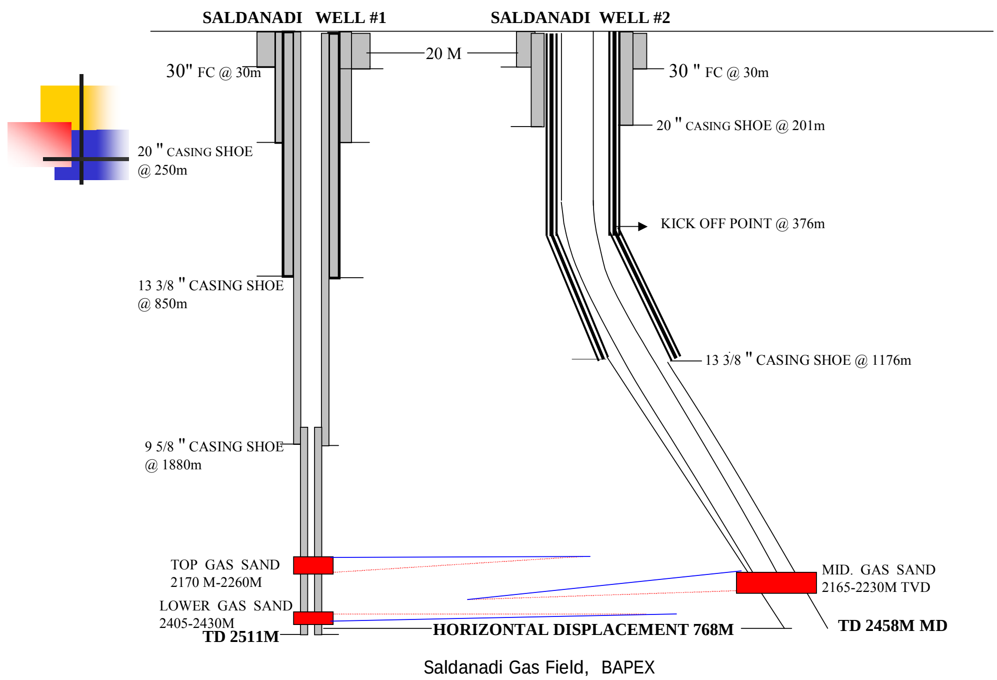

Figure-1, Subsurface well view.

From the graph, it is shown that Saldanadi gas field well # 1 is vertical well and well # 2 is deviated well.

Chapter 4

Reserve Estimate by using MBAL Software.

4.1 Introductions.

Reserve estimation is an essential study 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 and profitable.

This study will focus on the well test analysis and production simulation of Saldanadi gas field reserve estimation by using MBAL software. These data are used in the reserve estimation and production performance analysis of the gas field.

The production and pressure data are used to calculate gas in place by MBAL software.

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

4.2 Rough Approximations about Reservoir for Well # 1(S.S):

It is plot P/Z vs. Gp (Cumulative production for this reservoir) and makes a rough approximation about this reservoir.

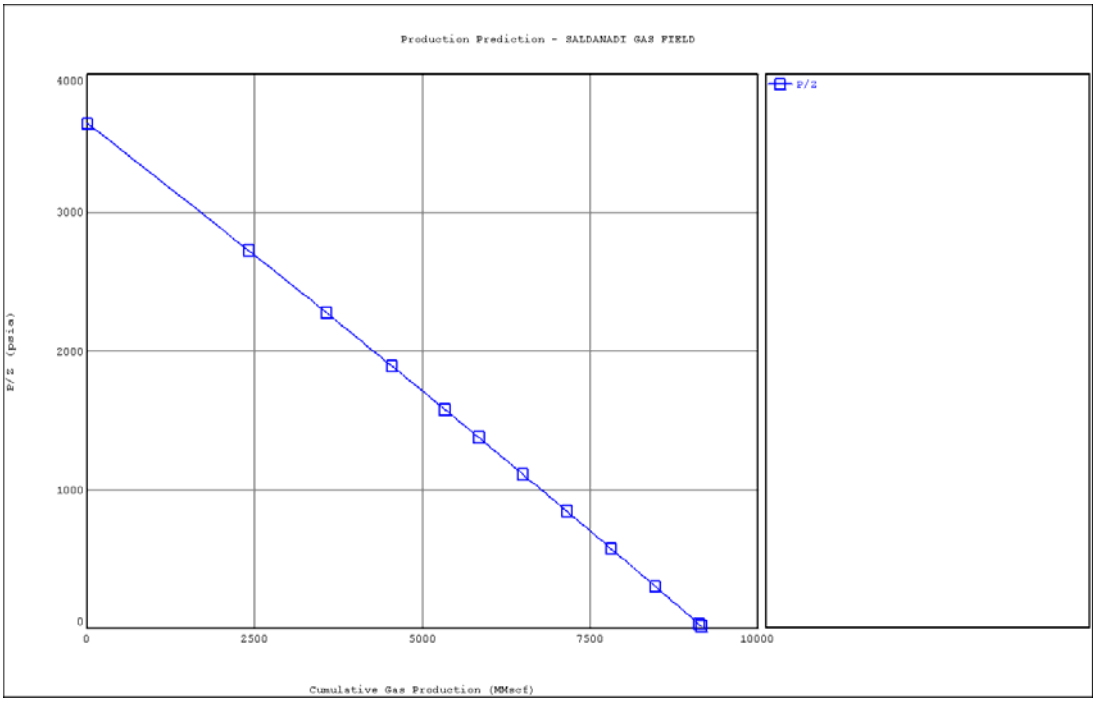

Figure-2, P/Z vs. Cumulative gas production, Gp.

By P/Z vs. Gp plot give us, the reserve Gp is near about 9.16 BCF, where the initial prediction 42.71 BCF (Table -1) for SALDANADI Well # 1(S.S).

It can be concluded that P/Z vs. Gp curve predicts the almost real scenario of this reservoir.

4.3 Results for Well # 1(S.S):

The total gas in place of Saldanadi gas field obtained by using MBAL software calculation is 9.16 BCF and previous gas reserve estimate was 42.710 BCF (Table -1). In October 2010, the cumulative production of the field is 5.841 BCF. Thus the overall gas in place recovery of the field is 64%.

4.4 Rough Approximations about Reservoir for Well # 1(L.S):

It is plot P/Z vs. Gp (Cumulative production for this reservoir) and makes a rough approximation about this reservoir.

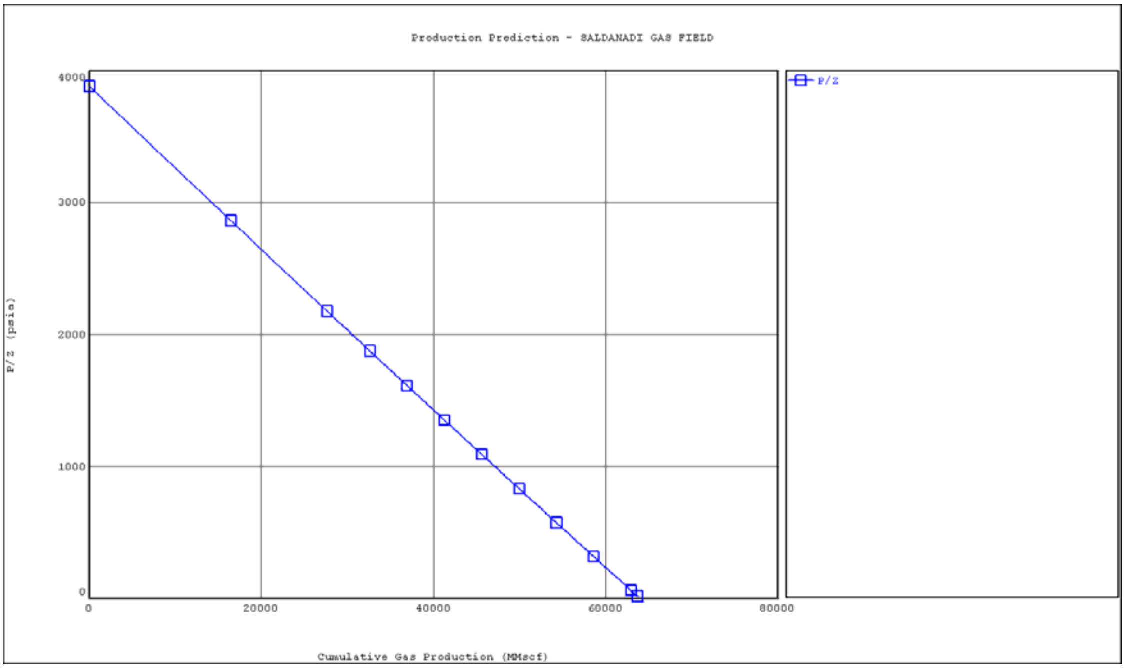

Figure-3, P/Z vs. Cumulative gas production, Gp

By P/Z vs. Gp plot give us, the reserve Gp is near about 63.9 BCF, where the initial prediction 52.410 BCF (Table -1) for SALDANADI Well # 1(L.S).

It can be concluded that P/Z vs. Gp curve predicts the almost real scenario of this reservoir.

4.5 Results for Well # 1(L.S):

The total gas in place value of Saldanadi gas field obtained by using MBAL software calculation is 63.9 BCF and previous gas reserve estimate was 52.410 BCF (Table -1). In October 2010, the cumulative production of the field is 29.907 BCF. Thus the overall gas in place recovery of the field is 47%.

4.6 Rough Approximations about Reservoir for Well # 2:

It is plot P/Z vs. Gp (Cumulative production for this reservoir) and makes a rough approximation about this reservoir.

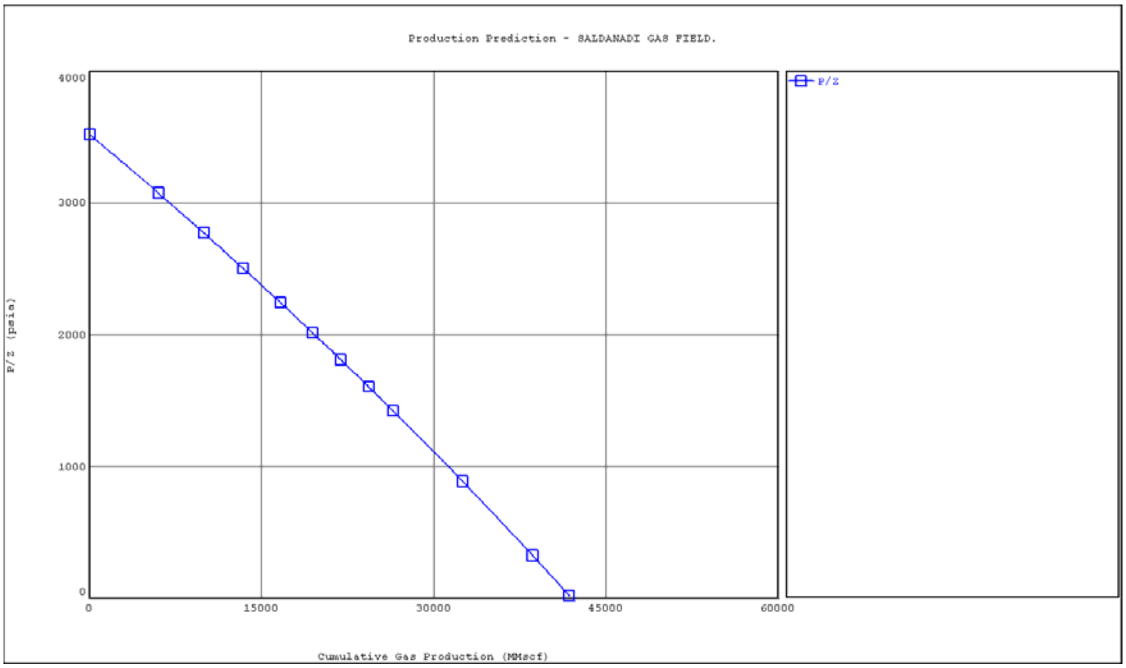

Figure-4, P/Z vs. Cumulative gas production, Gp

By P/Z vs. Gp plot give us, the reserve Gp is near about 41.9 BCF, where the initial prediction 70.68 BCF (Table -1) for SALDANADI Well # 2.

It can be concluded that P/Z vs. Gp curve predicts the almost real scenario of this reservoir.

4.7 Results for Well # 2:

The total gas in place value of Saldanadi gas field obtained by using MBAL software calculation is 41.9 BCF and previous gas reserve estimate was 70.68 BCF (Table -1). In October 2010, the cumulative production of the field is 26.573 BCF. Thus the overall gas in place recovery of the field is 64%.

4.8 Conclusions:

This model has been developed as a response to the industry need of being able to calculate the GIIP and be able to perform forecasting for transient gas reservoirs without having to resort to simulation models. It is commonly known that the method of Material Balance is only valid when the reservoir has developed fully into pseudo-steady state and where average reservoir pressures can be estimated. In some tight gas reservoirs however, the period of interest may be during the transient period. So the basic assumption of material balance will lead to errors in the estimation of the gas in place and hence the forecasted volumes.

The total gas in place value of Saldanadi gas field obtained by using MBAL software calculation is 114.96 BCF and previous gas reserve estimate was 165.80 BCF (Table -1). In October 2010, the cumulative production of the field is 62.321 BCF. Thus the overall gas in place recovery of the field is 54%.

The Saldanadi gas field Well # 1(S.S), Well # 1(L.S) and Well # 2 has no aquifer support. The water production of the Well # 1(S.S), Well # 1(L.S) and Well # 2 is due to the presence of mobile water.

The gas reserve value estimated from MBAL software study is lower than gas reserve based on volumetric estimate. It can be inferred from the study that gas reserve calculation done earlier were over estimated.

Well test for Well # 1(S.S), Well # 1(L.S) and Well # 2 was performed around 10 years ago. Some of the calculations are performed of this well on the basis of these old test data. Data on current reservoir pressure are not available. Obviously, there is a decline in reservoir pressure as it is producing for last 10 years.

4.9 Recommendations:

- Comprehensive pressure survey test should be conducted in well to find out up-to-date values of reservoir parameters.
- Well tests are to be performed regularly to know the condition of the well which will be helping production longevity and production volume in advance.

Chapter 5

Well Performance by using PROSPER Software.

5.1 Introduction:

Prosper is one of the most common software for the petroleum industry. It is the petroleum Experts Limited’s advance Production and systems performance analysis software. Prosper can assist the production or reservoir engineer to predict tubing and pipeline hydraulics and temperatures with accuracy and speed. Prospers powerful sensitivity calculation features enables existing designs to be optimized and the effects of future changes in the system parameters to be assessed.

Prosper is a fundamental element in the Integrated Production Model (IPM) as defined by Petroleum Experts, linking to GAP, the production network optimization program for gathering system modeling and MBAL, the reservoir engineering and modeling tool for making fully integrated total system modeling and production forecasting.

The objective of this section is to set up prosper model for a gas well, input the PVT values, draw the phase diagram, draw the down hole, construct the IPR , matching the model to a well test and performing the calculation of well performance, gradient transverse and vertical lift performance curves.

The PROSPER main screen is divided in to 5main sections. They are

- Options.
- PVT Data.
- Equipment Data.
- IPR Data.
- Calculation Summary.

5.2 Well # 1(S.S):

In this section, all equipment data are provided to the Prosper as follows.

- Deviation Survey.
- Surface Equipment.
- Downhole Equipment.
- Geo-Thermal Gradient.
- Average Heat capacities.

For this process, no surface equipment data are provided. The geo-thermal gradient is calculated by Hasan Kabir correlation. Average heat capacities are taken as default value given by the Prosper.

After providing all the input, it can be possible to summarize the down hole equipment from the draw down hole menu as:

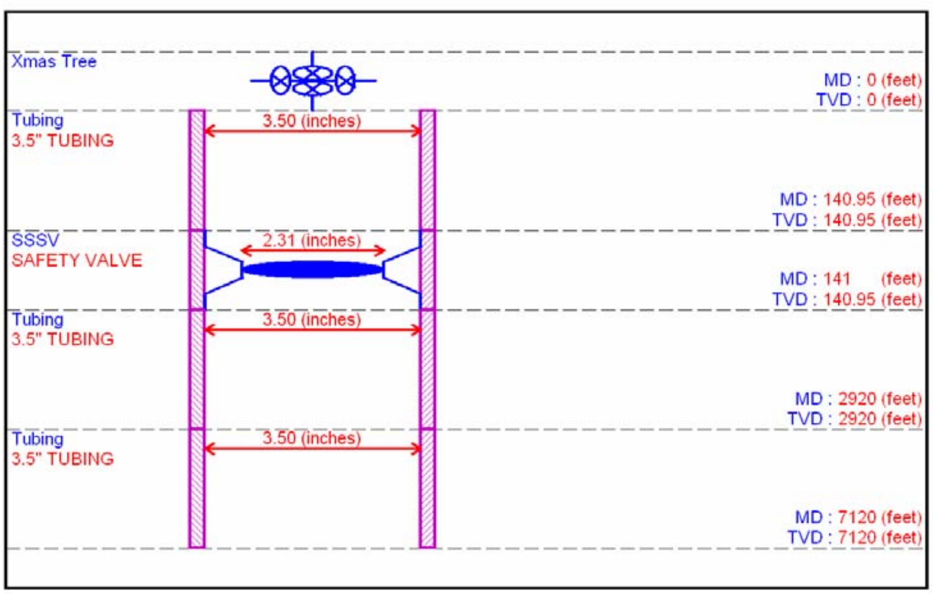

Figure-5, Down hole equipment for well # 1(S.S):

IPR Data:

In this section, IPR data are provided as point. To do so, Multi Rate C and n is selected since the well test pressure data's are available for different flow rate. There different flows rates with corresponding pressure are supplied.

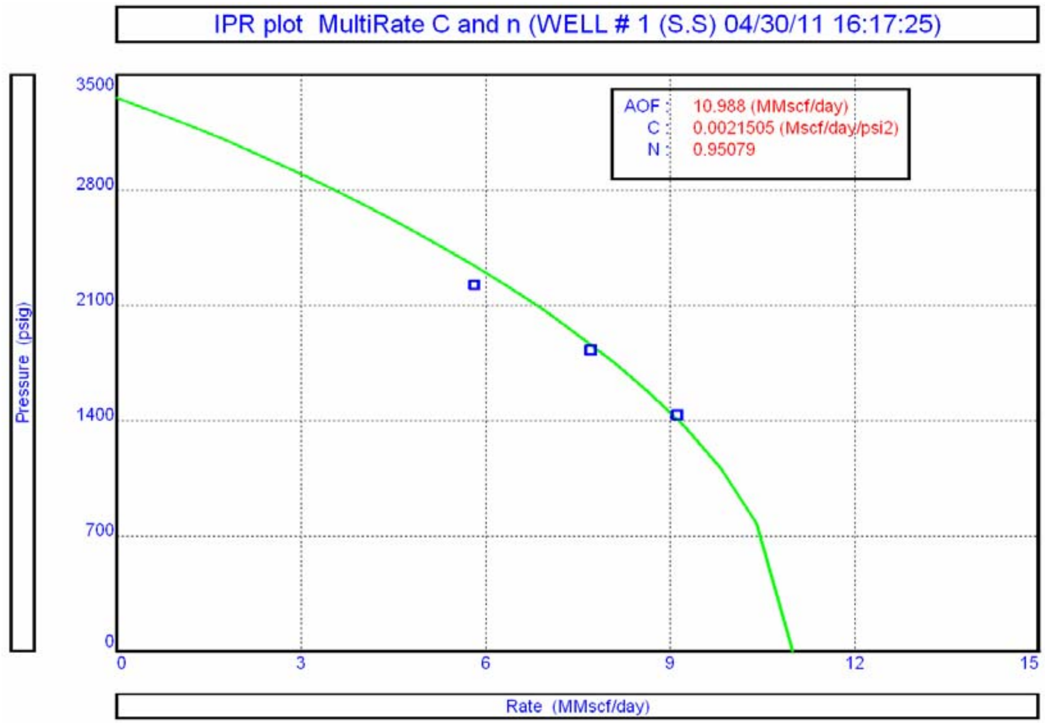

Figure-6, IPR curve for well # 1(S.S):

From the IPR curve, it is observed that Absolute Open Flow potential (AOF) is around 10.988 MMscf/D. In addition, C value is 0.0021505 (Mscf/day/psi*2) and N = 0.95079.

