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# Production Optimization of Gas Wells Using MBAL

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**Abstract:** *This project focuses on optimizing production of a gas well. The reservoir in this study involves a gas condensate reservoir. Gas condensate reservoirs behave in a complex manner as it introduces liquid condensate near the wellbore region which leads to significant decrease in productivity of the well. Liquid hold up is also an important issue to consider in a gas condensate reservoir as this could impact the wells productivity. Parameters such as tubing size, skin factor, condensate gas ratio, wellhead pressure and water gas ratio are used to implement a sensitivity analysis in Prosper. Based on the Monte Carlo results from MBAL, there is a 90 percent probability of the gas condensate reservoir to produce 360 Bscf of gas and 23 MMstb of recoverable condensate. Overall, the 4.5 inch tubing pipe promotes the optimum rate based on water gas ratio, condensate gas ratio and wellhead pressure. The 4.5-inch tubing does not promote erosional velocity and liquid loading issues compared to various tubing sizes.*

**Keyword:** *Well optimization, modeling, gas condensate, improve production, MBAL, PROSPER.*

## 1. INTRODUCTION

Production optimization is one of the most important key in the oil and gas industry. Due to economic restraints, petroleum engineers have to implement future forecasting and prediction techniques to evaluate thus optimize reservoirs performance. Reserves estimation is also important as it confirms whether the reservoir is economically viable to be explored. Gas reservoirs are divided into many other categories which are condensate, dry gas and wet gas. In this study, the main focus of production optimization is, particularly for gas condensate reservoirs. It is important to understand the characteristics and behavior of a gas condensate reservoirs with depletion in pressure. As production begins, the reservoir pressure declines gradually till the dew point. Once the reservoir pressure depletes till the dew point, the liquid condensates starts to form therefore, introducing a multiphase system. The building up of liquid condensate will impact the wells productivity by reducing the permeability.

When natural gas is produced, the energy for transporting the produced fluids decreases and eventually the liquid will be held in the wellbore (S.B. Coleman 1990) . 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 pipe (J. Kjolaas 2015).Gas condensate systems often show liquid phase contamination problem due to solid phase instability. Generally, a few solids will precipitate from a gas condensate system. The precipitation of sulfur in the example is extremely dangerous and the trace can be found by the condition of the production string.(Thomas 1995).Reservoir properties such as permeability, skin factor, pay thickness, porosity, and reservoir pressure are used as a parameter for sensitivity analysis by the material balance MBAL and PROSPER software.

### 1.1. Problem Statement and Objectives

Liquid hold up in the wellbore promotes additional pressure drop which will result in reduction of the transport energy. If the liquids accumulate over time, the gas velocity is not able to lift all the fluids to the surface causing the well to die and this phenomenon is known as liquid loading. The condensate blockage also reduces the gas deliverability and this will require more additional wells to drain the reservoir(C.H. Whitson 2005). The objectives would be to evaluate the current reserves and well productivity of the gas condensate reservoir. Sensitivity analysis is also implemented to analyze the optimum gas production rates through various parameters. Liquid loading is a primary concern and prevention of this phenomenon is crucial in this study.

## 2. Methodology

### 2.1. PVT Matching

Before any simulation is done, an appropriate PVT matching has to be implemented for accurate predictions. Table 1 represents the PVT data input to be run for matching. The black oil method is used to match the PVT and the representation of the plots is shown in Appendix A. The matching is done by running through a range of temperatures and pressures. For accurate matching the range of temperatures used for this calculation is from 70°F – 240°F. Pressure values are calculated from 1000 psig to 3210 psig. The number of steps used for the matching is 10.

**Table1.** *Data Input*

| | |
|---|---|
| Separator Pressure (psig) | 500 |
| Separator Temperature (° F) | 70 |
| Separator GOR (scf/stb) | 20860 |
| Condensate Gravity (API) | 47 |
| Water Salinity (ppm) | 10000 |
| Dew point @ Reservoir Temperature (psig) | 3178 |
| Reservoir Temperature (° F) | 240 |
| Reservoir Pressure (psig) | 3210 |
| Porosity (%) | 0.1 |
| Gas Gravity (sp.gravity) | 0.756 |
| Rock Compressibility ($psi^{-1}$) | 3.4E-6 |
| Thickness (ft.) | 600 |
| Reservoir Radius (ft.) | 3000 |
| Connate Water Saturation (%) | 0.2 |

### 2.2. VLP/IPR Match

Before any analysis is done in PROSPER, the vertical lift curve and inflow performance curve has to be matched with correlations for accurate sensitivity analysis. Based on the input of PVT parameters in the software, a matching is implemented to find the percentage difference of the measured and calculated rate of gas and bottom hole pressure. Figure 1 indicates a VLP/IPR match for Hagedorn Brown's correlation. The calculated gas rate is 27.5 MMscf/d the measure and gives a difference of 2.0% from the measured rate. The bottom hole pressure is calculated to be 1505 psigwhich results in a measured difference of 1.7 %.Therefore, this correlation is the most accurate compared to the others.

