Optimizing Gas Production Strategy in Offshore Niger Delta Gas Condensate Field Using Dynamic Simulation Model

By

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Abstract

In a natural gas field development, determining the life of the field and deciding the best optimized production strategy as well as meeting the economic viability are the most important considerations to sustain gas production. Optimizing gas condensate bearing reservoirs below dew point exhibit complexities due to hydrocarbon condensation and many times, an in-situ oil phase, may result to reduce gas well productivity. The condensate liquid migrates down the tubing and accumulates at the bottom of the completion, increasing the bottom hole flowing pressure, thereby, reducing the production rate. Preventive actions need to be considered for predicting and monitoring of liquid loading before it becomes a serious problem in production system from reservoir to surface facilities. This study focuses on optimizing gas production strategy in an offshore Niger Delta gas condensate field. Sensitivity analysis was implemented on well level through optimizing well parameters such as tubing sizes, wellhead pressures and skin factors using PROSPER simulation program in order to select best well model construction that promote high gas deliverability and low condensate production. The reservoir GIIP has been estimated to 370Bscf. From the dynamic nodal analysis result, 5.5-inch tubing size promotes the optimum gas rate and low condensate production based on the investigated parameters.

Keywords: Gas condensate, optimization, Prosper

INTRODUCTION

Production optimization is one of the most important key in the oil and gas industry. Due to the economic restraints, petroleum engineers have to implement future forecasting and prediction of the well performance. Gas reservoirs are divided into three categories which are condensate, dry gas and wet gas. The main focus of the production optimization is to understand the behavior of a gas condensate reservoir with the pressure depletion. When the natural gas is produced, the energy for transporting the produced fluids decreases and eventually the liquid will be held in the wellbore[1]. Increase in the liquid flow rate will significantly reduce the gas rate which can lead to unstable flow and increase the pressure drop in the tubing[2]. Reservoir properties such as permeability, skin factor, pay thickness, and reservoir pressure are used as a parameter for sensitivity analysis by the Prosper software.

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[1] Coleman S. B., Hartley B. Clay, David G.McCurdy, and H.Lee Norris. (1990) "A New Look at Predicting Gas-Well Load Up." Optimizing Recovery of Natural Gas From Depletion Drive Reservoris: Part 1-A Study to Verify the Minimum Flow Rate Required for Continious Removal of Liquids From Low-Pressure Gas-Wells, 329-333.

[2] Louis Ray and Kenneth Juran. (2000) “Benefits of Using Automation Software for Gas Production Optimization” SPE paper 59713 presented at the Permian Basin Oil and Gas Recovery Conference held in Midland, Texas, 10-15 September.

The production performance of a gas condensate well is the same as a dry gas well as long as the well flowing bottom-hole pressure (FBHP) is above the reservoir dew point pressure. Below the dew point, the well's performance starts to deviate from that of a dry gas well. Condensate begins to drop out first near the wellbore, accumulates until the critical condensate saturation is reached. Condensate banking causes a reduction in the gas relative permeability and acts as a partial blockage to the gas production. In predicting gas condensate well performance with reservoir simulators, local grid refinement is needed around the well in order to capture the impact of condensate banking. The determination of gas condensate well production performance can be done by applying the two-phase pseudo pressure technique. Simplified methods have been published recently to calculate gas condensate well production deliverability without the use of reservoir simulators[3].

Well development design and well performance diagnosis and optimization heavily rely on well deliverability modeling, which combines tubular hydraulic calculations with a reservoir deliverability model. Condensate banking is the accumulation of liquid in the near-wellbore region of the reservoir due to pressure falling below the dew point (Figure 1)[4]. This liquid dropout phenomenon hinders the flow of gas due to the decrease in gas relative permeability. As pressure in the reservoir declines below the dew point, condensate can rapidly build up[5].

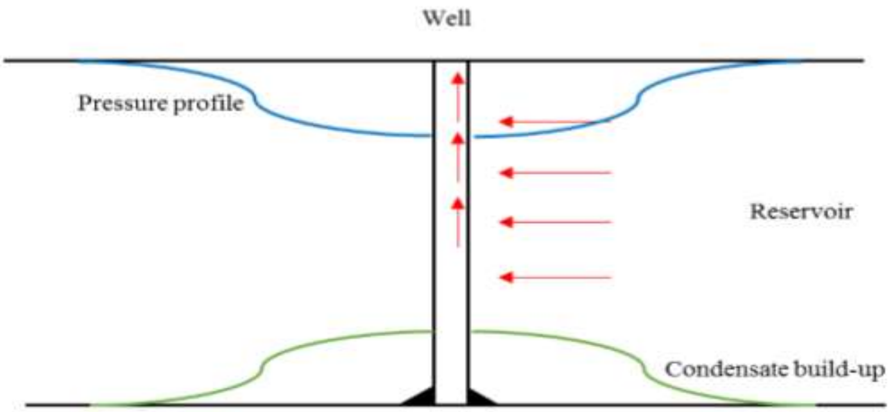

Figure 1. Condensate buildup in the near-wellbore area (after Baker 2005)

Operators typically execute well production strategies to avoid condensate buildup. These strategies are mostly related to pressure maintenance[6], such as keeping the bottom-hole pressure (BHP) above saturation pressure or gas injection for pressure maintenance. Some operators also attempt remediation by implementing well shut-ins to build up pressure, thus re-vaporizing the condensates and recovering gas flow. Methods to circumvent this condensate-banking problem include drilling horizontal wells, re-entry drilling, or hydraulic

[3] Ahmad J., Xiao A. J. and AL-Muaraikhi. (2004) "A New Methodfor the Determination of Gas Condensate Well Production Performance", SPE paper 90290 presented at the Annual Technical Conference and Exhibition held in Houston, Texas, 14-16 September.

[4] Barker, J.W. (2005). Experience with Simulation of Condensate Banking Effects in Various Gas Condensate Reservoirs. IPTC-10382-MS. DOI: 10.2523/IPTC-10382-MS. Presented at the International Petroleum Technology Conference, Doha, Qatar, 21-23 November.

[5] Stoisits R. F., P.W. Scherer and S.E. Schmidt. (1994) "Gas Optimization at the Kuparuk River Field". SPE paper 28467 presented at the Annular Technical Conference and Exhibition held in New Orleans, U.S.A, 26 -28 May.

[6] Lea J. F. and Kermit Brown. (1986) "Optimization Using a Computerized Well Model" SPE paper 14121 presented at the International Meeting on Petroleum Engineering held in Beijing, China, 15-17 June.

fracturing completions as said by Hashemi and Grangarten[7]. Because condensate banking in the vicinity of the wellbore impacts the production from gas-condensate reservoirs, several methods have been developed to forecast its presence. These include compositional reservoir simulation studies with fine gridding and empirical models that can account for the production decrease it causes. Compositional reservoir simulation is a forecasting method used for gas-condensate reservoirs. The near-wellbore area experiences a greater change in pressure than the rest of the reservoir, thereby becoming the area of interest for condensate banking effects[8]. As a reservoir nears depletion, the gas flow rate will become too low to continuously carry the condensed water out of the well bore. This minimum flow rate and corresponding pressure mark the onset of load-up. Produced liquids will begin accumulating in the well bore until the hydrostatic pressure becomes too large for the well to overcome and the production flow ceases according to Moltz[9].

Production rate from wells is affected by several natural variables such as reservoir pressure, permeability, PVT properties and time. It is also influenced by other production induced variables such as non-Darcy flow, mechanical skin, and multiphase flow etc. However, the interaction between such variables to accurately define the well-deliverability equation for a specific gas condensate reservoir is not well understood. Well deliverability is defined in two ways: the wellhead and well deliverability. Well deliverability is the most common one and accounts for all the sources of pressure loss from the reservoir to surface separators (reservoir bulk, wellbore vicinity, tubing flow and flow lines); while, the wellhead deliverability is used in reservoir simulation study and considers the sources of pressure loss in the reservoir and well skin only[10]. In tight gas condensate reservoir with permeability < 50mD, the wellbore and wellhead deliverabilities reduction are due to the condensate blockage only. In higher permeability gas condensate reservoirs greater than 200mD, the wellbore deliverability reduction is due to the condensate blockage, while the wellhead deliverability is due to the tubing pressure losses[11]. Productivity may be reduced by a factor of about two as the pressure drops below the dewpoint pressure according to Barnum et al.[12] David[13] conducted parametric studies with the neuro-simulation technique to identify the most influential reservoir and fluid characteristics in the establishment of the optimum production strategies for a gas-condensate system.

