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PRODUCTION OPTIMIZATION YIELDS NEW INSIGHTS ON FENCHUGONJ GAS FIELD

Md. Bashirul Haq, Edmond Gomes and Mohammad Tamim

Department of PMRE, BUET, Dhaka

ABSTRACT

Overall performance of a well drilled into a reservoir depends on a number of factors including reservoir pressure, well configuration and surface facilities. By applying nodal analysis technique performance of a well can be optimized. Nodal analysis technique identifies each component as a resistance in the system starting from reservoir to the outlet pressure of the separator. It allows sensitivity study of each component and optimizes the overall performance of the production system. Production capacity of the well # 2 of the Fenchugonj Gas Field has been optimized using nodal analysis technique. At the same time different sensitivity studies have been performed to determine the effect of different system components. This study finds the optimum production rates of the well # 2 at different operating conditions. This study also recommends operating range of various system components for optimum production and performs sensitivity analysis of system component.

Keywords: Nodal analysis, production optimization, IPR, and OPR

1. INTRODUCTION

Fenchuganj structure was first delineated in 1957 by Pakistan Petroleum Limited (PPL) using a single fold seismic survey. A well was drilled on March 1960 and terminated at 8000 ft on April 1960. The well turned out to be a dry hole.

During 1979 to 1981 field seasons, Prakla Seismos carried out multifold seismic survey on behalf of Petrobangla. German Geological Advisory Group interpreted the data and a comprehensive picture of an anticline was obtained. A location was selected and the well was spudded in January 1985. The well was drilled up to 16329 ft in November 1986.

Four different zones were selected for DST (Drill Stem Test) on the basis of available well logs and drilling information. The first zone (3064 m – 3085 m) produced initially waxy oil with huge water and subsequently only water. Rest of the zones turned out to have commercial gas deposits.

The geology of Fenchuganj gas field is similar to that of other fields situated in Surma Basin. The field is located close to the eastern margin of the basin and surrounded by Kailastilla to north, Beani Bazar to the east and Rashidpur to the south.

Fenchuganj anticline is higher than Jalalabad, Kailastilla and Beani Bazar structure with reference to the possible prominent reflector i.e. the upper marine shale. Previously PPL defined this structure as a simple anticline. But present data suggests it to be an overthrusted assymetrical anticline with a steeper dip in the east. Maximum area obtained from structural map drawn on upper marine shale is about 16 km long and 3.5 km wide. Like other major gas fields, the reservoir consists of BokaBil formation of Miocene age. Well #2 has not been produced yet. But Petrobangla has plans to produce this well in near future.

2. NODAL ANALYSIS

Nodal Analysis is the method for analyzing any well, which will allow determination of the producing capacity for any combination of components. This method may be used to determine locations of excessive flow resistance or pressure drop in any part of the system.

The success of Nodal Analysis method, however, depends on the use of appropriate correlation and equations while analyzing inflow performance relationship (IPR) and outflow performance relationship (OPR).

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

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

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At a particular time in the life of the well, there are always two pressures that remain fixed and are not function of flow rate. One of these pressures is the average reservoir pressure P_r and the other is the system outlet pressure, usually the separator pressure.

Once the node is selected, the node pressure is calculated from both directions starting at the fixed pressures.

Inflow to the node: P_r - ΔP (upstream components) = P_{node}

Outflow of the node: P_{scp} + ΔP (down stream components) = P_{nodc}

The pressure drop, ΔP, in any component varies with flow rate q. Therefore, a plot of node pressure versus flow rate will produce two curves of Inflow and outflow, the intersection of which will give the conditions satisfying requirements 1 and 2. The procedure is illustrated graphically in Figure 1.

The effect of a change in any of the components can be analyzed by recalculating the node pressure versus flow rate using the new characteristics of the component that was changed. If a change was made in an upstream component, the outflow curve will remain unchanged. However, if either curve is changed, the intersection will be shifted, and a flow capacity and node pressure will exist. The curves will also be shifted if either of the fixed pressures is changed, which may occur with depletion or a change in separation conditions.