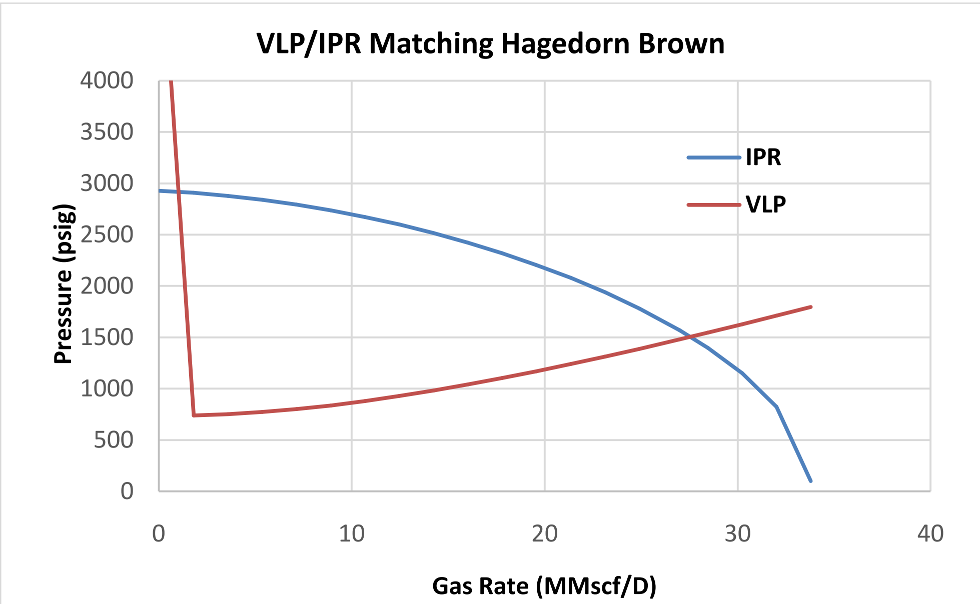


**Figure1.** *VLP/IPR Matching Hagedorn Brown*

Another VLP/IPR matching in figure 2 is made for the correlation of Beggs & Brill. From this plot, it is observable that the calculated gas rate is 30.6 MMscf/D and shows a measured difference of 13.6%. The bottom hole pressure is calculated to be 1069 psig which indicates a measured difference of 11.6 %. The matching is not as accurate compared to Hagedorn Brown. Beggs and Brill correlation is a typical correlation for pipeline flow. This correlation is formed based on gas-water data from horizontal and slanted pipes (O. Fevang 2012). Fancher Brown method is not reliable as it is a no-slip correlation. Therefore, the calculated rate is under estimated due to the correlation not considering the liquid hold up.

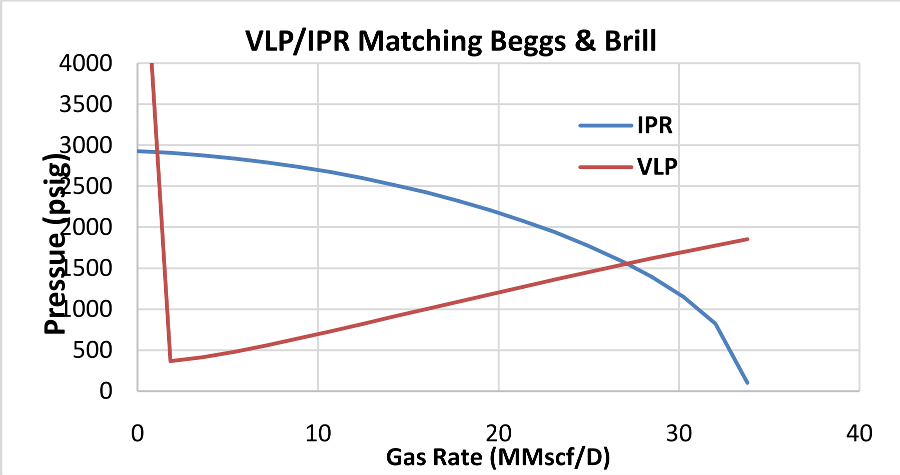


**Figure2.** *VLP/IPR Matching Beggs & Brill*

## 3. History Matching

A proper history match has to be presented in order to determine if the model is appropriate to the production history. Once a good match is achieved, the software is then able to make appropriate estimates of the reservoirs future performance. The history match implemented through MBAL is an analytical method plot which is presented in figure 3.

### 3.1. Analytical Plot

Analytical plot is a section of history matching that uses a non–linear regression method to improve history matching. Figure 3 represents the match points for presence of aquifer influx and no influx. As seen, the match points status is matched along with the aquifer influx which is represented by the blue line. Once this match is achieved, an accurate reserves estimate can be made.

## 4. P/Z vs Cumulative Gas Produced

P/Z method is a graphical method of describing the original gas in place. The intercept on the cumulative gas produced axis will result in the estimate of the original gas in place (GIIP). Figure 4 is a P/Z plot where the best fit line intercepts to produce a GIIP of 2.05 Tcf of gas. From this plot, an estimate of the reserves gas in place is possible. With this, a probabilistic technique is used to predict the percentage of recovery based on number of cases and distribution input through Monte Carlo tool. Based on this initial estimate of 2.05 Tcf, a 90, 50, and 10 percent probabilistic curve can be analyzed.

