LONG TERMOPTIMIZATION OF GAS WELL PRODUCTION

Ehsan Khamehchi ,Syyed Vahid Yasrebi , Seyyed Mohammad Chashi
Faculty of Petroleum Engineering, Amirkabir University of Technology (Tehran Polytechnic), IRAN.

ABSTRACT: *Well performance analysis plays a crucial role in the management of producing fieldsand and optimizing the productivity of a gas well. These issues are divided into two types: Initially, the behavior of the well in designing a completion for a new well during a short term where we need to assess the effect of the form of completion, and initial production condition on well productivity.The second issue is related to the long-term behavior of the well where the productivity changesare considered and predicted as the reservoir pressure declines.This study uses the reservoir model for this meansand carries out sensitivity analysis to evaluate its impact for current and future wellbore optimization and improve well performance by lowering wellhead pressure and similarly to find optimum time to change the tubing size andthus make it possible to observe the longevity of the well.*

Keywords: Gas Production Optimization, Nodal Analysis, ReservoirPerformance, WellborePerformance, LiquidLoading, CriticalRate, ErosionalVelocity, Future IPR, ReservoirModel, Long-Term Optimization

1-THEORITICAL BACKGROUND

The main objective of this study was to optimize the production rates, and to maintain the gas production rate plateau for the longest period to ensure the delivery of gas to the pipeline as per the daily contracted quantity. Before optimization of the gas production operation, a system performance model should be made up to investigate different well completion and production scenario alternatives so single-well reservoir simulation models were constructed. In addition, production constraints were chosen to represent the operating conditionsexpected in the field.

This paper will first describe the process in more detail, and then show how the process has been applied to gas production systems. These applications have been extremely important in helping make business investment decisions as well as better managing daily operations. This integrated modeling has three main components:

1) Nodal Analysis,

2) Flow Constraints,3) reservoir components. The primary conceptions areinitially introduced.

1-1-RESERVOIR INFLOW PERFORMANCE

There must be a pressure differential fromthe reservoir to the wellbore at the reservoir depth. If the wellborepressure is equal to the reservoir pressure, there can be no inflow. If the Systems Nodal Analysis wellbore pressure is zero, the inflow would be the maximum possibleAbsolute Open Flow (AOF). For intermediate wellbore pressures, the inflow will vary. For each reservoir, there will be a unique relationship between the inflow rate and wellbore pressure.

A number of equations can be used to generate an inflow curve of gas rate vs. P_{wf} for a gas well if all the preceding data is known. However, the data often required to use this equation are not well known, and a simplified equation is used to generate an inflow equation for gas flow that utilizes well test data to solve the indicated constants.

$$q_0 = c\left(\overline{p}_R^{\ 2} - p_{wf}^{\ 2}\right)^n$$

Where P_R is Reservoir Pressure, P_{wf} is wellbore fluid pressure, q is flow rate and C, n are Fetkovich parameters.

This equation is often called the back pressure equation with the radial flow details of Equation 1 absorbed into the constant C .The exponent n must be determined empirically [1].The values of Cand n are determined from well flow tests. At least two test rates are required,since there are two unknowns, C and n, in the equation, but four test rates are recommended to minimize the effects of measurement error.If more than two test points are available, the data can be plotted on log-log paper and a least squares line fit to the data, to determinen and C.

1-2-TUBING PERFORMANCE CURVE

The outflow or tubing performance curve (TPC) shows the relationship between the total tubing pressure drop and a surface pressure value, with the total liquid flow rate. The tubing pressure drop is essentially the sum of the surface pressure, the hydrostatic pressure of thefluid column (composed of the liquid “hold up” or liquid accumulatedin the tubing and the weight of the gas), and the frictional pressure loss resulting from the flow of the fluid out of the well. For very high flow rates there can be an additional “acceleration term” to add to the pressure drop but the acceleration term is usually negligible compared to the friction and hydrostatic components [2].

