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Investigate a Gas Well Performance Using Nodal Analysis

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Abstract. Gas condensate well has unique reservoir characteristics and ups and downs in well behaviour affect the production rate significantly. A proper optimization can reduce the operating cost, maximize the hydrocarbon recovery and increase the net present value. Well level optimization can be achieved through optimizing well parameters, such as wellhead, tubing size, and skin factor. All of these factors have been investigated using a real field of Thrace Basin and PROSPER simulation program. The history matching data are validated to identify the future performance prediction for the same reservoir deliverability following the period changes. Therefore, predicted results are compared and validated with measured field data to provide the best production practices. Moreover, the results show that the skin factor has a large influence on the production rate by 45% reduction. The reduction in the reservoir pressure declines the production rate dramatically resulted in 70% decline. While manipulating the wellhead pressure shows minor decline compare to tubing size that does not show any significant change to production rate.

Keywords: Gas condensate; Well optimization; Production rate; PROSPER

1. Introduction

Inconsiderable fraction of the hydrocarbon can be produced by the natural drive of the reservoir. Practical knowledge has proven that when the reservoir pressure is depleted, the recovery factor nearly reaches 20%. Some of heavy fluid reservoirs cannot be produced by all natural energy drivers [1]. Gas condensate reservoir acts differently than a typical oil field in which two-phase oil-gas flow in porous media is often taken place during oil production. Traditionally such flow is modelled by extending the Darcy's law to two-phase flow by employing the concept of saturation dependent on relative permeability [2]. While Retrograde gas fields always exist beyond the critical temperature (as shown in figure 1). In this type of reservoir, the pressure is the main factor to yield any liquid and this would influence the production rate at surface. According to Darcy's law of steady state radial flow of single phase, the production rate is directly proportional to the pressure difference or drawdown between the reservoir and the wellbore. Thus the productivity index is constant over the pressure, which is principally termed as ideal case. However, the ideal case does not exist in the real situation that is related to the reduction of pressure followed by viscosity and gas-oil ratio changes. The ideal case would not able to stabilize when two-phase (liquid and gas) flow presented in a reservoir [3].

To determine the production capacity of a well for a set of well conditions, it's important to determine the quantitative effect and the importance of each variable within the system performance. Therefore, one of the advantages of the system analysis approach is the ability to predict the result due to changes in design variables [4]. Currently nodal analysis is used to accomplish this study as nodal analysis involves calculating the pressure drop in individual components within the production system, thus that the pressure value at a given node in the production system (e.g., bottom hole pressure) can be calculated from both ends (separator and reservoir) (See figure 2). The rate at which pressure is calculated at the node from both ends must be the same. This is the rate at which the well produces. Once the rate under existing conditions is obtained, by adjusting individual components, the sensitivity of individual components on the overall production can be investigated; hence an optimum selection of components can be obtained at a given time [5,7,8].

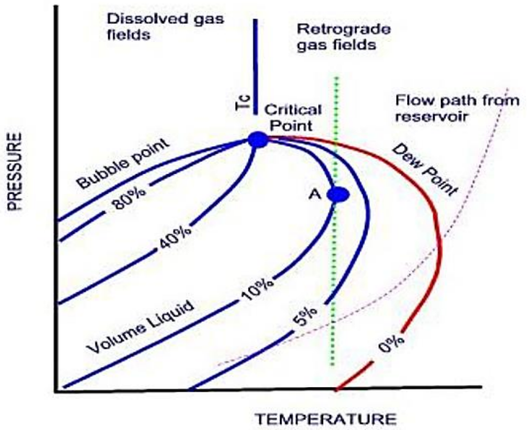

Figure 1. A typical gas condensate reservoir phase curve [6]

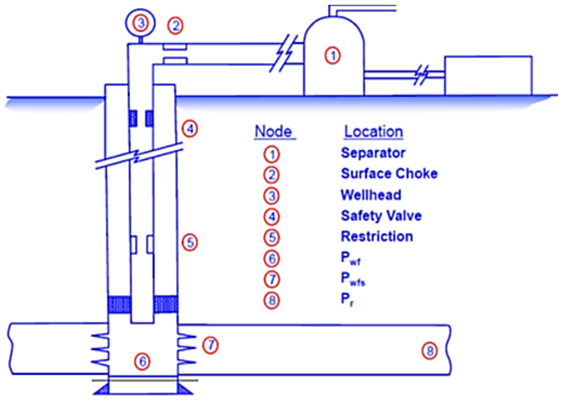

Figure 2. Location of various nodes in the production system

2. Dynamic Nodal Analysis

The estimation of the relationship between the bottomhole pressure and the flowrate is very important as it assists to analyze and to predict the individual well performance. This type of flow process is known as the inflow performance relationship (IPR). The first presentation of IPR concept was made by Gilbert. However, it is only a concept of gas flow for 24 hours versus the flowing well head pressure to obtain graphical results, which are not well detailed [9].

In 1954, Gilbert presented the same concept of inflow performance relationship (IPR) for the purpose of enhancing oil field production rate and flowing bottomhole pressures. The concept focused on the depletion pressure and flow rates only, which are simplistic and not consider many other factors such as skin factor, reservoir condition, restrictions due to production line components and sand screens. Therefore, the actual inflow performance shows linear relationship between the well head pressure and production rates [10]. Nonetheless, the nodal system analysis is developed and begins to using systematic numerical simulations tool in order to obtain best results for optimizing productions and reservoir sustainability. Nodal system analysis then refers to the systems approach for the optimization of the production operations of oil and gas wells thorough evaluation of the complete well production system [11]. It involves engaging correlations to forecast multiphase flow behaviour through pipe lines, well completions components, restrictions due to skin factors and the reservoir in order to analyse the inflow and outflow performance in the complete production [12]. The results obtained were non-linear relationship curves between inflow and outflow performance in multi-phase flow behaviour.