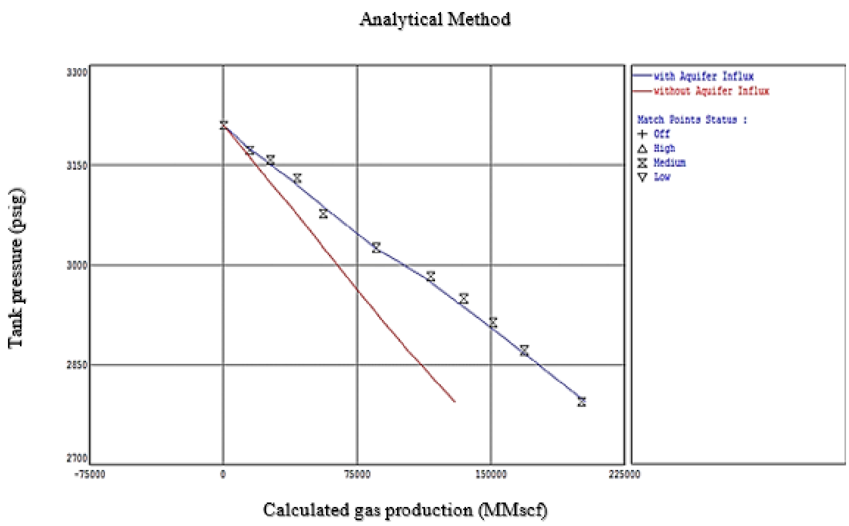


**Figure3.** *Analytical Plot*

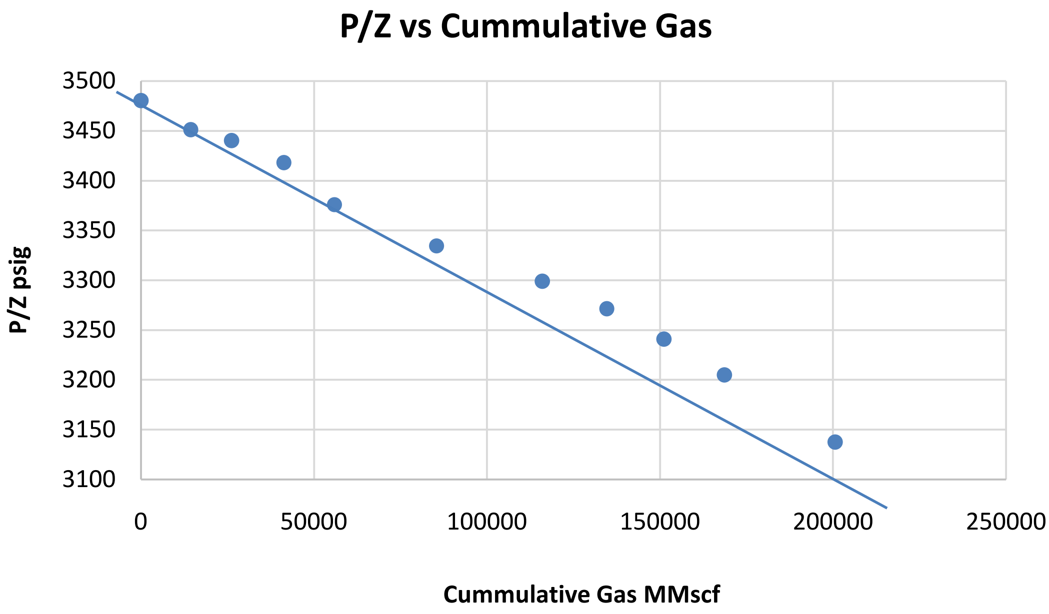


**Figure4**. *P/Z vs. Cumulative Gas Produced*

### 4.1. Monte Carlo (Reserve Estimation)

Monte Carlo tool included in MBAL software is used to estimate the reserves. Figure 5 indicates the percentage probability of gas initially in place. 90 percent probability represents the less optimistic estimation which is 360 Bcf. 50 percent probability shows a higher rate at 1028 Bcf of gas. 10 percent probability which is the most optimistic rate is highest at 1985 Bcf. Therefore, there is a 90 % chance of recovering gas of 360 Bcf worth 360 $ Million when price of natural gas is around USD 2.90 per MMbtu.

Recoverable condensate is crucial for gas condensate reservoir. Figure 6 represents the probabilistic curve for oil or condensate. Figure shows that there is a 90 percent probability that 23 MMstb of condensate can be recovered. 50 percent probability indicates that the condensate recoverable is 57 MMstb. The 10 percent probability is the most optimistic which is at 120 MMstb. Similarly, for condensate, there is a 90 % chance of recovering 23 MMstb of condensate worth 1.2 billion USD when price of crude is around 50 USD per barrel.