Notice that the TPC passes through a minimum to the right of the minimum, and the total tubing pressure loss increases due to increased friction loss at higher flow rates. The flow to the right of the minimum is usually in the mist flow regime that effectively transports small droplets of liquids to the surface .At the far left of the TPC the flow rate is low and the total pressure loss is dominated by the hydrostatic pressure of the fluid column brought about by the liquid hold up, or that percent of the fluid column occupiedby liquid. It is common practice to use the TPC alone, in the absence of up-to-date reservoir performance data, to predict gas well liquid loading problems. Therefore, you can just select the flow rate you are measuring currently and see if it is in a favorably predicted portion of the TPC or not, regardless of having the reservoir inflow curve.With reservoir performance data, however, intersections of the tubing outflow curve and the reservoir inflow curve allow a prediction where the well is flowing now and into the future if reservoir future IPR curves can be generated [3,4].

1-3-NODAL EXAMPLE

The Systems Nodal Analysis can be used to study the effects of a wide variety of conditions on the performance of gas wells.The effects of tapered tubing strings, perforation density and size, formation fluid properties, and fluid production rates are just a few of the many parameters that the technique can analyze. Only a few sample problems vary tubing size and surface pressure with different inflow expressions. The Nodal Analysis is used to examine the effects of variables that you have control of such as number of perforations, perhaps surface pressure, and tubular sizes if designing a well or considering tubing resize [5].

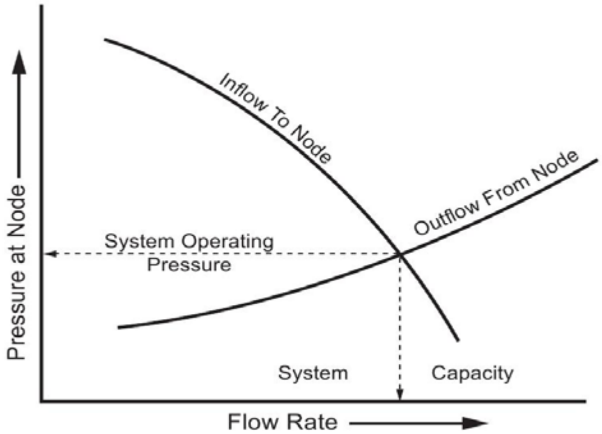

Figure 1-Nodal Analysis by using IPR and TPC

1-3-1-NODAL EXAMPLE—TUBING SIZE

From the preceding analysis, it is clear that the size (diameter) of the production tubing can play an important role in the effectiveness with whichthe well can produce liquids. Larger tubing sizes tend to have lower frictional pressure drops due to lower gas velocities that in turn lowerthe liquid carrying capacity [6]. Smaller tubing sizes, on the other hand, have higher frictional loss but also higher gas velocities provide better transport for the produced liquids.In designing the tubing string, it then becomes important to balance these effects over the life of the field. To optimize production it may benecessary to reduce the tubing size further on in the life of the well.

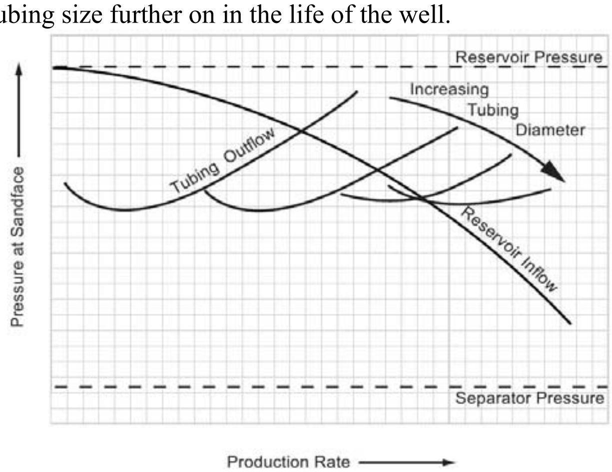

Figure 2-Effect of Tubing Size in Nodal Analysis

1-3-2-NODAL EXAMPLE—SURFACE PRESSURE EFFECTS

Frequent use of compression to lower surface pressure and production sales line pressure dictates the surface pressure at the wellhead, which may be beyond the control of the field production engineer. Some installations, however, have compressor stations near the sales line to maintain low pressures at the well head while boosting pressure to meet the levels of the sales line. Other methods to lower surface pressure are available to the engineer or technician. Figure-3 shows various tubing performance curves plotted against an IPR curve. The TPC curves or the J-curves are all computed usingthe same tubing size but with various tubing surface pressures.Note that reducing the surface pressure has the effect of lowering the tubing performance curve. Lower pressures are beneficial until the steep portion of the gas deliverability curve is reached and then productionreturns diminish. For instance, the drop in surface pressure from 100 topsi shows only a small gain in production because the deliverability curve is steep in this portion of the curve near the maximum flow rate or the AOF.