However, Kosmidis et al. [13] highlighted that nodal analysis is restricted only to oil fields with a small number of wells due to its trial-and-error nature during forecasts. In contrast, such as gas lift optimization system, injection system and tubing size adjustments using nodal analysis have been invented in gas wells as well. Mustafa Al Lawati [14] has investigated gas lift nodal analysis model, which explains the mature well produces an extra 153 BOPD after optimization process. By analysing the VLP/IPR relationships, running some sensitivity tests and calculate the gas mandrel depth via nodal analysis results in positive changes to the well, which produces 170 BOPD tend to improve the production up to 323 BOPD.

Therefore, nodal analysis plays an essential part with integrated production models, recommends a cost effective means for optimize performance, therefore; offering more economic systems. For instance, to optimize the production in a mature Niger Delta field, PROSPER's nodal analysis tool has been used in order to enhance the choke performance, which obtained better production results. The study of sensitivity tests and choke performance analysis tend to address the issues relating production enhancements since choke size is an important indicator of productivity [15].

Furthermore, in Nigerian gas field, nodal analysis was applied to determine the pressure drop and optimum tubing size from erosion through simulations. The bottomhole pressure and well head pressure can be easily determined by having any one of the data to find out others or vice-versa. In a natural flowing gas well, the flow velocity is very high, thus erosion could take place inside the production tubing. The IPR and VLP relationship is applicable to examine the pressure drop in the system, pressure drop across perforation and respective tubing size effects [16]. Therefore, the nodal analysis system is applicable to gas or oil field to obtain well production performance for inflow and outflow performance. Nevertheless, there are many other elements have to be considered into the calculation method and approach for extract accurate results.

The aim of this study is to evaluate the best production practice of gas condensate reservoir in Thrace Basin in order to meet the economical aspect of the future field development where the challenging part is to maximize the accumulated recovery since the reservoir pressure is in a rapid depletion due to weak reservoir drive mechanism. An educational software known as PROSPER is used for this study to perform history matching and conduct appropriate sensitivity analysis.

3. Reservoir Description

3.1. Geological Characteristics of Thrace Basin

Thrace basin originated from tertiary age and triangular intermontane basin filled with middle Eocene to Pliocene. In early Oligocene the transgression reached maximum level. Deep basin troughs mostly filled with clastic termed as turbiditic clastic and overlain by thick marine clastic on the northern shelf. Some andesitic tuffs were in inter-bedded formation depicting active volcanism. Overall, the wide-spread Thrace basin contains mostly clastic sediments, marginal marine and terrestrial environments [17]. Figure 3 shows the overall view of Thrace Basin location and the nearby fields.

3.2 Field Data

The W-1 well located in Thrace Basin, which was discovered in year 2000. W-1 well production data available in Appendix A. The formation is mainly sandstone and small indications of shale and has an anticlinal structure. The production mechanism mainly functions due to volumetric depletion. Table 1 shows production W-1 well and reservoir data as well as gas well composition.

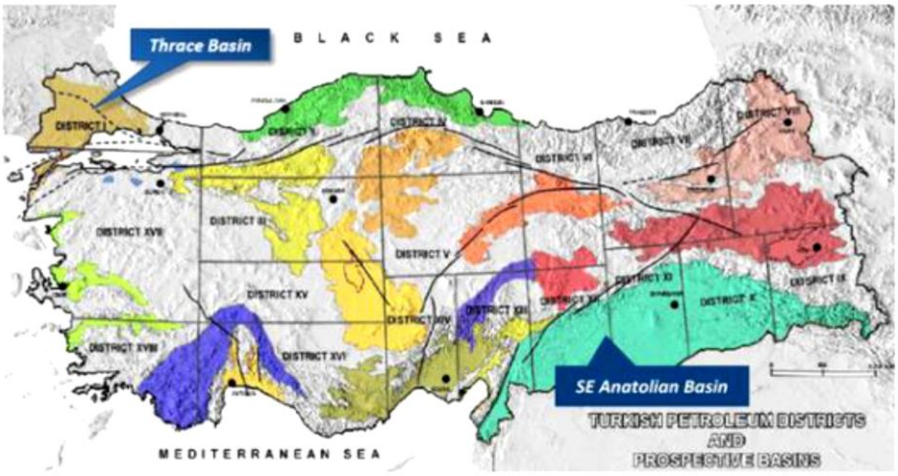

Figure 3. Thrace Basin map view [17]

Table 1. Production well and reservoir data [16].

Well ID	Value	W-1 Composition	%
Reservoir pressure	1,875 psi	C_1	93.25
Reservoir temperature	135oF	C_2	3.25
Datum depth	4,200 ft	C_3	1.45
Water-gas contact	3,788 ft	i-C_4	0.36
Gas specific gravity	0.611	n-C_4	0.45
Tubing size, OD	2.875 in	i-C_5	0.16
Tubing size, ID	2.44 in	n-C_5	0.13
Formation layer height	20 ft	C_6	0.16
Reservoir radius	2,107 ft	N_2	0.76
Oil density	48.56 lb/ft3		
Average porosity	15%		
Average permeability	13 md		
Well radius	0.583 ft		

4. Well model construction

The production system has been modelled using PROSPOR software. Actual field data were entered to the model. The input data including the rock fluid, reservoir properties as well as gas composition as listed in table 1. First of all, PVT data, downhole equipment and IPR were modelled, and then the nodal analysis was conducted on interesting nodes in order to gather enough data for any alteration purpose. Figure 4a and b describe the real and model in software, respectively.