Matching of the model to a test.

The matching process consists of two main steps:

- Matching of the VLP: The multiphase flow correction will be tuned in order to match a down hole pressure measurement.
- Matching of the IPR: The IPR will be turned so that the intersection of VLP/IPR will match the production rate as per well test.

VLP Matching: The matching of the multiphase flow correlation will be carried out by entering the well test data and comparing the multiphase flow correlations (QC) followed by selecting the best correlation. Before running the comparison of the correlation, it is possible to tune the temperature prediction model to match the temperature measurement of the test. And the Prosper will calculate the overall heat transfer coefficient that match the well test temperature measurement, it found that

Test point 1:

Heat transfer Coefficient = 1.022 (BTU/h/ft*2/F).

Then it can be possible to adjust the geothermal gradient in the equipment data.

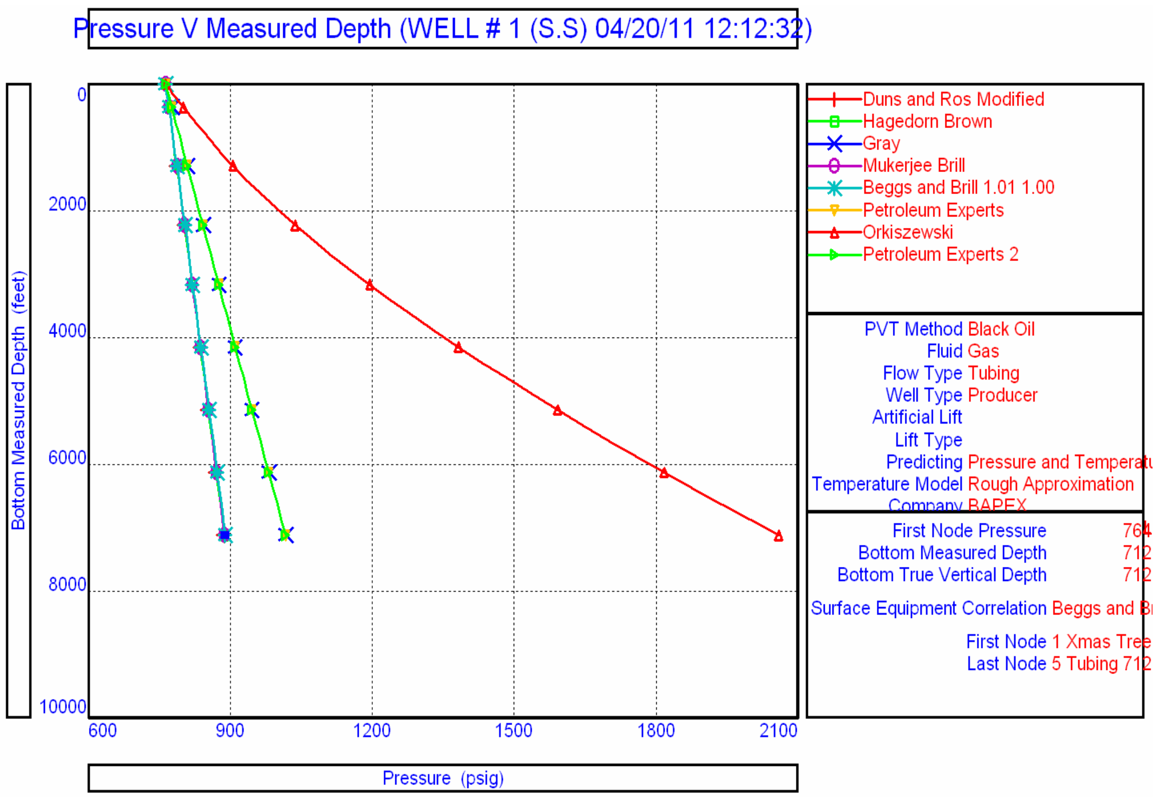

Figure -7, Tubing correlation comparison for well # 1(S.S).

Now, it is possible to select the different correction to match the consistency of the test data. Duns Ros Modified, Hagedorn Brown, Gray, Mukerjee Brill, Beggs and Brill, Petroleum Expart 1, Orkiszewski, Petroleum Expart 2, Duns and Ros Original 1, Petroleum Expart 3 and calculating and plotting the result shows.

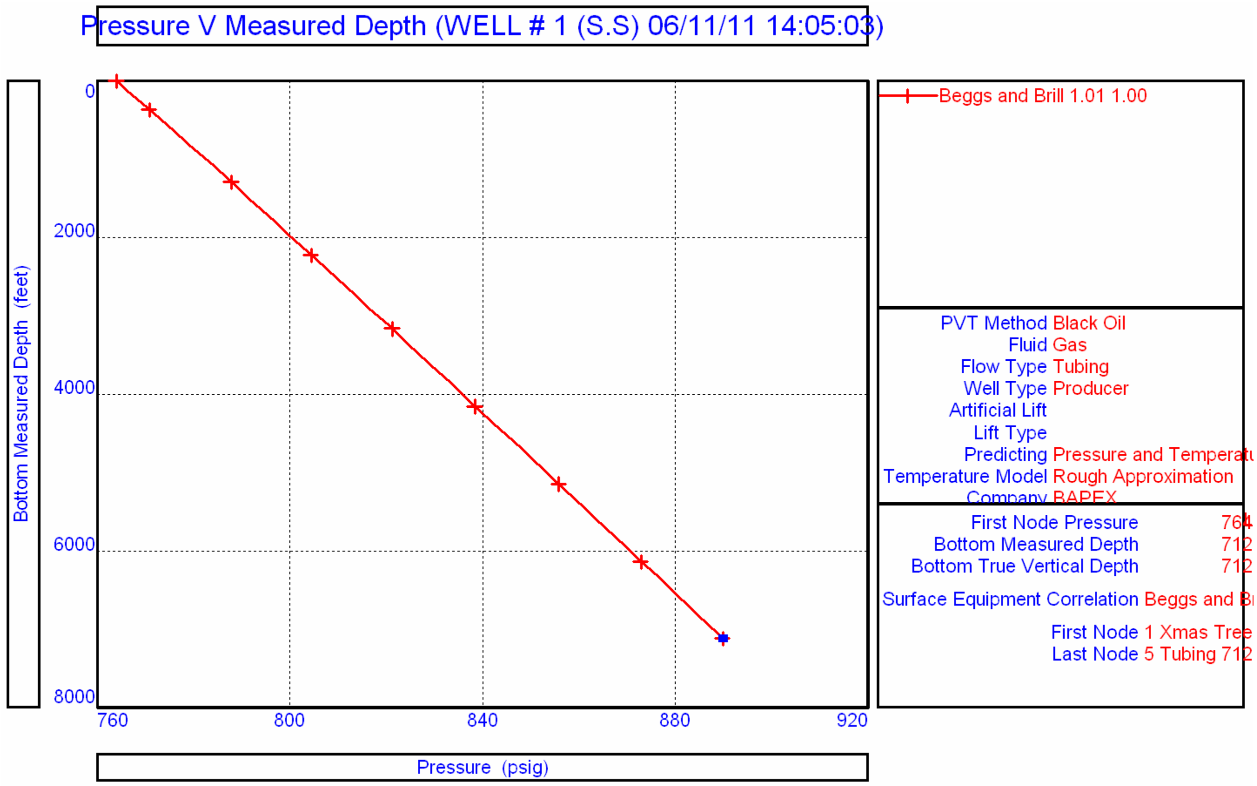

Figure -8, Besting Tubing correlation comparison for well # 1(S.S).

Result: It is observed that the Beggs and Brill correlation match the perfectly for the given test data.

Matching the correlation to the test:

Once chosen the best correlation, it is possible to adjust the correlation to best fit the down hole pressure measurement. Prosper does this using a non-linear regression technique which applies multipliers to the gravity and friction components of the pressure drop prediction by multiphase flow correlation.

IPR Matching.

The IPR is tuned so that the intersection of VLP and IPR fit the well test rate measurement. Prosper will calculated the VLP curve for match data using matched VLP correlation. Then it is possible to calculate and draw the IPR curve again which shows the VLP and IPR lines intersect quite close to measured data point.

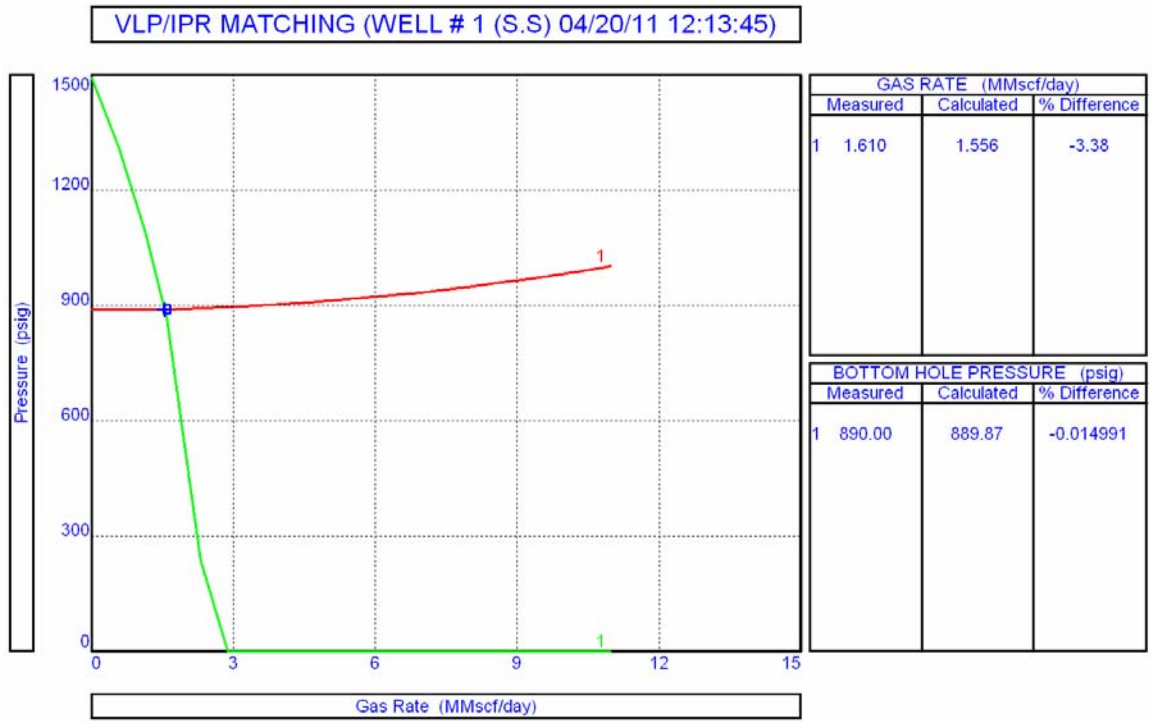

Figure-9, IPR/VLP matching for Well # 1(S.S).

From the figure, it is observed that, there are only 3.38 % difference between measured gas rate and calculated gas rate where as for the bottom hole pressure, the difference is only 0.014991%.

5.3 Well # 1 (L.S):

In this section, all equipment data are provided to the Prosper as follows.

- Deviation Survey.
- Surface Equipment.
- Down hole Equipment.
- Geo-Thermal Gradient.
- Average Heat capacities.

For this process, no surface equipment data are provided. The geo-thermal gradient is calculated by Hasan Kabir correlation. Average heat capacities are taken as default value given by the Prosper.

After providing all the input, it can be possible to summarize the down hole equipment from the draw down hole menu as:

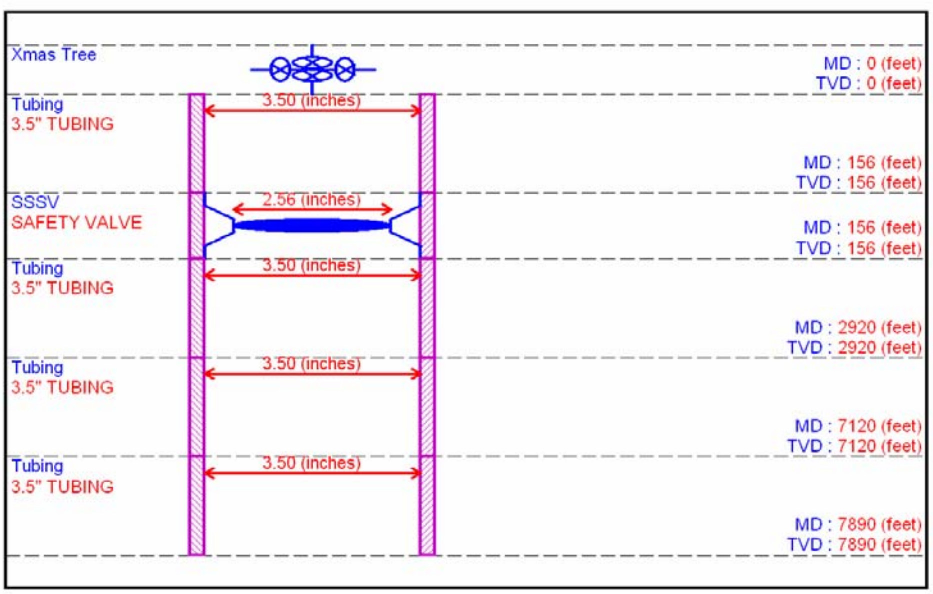

Figure-10, Down hole equipment for well # 1(L.S):

In this section, IPR data are provided as point. To do so, Multi Rate C and n is selected since the well test pressure data's are available for different flow rate. There different flows rates with corresponding pressure are supplied.

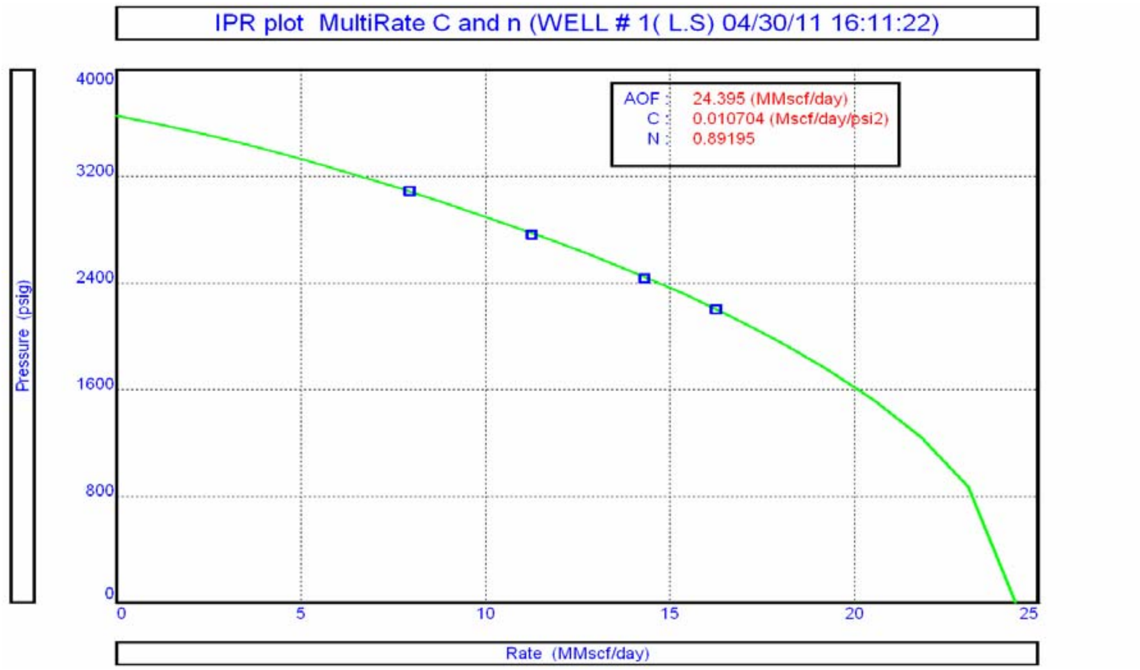

Figure-11, IPR curve for well # 1(L.S):

from the IPR curve, it is observed that Absolute Open Flow potential (AOF) is around 24.395 MMscf/D. In addition, C value is 0.010704 (Mscf/day/psi*2) and N = 0.89195.

Matching of the model to a test.

The matching process consists of two main steps:

- Matching of the VLP: The multiphase flow correction will be tuned in order to match a down hole pressure measurement.
- Matching of the IPR: The IPR will be turned so that the intersection of VLP/IPR will match the production rate as per well test.

VLP Matching: The matching of the multiphase flow correlation will be carried out by entering the well test data and comparing the multiphase flow correlations (QC) followed by selecting the best correlation. Before running the comparison of the correlation, it is possible to tune the temperature prediction model to match the temperature measurement of the test. And the Prosper will calculate the overall heat transfer coefficient that match the well test temperature measurement, it found that

Test point 1:

Heat transfer Coefficient = 1.84 (BTU/h/ft*2/F).

Then it can be possible to adjust the geothermal gradient in the equipment data.

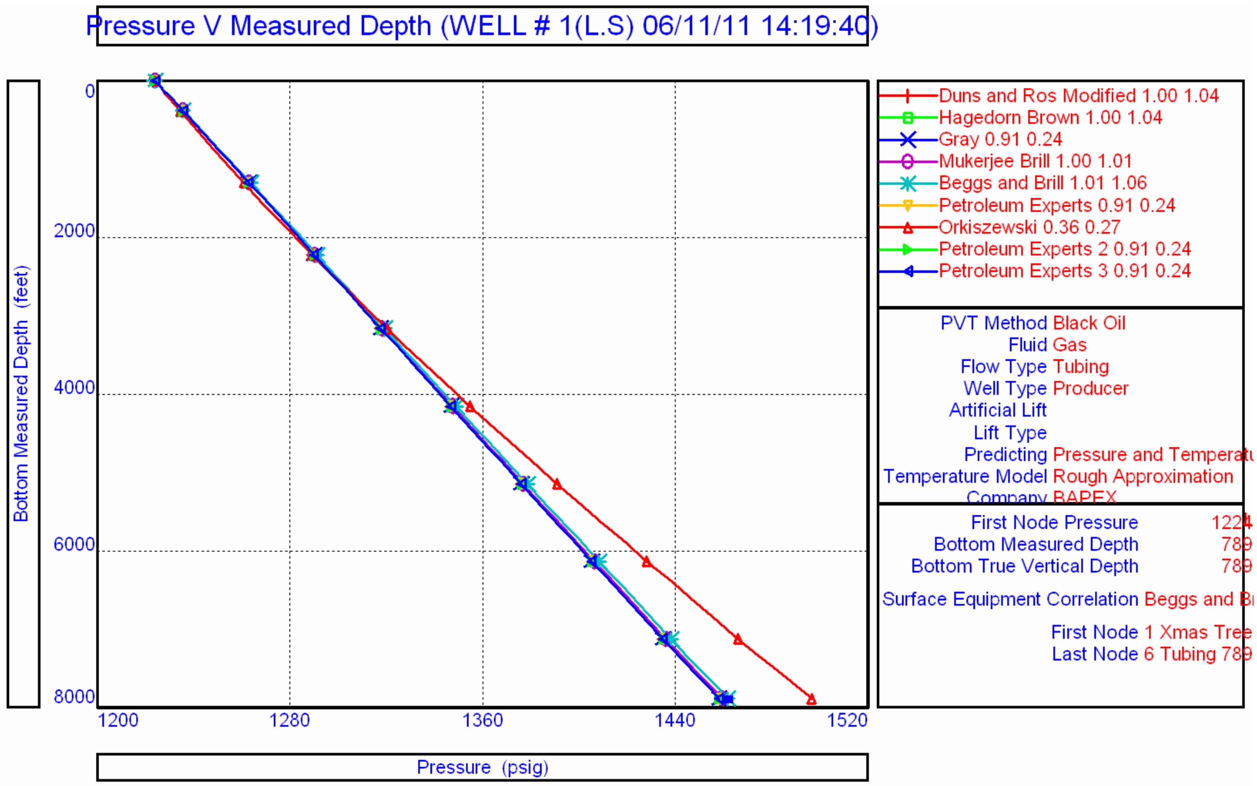

Figure -12, Tubing correlation comparison for well # 1(L.S):

Now, it is possible to select the different correction to match the consistency of the test data. Duns Ros Modified, Hagedorn Brown, Gray, Mukerjee Brill, Beggs and Brill, Petroleum Expart 1, Orkiszewski, Petroleum Expart 2, Duns and Ros Original 1, Petroleum Expart 3 and calculating and plotting the result shows.