There is a need for the NLNG to increase their daily production capacity and therefore explored some of their available fields so as to determine which of these fields can cater the

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[7] Hashemi A. and Grangarten, A.C. (2005), „Comparison of Well Productivity between Vertical, Horizontal and Hydraulically Fractured Wells in Gas-Condensate Reservoirs", SPE Paper 94178, SPE Europec/EAGE Annual Conference, Madrid, Spain, 13-16 June.
[8] Park, H.Y. (2008) Decisionmatrix for liquid loading in gas wells for cost/benefit Analysis of lifting options, Thesis Submitted to the office of the Graduate Studies of Texas A&M University.
[9] Moltz A. K. (1992) "Predicting Gas Well Load-Up Using Nodal System Analysis" SPE paper 24860 presented at the Annular Technical Conference and Exhibition held in Washington D.C., 16 -18 September.

[10] Ayala, L., Ertekin, T., and Adewumi, M. (2007). "Study of Gas/Condensate Reservoir Exploitation Using Neurosimulation". Petroleum Transactions, AIME April
[11] Wang S.W., Ringe D.P., M.M Gable, and D.J. Staples. (2001) "Integrated Simulation of Reservoir, Gas Plant and Economics for A Rich Gas Condensate Reservoir" SPE paper 71598 presented at the Annular Technical Conference and Exhibition held in New Orleans, Louisiana, 18-20 March..
[12] Barnum C. F., Lea J. F. and Kermit Brown. (1986) "Optimization Using a Computerized Well Model" SPE paper 14121 presented at the International Meeting on Petroleum Engineering held in Beijing, China, 15-17 June.
[13] David B. Foo. (2000) "Optimization of Gas Wells by Automated Unloading: Case Histories" SPE paper, 59748 presented at the Gas Technology Synposium held in Calgary, Alberta, 4-7 May.

increase in production demand. The REX "XZ" reservoir is one of the three structures of the REX Field and can be developed to meet the production demand by the NLNG. The aim of this project is to design production model for the Niger Delta gas condensate field so that to determine the optimum production strategy that will give high gas deliverability and low condensate production under the operating constraints and market demand profile specified by the NLNG.

Reservoir Geological Structure

The Geology of the Niger Delta

The Niger Delta is a tertiary accurate delta with strong wave and tide influence. It is covers an area of 75,000 Km^2 and located in the Gulf of Guinea said Burke[14]. Three formations contain in the thick wedge Sediments of the Niger Delta based on litho-stratigraphy[15]. The Akata Formation is over-pressure sediment and under-compacted sequence of marine shale according to Doust and Omatsola[16]. It is also comprises continental slope channel-fills and turbidite sands. The Akata Formation is the source rock and ranges in thickness from 600 to probably over 6000m (Figure 2).

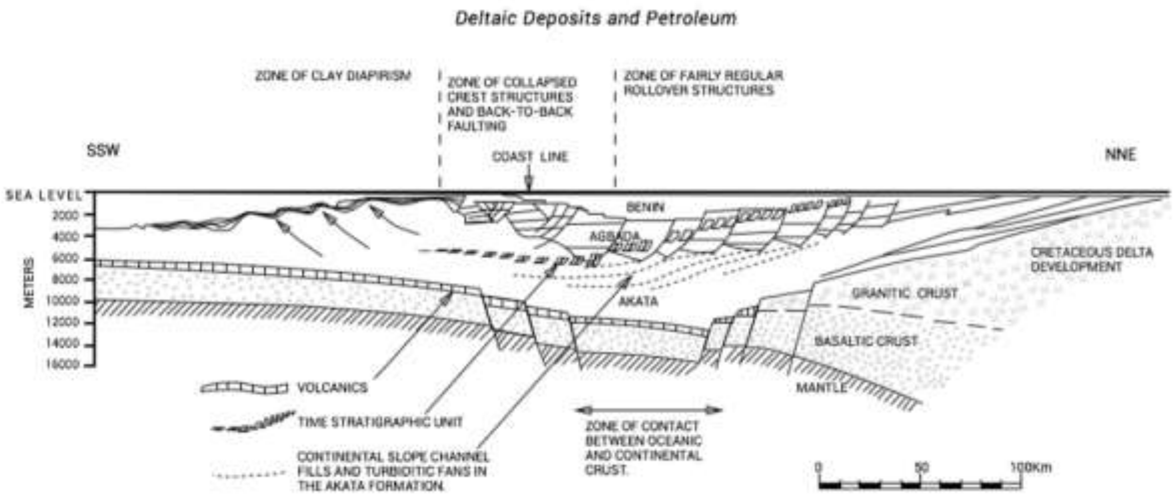

Figure 2. Schematic dip section of the Niger Delta (after P. Kamerling)

Agbada formation is the overlying paralic sequence of petroleum bearing sands which consists of inter-bedded sands and shale with a thickness between 300m to about 4500m. It is built up with numerous off-lap cycles and the sandy lithology which divided into the main hydrocarbon reservoir sand and the shale (cap-rocks). Hydrocarbon reservoirs in the Niger Delta are produced from sandstones and unconsolidated sands in the Agbada formation. Reservoir geometry and quality, and lateral variation in thickness are strongly controlled by growth fault[17]. Clay smears along faults, inter-bedded sealing unit juxtaposed against

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14 Burke K. (1996): "The African Plate". South African J Geol. 99 (4):341-410.
15 Short, K.C. and Stauble, A.J. (1967). "Outline Geology of the Niger Delta". AAPG Bull 51; 761-779.
16 Doust, H. and Omatsola. E.M. (1990): "Niger Delta". In: Divergent/Passive Margin Basins. D.Edwards, and P.A. Santagrossi (eds) AAPG Memoir 45: Oklahoma. (1990) 201-238.
17 Weber, K.J and Daukoru., E. (1975): "Petroleum Geology of the Niger Delta". 9th World Petroleum Congress Proceedings. 2:209-221.

reservoir sands and vertical seals from laterally continuous shale-rich strata are found within the Agbada Formation as seal rocks[15].

Production and System Performance Analysis Software (PROSPER)

PROSPER is the industry standard single and multilateral well performance design and optimization software. It can model and optimize most types of well completions and artificial lifting methods. Sensitivity analyses for a wide range of operating conditions can be held by means of Nodal Analysis. PROSPER generates a model for each component of the producing well system separately which contributes to overall performance, and then allows to verify each model subsystem by performance matching. Therefore, the program ensures that the calculation is as accurate as possible. All calculations in study regarding the generation of a well model, sensitivity analyses and design of an optimum gas lift system have been carried out by using PROSPER.

Dynamic Nodal Analysis

The objective of nodal system analysis is to combine the various components of the oil or gas well in order to predict flow rates and to optimize the various components in the system from the outer boundary of the reservoir to the sand face, across the perforation and completion section to the tubing intake and up the tubing string, including any restrictions and down-hole safety valves, choke, flow line and the separator. The major drawback of the conventional nodal analysis is that it only provides the user with a snapshot picture of the well production. It does not provide any information as to how the production will change as a function of time and the technique should overcome the following aspects:

- Predict the future performance as a function of time in the presence of various production components including the reservoir.
- Match the prior production data in the presence of various production components so that the appropriate parameters can be assigned for future production prediction. This is similar to decline curve analysis except that we need to include the production components in the system.
- Quantify the uncertainties with respect to various parameters by generating alternate possibilities of parameters which can match the production data.
- Predict the future performance under existing conditions as well as altered conditions to compare the production scenarios in the future.

It can optimize the producing well configuration so that the net profit over the life of the well will be maximized according to Bitsindou and Keikar[18].