3. INFLOW AND OUTFLOW PERFORMANCE RELATIONSHIP CURVES

3.1 Inflow Performance Relationship Curves

The pressure difference between the average reservoir pressure (P_r) and the stabilized bottomhole flowing pressure (P_{bhf}) is referred to as the pressure drawdown. The drawdown pressure can be expressed as:

Drawdown Pressure = P_r - P_{bhf} ...(1)

The relationship between the flow rate and the bottomhole flowing pressure is referred to as the IPR. This relationship is the starting point in the analysis of well behavior.

There are numerous, widely used well inflow performance models available in PIPESIM for WINDOWS. These models are well productivity index (oil and gas), Vogel's equation, Fetkovich's equation, Jones's equation, pseudo steady state equation and back pressure equation. In this model back pressure equation is used. The back pressure equation constant (C) represents the reservoir rock and fluid properties, flow geometry and transient effects. The unit for 'C' is MMSCF/D/(psi**2)n. The back pressure equation exponent (n) accounts for turbulence and is dimensionless.

3.2 Outflow Performance Relationship Curves

All of the components upstream of the node comprise the inflow section, while the outflow section consists of all the components downstream of the node. A relationship between flow rate and pressure drop of all downstream section is referred to as the outflow performance relationship (OPR).

3.3 IPR Curve of Fenchugonj Well # 2 (Upper Zone)

The IPR curve is constructed by the PIPESIM software using the data that is shown in Table 1. Figure 2 shows the inflow performance relationship curve for Fenchugonj well # 2 (upper zone) with an average reservoir pressures 2925. The values of C and N are 0.0000011483 and 0.99984 respectively. Table 1 represents the Production Test data.

4. PHASE ENVELOPE

A phase envelope of Fanchugonj gas field has been drawn by the PIPESIM software using Table 2. In Figure 3, line AB is the bubble point curve and line BC is the dew point curve. The critical point B, is the intersecting point of two curves. The values are 700 psia and -115^{o}F. Point b is the criocondenbar, that symbolizes the maximum pressure at which liquid and vapor may subsist in equilibrium. Point B is the cricondentherm, the maximum temperature at which liquid and vapor may co-exist in equilibrium. The criocondenbar is 700 psia and cricondentherm is -115^{o}F.

5. PRESSURE LOSSES IN A PRODUCING WELLS

A series of pressure drops occur when reservoir fluid moves from the reservoir to surface through wellbore, tubing string and process facilities. The system has been divided into five major components for better understanding the pressure losses. Figure 4 shows the pressure losses in a producing well. These are summarized as follows:

(i) the pressure loss in the producing formation required to get the fluid into the wellbore;

(ii) the pressure loss in the tubing string from the bottom of the tubing to the surface which includes all downhole chokes, restrictions, etc. within the tubing string and the wellhead;

(iii) the surface choke;

(iv) the surface flow lines from the choke to the separator; and

(v) the separator (or separators).

Adding up all five pressure losses give the total pressure loss that occurs between the reservoir and the stock tank or sales line. The design pressure drop can be determined when any four of the pressure drops are known. In our country, the separator pressure is fixed depending upon the flow rate. Therefore, any trial and error solution of any of the other losses will require beginning the calculation either in the reservoir, or at the separator, or both.

6. SYSTEMS ANALYSIS AS APPLIED TO PRODUCING WELLS

The effect of various changes in one component of the system has an overall effect on the entire system. Typical wells are selected in order to show the effect of various changes, such as: separator pressure; surface

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choke size, tubing size and average reservoir pressure. The effect on production rate of various restrictions, such as surface chokes, downhole chokes, safety valves, and completion restrictions, can all be properly accounted for. The analysis will show whether or not the particular well is limited in its production rate by the reservoir's ability to give up fluids or by the producing system.

6.1 Effect of Separator Pressure

The selection of various parameters, such as separator pressure is related to economics. For example, the selection of the separator pressure in a gas-lift system is extremely important in determining compressor horsepower (HP). Separator pressures of from 300 to 1100 psi may have very little effect on the flow rate from a low productivity well, but may have a very decisive effect of the flow rate of high productivity wells. A complete systems analysis will show the effect of varying the separator pressure on compressor HP and, hence, the economic feasibility of buying more or less HP. The various profit indicators such as pay out, rate of return, net present value etc, can be used to make the decision.