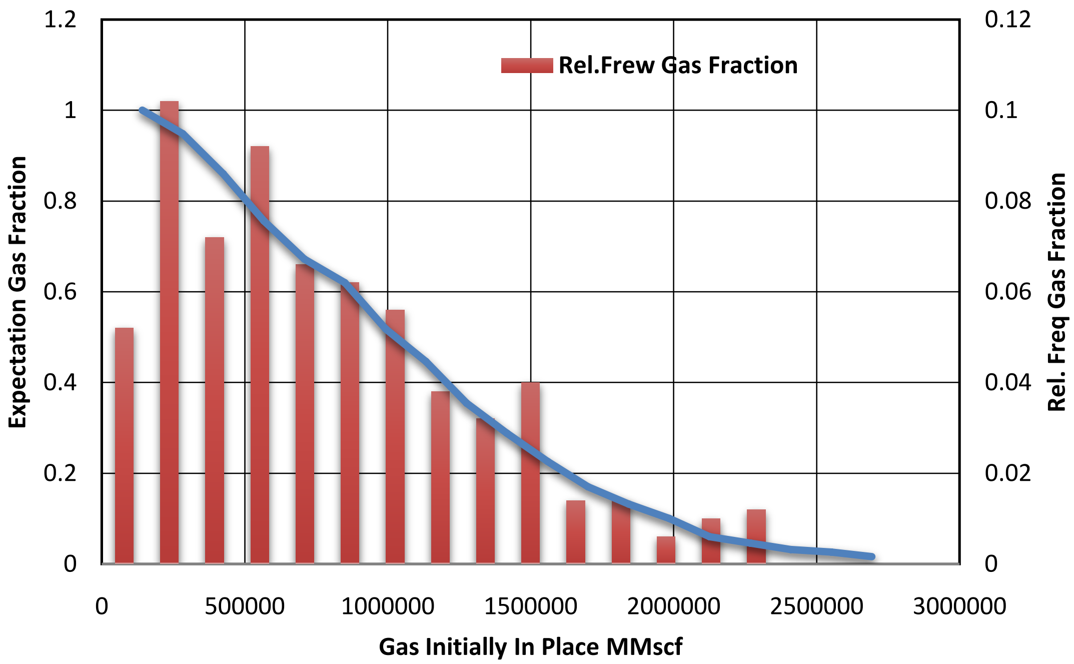


**Figure5**. *Probabilistic Curve (GIIP)*

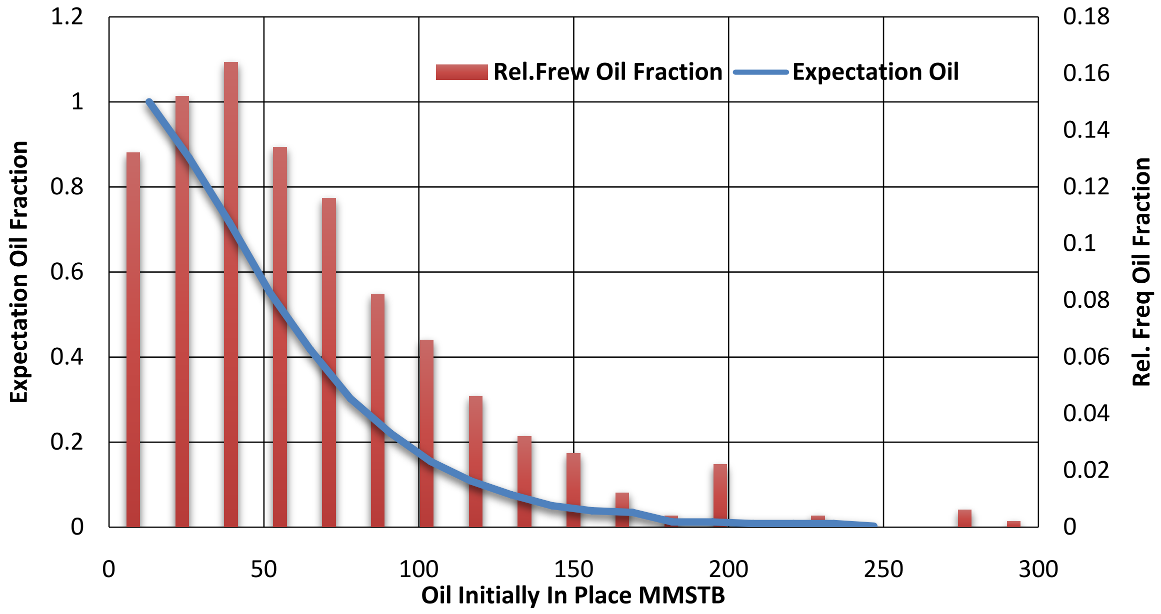


**Figure6.** *Probabilistic Curve (OOIP)*

## 5. Sensitivity Analysis

Sensitivity analysis is a tool that is used in PROSPER which is able to correlate the various options available in the software to promote better-flowing rates. Parameters such as tubing size, wellhead pressure, water gas ratio and condensate gas ratio is analyzed to achieve optimum production rates.

### 5.1. Tubing Size

The various tubing sizes used is (2.5, 3.0, 3.5, 4.0, 4.5, & 5.0) inches and it is cross-plotted with the inflow performance curve as seen in figure 7, 8& 9. The inflow performance curve is set at skin of (-10, 0, & +10) to simulate damage near the wellbore. Inflow curve with depletion is also included in the plot to determine the rates of gas and oil when the reservoir has depleted from 3000 psig to 2000 psig.

Since, the 4.5-inch tubing has a lower rate drop with depletion in reservoir pressure with various skin, it is then set to promote the optimum rate. The optimum gas and condensate rate is set at 30.6 (MMScf/D) and 604 STB/D. 5.0-inch tubing does promote the highest rates but with pressure depletion and condensate build-up, the 5.0 inch tubing pipe will promote liquid loading issues.