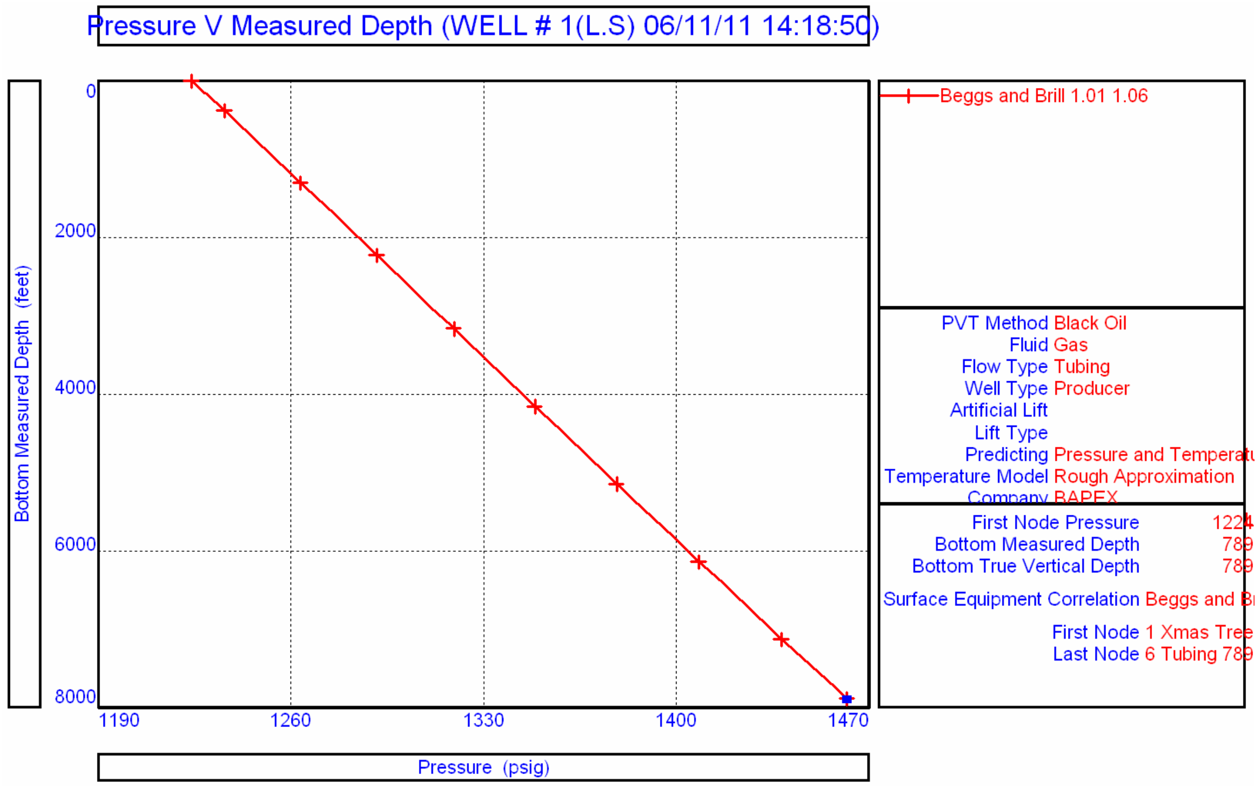

Figure -13, Besting Tubing correlation comparison for well # 1(L.S).

Result: It is observed that the Beggs and Brill correlation match the perfectly for the given test data.

Matching the correlation to the test:

Once chosen the best correlation, it is possible to adjust the correlation to best fit the down hole pressure measurement. Prosper does this using a non-linear regression technique which applies multipliers to the gravity and friction components of the pressure drop prediction by multiphase flow correlation.

IPR Matching.

The IPR is tuned so that the intersection of VLP and IPR fit the well test rate measurement. Prosper will calculated the VLP curve for match data using matched VLP correlation. Then it is possible to calculate and draw the IPR curve again which shows the VLP and IPR lines intersect quite close to measured data point.

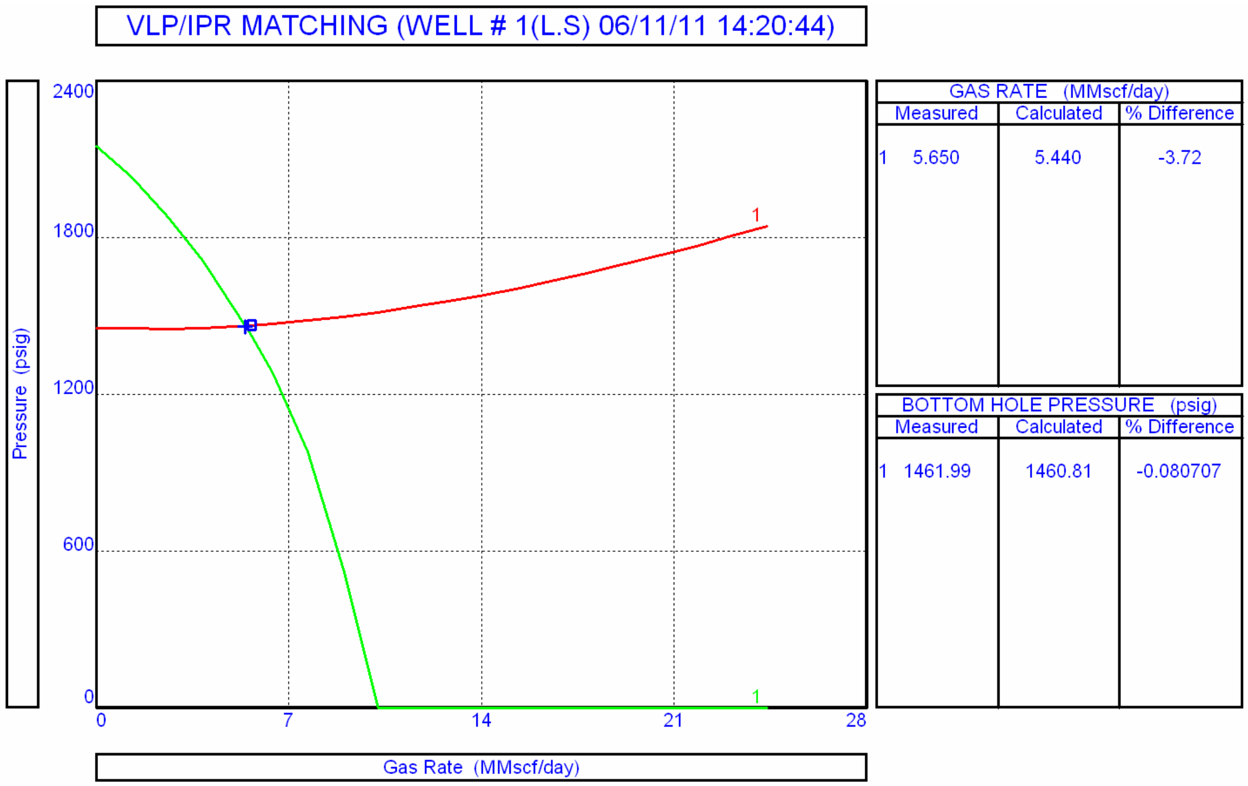

Figure-14, IPR/VLP matching for Well # 1(L.S).

From the figure, it is observed that, there are only 3.72 % difference between measured gas rate and calculated gas rate where as for the bottom hole pressure, the difference is only 0.080707%.

5.4 Well # 2:

In this section, all equipment data are provided to the Prosper as follows.

- Deviation Survey.
- Surface Equipment.
- Downhole Equipment.
- Geo-Thermal Gradient.
- Average Heat capacities.

For this process, no surface equipment data are provided. The geo-thermal gradient is calculated by Hasan Kabir correlation. Average heat capacities are taken as default value given by the Prosper.

After providing all the input, it can be possible to summarize the down hole equipment from the draw down hole menu as:

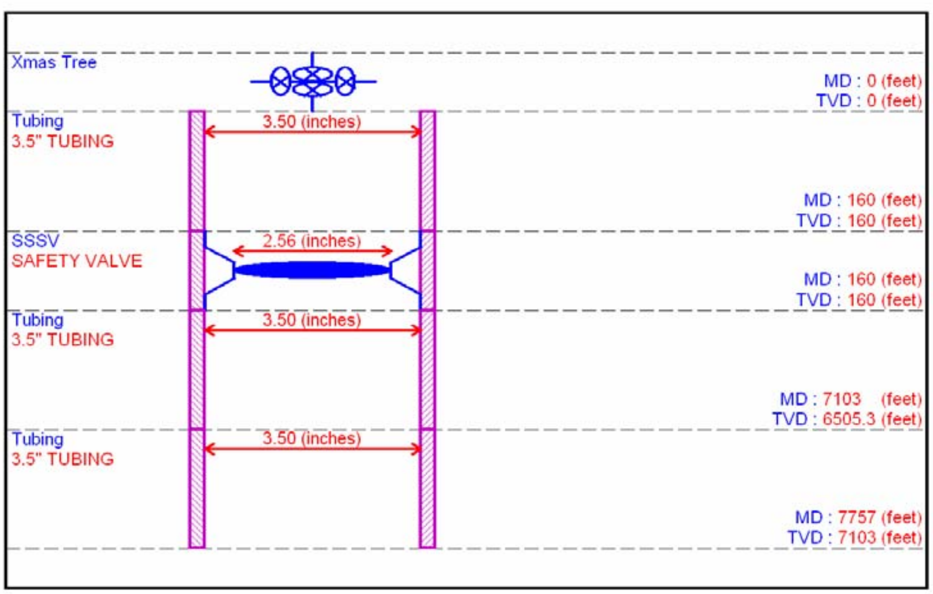

Figure-15, Down hole equipment for well # 2:

In this section, IPR data are provided as point. To do so, Multi Rate C and n is selected since the well test pressure data's are available for different flow rate. There different flows rates with corresponding pressure are supplied.

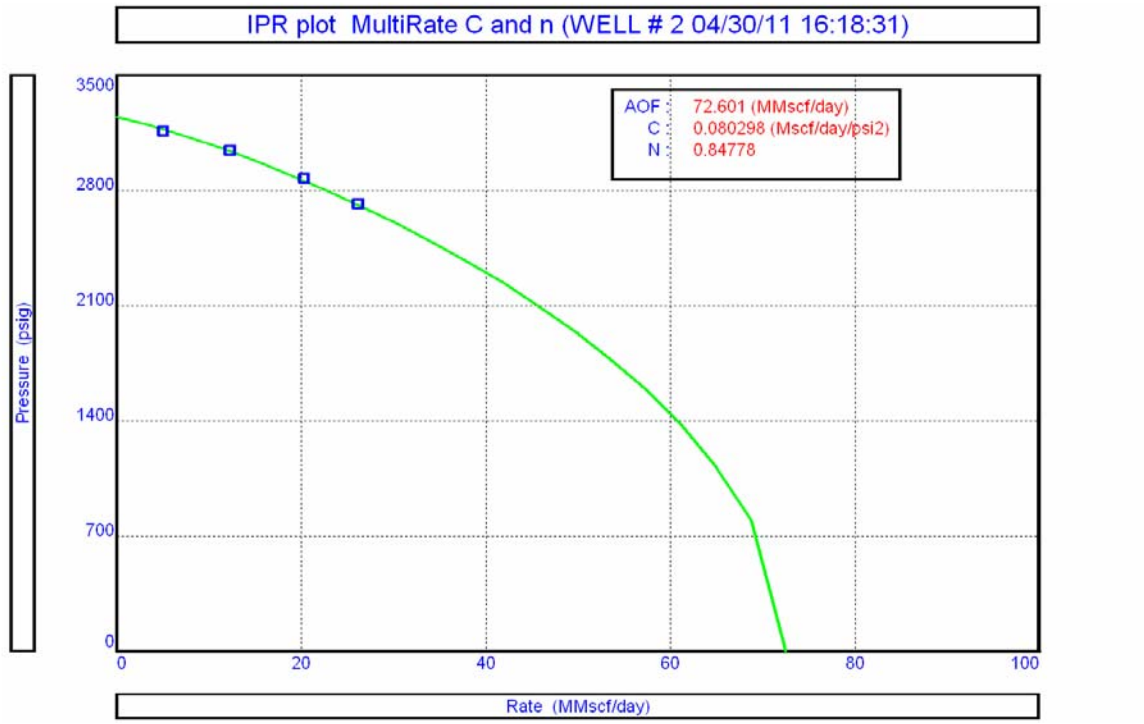

Figure-16, IPR curve for well # 2:

from the IPR curve, it is observed that Absolute Open Flow potential (AOF) is around 72.601 MMscf/D. In addition, C value is 0.080298 (Mscf/day/psi*2) and N = 0.84778.

Matching of the model to a test.

The matching process consists of two main steps:

- Matching of the VLP: The multiphase flow correction will be tuned in order to match a down hole pressure measurement.
- Matching of the IPR: The IPR will be turned so that the intersection of VLP/IPR will match the production rate as per well test.

VLP Matching: The matching of the multiphase flow correlation will be carried out by entering the well test data and comparing the multiphase flow correlations (QC) followed by selecting the best correlation. Before running the comparison of the correlation, it is possible to tune the temperature prediction model to match the temperature measurement of the test. And the Prosper will calculate the overall heat transfer coefficient that match the well test temperature measurement, it found that

Test point 1:

Heat transfer Coefficient = 2.67 (BTU/h/ft*2/F).

Then it can be possible to adjust the geothermal gradient in the equipment data.

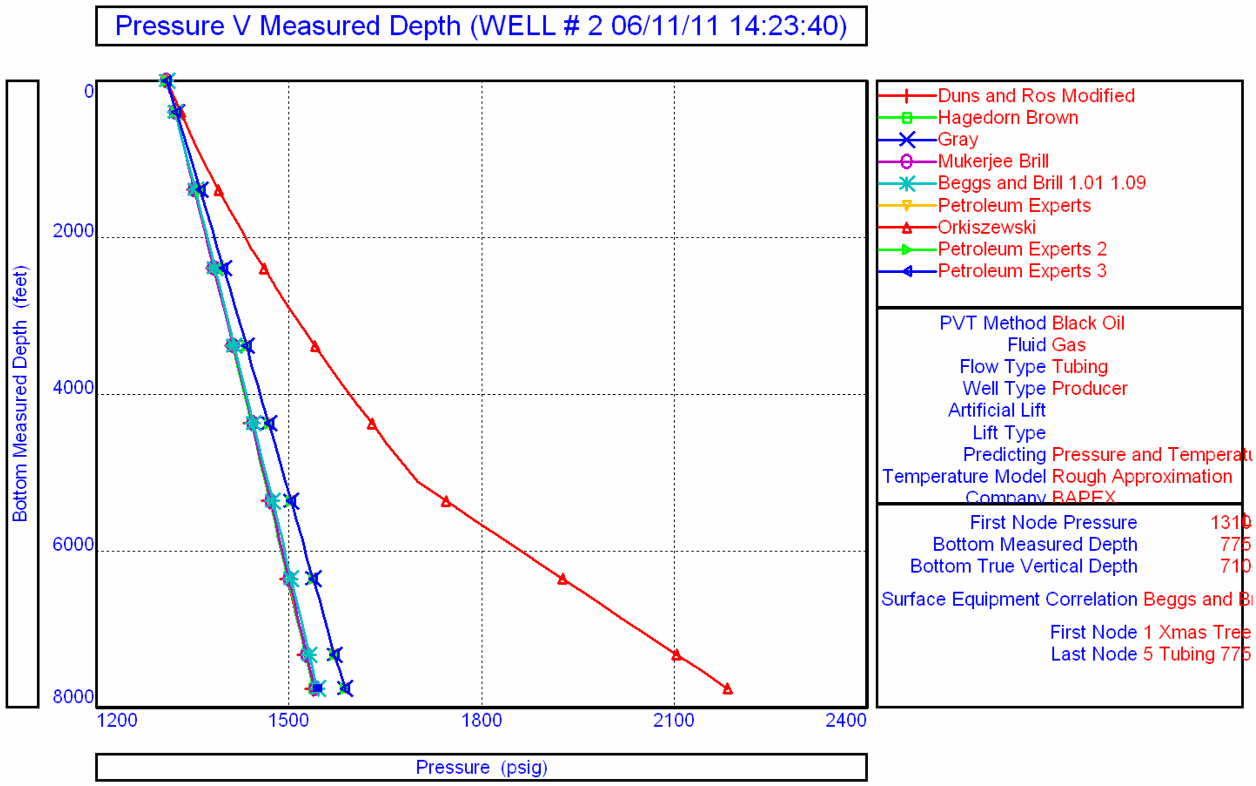

Figure -17, Tubing correlation comparison for well # 2

Now, it is possible to select the different correction to match the consistency of the test data. Duns Ros Modified, Hagedorn Brown, Gray, Mukerjee Brill, Beggs and Brill, Petroleum Expart 1, Orkiszewski, Petroleum Expart 2, Duns and Ros Original 1, Petroleum Expart 3 and calculating and plotting the result shows.