In analyzing these wells, it is important to see the effect of different separator pressures while maintaining everything else constant. Input data of this case study is presented in Table 3. Several computer runs were made varying the separator pressure from 300 to 1100 psia. At the same time average reservoir pressure were also varied from 1400 psia to initial reservoir pressure. The result of this case study is in Figures 5 and 6. The change in separator pressure has a significant effect on the flow rate.

6.2 Results of Separator Pressure of Fenchugonj Well # 2

Figure 5 shows the variation of average reservoir pressure with outlet pressure of Fenchugonj Well # 2. At average reservoir pressure of 2925 psia and outlet pressure of 1100 psia, the gas flow rate is 24.9 mmscfd. Gas flow rate can be calculated at average reservoir pressure range between 1400 psia and 2925 psia and outlet pressure range from 300 psia to 1100 psia. The optimum gas production rate at different reservoir pressures are tabulated in Table 4. The table shows the optimum gas rate and pressure at node analysis point (bottom hole) for the given separator pressure of 1100 psia. The optimum production rate of Fenchugonj Well # 2 is 24.9 mmscfd at reservoir 2925 psia.

A case study is also made when there is no SCSSV present at the tubing. *It indicates that there is a pressure loss across the SCSSV.* SCSSV has a prominent effect on gas rate in the well # 2. Removing SCSSV will cause a flow increase by about 4.82 %. The pressure losses across the SCSSV of the Fenchugonj well # 2 is calculated and presented in Figure 6. The optimum gas production rate at different reservoir pressures are calculated and presented in Table 5. The optimum gas rate and pressure at node analysis point are shown in Table 5.

6.3 Effect of Surface Wellhead Choke

The production rate largely depends on the surface chokes. The easiest way of increasing the flow rate is to increase the opening of the choke. The input data of this case study is presented in Table 6. Several computer runs are made varying the average reservoir pressure from 1400 psia to initial reservoir pressure and choke size 0.20 inch to 1.00 inch keeping all other parameters constant.

6.4 Results of Surface Wellhead Choke of Fenchugonj Well # 2

The variation of average reservoir pressure with choke size of Fenchugonj well # 2 is shown Figure 7. The present bean size of Fenchugonj well # 2 is 0.2366 inch. Bean size can be calculated from upstream and downstream pressure at any time. Calculation procedure is shown in Appendix A. The result of this case study is also shown in Table 7. Table 7 contains optimum gas rate, reservoir pressure and node point pressure. The values of the optimum gas rates at different bean sizes are presented in Table 8. Only optimum gas rate at bean size 1.00 inch is shown in the table. Other optimum gas rate at any reservoir pressure and bean size can be found from the Figure 7. At average reservoir pressure of 2925 psia and bean size of 1.00 inch, the optimum gas flow rate is 24.1 mmscfd. The optimum production rate of the Fenchugonj well # 2 is 24.1 mmscfd at reservoir pressure 2925 psia.

A case study is also made when there is no SCSSV present at the tubing. *It indicates that there is a pressure loss across the SCSSV.* SCSSV has a prominent effect on gas rate in the well # 2. Removing SCSSV will cause a flow increase by about 4.82 %. The pressure losses across the SCSSV of the Fenchugonj well # 2 is calculated and presented in Figure 8 The optimum gas production rate at different reservoir pressure are calculated and presented in Table 9. The values of the optimum gas rate at different bean size are shown in Table 10.

7. CONCLUSIONS

(i) Separator pressure may effect the gas rate within the range 0 to 26.70 mmscfd in the Fenchugonj Well # 2. Above the production rate 26.70 mmscfd, there is no effect of change of separator pressure on gas rate. Separator pressure was changed from 300 psia to 1100 psia.

(ii) SCSSV has a prominent effect on gas rate. Removing SCSSV will cause a flow increase by about 4.82 %.

(iii) The increase of bean size can considerably effect the optimum production rate. Significant additional production rate may be achieved in these wells after the bean size increase.

(iv) The optimum production rate under the initial operating condition of the Fenchugonj Well # 2 is 24.90 mmscfd.