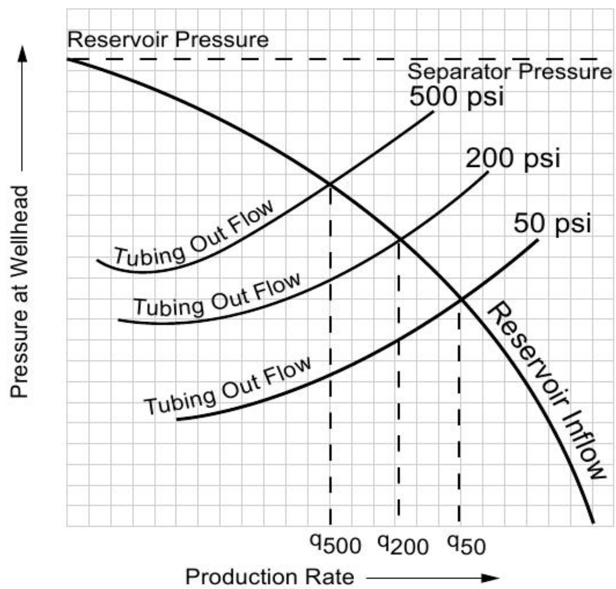

Figure 3-Effect of Wellhead Pressure in Nodal Analysis

1-4-Flow constraints

The production of hydrocarbons from underground reservoirs is associated mainly with the flow of a liquid (oil and water), gas (natural gas) or solid (sand). This flow situation is essentially one of a liquid-gas, two-phase flow with entrained solid particles.

The presence of a liquid phase during gas production has long been recognized as detrimental to well flow. In gas condensate reservoirs, as the gas in the reservoir travels towards the wellbore, it encounters decreasing pressures and as a result, a liquid hydrocarbon phase (condensate) is formed below the dew point pressure. Furthermore, as the gas travels to the surface, the pressure and temperature decreases causing more liquid to drop out of the gas phase. As long as the gas flow rate is sufficiently high to maintain annular mist flow, these liquids are lifted out of the well.

However, when the tubing velocity becomes too small to maintain steady flow conditions, liquid accumulation in the well becomes the problem. The problem can be attributed to a low gas production rate due to low bottom hole pressure in a mature reservoir and/or low gas relative permeability for given conditions. The flow regime in the wellbore switches from annular mist flow to churning or slug flow and the liquid lifting capacity of the gas decreases dramatically. The flow rate for this switch is called the critical flow rate [7].

It may be better to change tubing to one size too small than one size to large. In this manner, the well will at least flow smoothly without slugging. Although this outlook may not be altogether wrong, the thought process should incorporate nodal analysis to address the interaction of fluid loading and frictional loss and how they are related to production velocities. Even the most experienced individuals might be occasionally surprised.

Conversely, the erosional velocity represents the upper limit of gas velocity in a pipeline. As the gas velocity increases, vibration and noise result. Higher velocities also cause erosion of the pipe wall over a long period of time.

1-4-1CriticalRate

Regardless of initial well productivity, wells in the Ansell gas condensation field eventually liquid load due to declining reservoir pressure or low gas permeability. To effectively plan and design for gas well liquid loading problems [8], it is essential to be able to accurately predict when a particular wellmight begin to experience excessive liquid loading. The relatively simple "critical velocity " method is presented to predict the onset of liquid loading.This technique was developed from a substantial accumulation of welldata and has been shown to be reasonably accurate for vertical wells.The method of calculating a critical velocity will be shown to be applicable at any point in the well. It should be used in conjunction with methods of Nodal Analysis if possible [9].

$$q_{\min} = \frac{0.0676.P_{wh}.d_{tub}{}^{2}.(45-0.0031.P_{wh})^{0.25}}{(T_{wh}+460).Z.(0.0031.P_{wh})^{0.5}}$$

Where P_{wh} is wellhead pressure (psi), d_{tub} is tubing diameter (inch), γ_g is SG of gas and T_{wh} is wellhead temperature (F^{o}).