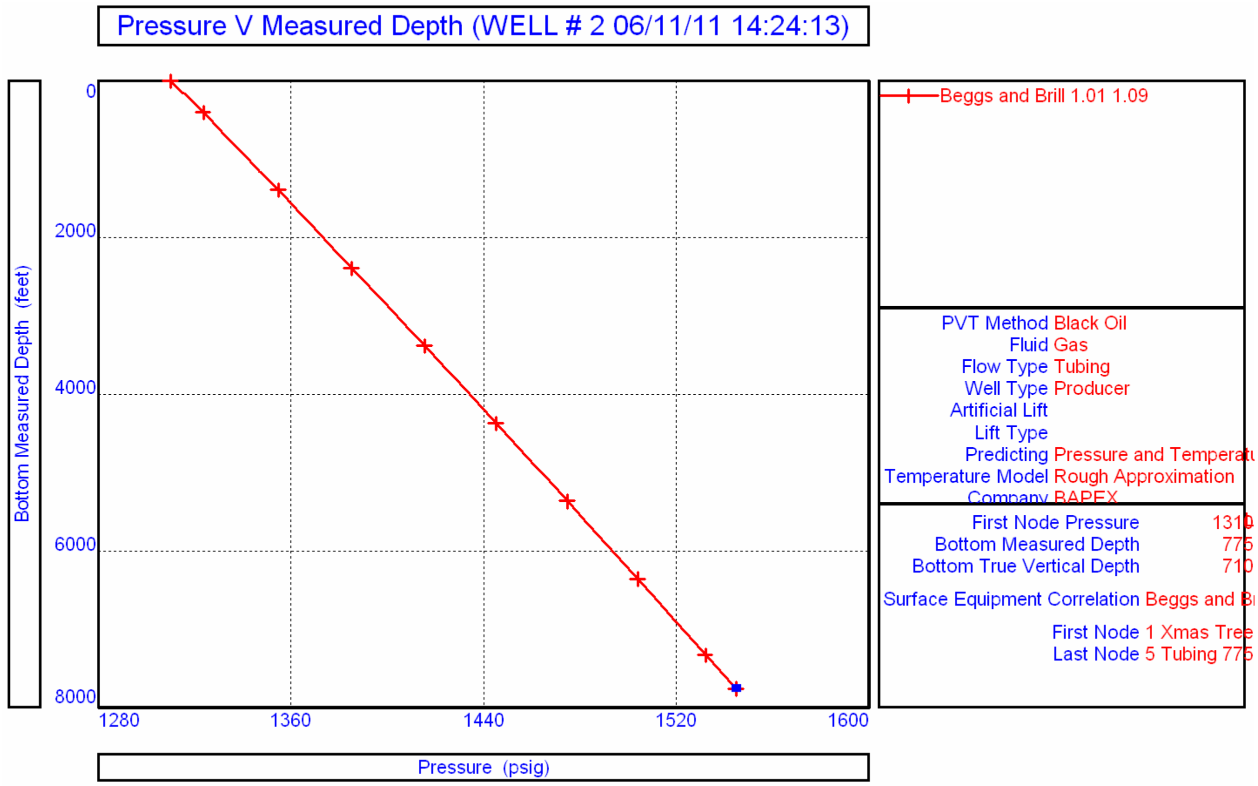

Figure -18, Besting Tubing correlation comparison for well # 2.

Result: It is observed that the Beggs and Brill correlation match the perfectly for the given test data.

Matching the correlation to the test:

Once chosen the best correlation, it is possible to adjust the correlation to best fit the down hole pressure measurement. Prosper does this using a non-linear regression technique which applies multipliers to the gravity and friction components of the pressure drop prediction by multiphase flow correlation.

IPR Matching.

The IPR is tuned so that the intersection of VLP and IPR fit the well test rate measurement. Prosper will calculated the VLP curve for match data using matched VLP correlation. Then it is possible to calculate and draw the IPR curve again which shows the VLP and IPR lines intersect quite close to measured data point.

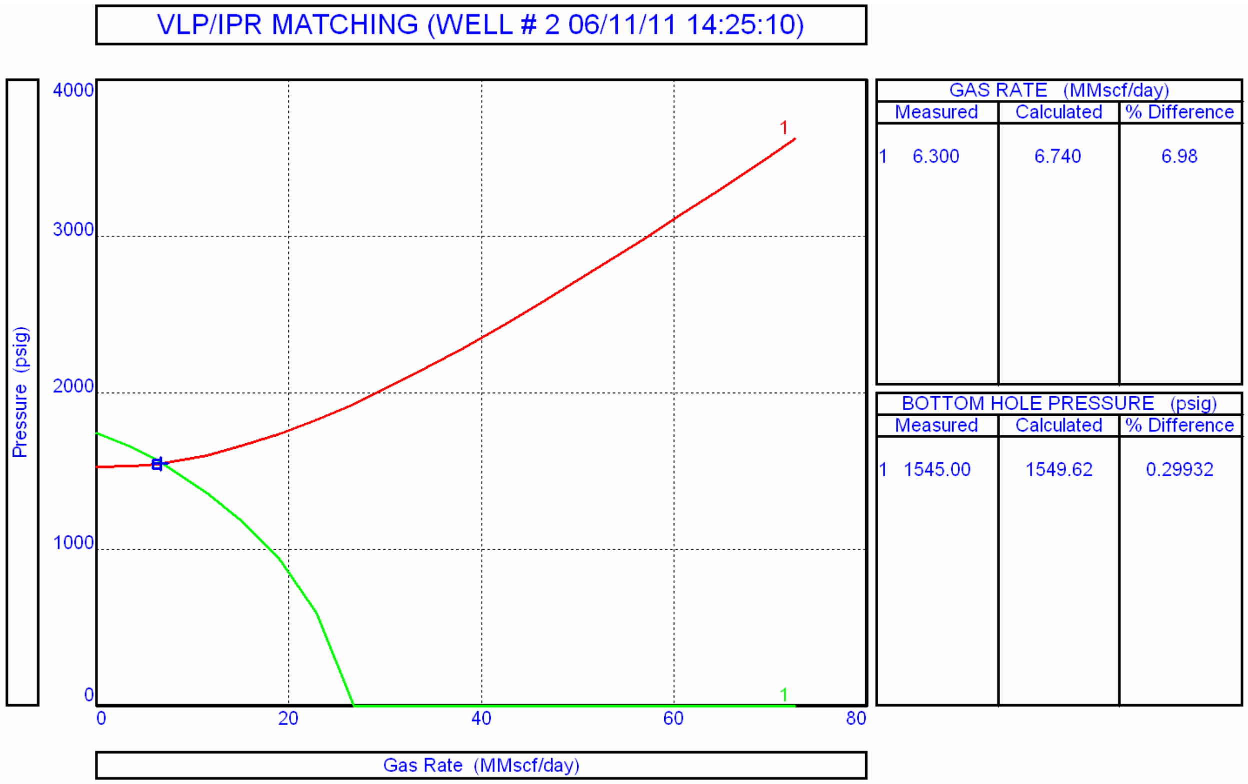

Figure-19, IPR/VLP matching for Well # 2.

From the figure, it is observed that, there are only 6.98 % difference between measured gas rate and calculated gas rate where as for the bottom hole pressure, the difference in only 0.29932%.

5.5 Conclusion:

Prosper is one of the most common software for the petroleum industry. It is the petroleum Experts Limited's advance Production and systems performance analysis software. Prosper can assist the production or reservoir engineer to predict tubing and pipeline hydraulics and temperatures with accuracy and speed.

From the figure 9, IPR/VLP matching for Well # 1(S.S), it is observed that, there are only 3.38 % difference between measured gas rate and calculated gas rate where as for the bottom hole pressure, the difference is only 0.014991%.

From the figure 14, IPR/VLP matching for Well # 1(L.S), it is observed that, there are only 3.72 % difference between measured gas rate and calculated gas rate where as for the bottom hole pressure, the difference is only 0.080707%.

From the figure-19, IPR/VLP matching for Well # 2, it is observed that, there are only 6.98 % difference between measured gas rate and calculated gas rate where as for the bottom hole pressure, the difference is only 0.29932%.

The measured gas rate and software calculated gas rate are almost similar and the result variations are less than 7%.

Chapter 6

Production Optimization by Using GAP Software.

6.1 Introduction:

Petroleum experts general allocation package is an extremely powerful and useful tool offered to the petroleum engineering community. Some of the tasks GAP can achieve are:

- Complete surface production/injection network modeling.
- Optimization.
- GAP has a powerful optimizer that is capable of handling a variety of wells in the same network.
- Naturally flowing oil wells.
- Gas lifted wells.
- ESP operated wells
- Condensate or gas producers.
- Water producers.
- Water or gas injectors.
- PCP wells.
- HSP wells.
- The optimizer controls production rates using well head chokes, ESP operating frequencies or allocating lift gas to maximize the hydrocarbon production while honoring constraints at the gathering system, well and reservoir levels.
- Allocation of production.
- Predictions (production forecast).
- GAP models both production and injection systems simultaneously, containing oil, gas condensate and/or water well to generate production profiles.
- GAP's powerful optimization engine can for example allocate gas for gas lift wells, alter the frequency of ESP pumps or sets well head chokes for naturally flowing wells to maximize revenue or oil production while honoring constraints at any level.
- GAP can also model and optimize injection network associated with the production system (both together).

6.2 Production Forecasting:

GAP calculates full field production forecasts including gas or water injection volumes required to meet reservoir unit pressure constraints.

Reservoir pressure is obtained from decline curve, material balance or simulation models.

The associated injection systems can be modeled and optimized so as to achieve injection targets for pressure maintenance programmers.

Link has an open Architecture that allows-

Third party software to exchange data with GAP.

Run and control GAP via the open server technology developed by petroleum experts.

Link to MBAL:

Reservoir performance for production forecasting is provided by links to petroleum experts MBAL material balance program.

Fully coupled production and injection models can be solved by GAP with optimization of production and calculation of injection pressures at every time step.

Link to PROSPER:

Well performance for production forecasting is provided by links to petroleum experts PROSPER the single well model package within the IPM suite. PROSPER can be run in a batch mode from GAP for generation of well performance and lift curves for simulation.

Fully Compositional or Compositional Tracking Modes:

GAP can calculate the PVT fully compositionally and track compositions from the well/source level through to the separators. In a prediction, GAP can take compositions calculated by MBAL and record the evolution of compositions throughout the system with time.

The compositional tracking can be done as in previous versions using the BO Model.

6.3 Result:

This screen displays the intermediate status messages of the prediction calculation. Wells require valid VLP tables and IPR data. In decline curve forecasting, the production data tables for both wells and tanks must be valid. In material balance forecasting, the tanks must have valid ***MBAL*** models associated with them.

Production tube id 3.5 inch.

Separator Pressure 700 psi:

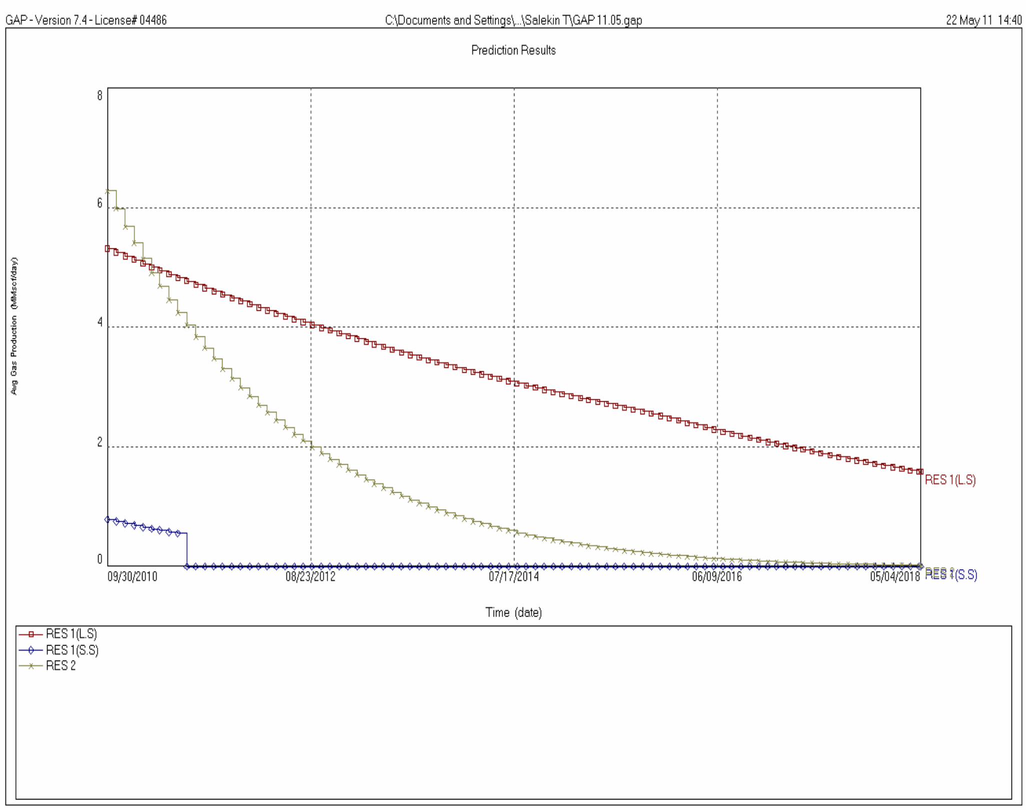

Figure-20, Average Gas Production vs. Time for Separator Pressure 700 psi and Tubing ID-3.5 inch.

Figure 20 shows that, when separator pressure 700 psi, the flow rate of the well # 2 is 6.2 MMSCFD and after 2018, the flow rate of the well # 2 is 0 MMSCFD, the flow rate of the well # 1(L.S) is 5.4 MMSCFD and after 2018, the flow rate of the well # 1(L.S) will produce 1.8

MMSCFD, the flow rate of the well # 1(S.S) is 0.5 MMSCFD, and after 2011, the flow rate of the well # 1(S.S) will produce 0 MMSCFD.

Separator Pressure 750 psi:

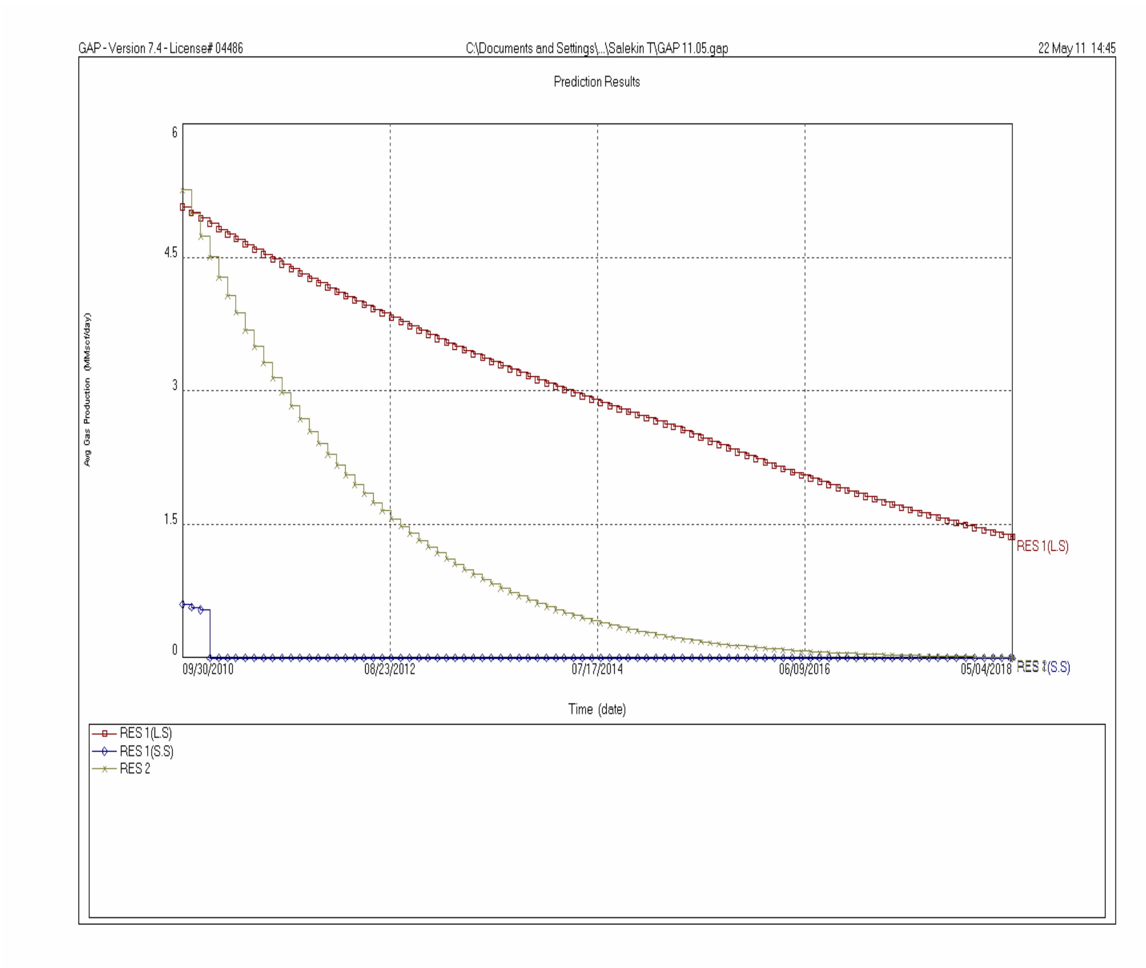

Figure-21, Average Gas Production vs. Time for Separator Pressure 750 psi and Tubing ID-3.5 inch.

Figure 21 shows that, when separator pressure 750 psi, the flow rate of the well # 2 is 5 MMSCFD and after 2017, the flow rate of the well # 2 is 0 MMSCFD, the flow rate of the well # 1(L.S) is 4.9 MMSCFD and after 2018, the flow rate of the well # 1(L.S) will produce 1.4 MMSCFD, the flow rate of the well # 1(S.S) is 0.5 MMSCFD, and after 2011, the flow rate of the well # 1(S.S) will produce 0 MMSCFD.

Separator Pressure 800 psi:

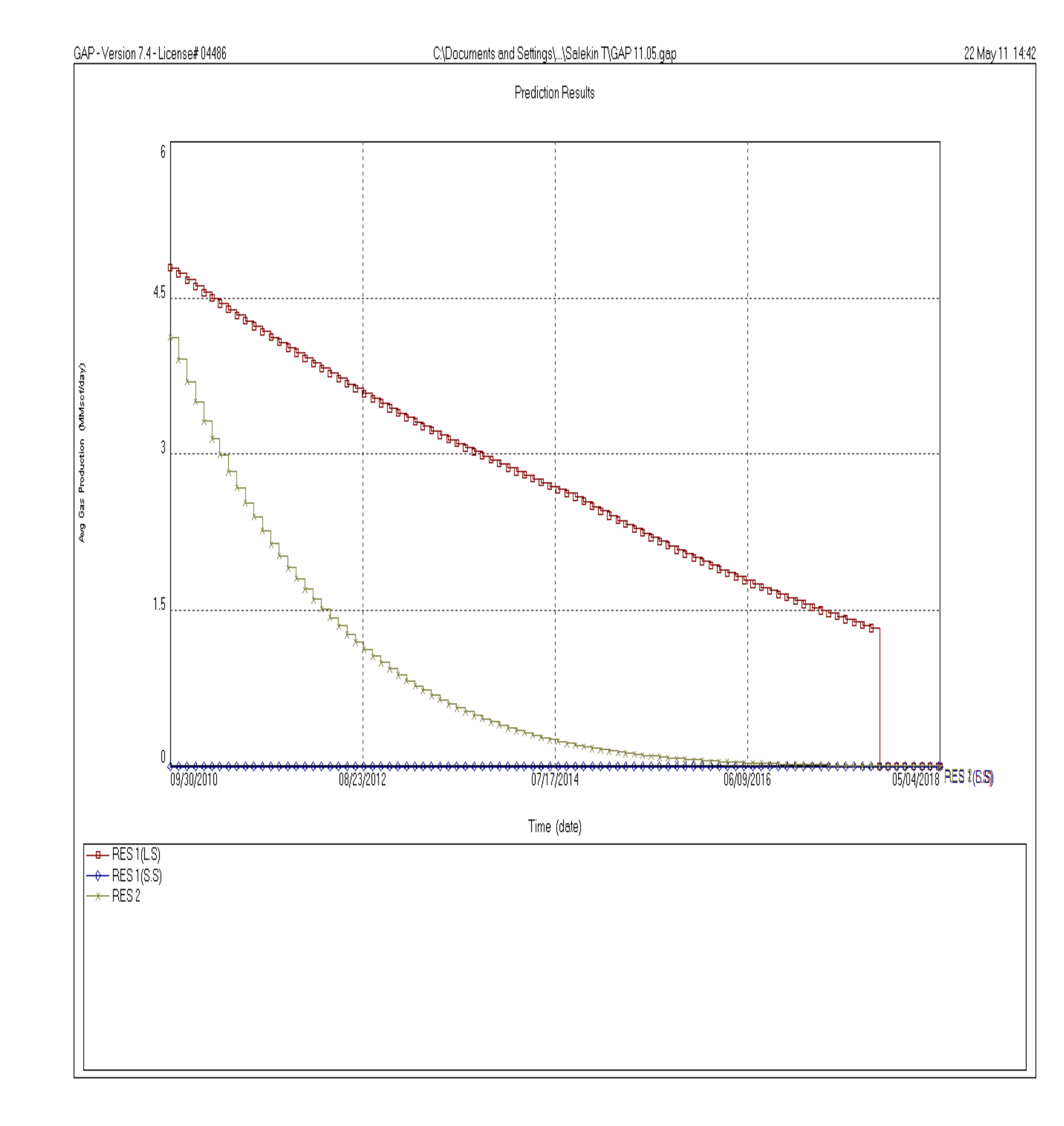

Figure-22, Average Gas Production vs. Time for Separator Pressure 800 psi and Tubing ID-3.5 inch.