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8. RECOMMENDATIONS

(i) Bean size of the surface wellhead chokes of the well should be exactly measured to find out the up to date values of the optimum rate.

(ii) A good reservoir simulation model should be developed for future optimization of the field.

9. REFERENCES

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10. ACRONYMS

DST	Drill Steam Test
NA	Node Analysis
HP	Horsepower
IPR	Inflow Performance Curve
OPR	Outflow Performance Curve
PPL	Pakistan Petroleum Limited
SCSSV	Surface Critical Sub-surface Safety Valve

11. NOMENCLATURE

q	Flow Rate
P_R	Reservoir Pressure
P_{node}	Node Pressure
P_{sep}	Separator Pressure
ΔP	Pressure Drop

Table 1 Production Test data of Fenchugonj well # 2 (Upper Zone)

Initial Res. Pres. (psia)	2926	
Av. Res. Pres. (psia)	2925	
Av. Res. Temp. (^oF)	157	
	BHP (psia)	Gas Rate (mmscf)
Flow Test 24/64" Choke	2829	9.62
Flow Test 32/64" Choke	2818	14.73
Flow Test 40/64" Choke	2715	20.64
Flow Test 48/64" Choke	2647	25.17

Table 2 Gas Composition of Fenchugonj Well # 2 (Upper Zone)

Components	**Mole (%)**
Nitrogen	0.10
Carbon dioxide	0.27
Methane	98.55
Ethane	1.07
Propane	0.03
Iso-Butane	Nil
n-Butane	Nil
Iso-Pentane	Nil
n-Pentane	Nil
Hexane	Nil

Table 3 Input Data for Separator Pres Fenchugonj Well # 2

Nodal Analysis Point		Wellhead
Maximum Gas Rate(mmscfd)		35
Inflow Sensitivity	Av. Res. Pres (psia)	2925-1400
Outflow Sensitivity	Separator Outlet Pres (psia)	300-1100

Table 4 Optimum Gas Flow Rate at Separator Pres 1100 psia

Res. Pres (psia)	Optimum Gas Rate (mmscfd)	Pres at NA Point (psia)
2925	24.9[a]	2660
2800	23.5	2555
2700	22.4	2458
2600	21.2	2369
2500	20.0	2272
2400	18.8	2175
2300	17.5	2086
2200	16.2	1989
2100	15.0	1900
2000	13.6	1811
1900	12.4	1722
1800	10.9	1633
1700	9.6	1553
1600	8.0	1472
1500	6.4	1399
1400	4.2	1326
a. Present flow rate from the well.		

Table 5 Optimum Gas Flow Rate at Separator Pres 1100 psia (Without SCSSV)

Reservoir Pres (psia)	Optimum Gas Rate (mmscfd)	Pres at NA Point (psia)
2925	26.10	2660
2800	24.50	2531
2700	23.40	2450
2600	22.00	2353
2500	20.8	2264
2400	19.5	2167
2300	18.2	2078
2200	16.80	1981
2100	15.50	1884
2000	14.10	1803
1900	12.80	1722
1800	11.40	1633
1700	9.90	1545
1600	8.20	1463
1500	6.40	1391
1400	4.50	1326

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Table 6 Input Data for Surface Wellhead Choke Fenchugonj Well # 2

Nodal Analysis Point		Bottomhole
Maximum Gas Rate(mmscfd)		35
System Outlet Pres (psia)		1100
Inflow Sensitivity	Av. Res. Pres (psia)	2925 - 1400
Outflow Sensitivity	Bean Size (inch)	0.20-1.00

Table 7 Optimum Gas Flow Rate at Bean Size 1.00 inch

Res Pres (psia)	Optimum Gas Rate (mmscfd)	Pres at NA Point (psia)
2925	24.90 [a]	2671
2800	25.50	2558
2700	22.30	2456
2600	21.20	2364
2500	19.90	2261
2400	18.70	2175
2300	17.60	2084
2200	16.20	1992
2100	15.00	1895
2000	13.70	1814
1900	12.40	1722
1800	10.90	1631
1700	9.50	1550
1600	8.00	1464
1500	6.4	1394
1400	4.40	1329

a. Present flow rate from the well.