METHODOLOGY

There are numerous sources of liquid loading in gas well. This study concentrates on Gas condensate reservoir only. Production data were gotten from the field and simulation study was run using PROSPER simulation software (Figure 3). The correlations of Beggs & Brill and Hagedorn Brown are selected for VLP/IPR matching. Well productivity was analyzed to determine optimum production conditions.

[18] Bitsindou A. B., and M.G.Keikar. (1999) “Gas Well Optimization Using Dynamic Nodal Analysis” SPE paper 52170 presented at the Mid-Continent Operations Symposium held in Oklahoma, 15-19 April.

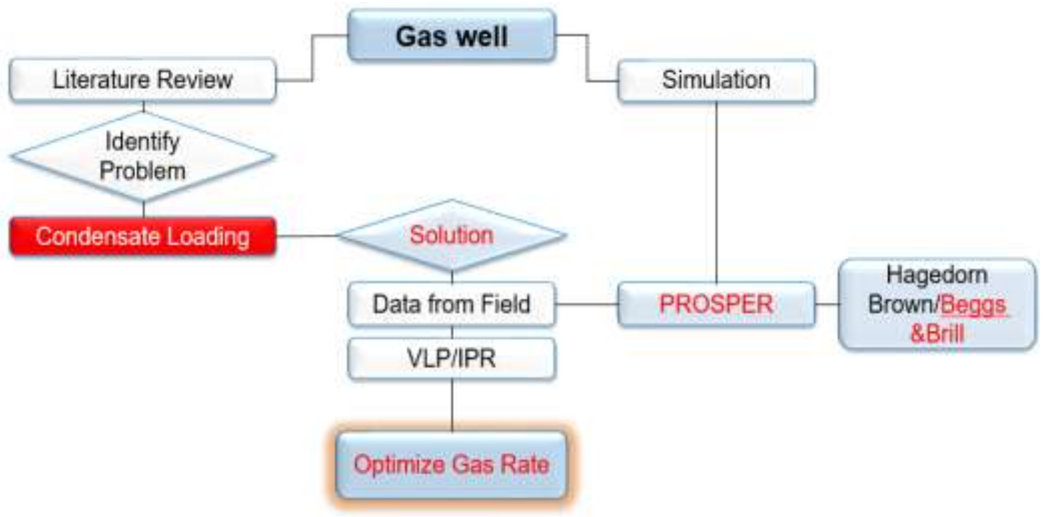

Figure 3 Flow diagram of the Gas condensate well optimization process

The Simulation Model Subsystem

PROSPER develops a model for each component of the producing well system separately which contributes to overall performance, and then allows to verify each model subsystem by performance matching. It is the process of setting up a reliable model with the available PVT, well and reservoir data. Prosper Software models are important tools for production engineers because they allow to explore the effect of individual variables on the production outcome. The simulation model used during the course of this study was newly built and a rock properties data used was derived from the “XZ” field geology received from TOTAL. The Field data for the simulation model were from the Appraisal wells (XZ 1, XZ 2 and XZ 3). The Rock and Fluid properties are shown in table 1 and table 2 respectively.

Table 1. Rock properties

Reservoir	Bulk Volume (10^9 ft^3)	Net Volume (10^9 ft^3)	Pore Volume (10^6 ft^3)	HCPV (10^6 ft^3)	GIIP (10^9 scf)
REX	**73.3**	**17.2**	**2401.4**	**1557.4**	**370**

Table 2. Fluid properties

Reservoir	Dynamic Unit	Sample Depth (ft)	Reservoir Pressure (psi)	Dew point Pressure (psi)	Reservoir Temperature (oF)	CGR (STB/MMScf)	API (o)	Viscosity (cp)
REX	**FU-REX**	**12200**	**5816**	**5575**	**284**	**140**	**42.3**	**0.0609**

Input Data

The developed model was based on the deep offshore gas field named XZ Field. Due to the reservoir pressure being close to the dew point pressure, the production well on the reservoir would liquid load. When this model is tuned to real field data, PROSPER can confidently predict the well's performance under various scenarios. In this work, several scenarios based on various operating conditions were carried out and a gas condensate production system was designed. A detailed explanation of the various operating scenarios was discussed and the input data for the simulation model are shown in figure 4.

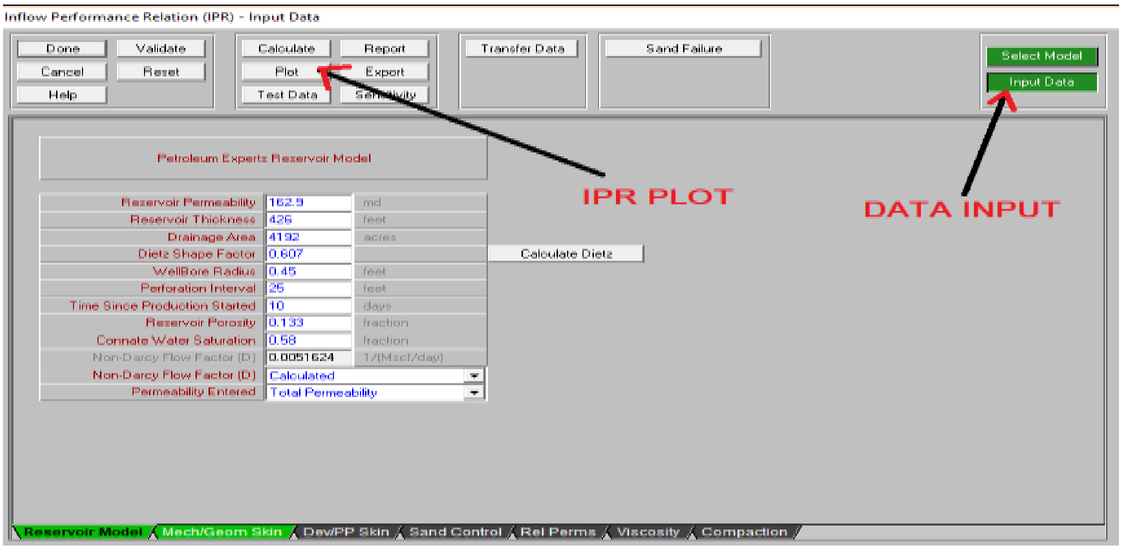

Figure 4. IPR input data (PROSPER)

SIMULATION RESULT

PVT Data Analysis

PVT data was used to predict the condensate formation within the production components and also to analyse gas composition using Lee et al correlation for gas condensate behaviour. The estimated components and their compositions in the XZ field are shown in Figure 5.

Component	Mole Percent (percent)	Critical Temperature (deg F)	Critical Pressure (psig)	Critical Volume (ft3/lb.mole)	Acentric Factor	Molecular Weight (lb/lb.mole)
N2	0.63282	-232.51	477.419	1.43842	0.04	28.01
CO2	1.89845	87.89	1054.74	1.50409	0.225	44.01
H2S	0.063282	212.09	1280.96	1.57938	0.1	34.08
C1	75.9379	-116.59	661.049	1.58899	0.0115	16.04
C2	6.96688	90.05	702.615	2.37547	0.0908	30.07
C3	3.33728	205.97	608.886	3.25166	0.1454	44.1
C4	1.8245	289.49	528.539	4.21274	0.1868	58.12
C5	1.1626	372.83	492.845	4.08459	0.2251	72.05
C6	1.08221	442.109	449.149	6.41068	0.25352	84
C7	0.91345	483.247	411.018	7.30352	0.27118	94.1122
C8	0.78578	523.677	381.61	8.18188	0.28848	105.063
C9	0.68496	562.42	357.885	9.04576	0.30542	116.5
C10	0.60284	599.311	338.196	9.89516	0.322	128.24
C11-C13	1.39915	666.244	307.059	11.5387	0.35385	151.586
C14-C25	2.00379	850.424	250.077	16.3157	0.44441	227.955
C25-C50	0.65526	1205.03	201.77	25.3585	0.60276	410.717
C50+	0.048856	1788.71	203.19	34.0265	0.68999	763.938

Figure 5. Estimated components and their compositions

IPR Plot

The IPR plot was created as shown in Figure 6 with no mechanical skin. The formation damage occurs in a gas well due to the PVT data variation with production and condensate formation near the wellbore area. From the IPR curve, the absolute open flow of the well is 107MMscf/day. It shows the maximum capacity of the gas condensate reservoir without considering pressure loss along the down-hole and the surface components of the well , and production decline due to the liquid hydrocarbon condensation.