Figure 22 shows that, when separator pressure 800 psi, the flow rate of the well # 2 is 4.2 MMSCFD and after 2016, the flow rate of the well # 2 is 0 MMSCFD, the flow rate of the well # 1(L.S) is 4.7 MMSCFD and after 2017, the flow rate of the well # 1(L.S) will produce 1.3 MMSCFD, the flow rate of the well # 1(S.S) is 0 MMSCFD.

Separator Pressure 850 psi:

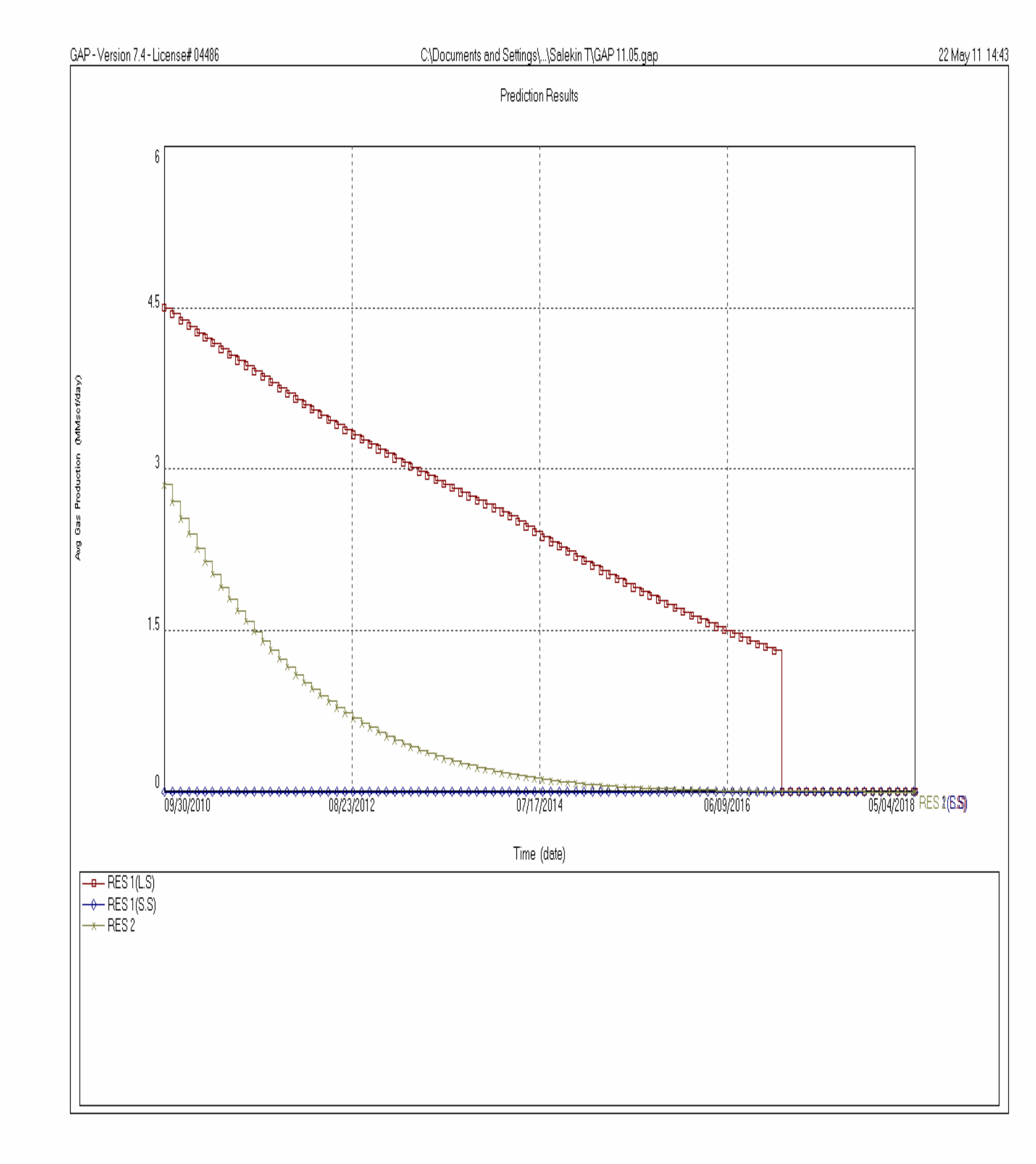

Figure-23, Average Gas Production vs. Time for Separator Pressure 850 psi and Tubing ID-3.5 inch.

Figure 23 shows that, when separator pressure 850 psi, the flow rate of the well # 2 is 2.8 MMSCFD and after 2015, the flow rate of the well # 2 is 0 MMSCFD, the flow rate of the well # 1(L.S) is 4.5 MMSCFD and after 2016, the flow rate of the well # 1(L.S) will produce 1.5

MMSCFD, the flow rate of the well # 1(S.S) is 0 MMSCFD.

Separator Pressure 900 psi:

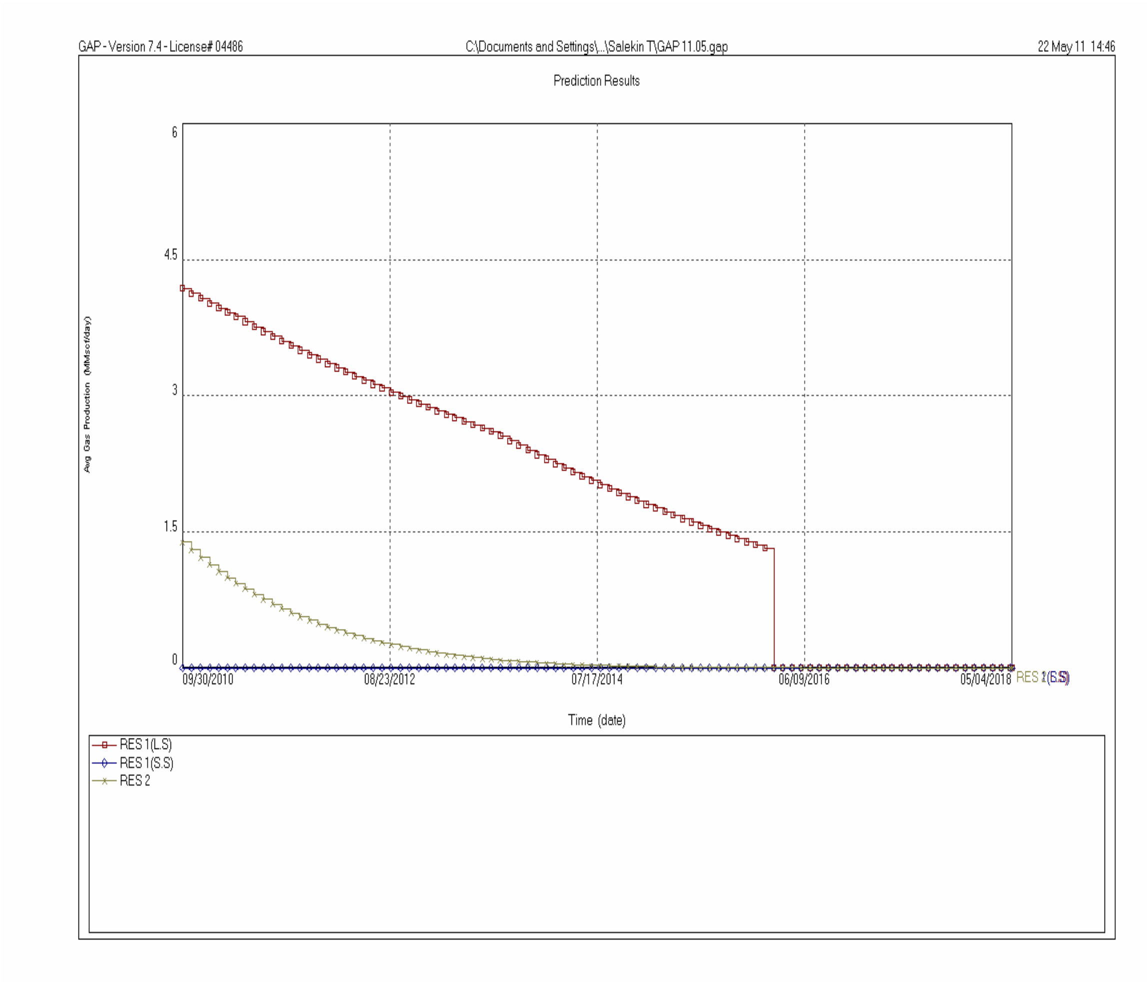

Figure-24, Average Gas Production vs. Time for Separator Pressure 900 psi and Tubing ID-3.5 inch.

Figure 24 shows that, when separator pressure 900 psi, the flow rate of the well # 2 is 1.4 MMSCFD and after 2014, the flow rate of the well # 2 is 0 MMSCFD, the flow rate of the well # 1(L.S) is 4.3 MMSCFD and after 2015, the flow rate of the well # 1(L.S) will produce 1.5 MMSCFD, the flow rate of the well # 1(S.S) is 0 MMSCFD.

Separator Pressure 950 psi:

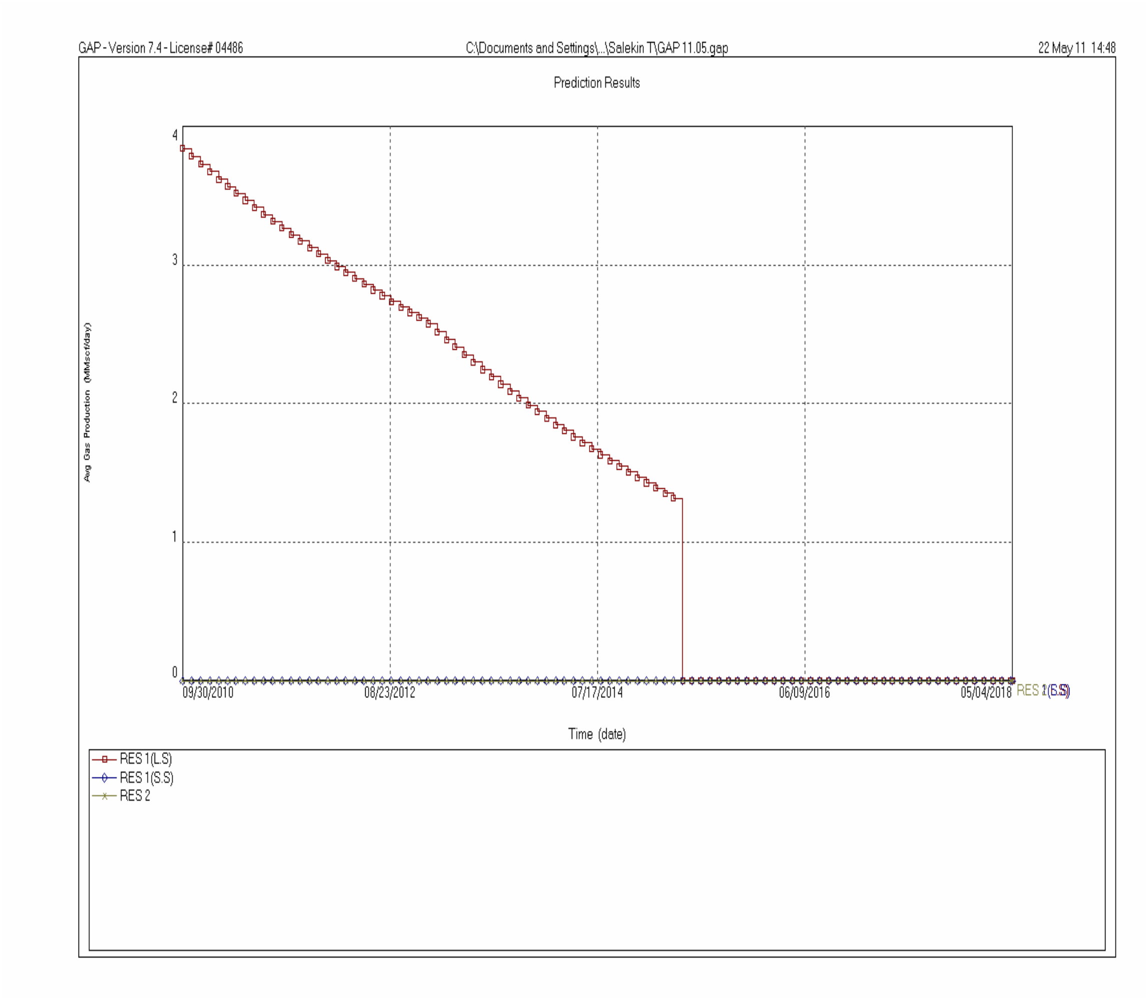

Figure-25, Average Gas Production vs. Time for Separator Pressure 950 psi and Tubing ID-3.5 inch.

Figure 25 shows that, when separator pressure 950 psi, the flow rate of the well # 2 is 0 MMSCFD, the flow rate of the well # 1(L.S) is 3.8 MMSCFD and after 2014, the flow rate of the well # 1(L.S) will produce 1.5 MMSCFD, the flow rate of the well # 1(S.S) is 0 MMSCFD.

Separator Pressure 1000 psi:

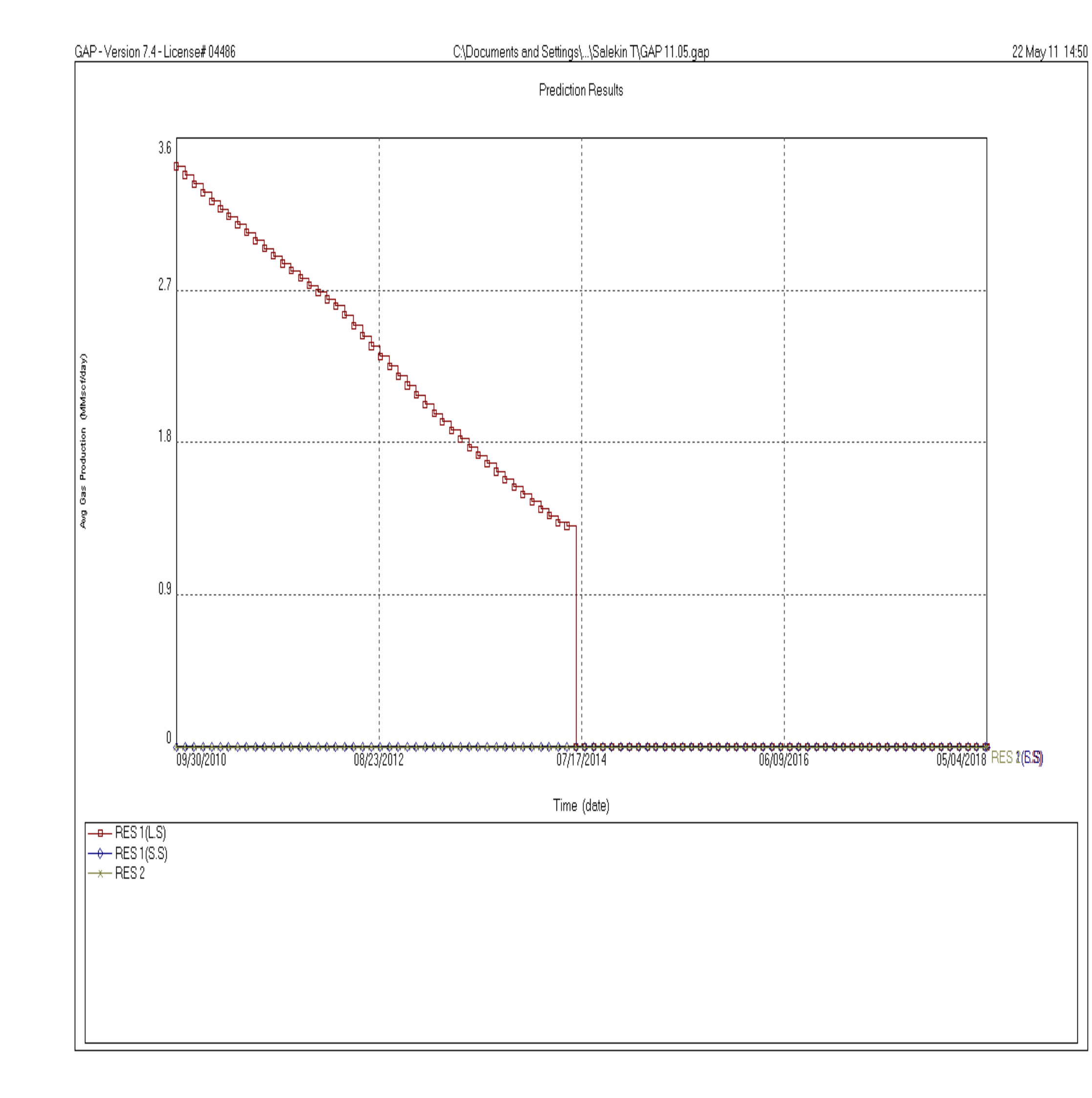

Figure-26, Average Gas Production vs. Time for Separator Pressure 1000 psi and Tubing ID-3.5 inch.

Figure 26 shows that, when separator pressure 1000 psi, the flow rate of the well # 2 is 0 MMSCFD, the flow rate of the well # 1(L.S) is 3.5 MMSCFD and after 2014, the flow rate of the well # 1(L.S) will produce 1.3 MMSCFD, the flow rate of the well # 1(S.S) is 0 MMSCFD.

Production tube id 3 inches:

Separator Pressure 700 psi:

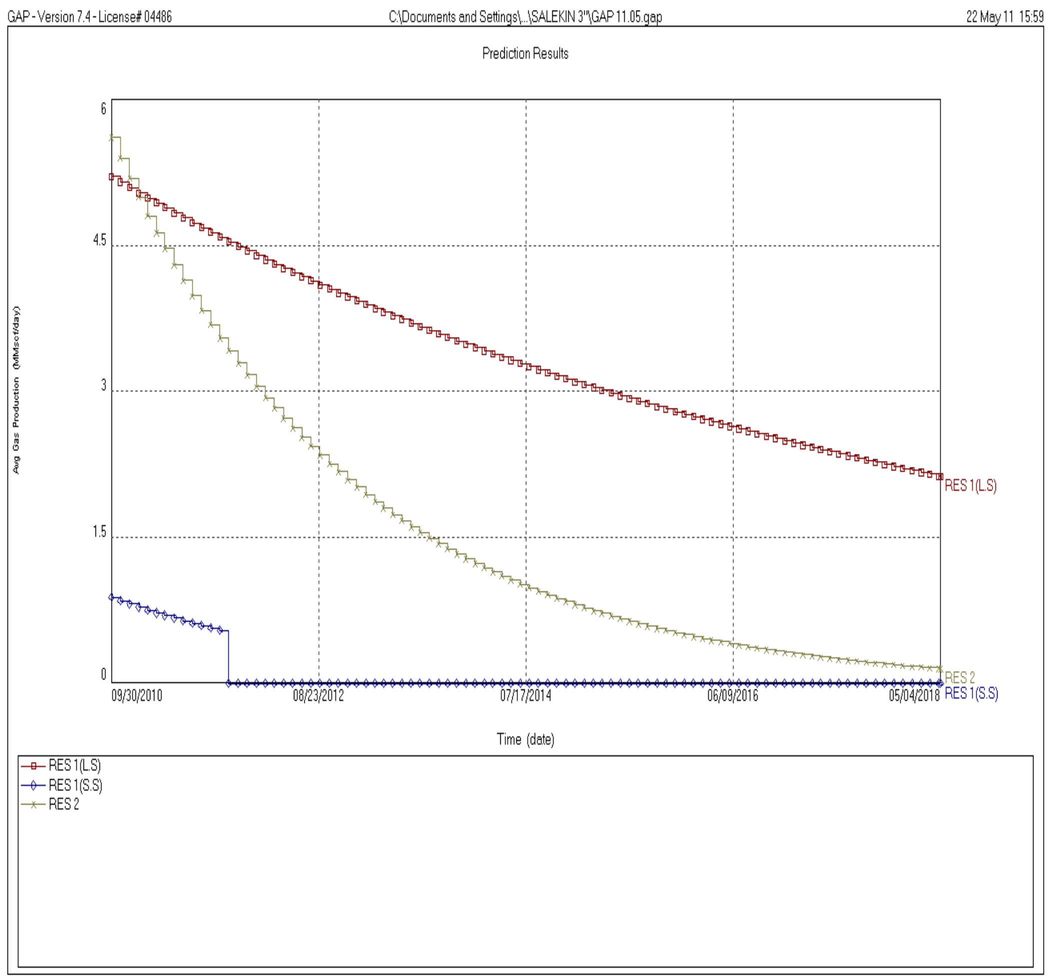

Figure-27, Average Gas Production vs. Time for Separator Pressure 700 psi and Tubing ID-3 inch.