Table 8 Optimum Gas Flow Rate at Initial Reservoir Pressure (2925 psia)

Bean Size (inch)	Optimum Gas Rate (mmscfd)
0.2000	2.00
0.3000	4.50
0.4000	7.80
0.5000	11.50
0.6000	15.40
0.7000	18.90
0.8000	21.60
0.9000	23.60
1.0000	24.90 [a]

a. Present flow rate from the well.

Table 9 Optimum Gas Flow Rate at Bean Size 1.00 inch (Without SCSSV)

Reservoir Pressure (psia)	Optimum Gas Rate (mmscfd)	Pressure at NA Point (psia)
2925	26.10	2655
2800	24.60	2542
2700	23.30	2445
2600	22.00	2353
2500	20.70	2251
2400	19.50	2164
2300	18.30	2078
2200	16.90	1981
2100	15.50	1889
2000	14.30	1803
1900	12.90	1711
1800	11.40	1631
1700	9.90	1539
1600	8.30	1464
1500	6.60	1394
1400	4.70	1328

Table 10 Optimum Gas Flow Rate at Initial Pres (2925 psia) (Without SCSSV)

Bean Size (inch)	Optimum Gas Rate (mmscfd)
0.2000	2.00
0.3000	4.10
0.4000	7.80
0.5000	11.60
0.6000	15.50
0.7000	19.30
0.8000	22.20
0.9000	24.40
1.0000	26.10

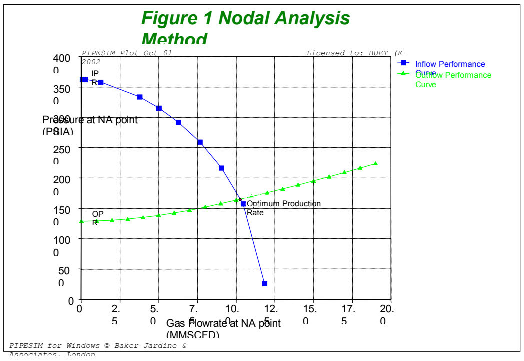

Figure 1 Nodal Analysis Method

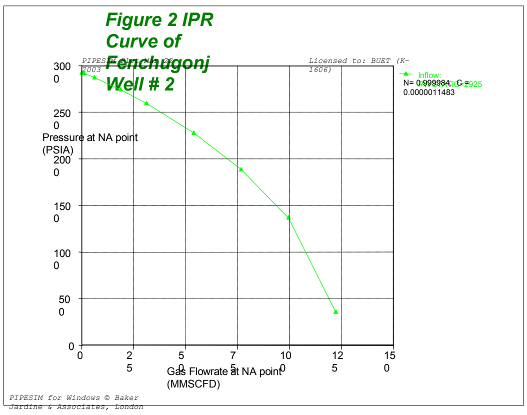

Figure 2 IPR Curve of Fenchugonj Well # 2

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Figure 3 Phase Envelope Plot of Fenchugonj Gas Field (Well # 2, Upper Zone)