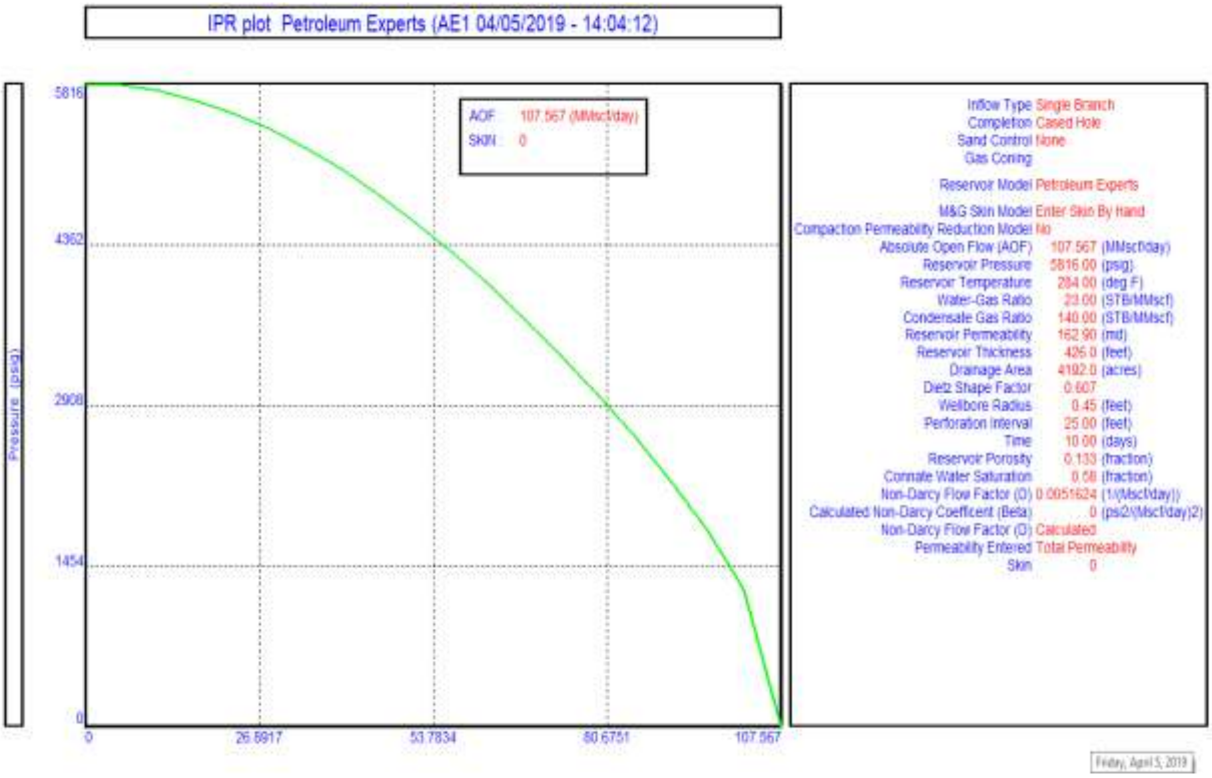

Figure 6 IPR Curve for gas condensate reservoir.

Therefore, the gas condensate reservoir IPR curve varies with the Future reservoir pressure than other variables. Reservoir pressure declines rapidly over a period of time due to the condensate blockage. The reservoir pressure depletion significantly affects future IPR curves which considerably reduces IPR and AOF values as shown in Figure 7.

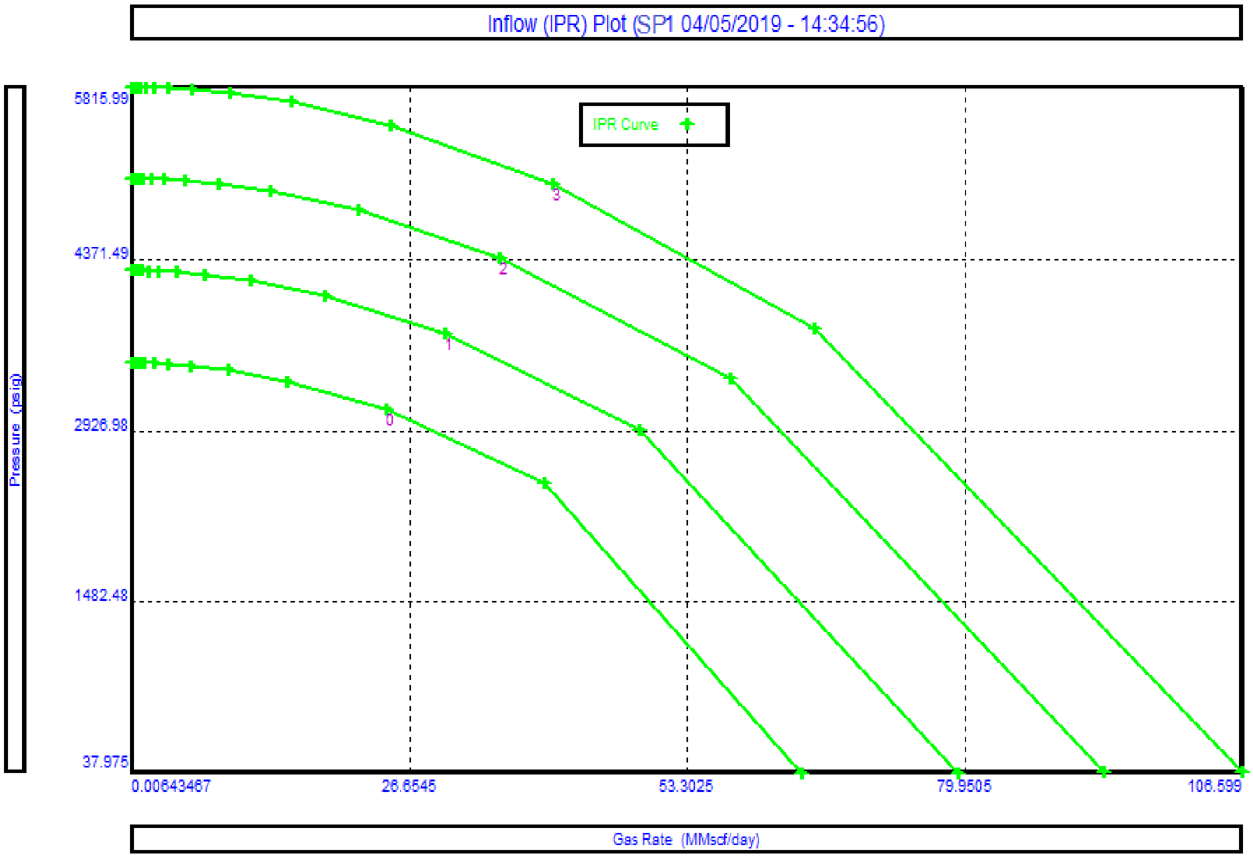

Figure 7. Effect of reservoir pressure on Future IPR.

Sensitivity Study for Different Tubing Sizes (Hagedorn Brown)

Before any analysis is done in PROSPER, the vertical lift correlations and inflow performance curve has to be matched for optimum operating conditions. The sensitivity analysis result for the "Hagedorn Brown" correlation demonstrated a great variation in the production rates with different tubing sizes (2", 2.5", 3", 3.5", 4", 4.5", 5", 5.5" & 6"). The 5.5" diameter tubing gives an optimum production rate of 46MMscf/day slightly higher than the production constraint given by the operating company. The well life was determined to be at 3600psi below which production will stop as shown in Figure 8.