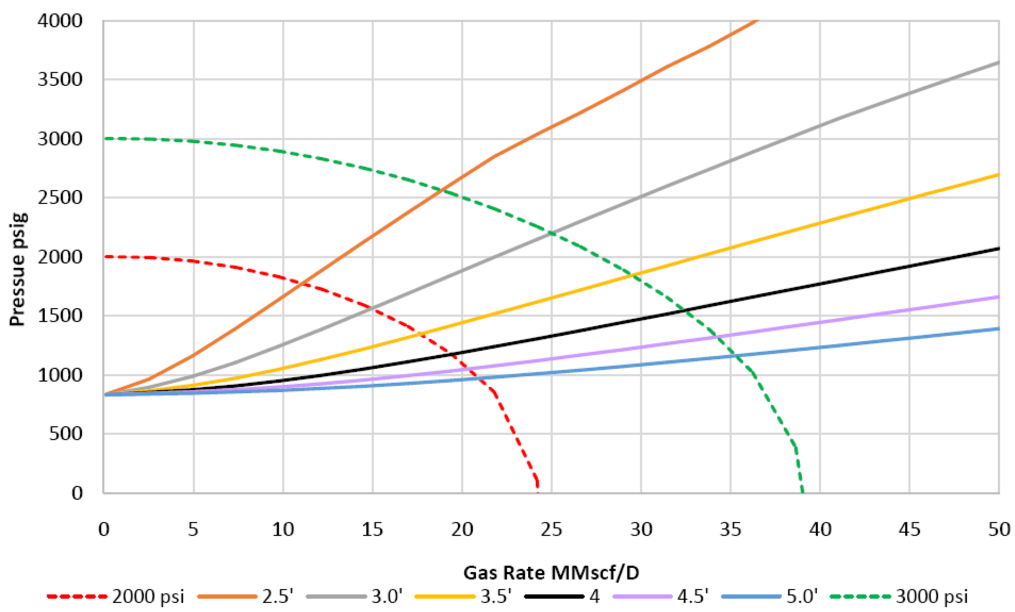


**Figure7.** *Vertical Lift Performance with IPR (Skin -10)*

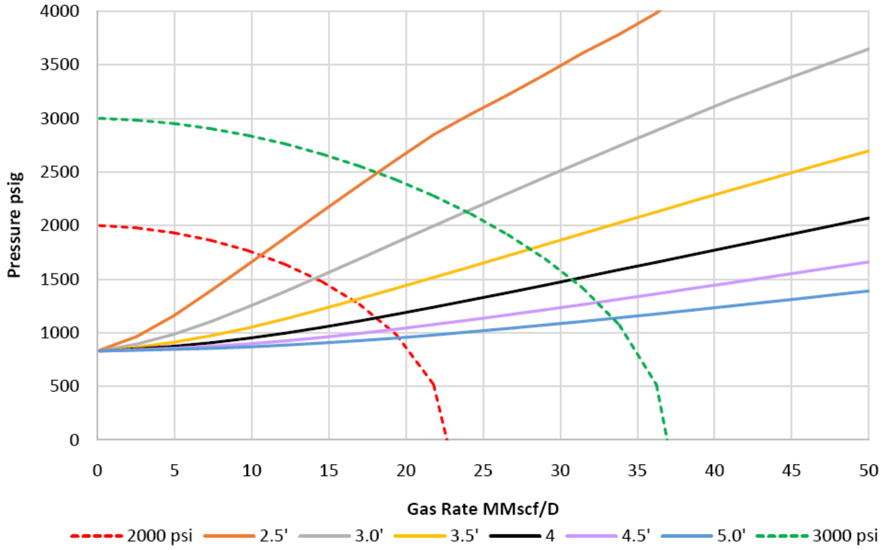


**Figure8.** *Vertical Lift Performance with IPR (Skin 0)*

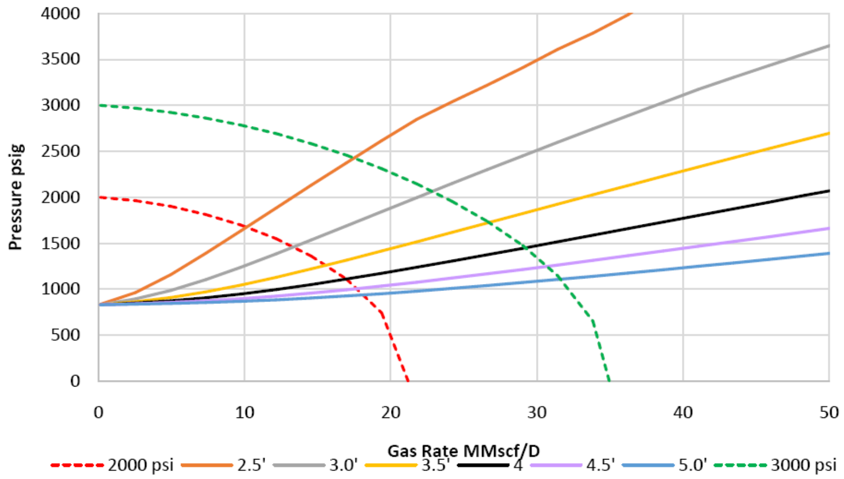


**Figure9.** *Vertical Lift Performance with IPR (Skin 10)*

## 5.2. Wellhead Pressure

The well flowing pressure is set at 3 different rates which are 300,500 & 800 psig as presented in figure 10. The variation of the well flowing pressure is then correlated with tubing size of 4.5 inches and the skin is set at -10, 0, & 10.For the worst case scenario of skin +10, the optimum rate of gas and oil is set at 30.7 MMscf/D and 605 STB/D. Skin -10 shows the best case scenario and the rates are 34 MMscf/D and 673 STB/D.