5. Result analysis and discussion

5.1. PVT data analysis

PVT data predicts the formation of condensate when the fluid flows to surface conditions, which would be integrated into reservoir data to obtain the dew point, critical point and bubble point. Table 1 data was used to analyse the PVT data and gas composition using Lee et al correlation, which would comply the gas condensate behaviour. The Dew point pressure at the reservoir temperature was obtained by approximation and trial and error method, which is about 810 psig.

5.2. IPR construction

The IPR curve was constructed Initially without considering formation damage (skin = 0) since the early production starts without any restriction. The skin effect may take place near the wellbore due to condensate banking and PVT changes. At figure 5, IPR curve has an absolute open flow (AOF) about 17 MMscf/day. This indicates the maximum amount of gas can be produced if there is no pressure drop between production tubing components.

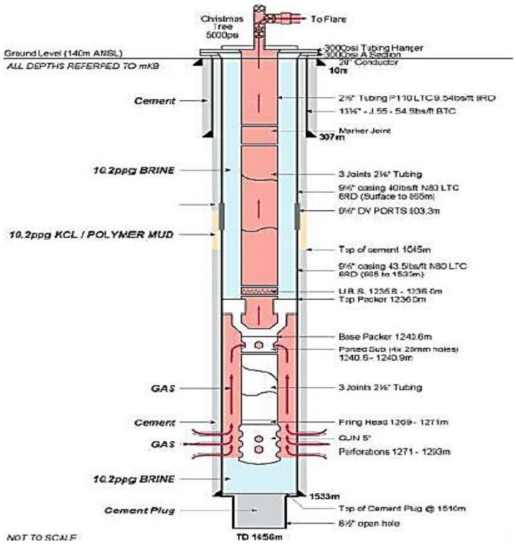

Figure 4a. W-1 Well diagram [17]

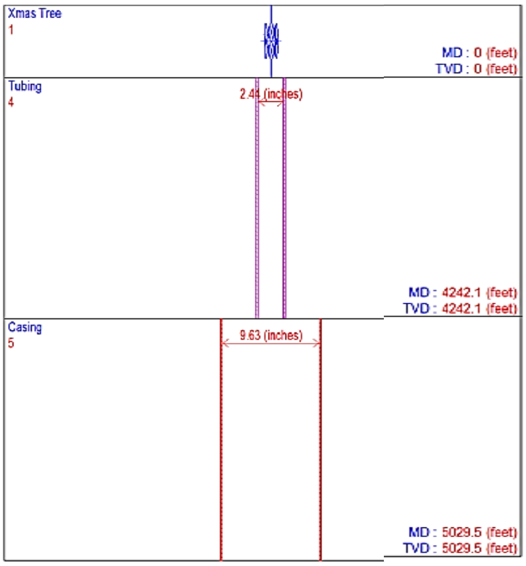

Figure 4b. Well completion from PROSPOR.

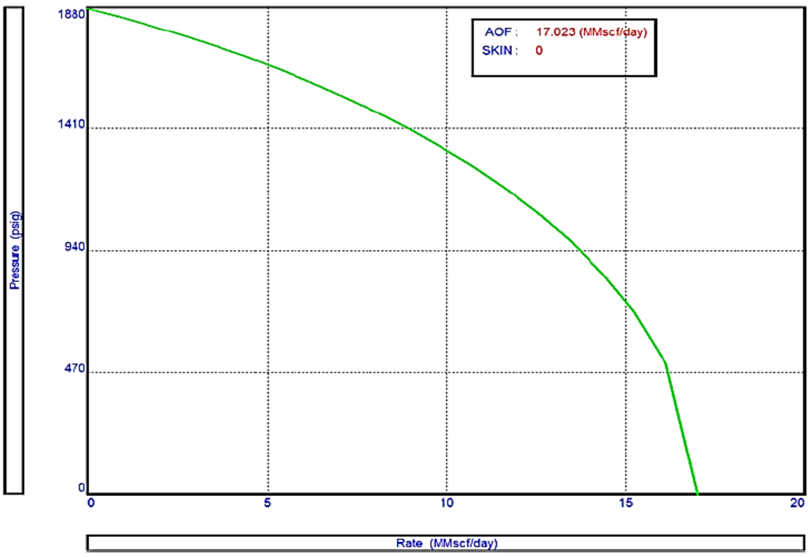

Figure 5. IPR Curve for initial reservoir properties.

However, the solution gas drive mechanism not having the same IPR curve over time because the reservoir pressure drops drastically than other reservoir drive mechanisms. For the gas condensate reservoir, the reservoir pressure drop has high probability of changing at a short period due to its behaviour. The result analysis of estimating reservoir pressure changes with respect to water-gas ratio (WGR) and condensate gas ratio (CGR) is shown in figure 6. It indicates that the variation of WGR (0.0002 to 0.0008 stb/Mscf) and CGR (0.007 to 0.01 stb/Mscf) does not have significant effect on IPR curve. Indeed, the drops in reservoir pressure (1,875 to 1,000 psig) changes considerably IPR and AOF reduced to approximately 6 MMscf/day when the reservoir pressure becomes 1000 psig. Therefore, IPR curve is too sensitive towards the reservoir pressure rather than CGR and WGR.