1-4-2-Erosional velocity

When the fluid flow in a pipe is disturbed due to a local change in direction, a velocity component normal to the pipe wall will be introduced, resulting in repeated impacts on the pipe wall. Erosion damage of the pipe is caused by the repeated bombardment of liquid and solid particles. The erosion damage is enhanced by increasing the production capacity of a given flow system (Le., increasing flow velocity). In order to avoid potential erosion problems, most oil companies have been limiting their production rate by reducing the flow velocity to a level below which it is believed erosion does not occur.This limitation of flow velocity is calculated using the recommended empirical equation [10].

$$\left(q_{sc}\right)_e = 3.056 \times u_e.A.\left(\frac{P}{ZT}\right)$$

Where A is tubing area (ft./sec), P is wellhead pressure (psi), T is wellhead temperature and u_e is erosion velocity calculated by the equation below.

$$u_e = \frac{C}{\sqrt{\rho}}$$

Where ρ is SG of gas and C is constant coefficient between 75 to 150

1-5-PREDICTING FUTURE IPR's FOR OIL WELLS

Regarding the future IPR curve with backpressure equation for predicting backpressure curves at different shut-in pressures (at different times), the following approximation from Fetkovitch [11] can be used for future inflow curves. In this method, only C would change as long as reservoir depletion:

$$C_F = C_P \frac{\left(\mu.Z\right)_F}{\left(\mu.Z\right)_P}$$

Where $\left(\mu.Z\right)_P$ fluid properties are in present time and $\left(\mu.Z\right)_F$ is the same parameter in the future which should be calculated by PVT calculations as a function of reservoir predicted pressure, we need to determine future pressure with the reservoir model.

1-5-1-Reservoir Model

If the objective of the integrated asset model is only to optimize performance for the current conditions, the reservoir component is not included, and the facility program runs simultaneously with the well program for each well. This calculation process is usually completed in seconds to a fraction of a minute, compared to several minutes to an hour for including the reservoir component.

The reservoir component is coupled to the well component. A program that runs the facility component begins calculations, and because the well and reservoir components are coupled, the programs for these components begin calculations as directed by the facility program. Figure 1 shows a simplified representation of an integrated asset model application. If the objective is to make predictions over time, then the reservoir component is required and the reservoir program calculates future performance to the next time step, typically one month into the future. The facility and well programs have to perform calculations for the new time step, and the reservoir program must calculate future reservoir conditions for the next time step. The process is repeated until the end of the predictions.

Now the whole package is ready to form a modeling and optimizing algorithm.

2-Optimization algorithm

The above complications in depletion planning of gas fields are best handled through integrated modeling. This process couples engineering aspects of reservoir performance, well inflow rate from the reservoir, and well flow characteristics up the well. The reservoir component is often modeled by material balance for coupled reservoir compartments and multiple horizons. Is this research, reservoir simulation is utilized in the process. However, numerical simulation can slow down the computations. All of the engineering components are coupled through a common program. The objective of the algorithm project will dictate which of the components are to be modeled. For example, if the objective is to maximize daily plant liquid production, the reservoir component might not be included, and the plant program will be driving the process. If the objective is to assess compressor size and timing of implementation, the reservoir component will be required to assess the reserve growth

3. EXAMPLE APPLICATION

For the purpose of this project, the data sets were manipulated to run the program and the results are given in table 1 and a flow test is presented in table 2 to calculate IPR whichis shown in table 3.