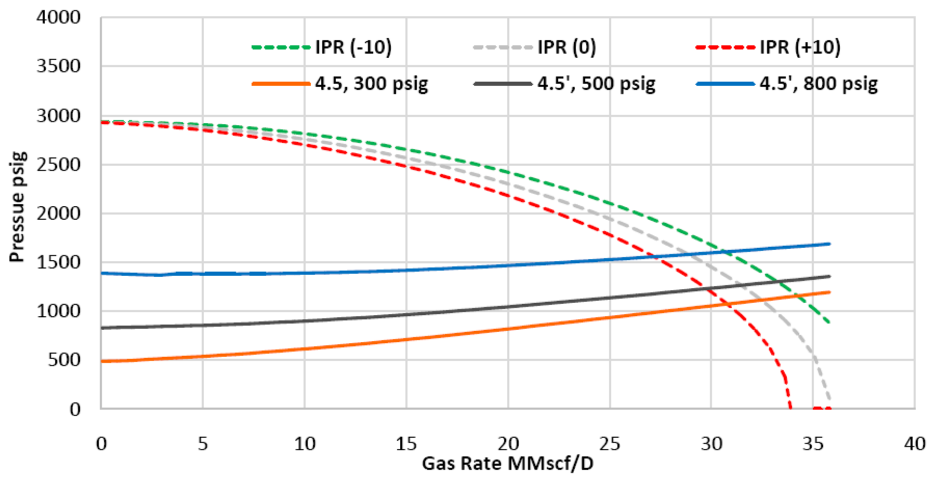


**Figure10.** *VLP/IPR (Wellhead Pressure)*

### 5.3. Water Cut

Figure 11 indicates the results of a sensitivity analysis with three different water-gas ratios (10.03, 25.03, and 50.03) stb/MMscf. For worst case scenario of skin (+10), the highest gas rate is 30 MMscf/D at water gas ratio of 10.03 stb/MMscf. Oil and water rate was observed to be at 577 STB/D and 294.6 STB/D.Oil and water rate was observed to be at 577 STB/D and 294.6 STB/D.The water rate in the well increases as the water gas ratio increases. WGR of 10.03, 25.03, & 50.03 produces a water rate of 294, 705, and 1332.1 STB. Tubing size of 5.0 inches could possibly cause the well to be abandoned since the velocity of gas is lowest.The rate of water surpasses the liquid loading criteria as the well would not be able to lift hydrocarbons to the surface.

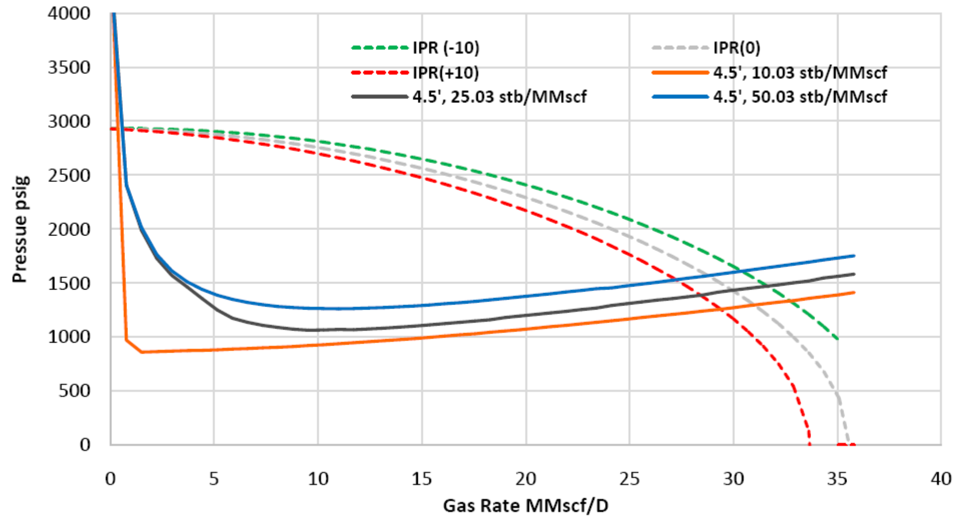


**Figure11.** *VLP/IPR (Water Gas Ratio)*

### 5.4. Condensation Gas Ratio

For this parameter, the 3 different variable used for condensate gas ratio is 40, 60, & 80 stb/MMscf. Based on figure 12, the highest rate results for worst case scenario (skin +10) is condensate gas ratio of 80 stb/MMscf which results in rates of 31 MMscf/D and 723 STB/D of oil.Where else the best case scenario (skin-10) is condensate gas ratio of 80 stb/MMscf which promotes the rate at 34.4 MMscf/D and 810 STB/D. The optimum tubing is 4.5 inches as it produces a better rate with gas velocity of 47 ft/s which does not damage the pipe.

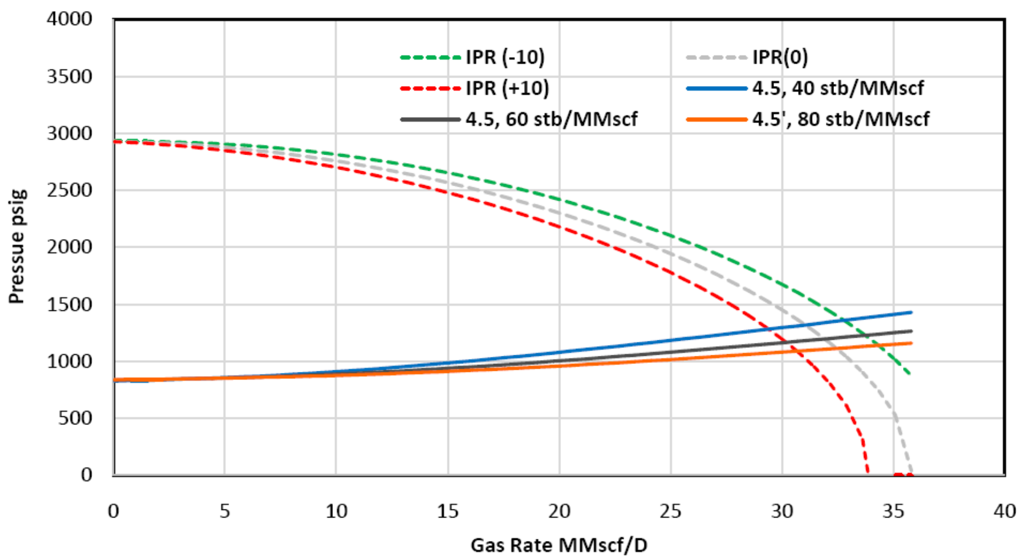


**Figure12.** *VLP/IPR (Condensate Gas Ratio)*

## 6. Conclusion

Optimization is achievable once an adequate analysis is run through computer simulation programs such as MBAL and PROSPER. From the simulation, the conclusion can be made as follows:

1. The tubing size which promotes the optimum rate would be tubing diameter of 4.5 inch.5.0 inch tubing pipe seems to promote at a slightly higher rate as seen with pressure depletion. This slight increase in both gas and oil rates is considered minimal as it almost cost the same to produce by using a 4.5-inch tubing.
2. The 4.0-inch tubing is eliminated due to the high rate drop with pressure depletion. Tubing sizes ranging from 2.5-3.5 inches faces erosional velocity issue. This is due to the high velocity of gas as it is producing through a smaller tubing diameter.
3. The Hagedorn Brown seems to promote the least measured difference in the VLP/IPR matching compared to Beggs & Brill therefore it is used for the optimization study in PROSPER.
4. Reserves estimates is possible with Monte Carlo analysis. The probabilistic curve for GIIP is able to confirm 90 percent probability that 360 Bcf worth $ 360 Million of gas is able to be recovered.
5. The probabilistic curve for OIIP is able to confirm there is a 90 percent probability to produce 22 MMSTB valued at $1.2 Billion.