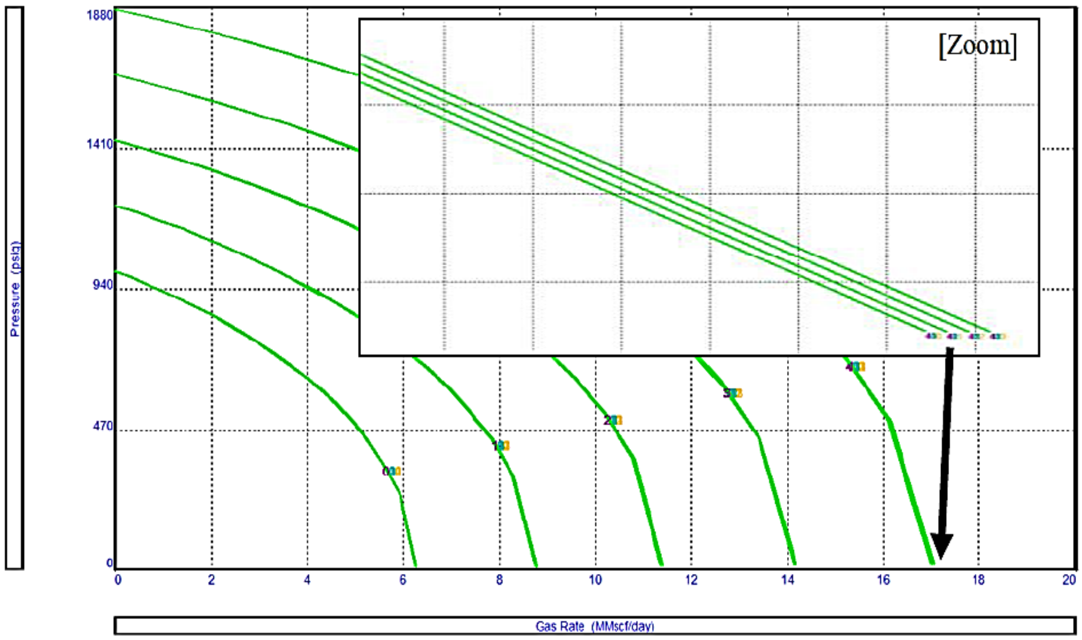

Figure 6. Effect IPR with reservoir pressure, WGR and CGR changes.

5.3. Operating point

According to production data, W-1 well has been produced since June 2002 to January 2005. In early production time, the reservoir pressure supported by a reservoir drive mechanism, thus maintaining VLP and IPR relationship. The reservoir pressure initially is 1,875 psig and well head pressure (WHP) is maintained at 1,590 psig. Implementing Jones reservoir model and Orkiszewski vertical gradient correlation, IPR versus VLP curves were constructed to obtain the bottomhole pressure and the production rate, which are 1,600 psig and 6.4 MMscf/day, respectively (Figure 7). While the field production rate is about 6.1 MMscf/day with less than 5% error. The model can be used for history matching and further analysis.

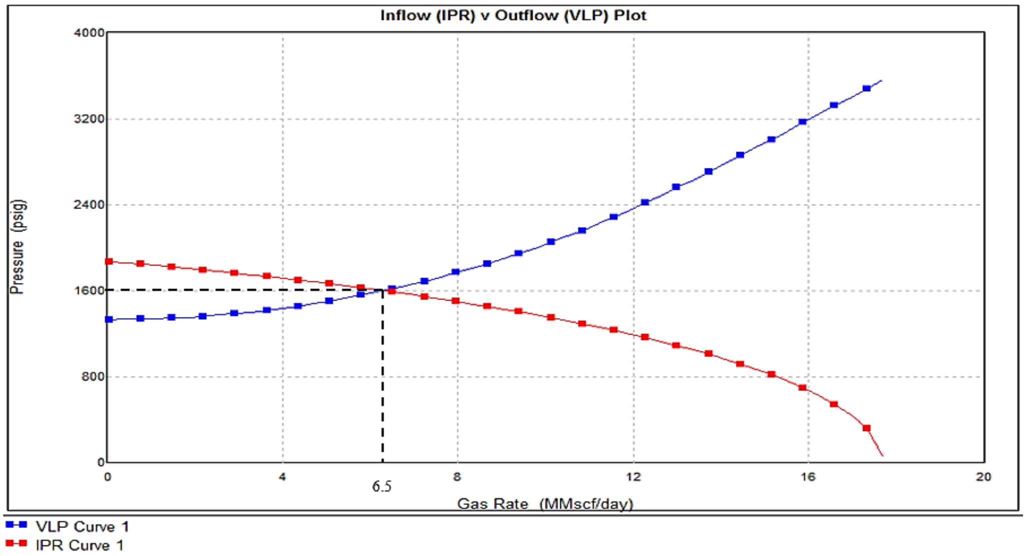

Figure 7. IPR versus VLP curve for initial reservoir condition of W-1.

5.4. History matching

In this case study, the production data depicts that W-1 well had been in operation since June 2002 until January 2005. The production data shows the inconsistency of gas and condensate production within this period. The production data changes due to many factors including changes of reservoir pressure, water cut increases, condensate banking, wellhead pressure adjustments and skin effects.