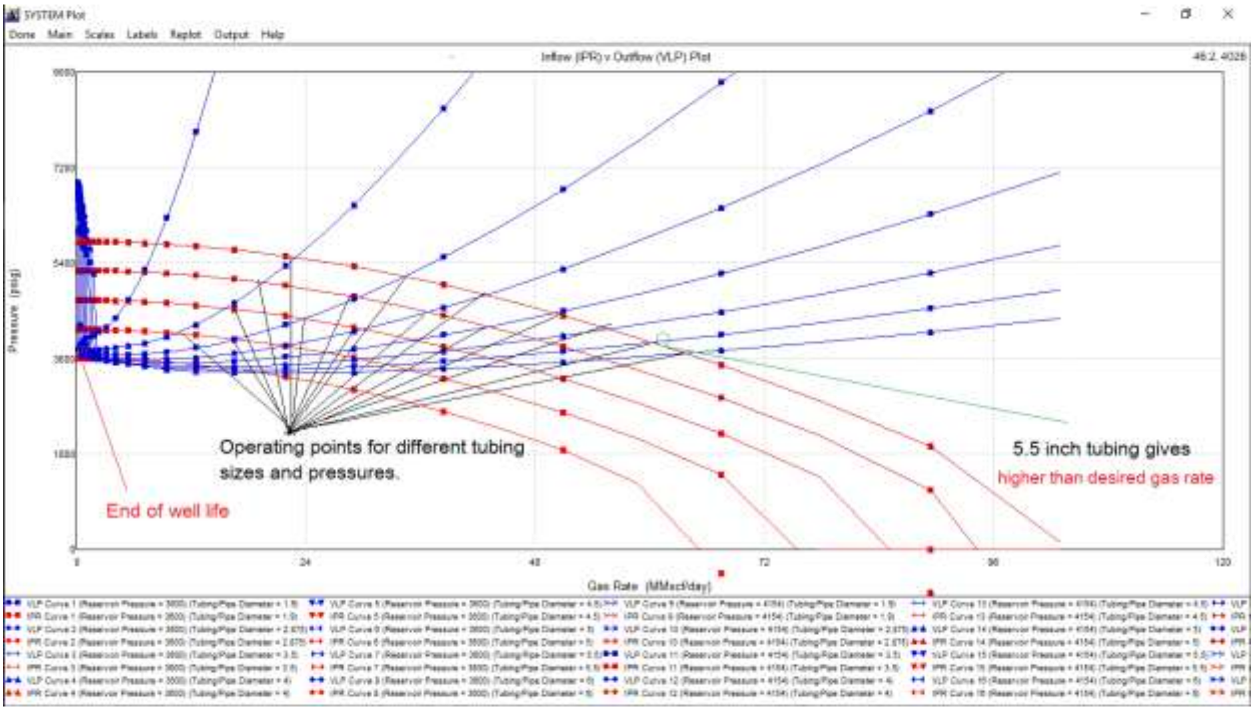

Figure 8 Different tubing sizes analysis (Hagedorn Brown)

Sensitivity Study for Different Tubing Sizes (Beggs & Brill)

The sensitivity analysis result for the "Beggs & Brill" correlation indicated similar trend in the production rates with the same tubing sizes used for the "Hagedorn Brown" correlation. The 5.5" diameter tubing gives the desired production rate of 45MMscf/day as specified by the operating company. The well life of the well was determined to be at 3600psi below which production will stop as shown in the sensitivity plot in Figure 9.

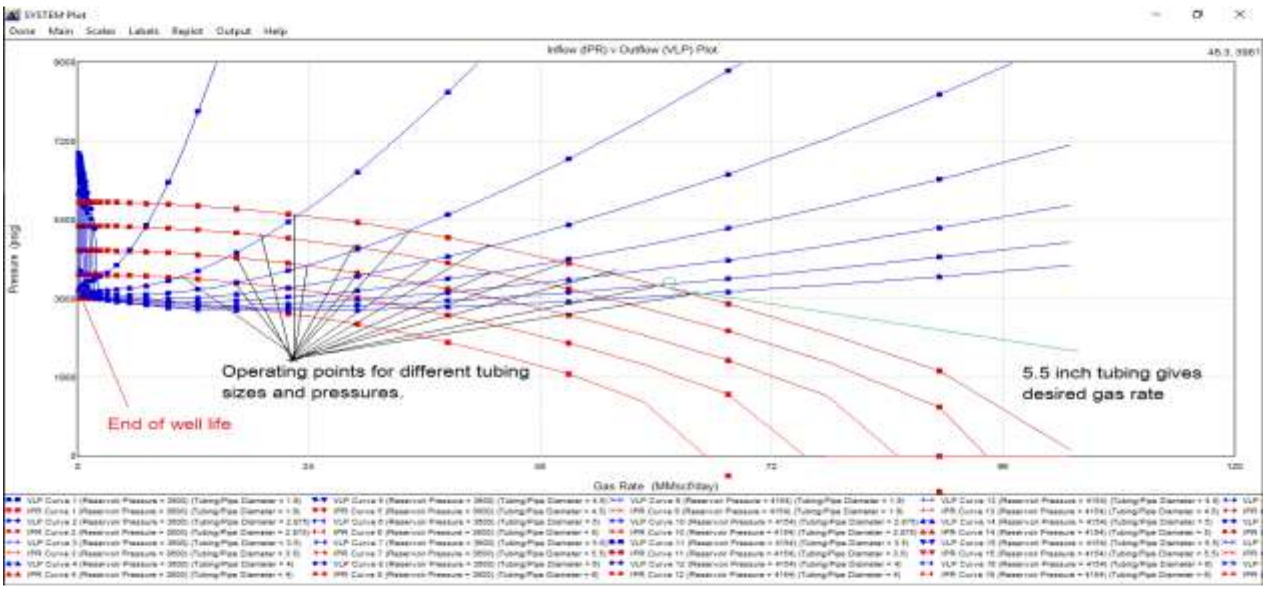

Figure 9 Different tubing sizes analysis (Beggs & Brill).

Tubing sizes with their corresponding gas production rates and erosional velocity status are presented in Table 3.

Table 3 Tubing sizes with their corresponding gas production rates and erosional velocity status

Tubing Diameter (Inch)	Gas Rate (MMscf/day)	Erosional Velocity
6	49.7	No
5.5	45.3	No
5	41	No
4.5	36.2	No
4	30.2	Yes
3.5	24.5	Yes
3	18.9	Yes
2.5	12.3	Yes
2	5.7	Yes

Well Optimum Vertical Lift Correlation

The best vertical lift correlation is the Beggs & Brill correlation because it gives the desired production rate of 45MMscf/day at 3981psig compared to the Hagedorn Brown which gives a production rate of 46MMscf/day at 4026psig. The 5.5in tubing has a higher erosional flow limit than other sizes at the observed rates. Hence, 5.5in size is the best tubing because of erosional damage prevention as shown in Figure 10.