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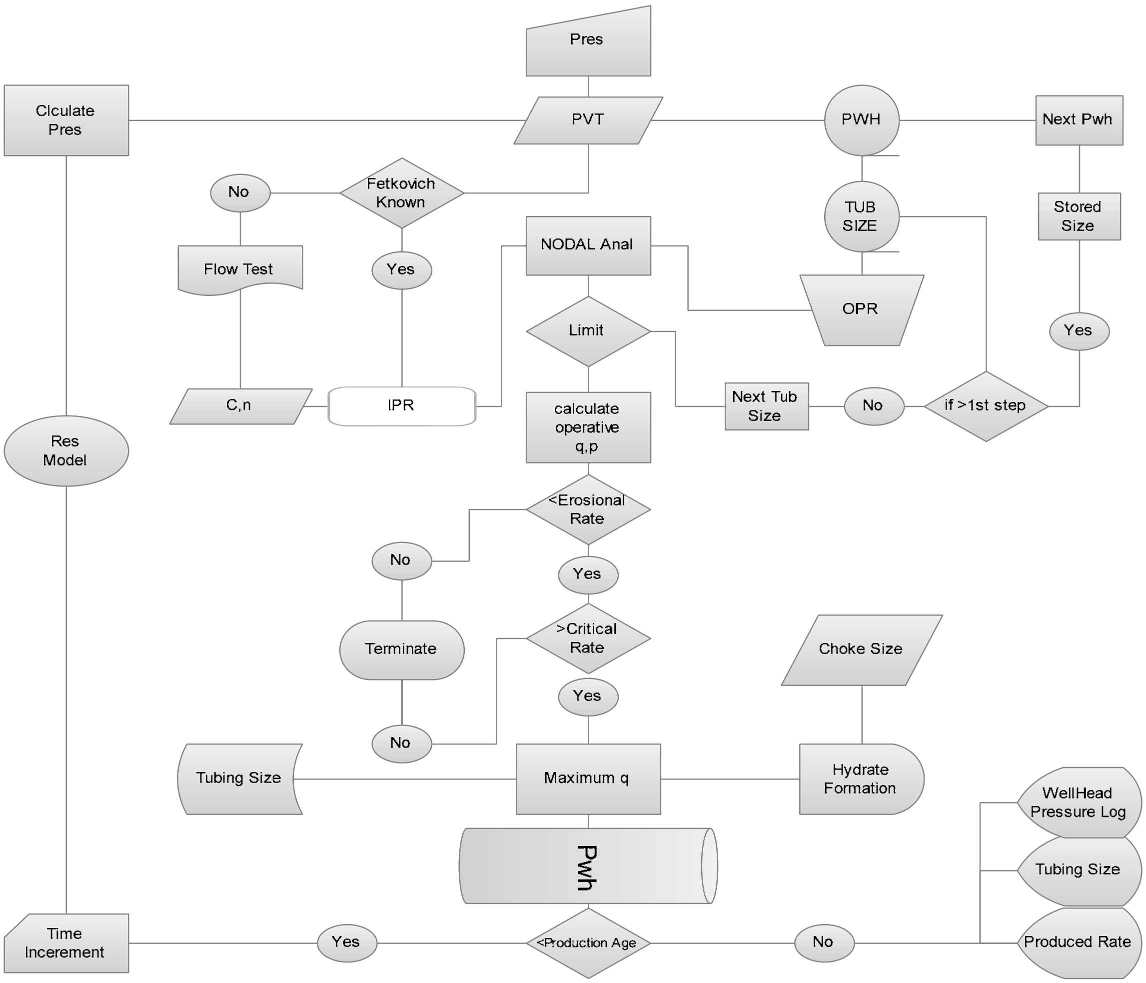

Figure 4-Integrated Algorithm

Table 1-Gas Well Data

Reservoir Pressure (Psig)	7198
Reservoir Temperature (F)	279
Water Cut (percent)	1.1
GOR (scf/stb)	855000

Table 2-Flow Test

Production Rate (MMscf/d)	Bottom hole Pressure (Psig)
16.656	6512
24.65	5674
23.985	4392
31.211	4842

Table 3-IPR parameters

C-constant in backpressure IPR model	1.79748871	Mscf/d-psi2n
n-exponent in backpressure IPR model	0.56886546	
AOF	43967.8625	Mscf/d