The condensate gas ratio (CGR) for overall production varies in negligible amount, which is only four percent (4%) changes from 0.0071 stb/Mscf to 0.0074 stb/Mscf. It indicates that CGR does not influence the overall production significantly. Therefore, the possibility of production data changes could be due to reservoir properties. The retrograde gas reservoir often affected by significant reservoir pressure drop due to its weak drive mechanism.

The history matching focuses on reservoir deliverability changes to find the recent gas and condensate production as function of well behaviour. Four particular test points were chosen for this purpose. The production data and WHP were taken from field production data while the reservoir pressure was assumed to be reducing gradually by 100 psig each year. Constructing the VLP versus IPR relationship for assumed reservoir data. The new solution rate is used to compare with field gas production data as presented in table 2. It indicates that the calculated reservoir pressure and field gas production data are in agreement with a minor error of less than 10%. Therefore, the estimated pressure can be used to predict the future performance for well behavior.

Table 2. Matched reservoir pressure for test points.

Test point	Date	WHP psig	Field production rate MMscf/d	Matched P_{re} psig	Calculated Q_g MMscf/d	Error %
1	1/06/2000	1590	6.438	2096.3	6.437	0.006
2	1/01/2003	1329	5.425	1772.5	5.456	0.571
3	1/01/2004	989	2.564	1259.8	2.552	0.468
4	1/12/2004	781	1.808	996.1	1.792	0.885

5.5. Well performance prediction
As the model was validated with field production data, the well behaviour can be analysed considering the wellhead pressure, tubing size, water cut, condensate banking, choke size, and skin factor.

5.5.1. Wellhead pressure
The initial setup of WHP is about 1,590 psig and decreased till 781 psig to sustain the production rate. By reducing the wellhead pressure leads to increase the pressure drawdown consequently it increases the production rate where the reservoir pressure has less influence to lift up the gas condensate to the surface facilities. The future prediction performance for W-1 well was analysed from pressure range of 765 to 500 psig as shown in figure 8.

The obtained results are tabulated in table 3, the reduction of WHP shows an increase in gas production rate. The predicted rate is significantly improved to 3.860 MMscf/day by reducing WHP to 500 psig compared to the production rate of 1.808 MMscf/day at 781 psig, which is slightly more than double of production rate. Thus, WHP variations play an important role in optimize and sustain the production.

5.5.2. Tubing size analysis
One of the important factor for optimizing the production over time is the installation of optimum tubing with appropriate internal diameter size. The tubing size allows the gas and condensate to lift up to the surface with a particular volume and pressure drop. The internal tubing size of W-1 well is a standard 2.441 inch. Therefore, the analysis is done by inserting different tubing sizes ranging from 2.0-4.92 inch to determine the optimum rate. Figure 9 shows the results of production gas rate for various tubing sizes. It is noted that gas production rate has not increased significantly, only 0.25 MMscf/d with respect to tubing size as listed in table 4. Therefore, the tubing variation should not be considered for future field development plan.

Table 3. Predicted result of wellhead pressure analysis.

No.	WHP (psig)	Predicted Q_g (MMscf/d)
6	765	2.14
5	712	2.74
4	659	3.06
3	606	3.18
2	553	3.28
1	500	3.86

Table 4. Predicted result of tubing size analysis.

No.	Tubing size (inch)	Predicted Q_g (MMscf/d)
1	2.00	1.99
2	2.44	2.14
3	2.99	2.21
4	3.96	2.24
5	4.92	2.24

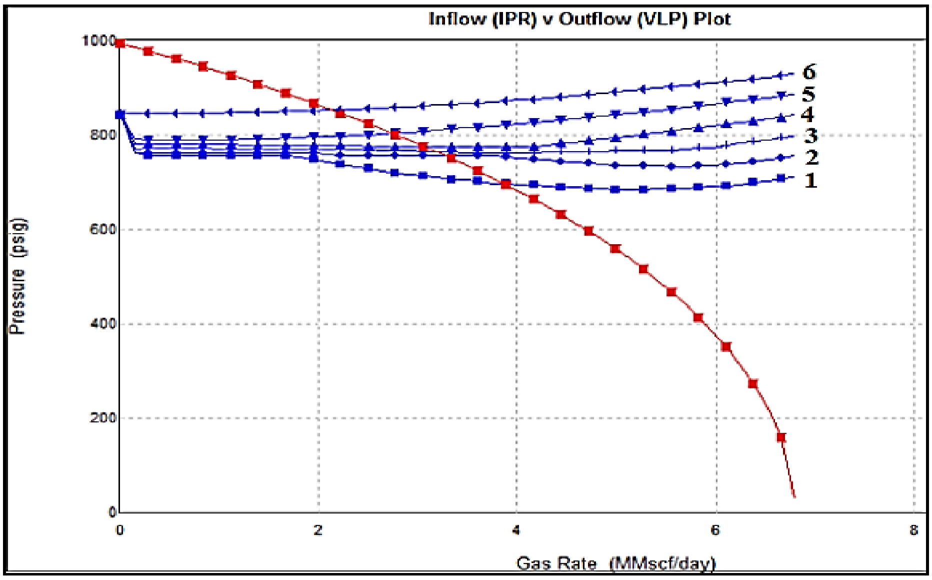

Figure 8. Sensitivity analysis of wellhead pressure.