Figure 27 shows that, when separator pressure 700 psi, the flow rate of the well # 2 is 5.7 MMSCFD and after 2018, the flow rate of the well # 2 is 0.2 MMSCFD, the flow rate of the well # 1(L.S) is 5 MMSCFD and after 2018, the flow rate of the well # 1(L.S) will produce 2.1 MMSCFD, the flow rate of the well # 1(S.S) is 0.75 MMSCFD, and after 2011, the flow rate of the well # 1(S.S) will produce 0.5 MMSCFD.

Separator Pressure 75O psi:

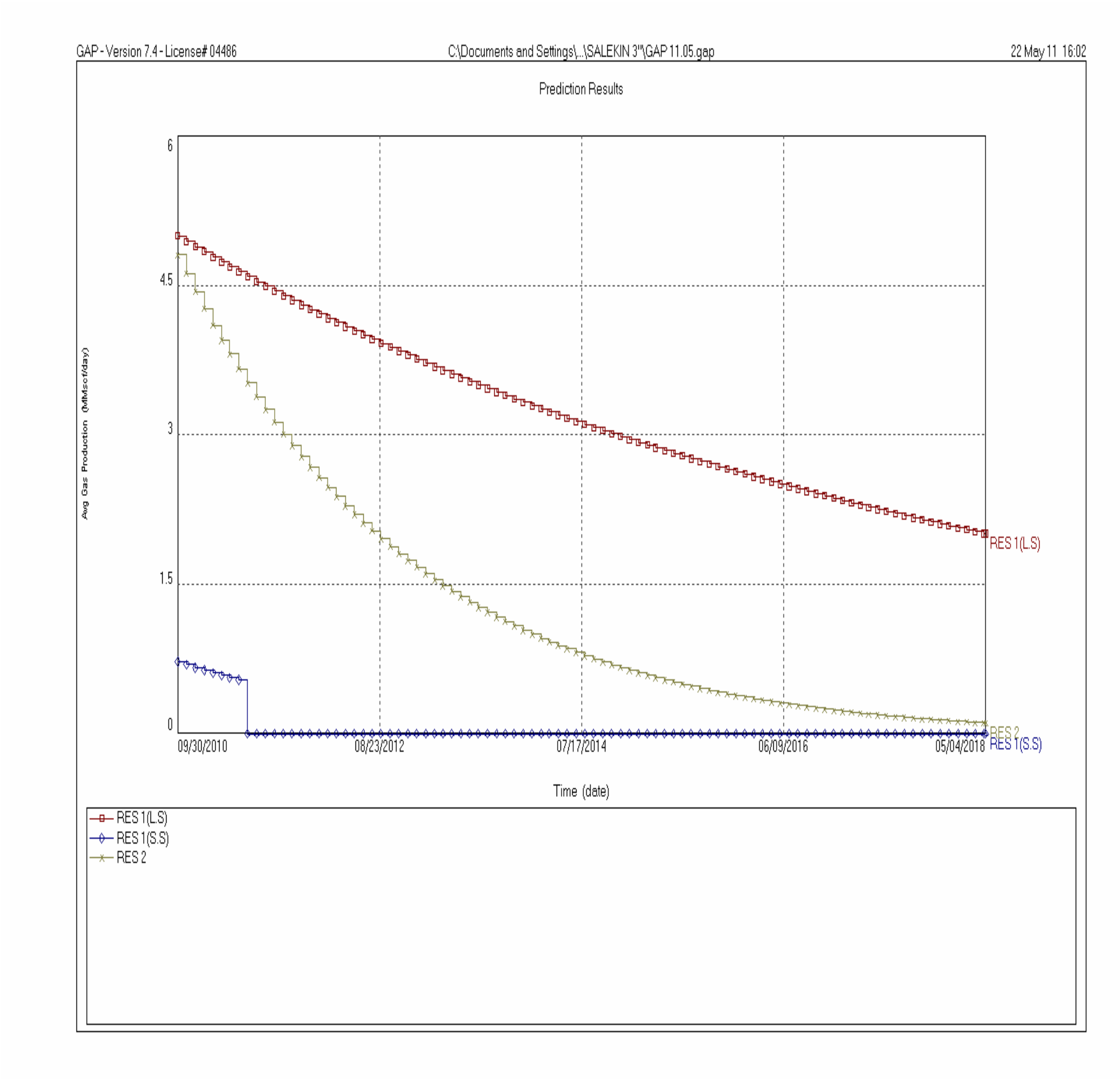

Figure-28, Average Gas Production vs. Time for Separator Pressure 750 psi and Tubing ID-3.5 inch.

Figure 28 shows that, when separator pressure 750 psi, the flow rate of the well # 2 is 4.7 MMSCFD and after 2018, the flow rate of the well # 2 is 0.1 MMSCFD, the flow rate of the well # 1(L.S) is 5 MMSCFD and after 2018, the flow rate of the well # 1(L.S) will produce 1.9 MMSCFD, the flow rate of the well # 1(S.S) is 0.6 MMSCFD, and after 2011, the flow rate of the well # 1(S.S) will produce 0 MMSCFD.

Separator Pressure 800 psi:

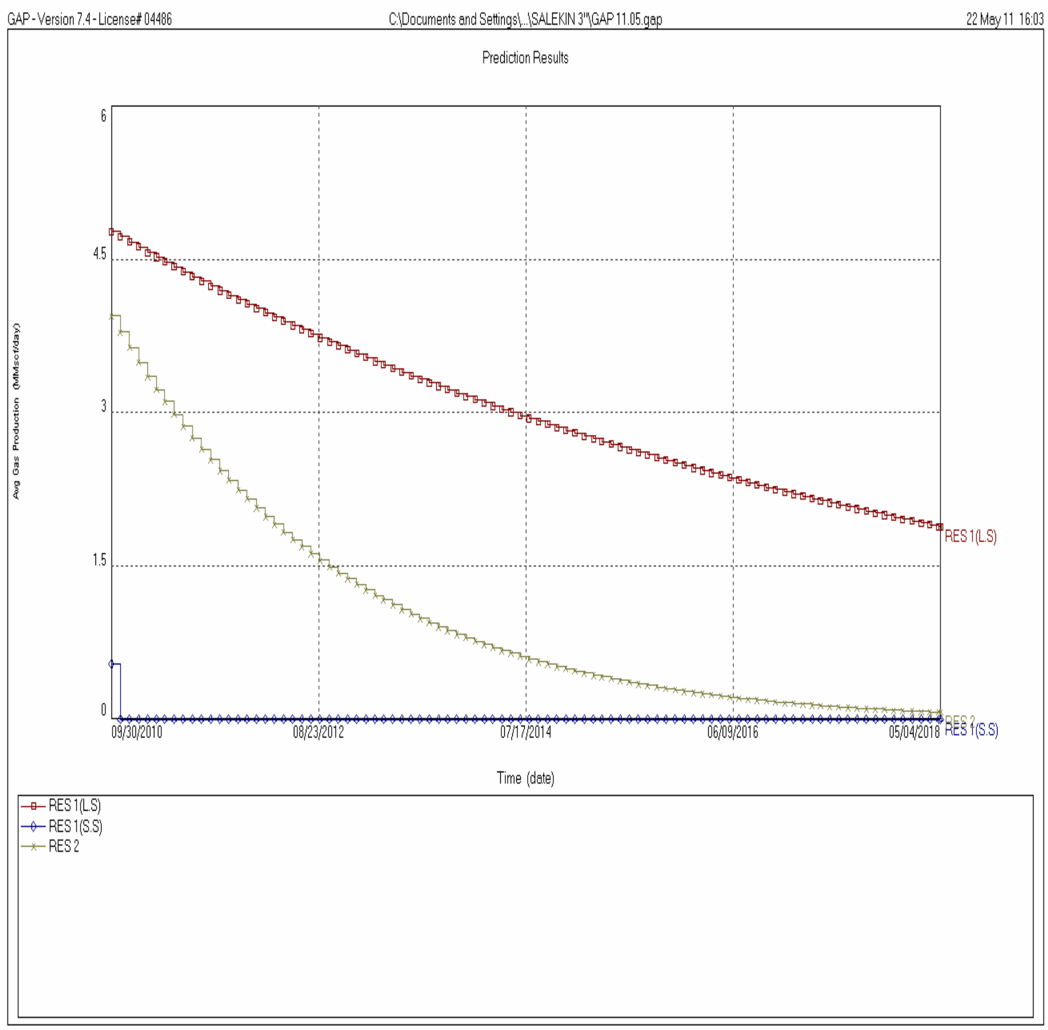

Figure-29, Average Gas Production vs. Time for Separator Pressure 800 psi and Tubing ID-3 inch.

Figure 29 shows that, when separator pressure 800 psi, the flow rate of the well # 2 is 4.1 MMSCFD and after 2018, the flow rate of the well # 2 is 0.1 MMSCFD, the flow rate of the well # 1(L.S) is 4.7 MMSCFD and after 2018, the flow rate of the well # 1(L.S) will produce 1.8 MMSCFD, the flow rate of the well # 1(S.S) is 0 MMSCFD.

Separator Pressure 850 psi:

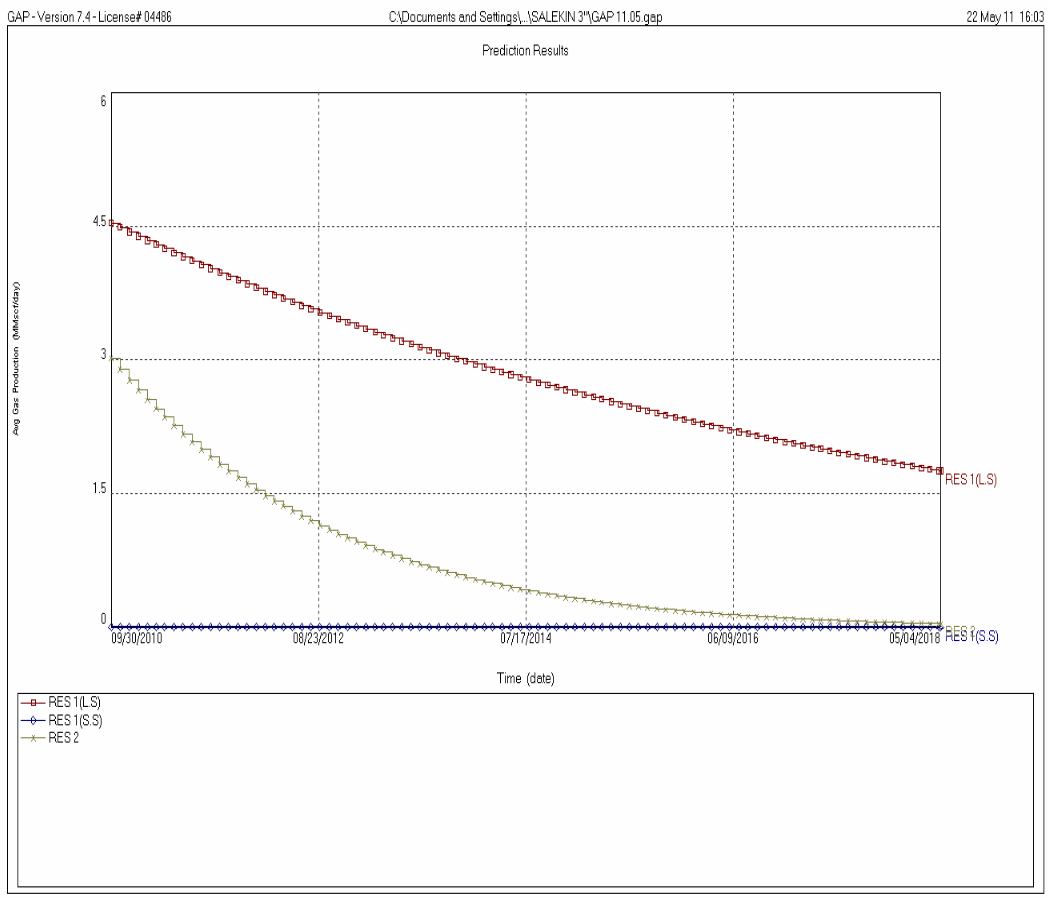

Figure-30, Average Gas Production vs. Time for Separator Pressure 850 psi and Tubing ID-3 inch.

Figure 30 shows that, when separator pressure 850 psi, the flow rate of the well # 2 is 3 MMSCFD and after 2018, the flow rate of the well # 2 is 0 MMSCFD, the flow rate of the well # 1(L.S) is 4.5 MMSCFD and after 2018, the flow rate of the well # 1(L.S) will produce 1.7 MMSCFD, the flow rate of the well # 1(S.S) is 0 MMSCFD.

Separator Pressure 900 psi:

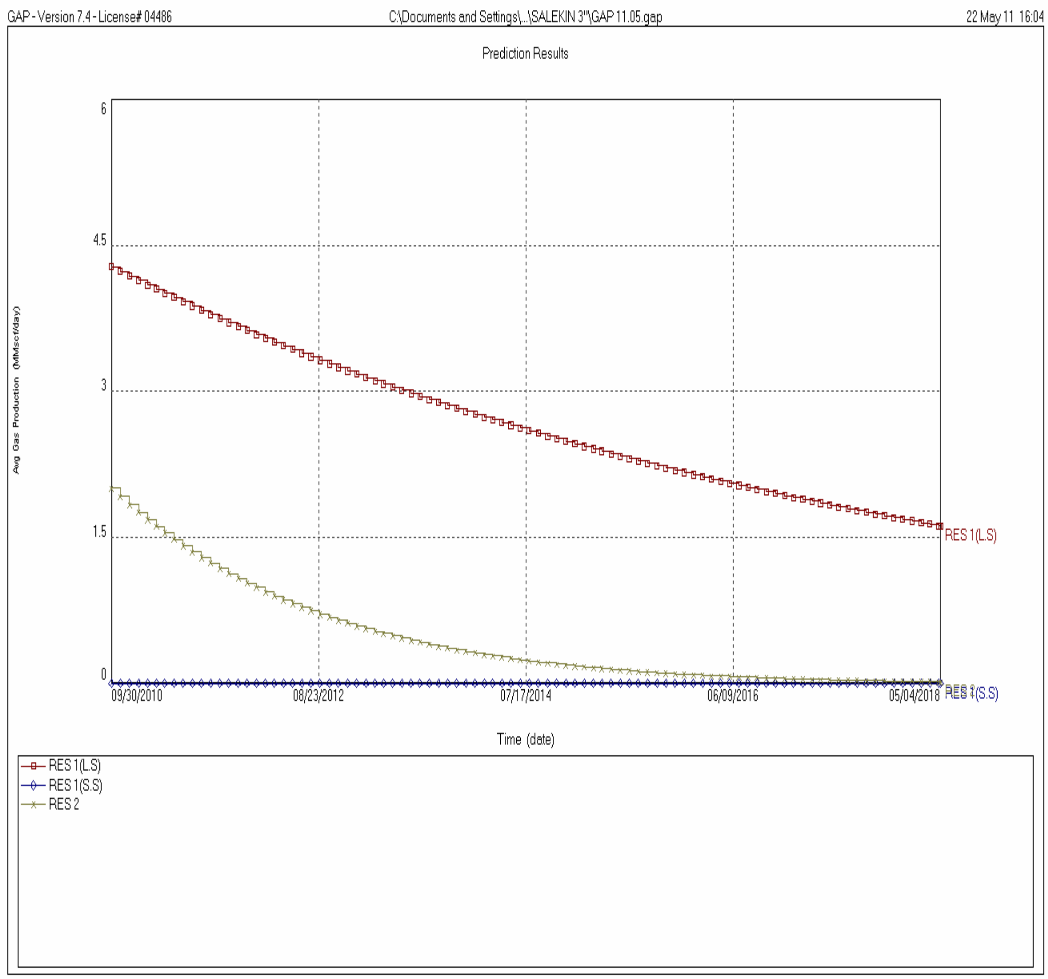

Figure-31, Average Gas Production vs. Time for Separator Pressure 900 psi and Tubing ID-3 inch.

Figure 31 shows that, when separator pressure 900 psi, the flow rate of the well # 2 is 1.8 MMSCFD and after 2018, the flow rate of the well # 2 is 0 MMSCFD, the flow rate of the well # 1(L.S) is 4.3 MMSCFD and after 2018, the flow rate of the well # 1(L.S) will produce 1.6 MMSCFD, the flow rate of the well # 1(S.S) is 0 MMSCFD.