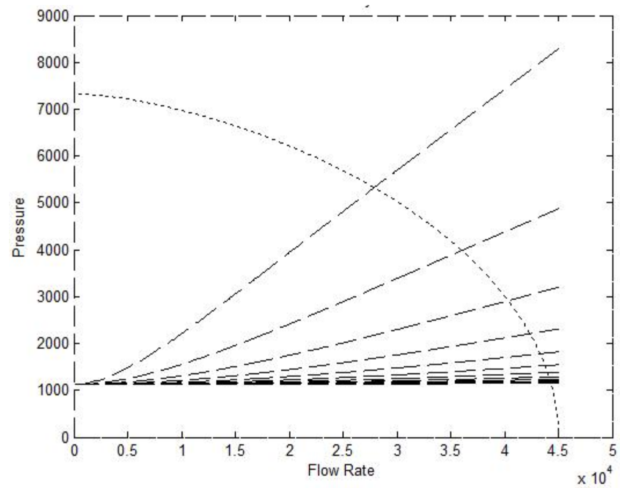

Figure 5-Nodal analysis with different tubing sizes

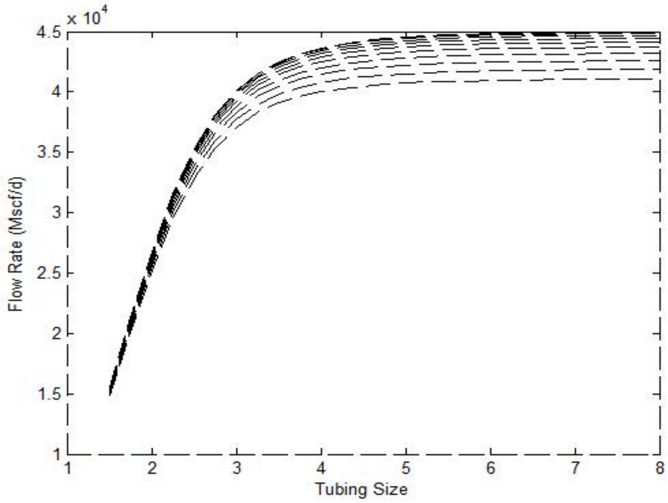

Figure 6-sensitivity analysis of tubing size

As shown in the algorithm, after nodal analysis, sensitivity analysis should be carried out as shown in figure 5-6 for tubing size and figure 7 for wellhead pressure.