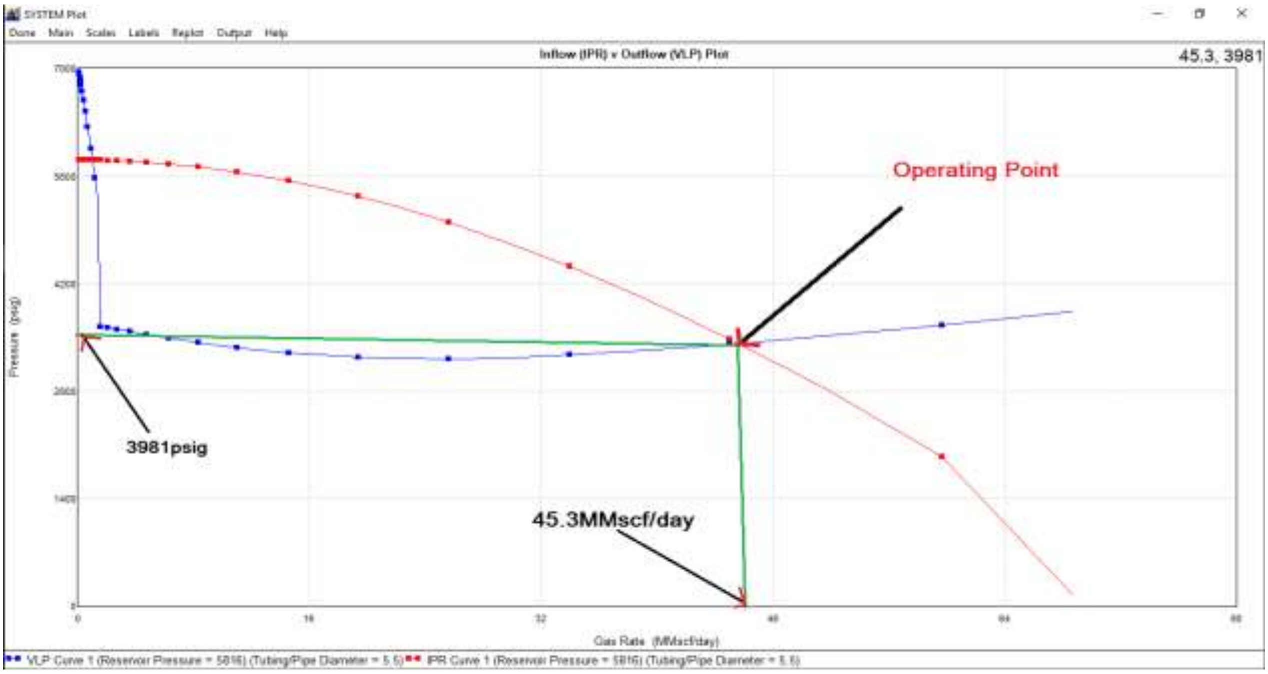

Figure 10 Inflow (IPR) Vs. Outflow (VLP) Plot for 5.5in tubing.

Sensitivity Study for Different Skin Factors

The most commonly used parameter of determining the formation damage in a gas condensate well is the Skin. The skin damage reduces the well productivity near the wellbore region. The formation of condensate banking increases the skin factor near the perforated area and restricts the gas flow. Sensitivity analysis was examined at skin values of +10, 0, and -10 (taking +10 at worst case scenario, 0 for normal and -10 at best case scenario). The skin factors of +10, 0, and -10 gave production rates of 44.4MMscf/day, 45.3MMscf/day and 45.9MMscf/day respectively as shown in Table 3. Therefore, the simulation model showed that the skin factor of +10 reduced the production rate by 1MMscf/day compare to normal formation while between 0 and -10 have least difference of 0.6MMscf/day as shown in Figure 11. Therefore, the skin value at the maximum of +10 does not affect the well production rate significantly.

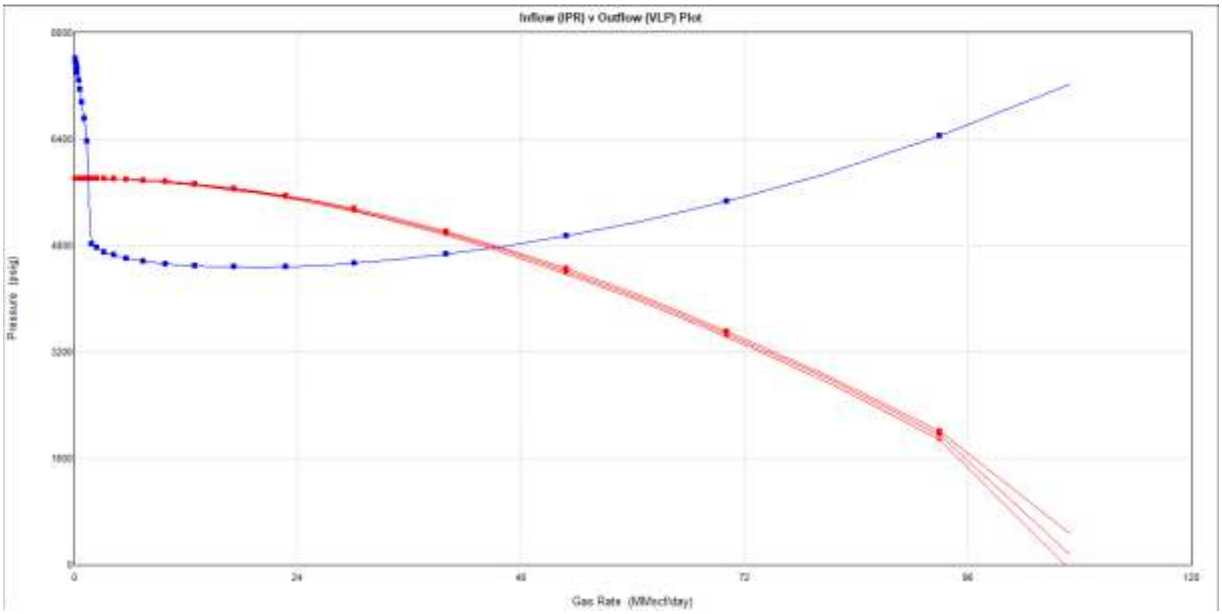

Figure 11 Sensitivity Analyses for Skin Factor.

Table 4 Skin Factors with corresponding production rates.

Skin Factor	Production Rate (MMscf/day)
10	44.4
0	45.3
-10	45.9

Sensitivity Study for Wellhead Pressures

Placing a choke at the wellhead means controlling the well flow at the wellhead pressure and, thus, the flowing bottom-hole pressure and production rate. For a given wellhead pressure, by calculating pressure loss in the tubing the flowing bottom-hole pressure can be determined. With operating WHP of 2500psi, 2000psi, 1500psi, 1000psi, and 500psi, different gas, water and condensate rates were obtained as shown in figure 12, 13, 14, 15 and 16 respectively.

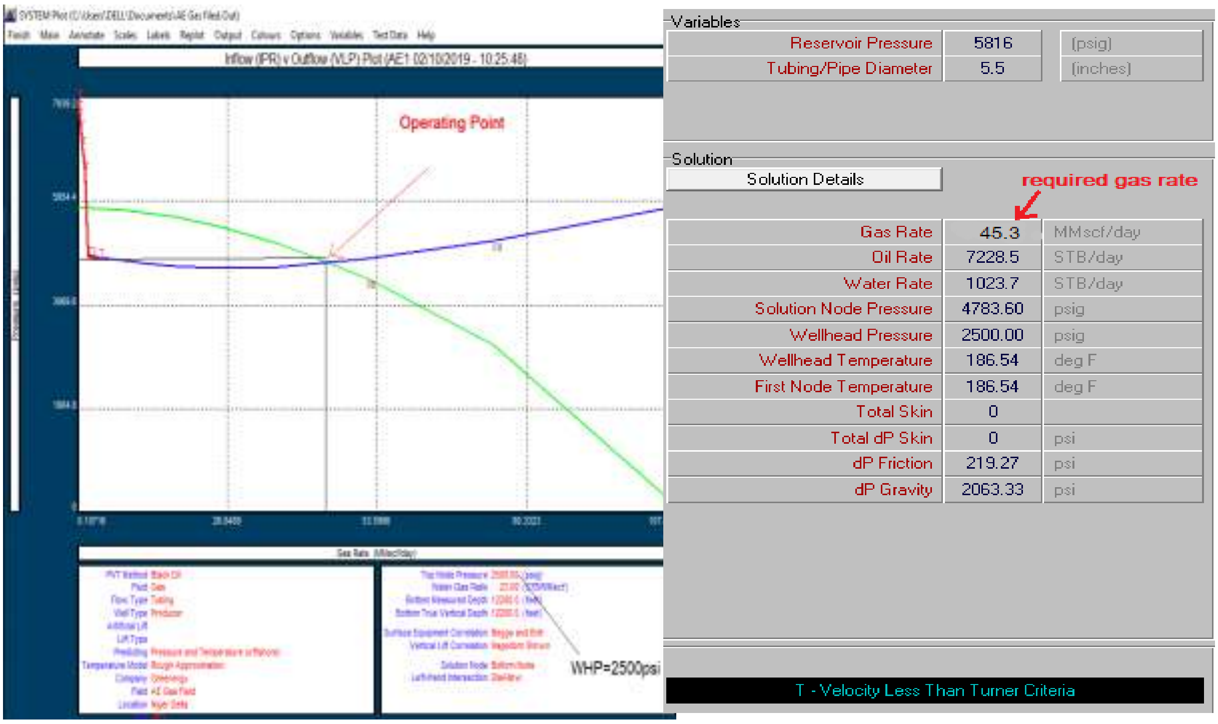

Figure 12 System analysis @ WHP=2500psi.