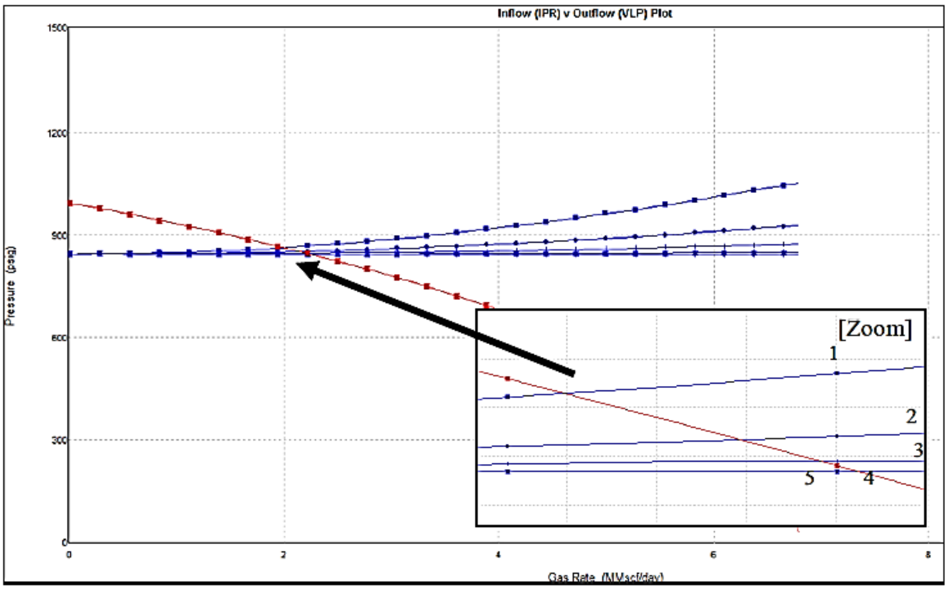

Figure 9. Results for different Tubing size.

5.5.3. Water cut impact

In this gas condensate reservoir, the solution drive mechanism acts as reservoir support where the water invasion is not in liquid form such as water drive but as vapour molecules mixed with hydrocarbon gas. As water gas ratio (WGR) increases theoretically it may have overall production effects due to increase the overall fluid density as water molecules have higher density than gas molecules. According to W-1 well history, WGR accumulated at the surface in a small quantity, which is only about 0.48 stb/MMscf with increment of only 0.03 stb/MMscf since June 2002. Thus, increasing WGR to 0.8 stb/MMscf, it shows less effect on the well production rate as shown in figure 10. Therefore, WGR is not an important factor in such reservoir characteristics.

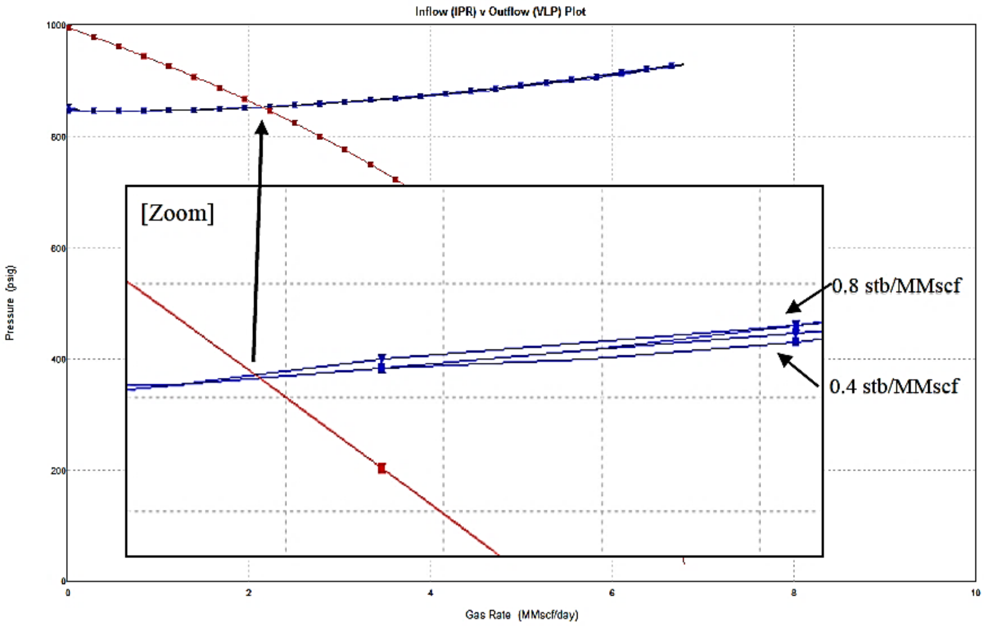

Figure 10. Results of Water Gas Ratio analysis.

5.5.4. Effect of gas condensate ratio

In the production of gas condensate wells there are two important components are profitably expected, which are hydrocarbon gas and condensate. Both produced fluids estimate the payback period in developing a field. In this case, the effect of gas condensate ratio (GCR) is considered for optimization purpose. Field production data shows GCR is 139.104 Mscf/stb in December 2004. Therefore, the considered range of GCR is between 120 and 160 Mscf/stb to predict the potential change of overall production.

Figure 11 displays the effect of gas condensate ratio on the well production. As can be seen that increasing GCR leads to increase the production rate but it is not significant at a small increment ratio. Thus, increasing GCR reduces the hydrostatic pressure gradient as well as the slip velocity. The overall results depicted that the gas rate production proportional to the GCR amount.