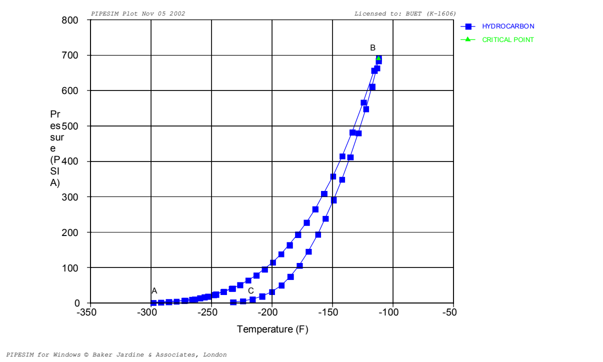


Figure 4 Pressure Losses in a Producing Well

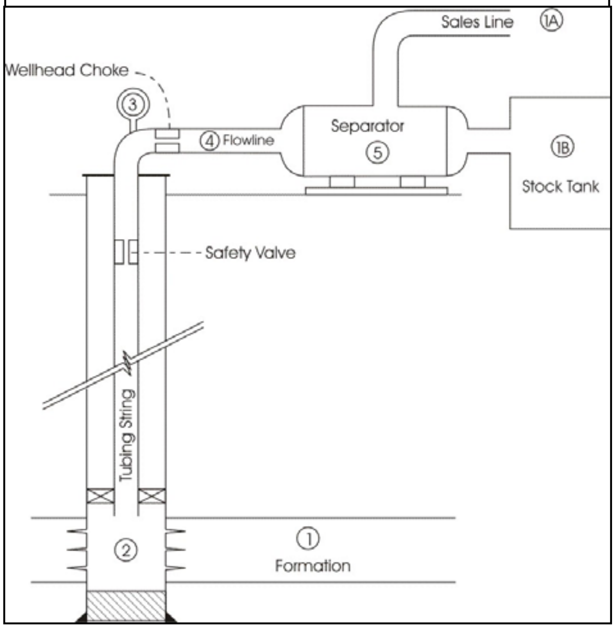


Figure 5 Effect of Separator Pressure

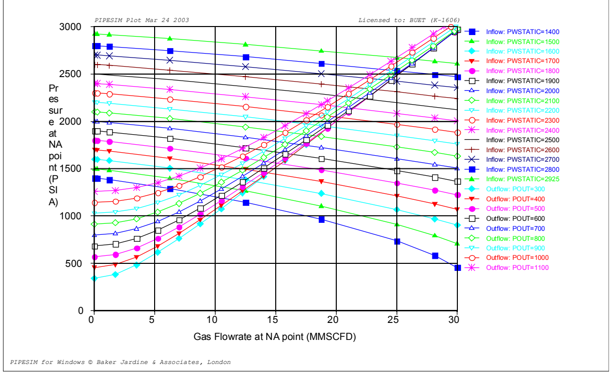


Figure 6 Effect of Separator Pressure (Without SCSSV)

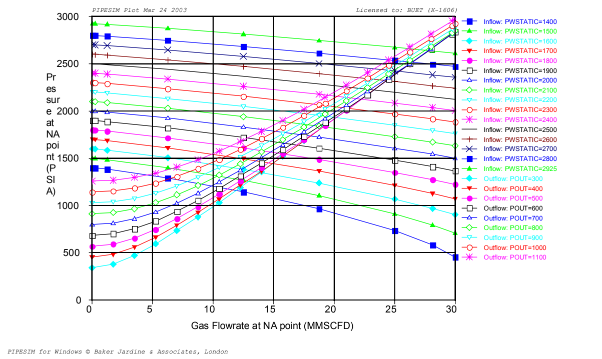


Figure 7 Effect of Surface Wellhead Choke

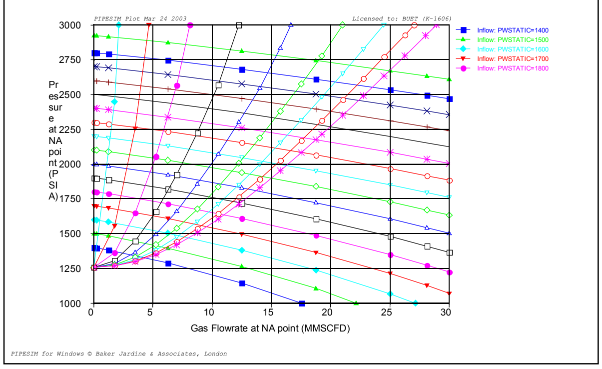
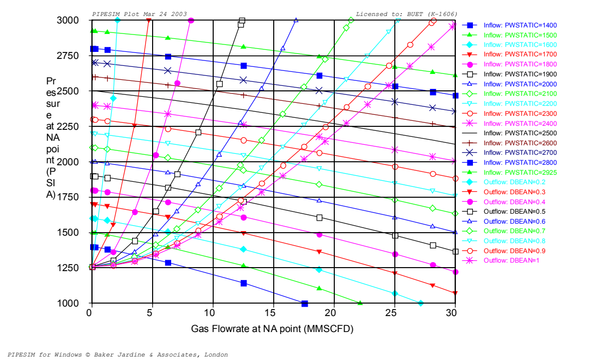


Figure 8 Effect of Surface Wellhead Choke (Without SCSSV)



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