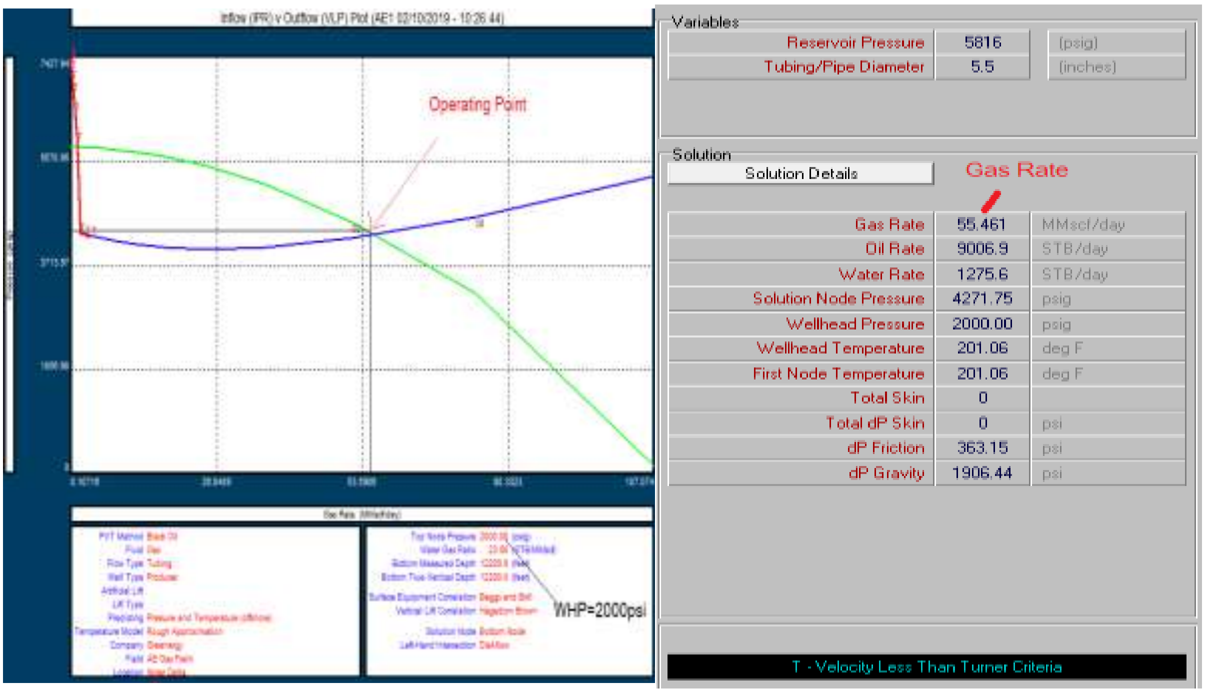

Figure 13 System analysis @ WHP=2000psi.

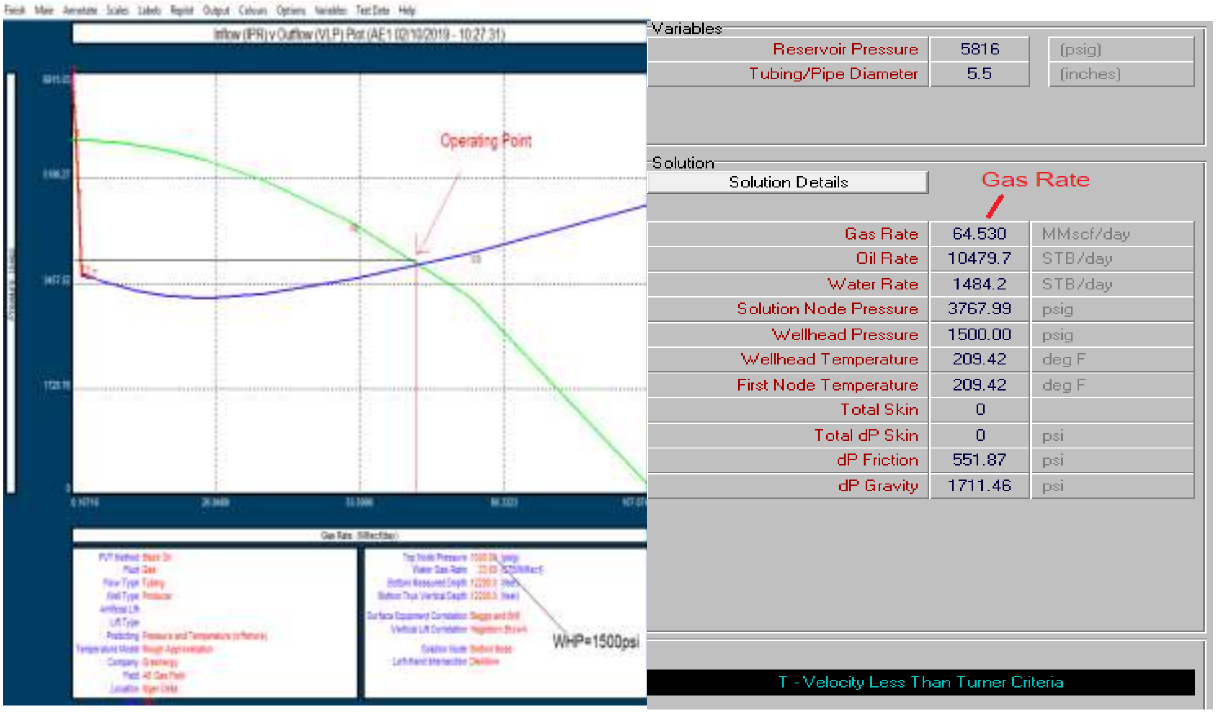

Figure 14 System analysis @ WHP=1500psi.