5.5.5. Skin effect

The skin effect is exaggerated by condensate banking and well deliverability nearby the wellbore. The condensate banking affects the gas flow within the tubing since the condensate fluid takes place near the perforated area. This leads to gas flow restriction, which increases the skin influence. Therefore, the effect of skin is analysed using positive values from +2 to +10, which represent the damage occurs nearby the wellbore area.

Figure 12 demonstrates the effect of skin on inflow performance relationship. As can be seen that the damage has a significant impact on the reservoir deliverability by achieving approximately 1 MMscf/d at a skin value of +10 in comparison to lower value of +2 with a production rate of 1.8 MMscf/d as listed in table 5. In gas condensate reservoir, the skin factor can be more than +20 in some cases if the well is not managed properly. Thus, the reservoirs deliverability is proportional to the skin factor that can affect the production rate significantly [18].

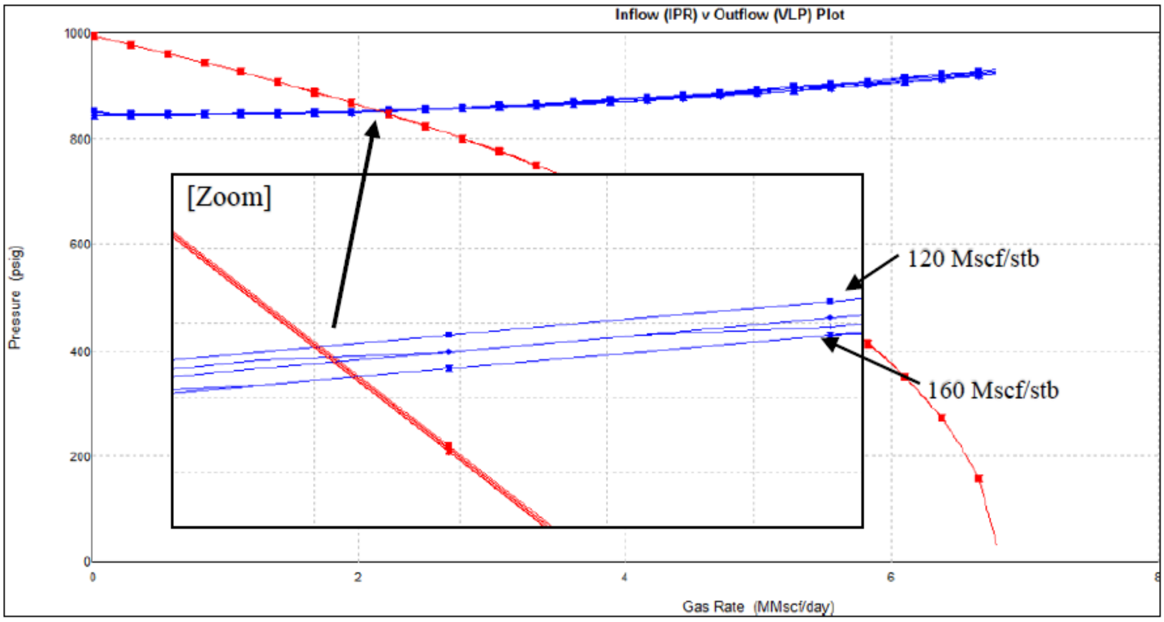

Figure 11. Results of IPR VLP relationship changes due to GCR.

Table 5. Predicted production from skin variations.

Skin factor	Predicted Q_g (MMscf/d)	Production decline %
+2	1.8	0
+4	1.5	16.7
+6	1.3	27.8
+8	1.1	38.9
+10	0.98	45.6

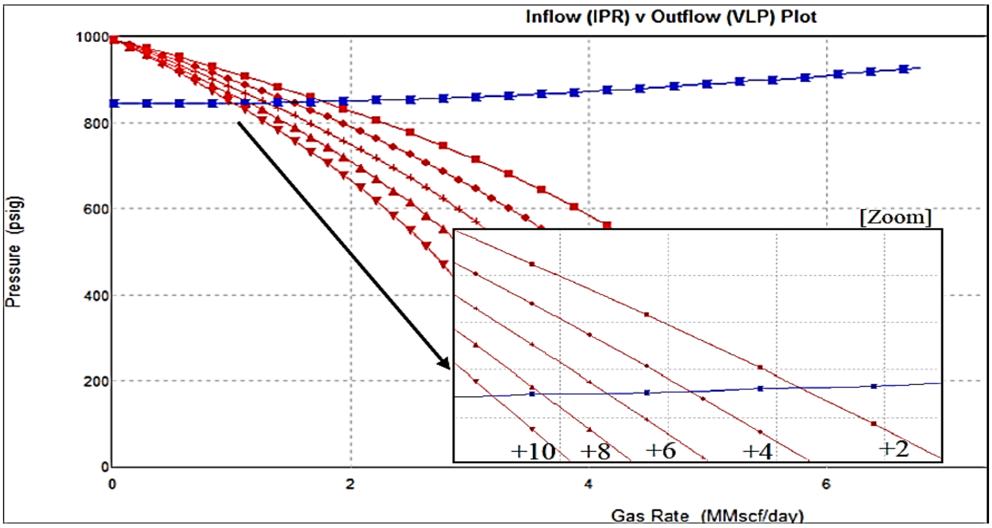

Figure 12. Results of overall skin effects on reservoir deliverability.