**Nomenclature**

| | |
|---|---|
| GIIP | Gas Initially In Place |
| OIIP | Oil Initially In Place |
| MMSCF | Million standard cubic feet |
| Bcf | Billion Cubic feer |
| MMstb | Million stock tank barrels |
| IPR | Inflow Performance Relationship |
| VLP | Vertical Lift Performance |

**Appendix A**

Havlena-Odeh (1963) introduced a correlation to determine the GIIP by linearizing the original material balance equation to a straight line P/Z versus Gp (cumulative gas production) plot (D. Havlena 1963).

$$G_{fgi}E_{gwf} + N_{foi}E_{owf} + We = G_p\left(\frac{Bg-BoRv}{1-RvRs}\right) + N_p\left(\frac{Bg-BoRv}{1-RvRs}\right) + (W_p - W_i)B \quad (1)$$

$$\frac{P}{Z} = \frac{P_i}{Z_i}\left[\frac{G_e-G_p}{G_e-\frac{z_{i,T,P}}{T,P,K_eS(p,t)}}\right] \quad (2)$$

Where:

$G_{fgi}$ = Dry Gas Initially In Place (GIIP)

$N_{foi}$ = Oil/Condensate Initially In Place (OIIP)

$W_e$ = Water Influx

$G_{ps}$= Represents the dry produced gas from the reservoir

$N_p$ = Represents the oil produced from the reservoir

$W_p$ = Water Production

$W_i$ = Water Injection

$B_g$ = Gas Formation Volume Factor

$B_o$ = Oil Formation Volume Factor

$R_v$ = Volatilized oil gas ratio

$R_s$ = Solution Gas Oil Ratio

$B_w$ = Formation Volume Factor (WATER)

**Table2.** *Gas Rate (MMscf/D)*

| Tubing Id ( inches) | MMscf/D | | Difference % |
|---|---|---|---|
| | 2000 psi | 3000 psi | |
| **2.5** | 10.1 | 17.3 | 71.3 |

| | | | |
|---|---|---|---|
| **3.0** | 13.3 | 22.3 | 67.6 |
| **3.5** | 15.2 | 26.7 | 75.7 |
| **4.0** | 16.4 | 29.2 | 78.0 |
| **4.5** | 17.7 | 30.6 | 72.8 |
| **5.0** | 18.0 | 31.6 | 76.0 |

**Table3.** *Oil Rate (STB/D)*

| **Tubing Id ( inches)** | **STB/D** | | **Difference %** |
|---|---|---|---|
| | **2000** | **3000** | |
| **2.5** | 200 | 343.7 | 72 |
| **3.0** | 262.6 | 450.0 | 71.4 |
| **3.5** | 306.4 | 525.4 | 71.5 |
| **4.0** | 333.3 | 574.5 | 72.3 |
| **4.5** | 349.1 | 604.3 | 73.1 |
| **5.0** | 358.3 | 622.4 | 74 |

**Table4.** *Erosional Velocity of Gas*

| **Tubing Id ( inches)** | **Ft/s** | |
|---|---|---|
| | **2000 psi** | **3000 psi** |
| **2.5** | 43.5 | 79.1 |
| **3.0** | 41.3 | 73.7 |
| **3.5** | 36.0 | 63.9 |
| **4.0** | 30.0 | 53.6 |
| **4.5** | 24.8 | 44.4 |
| **5.0** | 20.5 | 36.8 |

**Table5.** *Hagedorn-Brown VLP/IPR Matching*

| | **Measured** | **Calculated** |
|---|---|---|
| **Gas Rate (MMscf/D)** | 27 | 27.5 |
| **Bottom Hole Pressure (psig)** | 950 | 1505 |

**Table6.** *Beggs & Brill*

| | **Measured** | **Calculated** |
|---|---|---|
| **Gas Rate (MMscf/D)** | 27 | 30.6 |
| **Bottom Hole Pressure (psig)** | 950 | 1070 |

**Table7.** *Monte Carlo Results*

| | **Gas Initially In Place (Bscf)** | **Recoverable Condensate (MMstb)** |
|---|---|---|
| **90 Percent Probability** | 360 | 22.8 |
| **50 Percent Probability** | 1027.8 | 57.0 |
| **10 Percent Probability** | 1984.6 | 120.2 |