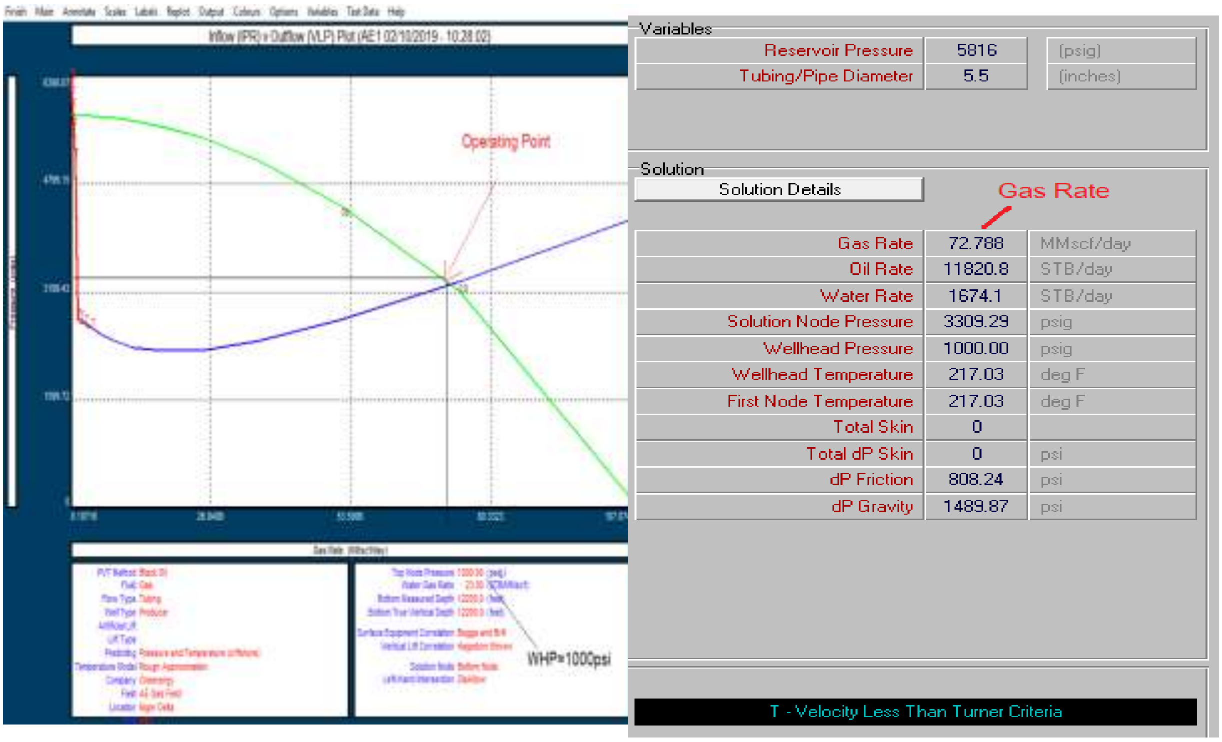

Figure 15 System analysis @ WHP=1000psi.

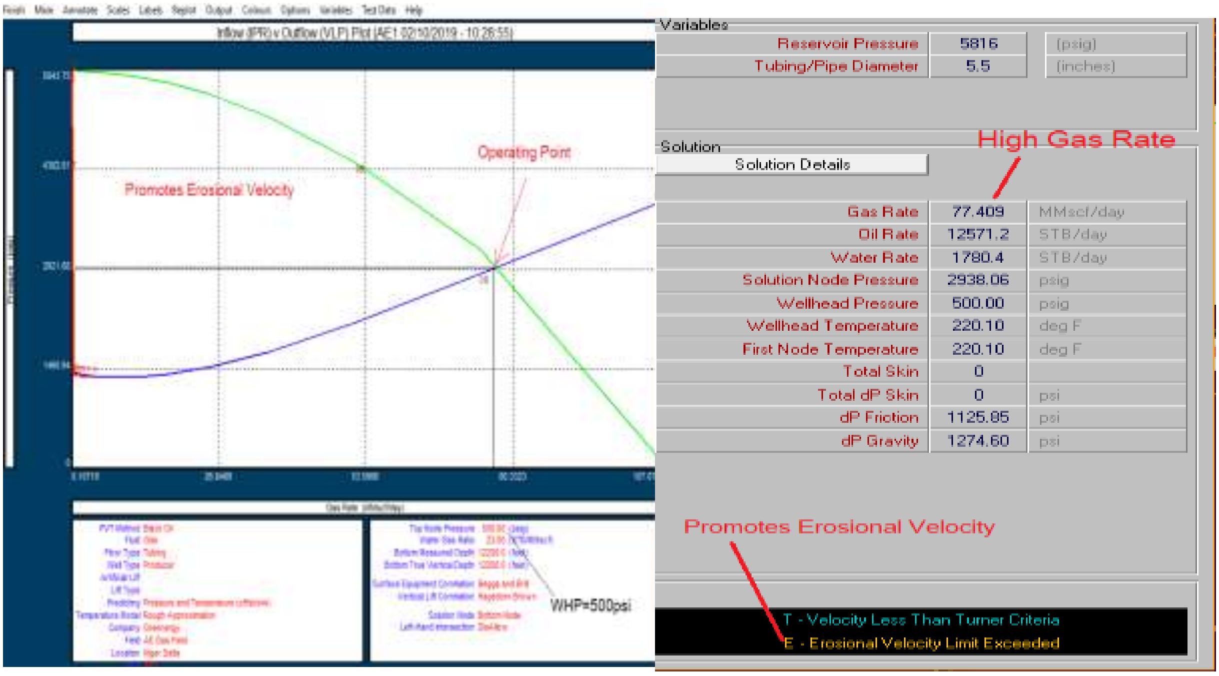

Figure 16 System analysis @ WHP=500psi.

Table 5. Wellhead pressures with corresponding gas and condensate production rates.

Wellhead Pressure (psig)	Gas Rate (MMscf/day)	Condensate Rate (STB/day)
2500	45.3	7228
2000	55.4	9006
1500	64.5	10479
1000	72.7	11820
500	77.4	12571

As the WHP was reduced from 2500psi to 500psi, an increase in the production rate was noticed as shown in Figure 12, 13, 14, 15 & 16. Therefore, the gas production rate can be increased to 72MMscf/day by reducing the WHP to 1000psi as market demand and the present operating condition constraint by the NLNG as shown in figure 15. Setting the WHP below 1000psi will demonstrate a high condensate production rate which is not needed within the production line as shown in Figure 16.

Downhole Equipment Summary

The down-hole equipment for the construction model consist of a wellhead at the surface and a 5.5in production tubing running through a 9.625in production casing as shown in Figure 17 below.

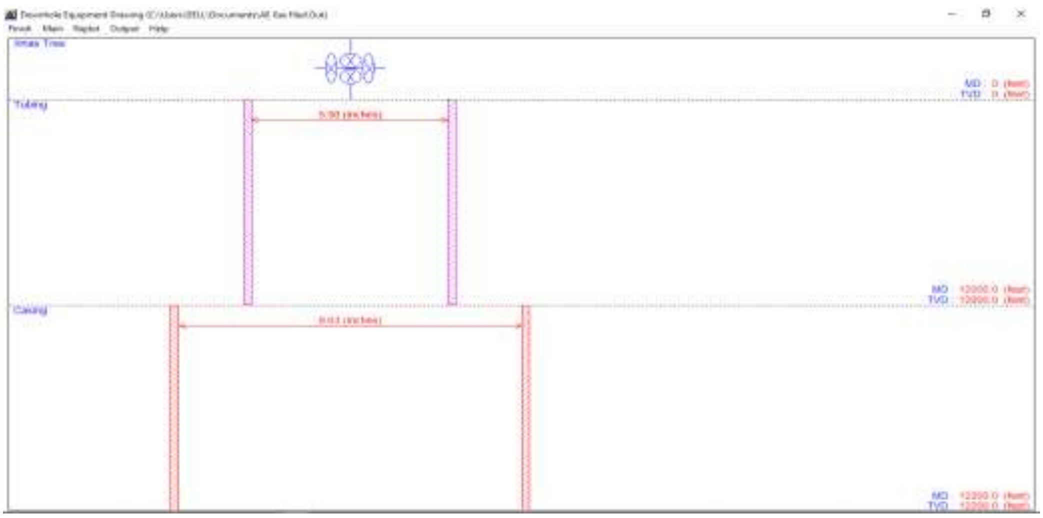

Figure 17. Down-hole equipment summary.

CONCLUSION

Regardless of initial well productivity, wells in the XZ will eventually liquid load due to declining the reservoir pressure below the dew point pressure. Nodal analysis was used to run a sensitivity study on the optimum production conditions of the gas condensate field that meet the NLNG designed capacity. Hence, the well will be operated by the Beggs & Brills and IPR matching which was the best VLP matching based on the gas rate and drawdown constraints. The desired production rate of 45MMscf/day was achieved with a 5.5” tubing size at a WHP of 2500. Consequently, production rates can be increased by reducing the wellhead pressure in the design model if market demand and operating conditions warrant. Based on the investigated parameters, the 5.5” tubing diameter gives the desired gas rate, low liquid production and operates within the erosional velocity limit. Conclusively, the best design model for the optimum production strategy of the field was created for future development.

RECOMMENDATION

Based on the designed model, it is recommended that;

1) 5.5inch tubing should be used in order to achieve the desired gas rate.
2) Two vertical wells should be drilled to meet the cumulative production demand.
3) The well head pressure should be set at 2500psi to achieve desired gas rate although a compression facility will be needed at the surface for gas compression.
4) A cost benefit analysis should be done to determine the impact of the designed model on project economics.
5) Further sensitivity study on water gas ratio and gas condensate ratio using the design model is recommended.