Separator Pressure 950 psi:

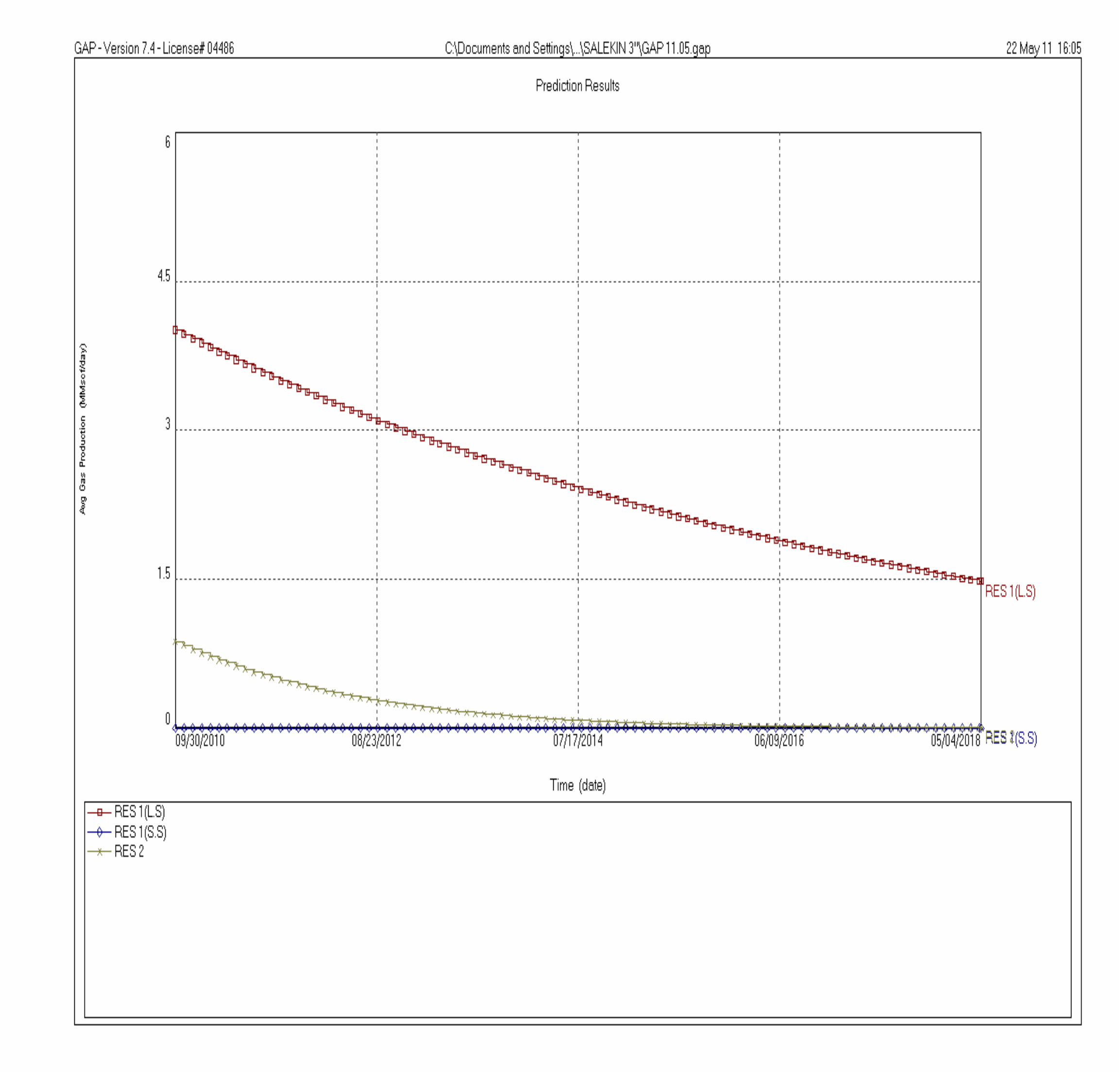

Figure-32, Average Gas Production vs. Time for Separator Pressure 950 psi and Tubing ID-3 inch.

Figure 32 shows that, when separator pressure 950 psi, the flow rate of the well # 2 is 1 MMSCFD and after 2014, the flow rate of the well # 2 is 0.1 MMSCFD, the flow rate of the well # 1(L.S) is 4 MMSCFD and after 2018, the flow rate of the well # 1(L.S) will produce 1.5 MMSCFD, the flow rate of the well # 1(S.S) is 0 MMSCFD.

Separator Pressure 1000 psi:

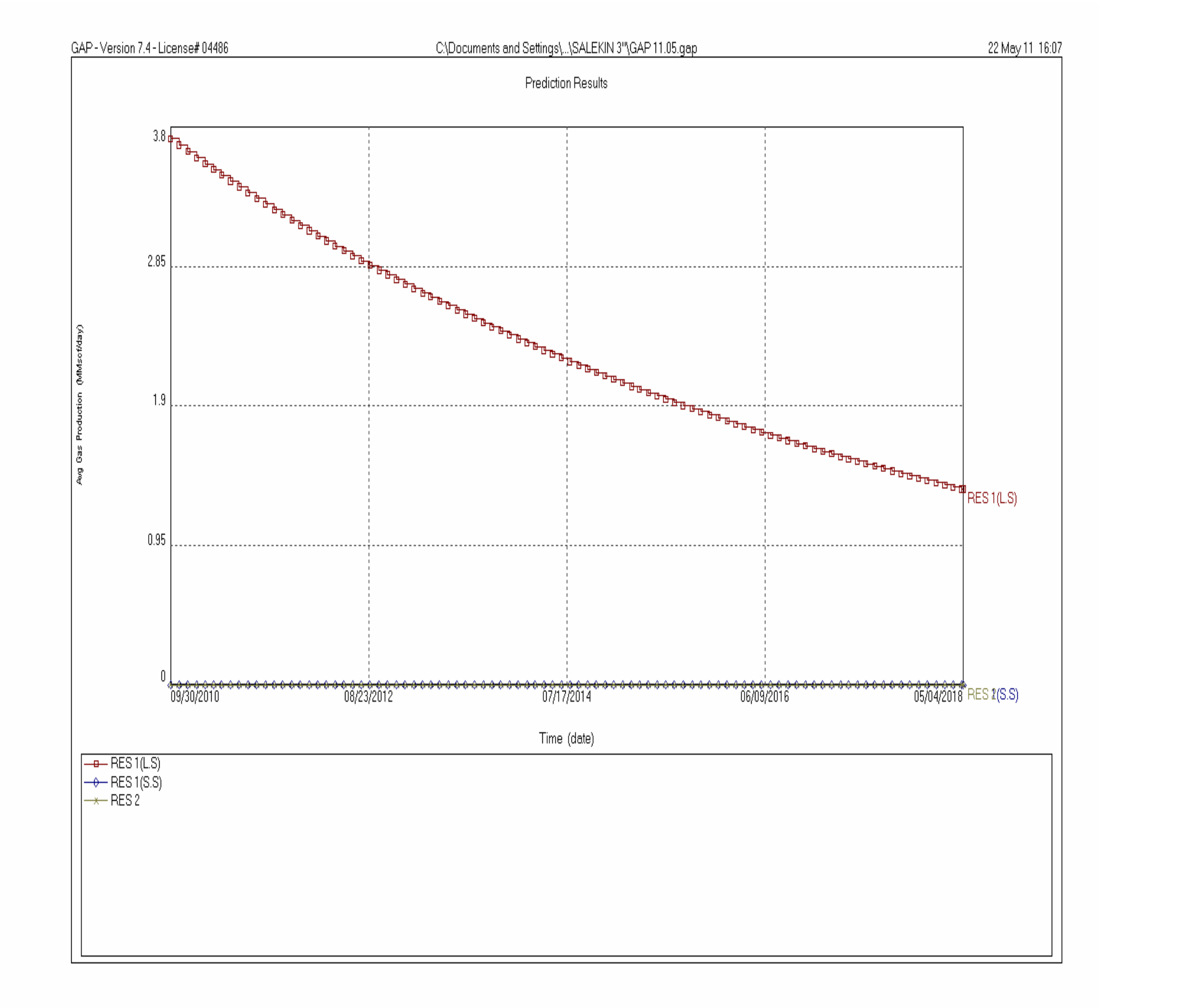

Figure-33, Average Gas Production vs. Time for Separator Pressure 1000 psi and Tubing ID-3 inch.

Figure 33 shows that, when separator pressure 1000 psi, the flow rate of the well # 2 is 0 MMSCFD, the flow rate of the well # 1(L.S) is 3.7 MMSCFD and after 2018, the flow rate of the well # 1(L.S) will produce 1.4 MMSCFD, the flow rate of the well # 1(S.S) is 0 MMSCFD.

Production tube id 4.5 inches:

Separator Pressure 700 psi:

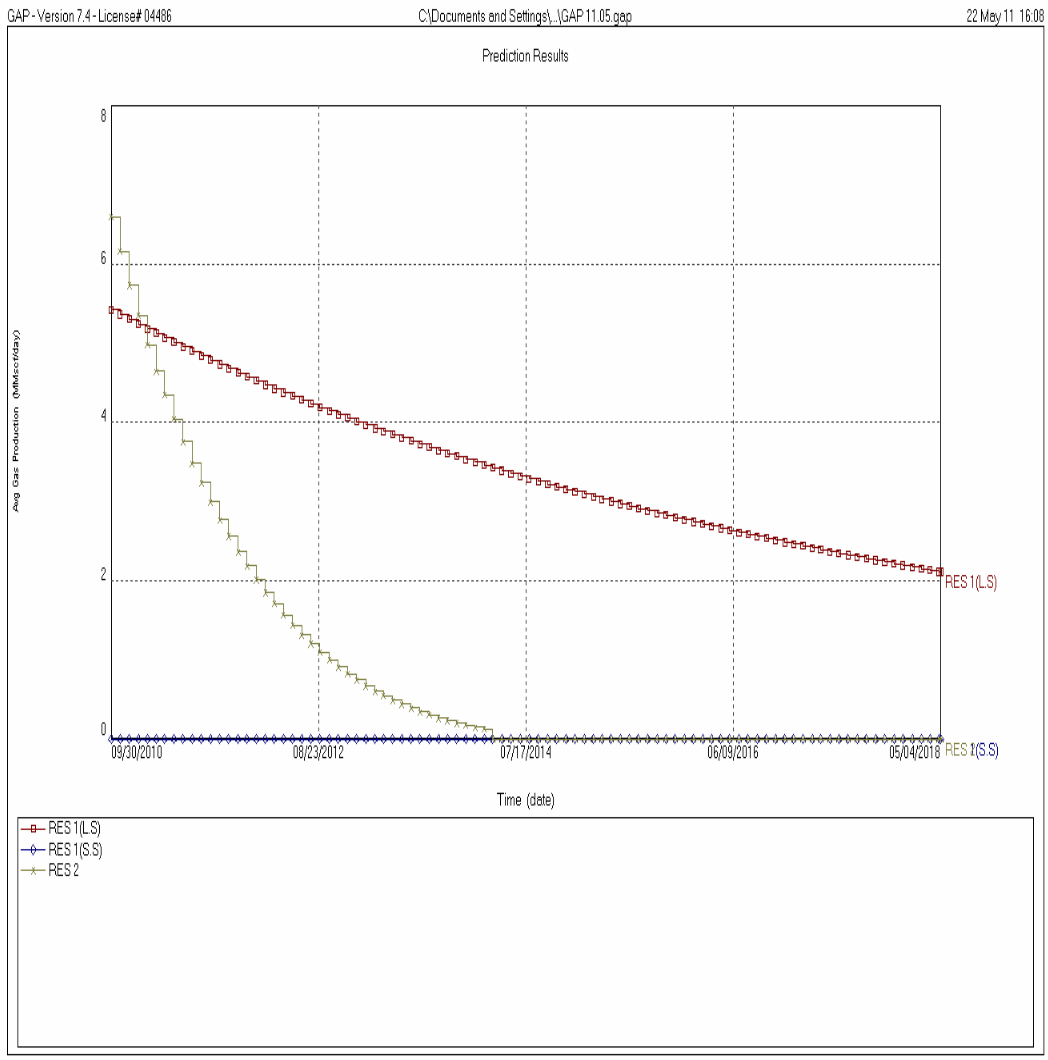

Figure-34, Average Gas Production vs. Time for Separator Pressure 700 psi and Tubing ID-4.5 inch.

Figure 34 shows that, when separator pressure 700 psi, the flow rate of the well # 2 is 6.5 MMSCFD and after 2013, the flow rate of the well # 2 is 0 MMSCFD, the flow rate of the well # 1(L.S) is 5.5 MMSCFD and after 2018, the flow rate of the well # 1(L.S) will produce 2.1 MMSCFD, the flow rate of the well # 1(S.S) is 0.

Separator Pressure 750 psi:

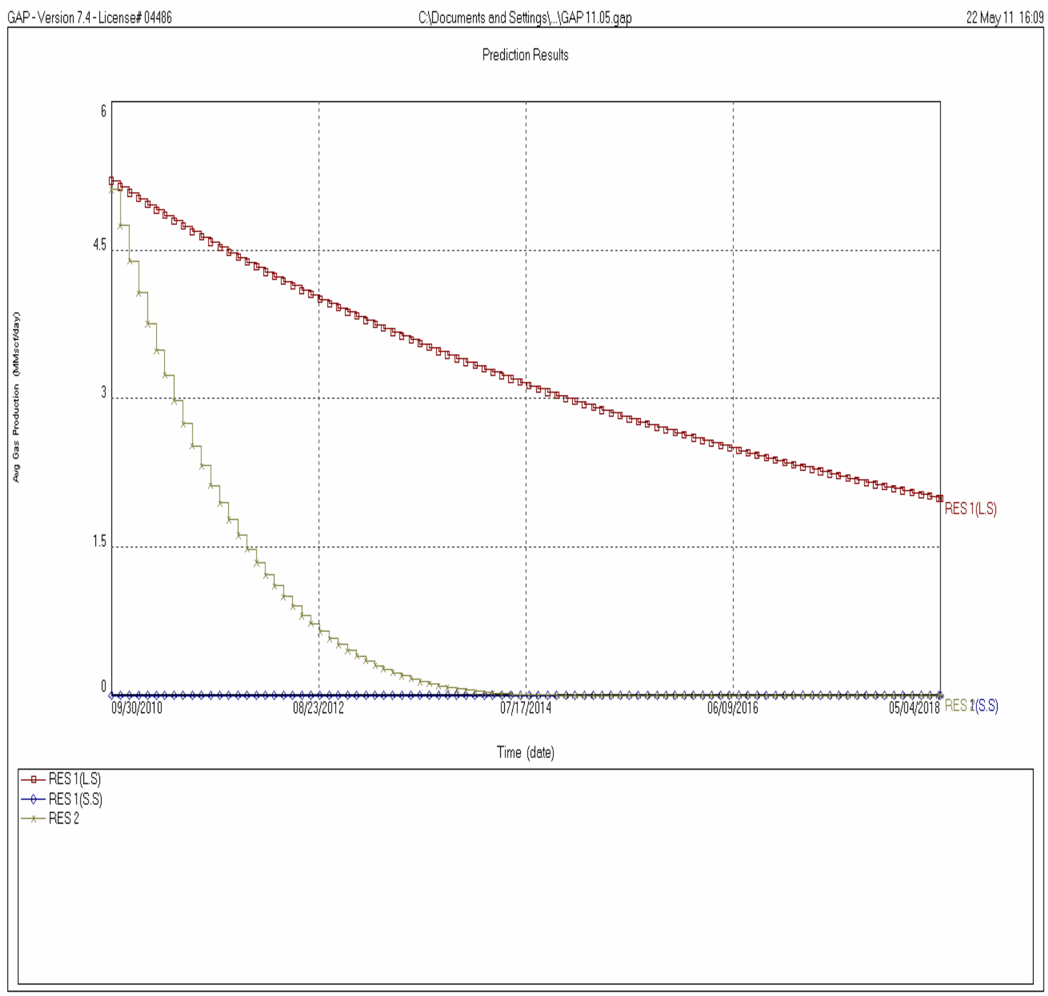

Figure-35, Average Gas Production vs. Time for Separator Pressure 750 psi and Tubing ID-4.5 inch.

Figure 35 shows that, when separator pressure 750 psi, the flow rate of the well # 2 is 5.2 MMSCFD and after 2014, the flow rate of the well # 2 is 0 MMSCFD, the flow rate of the well # 1(L.S) is 5.3 MMSCFD and after 2018, the flow rate of the well # 1(L.S) will produce 1.8 MMSCFD, the flow rate of the well # 1(S.S) is 0.

Separator Pressure 800 psi:

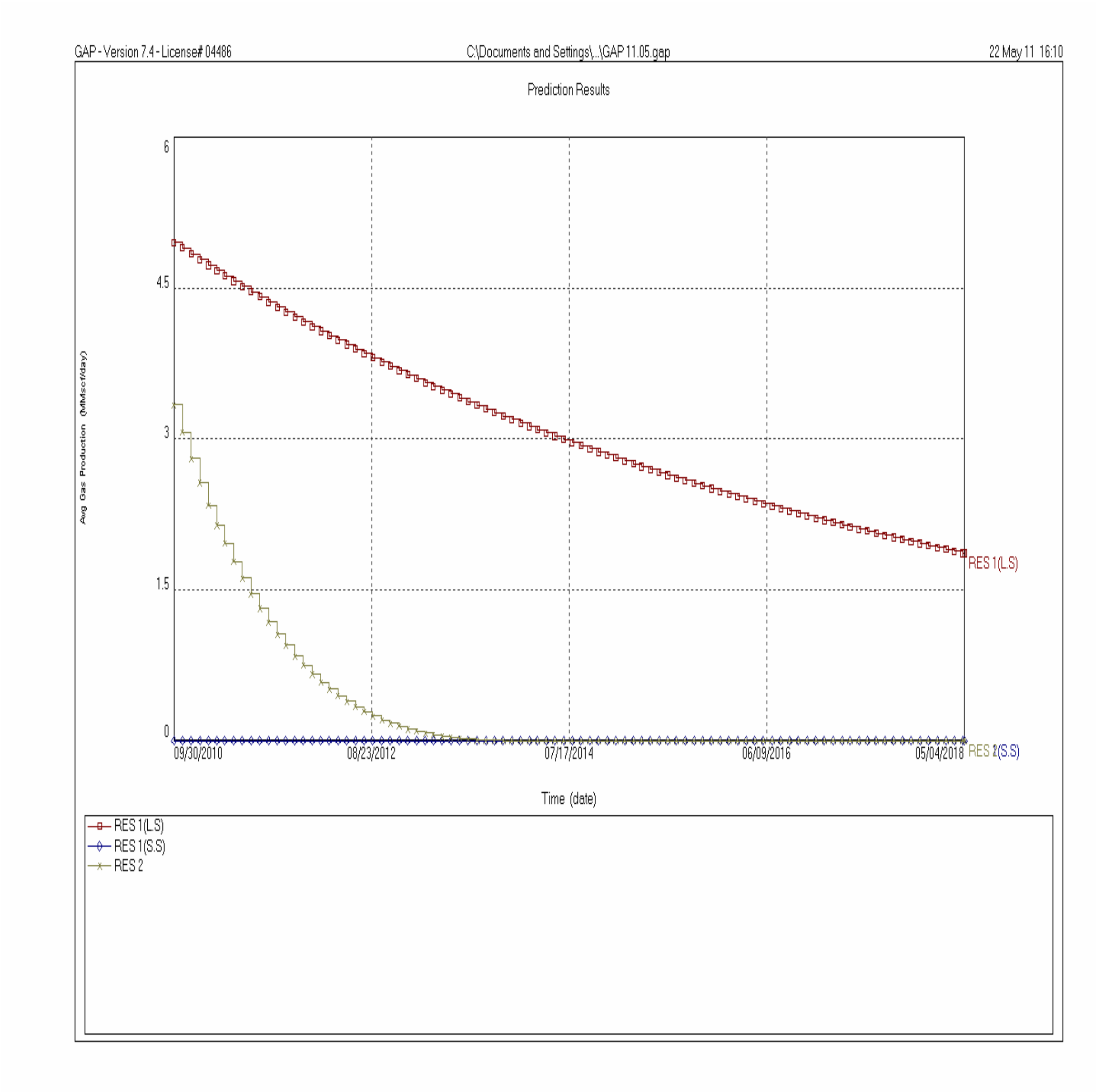

Figure-36, Average Gas Production vs. Time for Separator Pressure 800 psi and Tubing ID-4.5 inch.

Figure 36 shows that, when separator pressure 800 psi, the flow rate of the well # 2 is 3.3 MMSCFD and after 2013, the flow rate of the well # 2 is 0 MMSCFD, the flow rate of the well # 1(L.S) is 4.9 MMSCFD and after 2018, the flow rate of the well # 1(L.S) will produce 1.7 MMSCFD, the flow rate of the well # 1(S.S) is 0.