## Appendix B

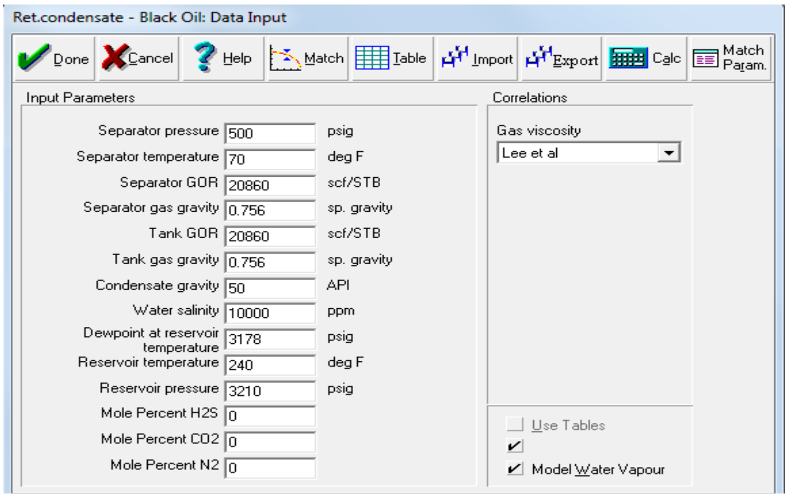


**Figure13.** *PVT Input (Mbal)*

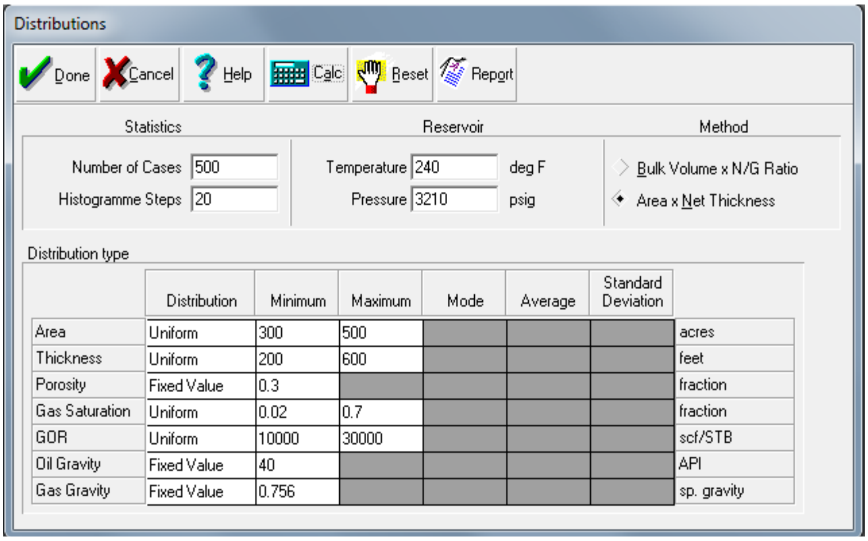


**Figure14.** *Monte Carlo Distribution Input*

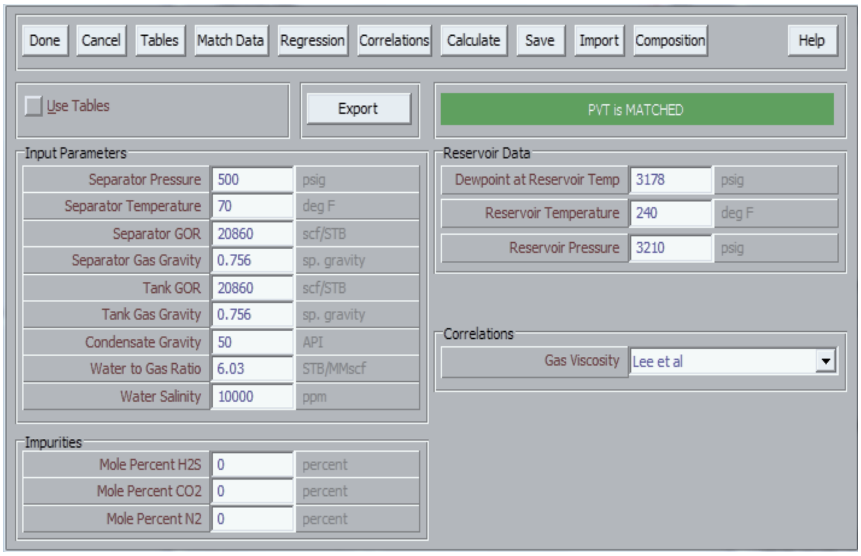


**Figure15**. *PVT Match (Prosper)*

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## AUTHORS' BIOGRAPHY

**Retnaruben Ratna Kumar,** from an Oil town in Kemaman, Terengganu and had a deep passion in Oil and Gas since I was small. My father used to work offshore and it inspired me to proceed and achieve my undergraduate degree in Petroleum Engineering in Curtin University, Malaysia. Part time work in service companies in the past enhanced my interest to have a deeper understanding in the Oil and Gas Industry. With guidance and knowledge provided by my lecturers and staffs in Curtin University, I manage to develop a better grasp in Petroleum Engineering thus able to write a thesis regarding Production Optimization. Therefore I would like to thank everybody in the Department of Petroleum Engineering in Curtin University for making this a memorable journey.

**Hisham Khaled Ben Mahmud,** has achieved Bachelor, Master and PhD degree in Chemical Engineering from Tripoli University, Sydney University and Curtin University, Australia, respectively. Also I have gained Graduate Diploma in oil and gas from University of Western Australia (UWA). I have expertise in modelling multiphase flow into subsea systems such as pipeline, jumper, riser evaluating pressure drop, and liquid holdup. Also optimize the risk of hydrate blockages into bend pipes. Recently I have involved into upstream research area including reservoir matrix acidizing, experimentally injecting a fluid (acid) into a core sample (sandstone or carbonate) to improve reservoir properties (porosity, permeability) observing wormhole and precipitation reaction. Another area I involve in is enhanced oil recovery (EOR) in brown oil field using different injecting fluids ($CO_2$, water, polymer, surfactant) or modify production wells in order to improve hydrocarbon fluid recovery by minimizing oil wettability, surface tension and increase contact area.