5.5.6. Surface choke size

The choke is mechanical equipment which can restrict the flow area by adjusting the bean size. It applies back pressure to the system to control the fluid flow nearby the wellbore and achieve stable flowing tubing head pressure (FTHP) on the surface. Therefore, the effect of bean size variations had been analysed in order to obtain the optimum rate of production.

Figure 13 shows the results of VLP and IPR relationship while changing the bean size from 0.5 (32/64) inch to 2.0 (128/64) inch. As the bean size increases the production also increases since it allows more gas flow easily to surface facilities by reducing the restrictions on pressure drop. Using choke size of 0.5 inch can yield about 1.78 MMscf/d, which is almost same as the average production. Moreover, as the bean size opened up to 2.0 inch, it enhanced the production to 2.14 MMscf/d, which is almost same as bean size of 1.0 inch that produces 2.1 MMscf/d. When the bean size increases reduce the back pressure towards to the reservoir, which leads to increase the drawdown pressure and fluid production.

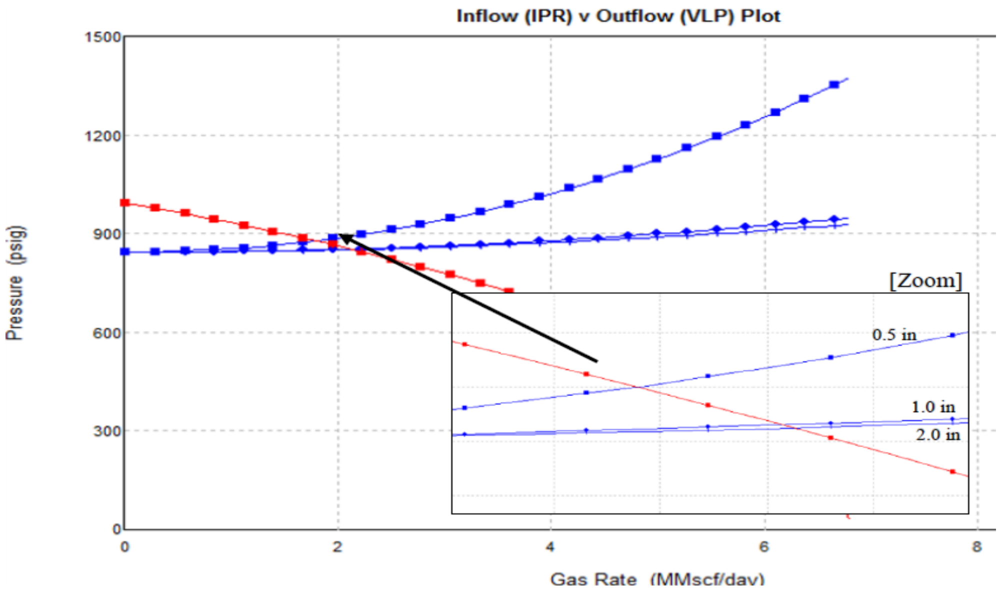

Figure 13. Choke size analysis.

6. Conclusion

Dynamic nodal analysis technique allows to perform sensitivity analysis of future performance for gas condensate wells after a satisfactory match of the previous production performance is obtained. The major contribution of this study is that it provides a comprehensive analysis the well performance changes as a function of time when the production parameters are altered.

The variation of tubing size can be optimized until 3.92 inch to improve the production rate from 1.8 MMscf/d to 2.24 MMscf/d, which is unprofitable due to production increment. However, changing tubing size is not economically in such well completion.

The well head pressure and choke size should be controlled to achieve and maintain the critical production flow rate. These two factors are able to predict how far each valve will open under current reservoir conditions to achieve optimum performance.

It is demonstrated that the skin factor has a large influence on the production performance and it is shown that the reduce of skin factor can improve the fluid flow without restrictions due to condensate banking.

Last not least, water gas ratio does not effectively affect the production performance of such reservoir characteristics. While increasing gas condensate ratio improved the well deliverability reduces the hydrostatic pressure gradient as well as the slip velocity.

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APPENDIX A: Well production data

W1 well production data shown in Table B.1 below from June 2002 until January 2005.

Table A.1: Well 1 production data [17]

Date	Gas Production (MMscf)	Condensate Production (bbl)	WHP (psi)
Jun-02	0	0	1,590
Jul-02	94	691	1,595
Aug-02	164	1183	1,595
Sep-02	219	1587	1,595
Oct-02	342	2491	1,519
Nov-02	508	3698	1,428
Dec-02	664	4833	1,390
Jan-03	829	6021	1,329
Feb-03	995	7230	1,312
Mar-03	1,089	7,927	1,278
Apr-03	1,217	8,854	1,228
May-03	1,334	9,716	1,193
Jun-03	1,438	10,464	1,160
Jul-03	1,540	11,204	1,120
Aug-03	1,646	11,790	1,100
Sep-03	1,752	12,548	1,070
Oct-03	1,851	13,254	1,050
Nov-03	1,932	13,787	1,030
Dec-03	2,021	14,400	1,010
Jan-04	2,099	14,946	989
Feb-04	2,167	15,408	977
Mar-04	2,240	15,940	956
Apr-04	2,304	16,417	940
May-04	2,356	16,811	918
Jun-04	2,414	17,235	879
Jul-04	2,443	17,784	865
Aug-04	2,485	18,003	855
Sep-04	2,504	18,269	843
Oct-04	2,532	18,396	821
Nov-04	2,566	18,609	800
Dec-04	2,621	18,842	781
Jan-05	2,742	19,954	765