Separator Pressure 850 psi:

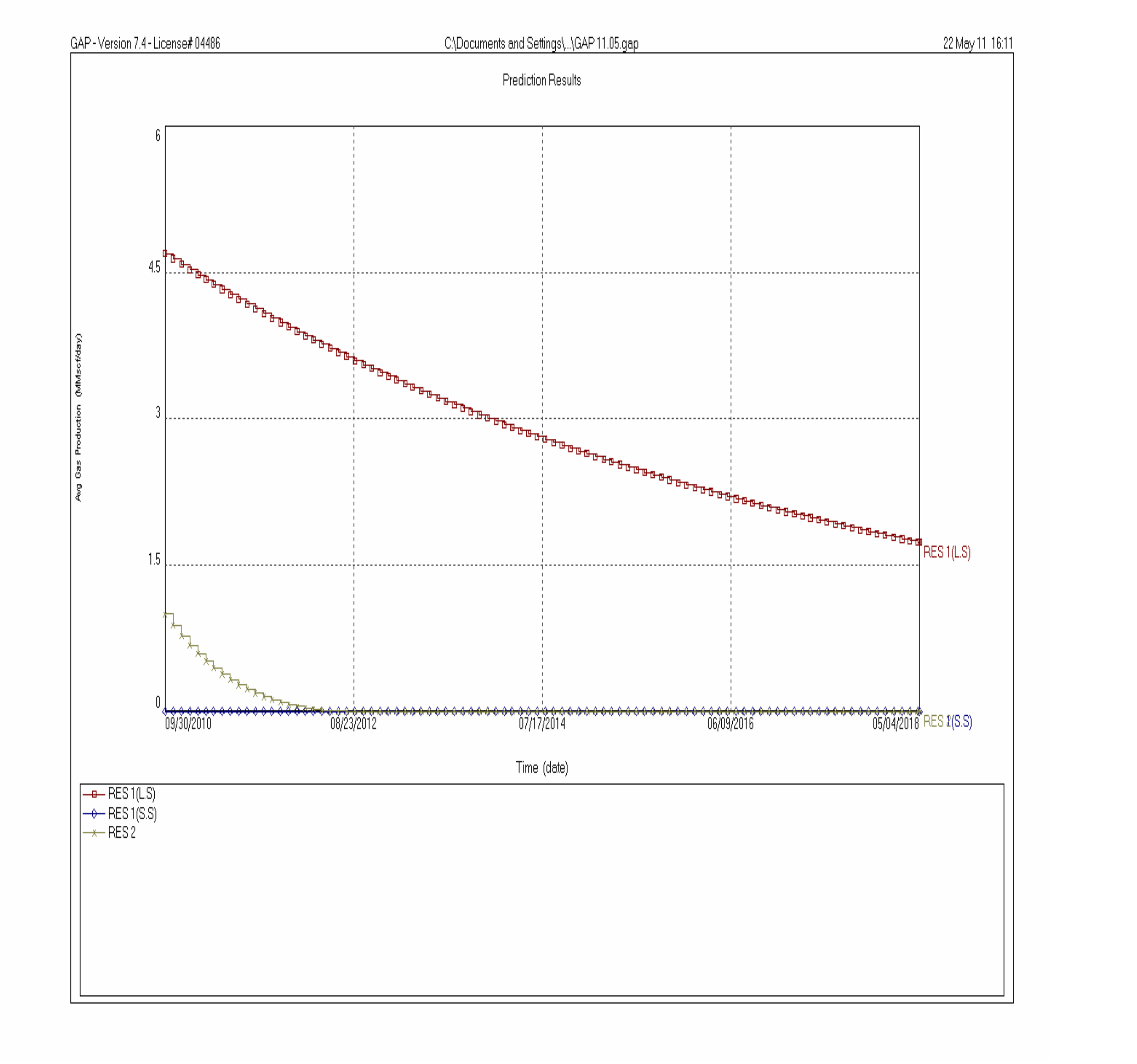

Figure-37, Average Gas Production vs. Time For Separator Pressure 850 psi and Tubing ID-4.5 inch.

Figure 37 shows that, when separator pressure 850 psi, the flow rate of the well # 2 is 1.2 MMSCFD and after 2011, the flow rate of the well # 2 is 0 MMSCFD, the flow rate of the well # 1(L.S) is 4.7 MMSCFD and after 2018, the flow rate of the well # 1(L.S) will produce 1.7 MMSCFD, the flow rate of the well # 1(S.S) is 0.

Separator Pressure 900 psi:

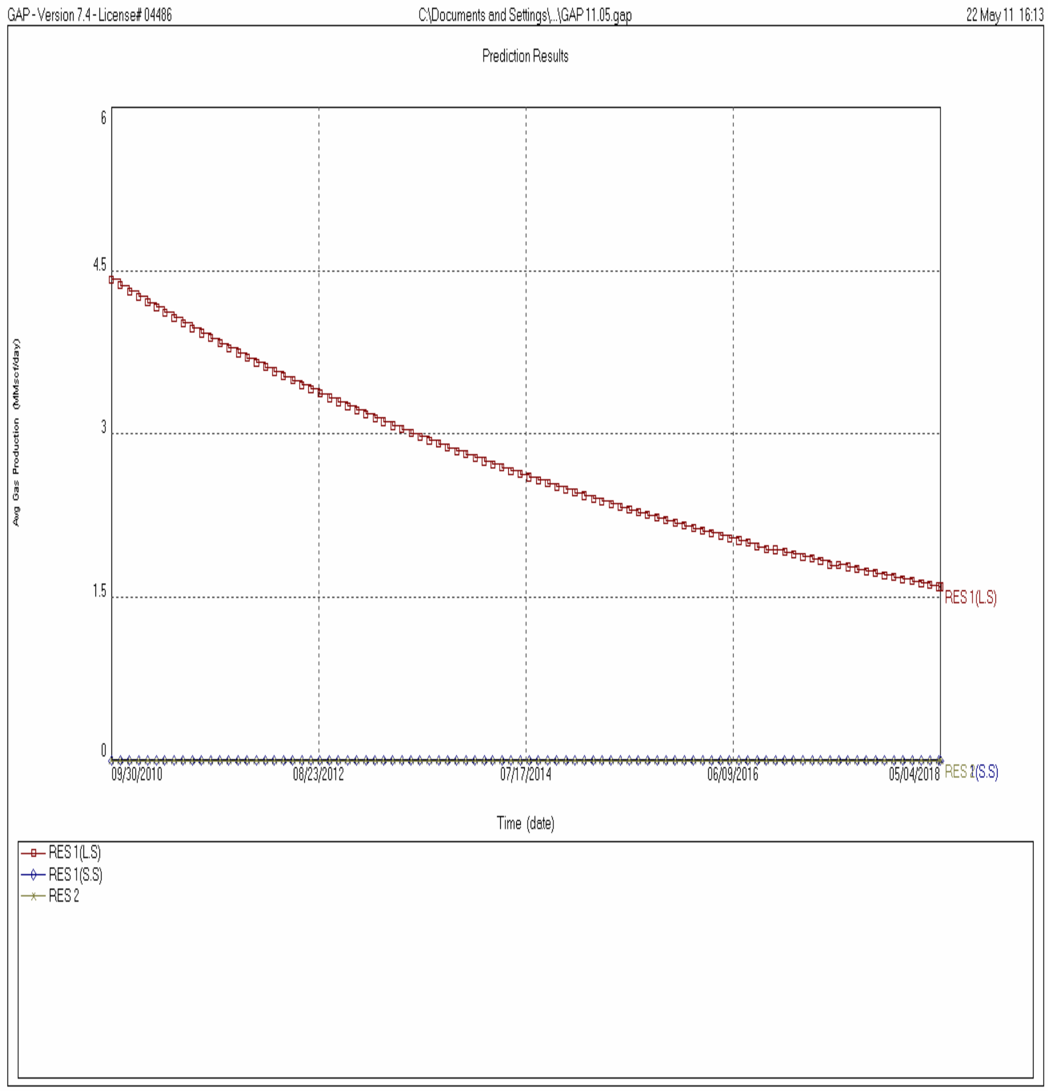

Figure-38, Average Gas Production vs. Time for Separator Pressure 900 psi and Tubing ID-4.5 inch.

Figure 38 shows that, when separator pressure 900 psi, the flow rate of the well # 2 is 0 MMSCFD, the flow rate of the well # 1(L.S) is 4.4 MMSCFD and after 2018, the flow rate of the well # 1(L.S) will produce 1.6 MMSCFD, the flow rate of the well # 1(S.S) is 0.

Separator Pressure 950 psi:

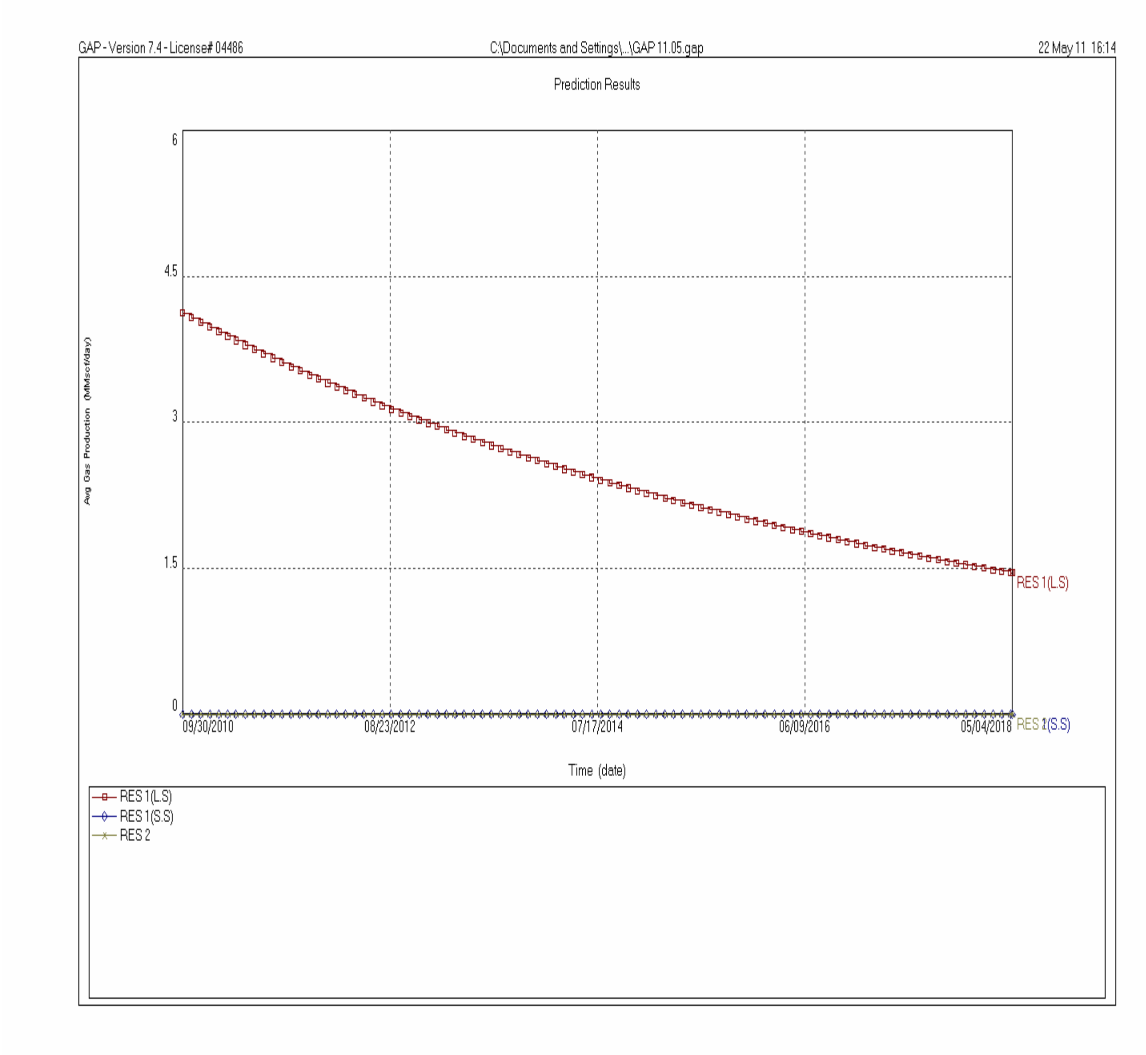

Figure-39, Average Gas Production vs. Time for Separator Pressure 950 psi and Tubing ID-4.5 inch.

Figure 39 shows that, when separator pressure 950 psi, the flow rate of the well # 2 is 0 MMSCFD, the flow rate of the well # 1(L.S) is 4.2 MMSCFD and after 2018, the flow rate of the well # 1(L.S) will produce 1.5 MMSCFD, the flow rate of the well # 1(S.S) is 0.

Separator Pressure 1000 psi:

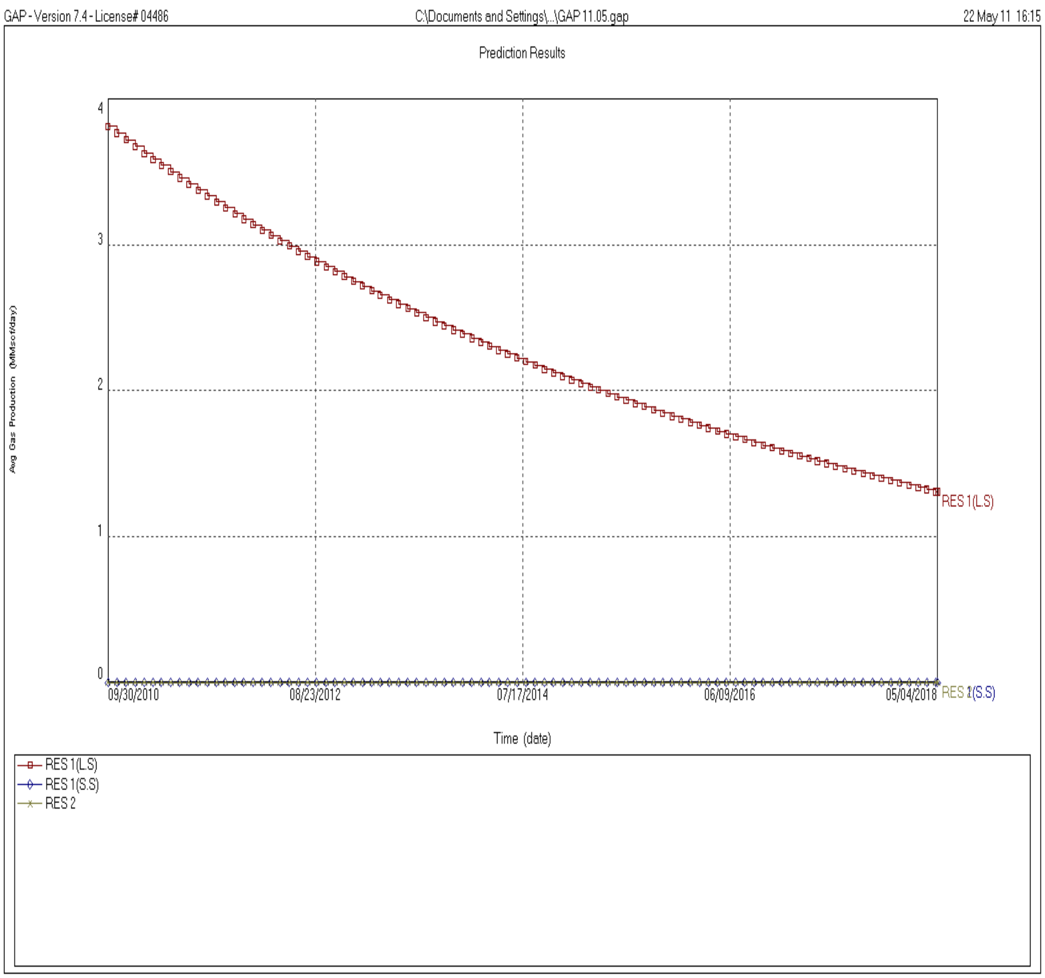

Figure-40, Average Gas Production vs. Time for Separator Pressure 1000 psi and Tubing ID-4.5 inch.

Figure 40 shows that, when separator pressure 1000 psi, the flow rate of the well # 2 is 0 MMSCFD, the flow rate of the well # 1(L.S) is 3.8 MMSCFD and after 2018, the flow rate of the well # 1(L.S) will produce 1.3 MMSCFD, the flow rate of the well # 1(S.S) is 0.

6.4 Conclusions:

Above figures show that the variation of flow rate with constant reservoir pressure for a tubing inner diameter of 3.5 inches, 3 inches and 4.5 inches. For well # 1(S.S), the reservoir pressure is 1190 psia, the flow rate was about 1.61 MMSCFD at flowing well head pressure 830 psia. For well # 1(L.S), the reservoir pressure of 1670 psia, the flow rate was about 5.65 MMSCFD at flowing well head pressure 1195 psia. For well # 2, the reservoir pressure of 1980 psia, the flow rate was about 7.68 MMSCFD at flowing well head pressure 1530 psia. Assuming all other parameters remains constant. These plots verify present and future well performances. This simulation is helpful for prediction of flow rate with time.

Different separator pressure is also investigated because it has a great influence in the flow period and flow rate. From the study, it is found that with the increase of separator pressure the flow period decreases i.e. the recovery of gas decreases. Various types of production tubing inner diameter is also used to find the great influence on the flow period and flow rate of gas. In this case, when production tubing inner diameter decreases then the gas flow rate also decreases but flow period of gas production increases i.e. recovery of gas increases.

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. Tubing size for well # 1(L.S) and well # 2 seem to be the right size to maintain the present production rate but the well # 1(S.S) tubing is oversized and the same flow rate can be achieved with a smaller tubing size.
3. At present condition, optimum production rate is 1.556 MMSCFD, 5.392 MMSCFD, 8.293 MMSCFD for well # 1(S.S), well # 1(L.S) and well # 2 respectively.
4. Lowering the separator pressure will increase the flow from the wells at present condition.

6.5 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 # 1(S.S) the tubing size is oversized and the recommended size is below 3 inches.

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Appendix 1.

Tank : WELL#1 (S.S)

Time	Reservoir Pressure	Cum. Gas Production	Cum. Water Production
(date m/d/y)	(psia)	(MMSCFD)	(MMSTB)
03/28/1998	3358	5.02	3e-006
12/31/1998		1021.93	0.00061
12/31/1999		1794.75	0.00111
12/31/2000		2618.14	0.00161
12/31/2001		2911.02	0.00178
12/31/2002		3456.95	0.00217
12/31/2003		3904.63	0.0025
12/31/2004		4257.32	0.00277
12/31/2005		4643.21	0.00317
12/31/2006	1495	5140.27	0.00407
12/31/2007		5276.18	0.00445
12/31/2008		5499.72	0.00543
12/31/2009		5644.41	0.00631
09/30/2010		5841.35	0.00784

Tank : WELL#1 (L.S)

Time	Reservoir Pressure	Cum. Gas Production	Cum. Water Production
(date m/d/y)	(psia)	(MMSCFD)	(MMSTB)
03/28/1998	3651	11.56	1e-005
12/31/1998		3504.18	0.00209
12/31/1999		7993.7	0.00498
12/31/2000		12639.9	0.00778
12/31/2001		14173.1	0.0087
12/31/2002		15303.7	0.00952
12/31/2003		17625	0.01124
12/31/2004		20009.4	0.01307
12/31/2005		22418.9	0.01556
12/31/2006	2150	24592.9	0.01954
12/31/2007		26457.7	0.02589
12/31/2008		28062.1	0.03348
12/31/2009		29288.3	0.04091
09/30/2010		29907.8	0.04581

Tank : WELL# 2

Time	Reservoir Pressure	Cum. Gas Production	Cum. Water Production
(date m/d/y)	(psia)	(MMSCFD)	(MMSTB)
05/31/2001	3244	438.24	0.000261
12/31/2001		3606.16	0.002365
12/31/2002		7821.96	0.005366
12/31/2003		10955.8	0.007691
12/31/2004		13848.2	0.009917
12/31/2005		16617	0.012777
12/31/2006	1745	19039.9	0.017188
12/31/2007		21234.1	0.024642
12/31/2008		23262.4	0.034274
12/31/2009		25223.9	0.046171
09/30/2010		26573	0.056948