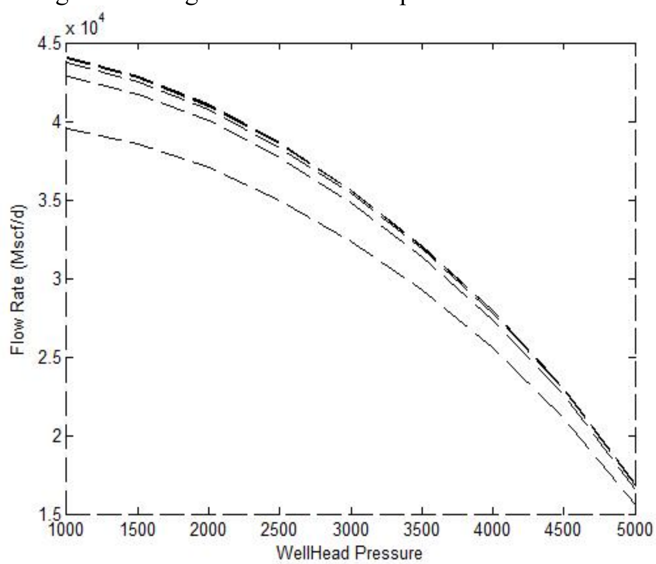

Figure 7-sensitivity analysis of wellhead pressure

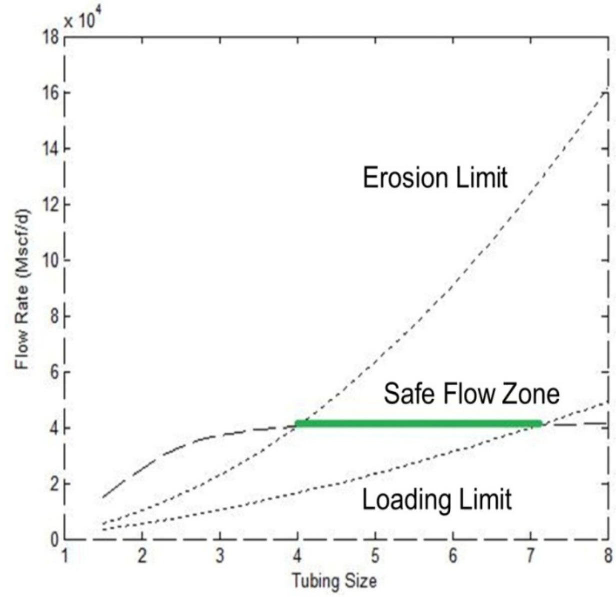

Figure 8-considering the flow constraints in sensitivity analysis

As previously mentioned, sensitivity analysis without considering flow constraints is making a huge mistake because it can change the desired response as shown in figure 8.

Finally, the whole body of the algorithm is repeated in new reservoir conditions predicted by the reservoir model which leads to new IPR in nodal analysis. Figure 9 shows tubing performance curves superimposed over some of these future IPR curves.

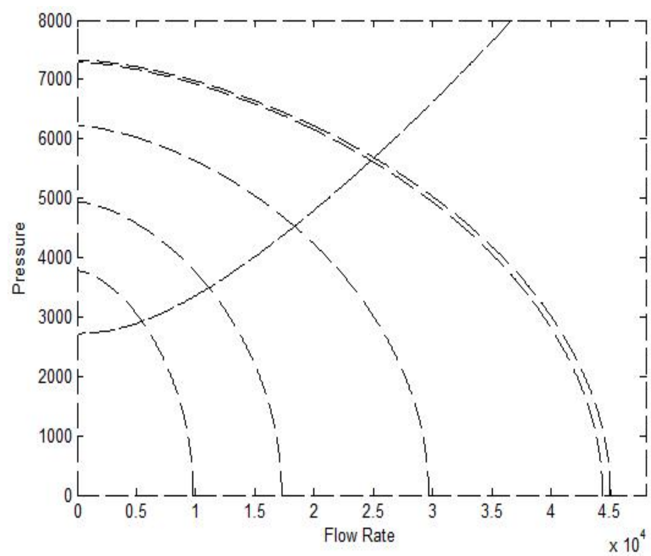

Figure 9-Future IPR role in nodal analysis

5-CONCLUSION

- This paper has presented an algorithm for modeling and planning several important and practical engineering practices involving the gas production which can be used for understanding gas field performance.

Table 4-Final Results of Application

Year	Tubing Size (inch)	Predicted Reservoir Pressure (psi)	Wellhead Pressure (psi)	Predicted Production Rate (Mscf/day)
1	6.5	7331.5332	2000	43880.58495
2	6.5	7280.8286	1800	44333.70292
3	6.5	7179.0205	1600	44144.62584
4	6.5	7086.6636	800	44450.33226
5	6.5	6908.2046	800	41759.51866
6	6.5	6673.4961	800	38397.56567
7	6.5	6218.3667	800	32794.93679
8	6.5	5996.7188	400	30141.01491
9	6.5	5778.812	400	27685.69586
10	6.5	5564.5083	400	25418.09898
11	6.5	5353.6582	400	23324.46499
12	6.5	5146.1396	400	21392.15829
13	6.5	4941.8384	400	19607.04726
14	6.5	4740.6328	400	17958.44803
15	6.5	4542.4224	400	16440.6341
16	6.5	4347.0933	400	15039.53973
17	6.5	4154.5342	400	13748.25705
18	6.5	3964.6313	400	12556.50361
19	6.5	3777.2847	400	11456.66829
20	6	3597.6298	400	11005.6167

- A component EOS model is used to represent the fluid behavior. The fluid model was based on matching the fluid behavior for an average recombined sample from the field.
- Gas flow main constraints are officially considered in the algorithm for management and alarming to reduce operational and avoid possible financial risk.
- Case studies were presented, involving the application of modeling by the introduced algorithm, and their benefits are increased.
- Gas production rate and reserves. Tune up algorithm with dynamic modeling future development of gas fields with reservoir model, optimizing production day-to-day reservoir conditions
- Flow characteristics through the gas gathering system, and flow through facility equipment (compressors, chokes, and separators) can be easily added to the algorithm.

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