Application of pressure build up analysis for reservoir oil

A H Sunardi, R Setiati and S Samsol*
Petroleum Engineering, FTKE, Universitas Trisakti, Jakarta, Indonesia

Abstract. The well analysed in this paper is A-1 well, T field, located approximately 90 km north of Bali. Reservoir in this field is gas reservoir with sandstone rock formation, one of the problems of A-1 well is sand problem. Due to the sand problem in well A-1, well test analysis must be done first, to see if there is any damage to the formation if the flow rate is increased. Identification of formation damage in a well can be done by doing Pressure Build up test. The method used is pressure build up test by Horner method with Sapphire software v.3.20. The determination of deliverability test was conducted by back pressure test. Given the results of the analysis, the permeability value remains, the value of the skin and reservoir pressure decreased. From the results of the tests, there were no significant changes, indicating no formation damage. The results of the deliverability tests decrease, due to decreased reservoir pressure. Since there is no formation damage, the flow rate can still be increased up to 30% of AOFP.

1. Introduction
Hydrocarbon in the reservoir rock is expected to flow into the wellbore. Production rate of hydrocarbon into the production wellbore is attempted to have a very large flow rate so that the hydrocarbon produced is also large. In time a production well will definitely experience obstacles or decreases in production. One of the causes is damage to the well formation, where formation damage around oil and gas wellbore causes a decrease in the ability of the fluid to flow in the reservoir rock.

From the test results, there will be a lot of information to be obtained such as effective fluid permeability, formation damage or repair around the boreholes tested, reservoir pressure, the boundary of a reservoir, the shape of the drain radius, heterogeneity of a layer [1].

The purpose of this paper is to analyses the formation characteristics of the A-1 well such as permeability, skin factor, reservoir pressure, and formation productivity based on the Pressure Build Up Test analysis using Sapphire v3.20 software. From the test result, it can be known if there’s a formation damage due to increased flow rate. To know the ability of a well to produce, productivity of the well or Absolute Open Flow Potential (AOFP) is calculated. After knowing the AOFP value, then the Inflow Performance Relationship (IPR) curve is made to predict the well flow at different bottom well flow pressures, so that the flow rate in the well can be optimized.

2. Methodology
Pressure build up testing is the industry’s most famous method of a well testing. One reason for this preference is that the pressure build up tests do not require the close supervision demanded by other methods of testing. A pressure builds up test is performed as follows: the well is produced at a constant rate for a period of time, a pressure recorder is lowered into the well shortly before closing the well, and then the well is closed. If it were possible to produce the well at a constant rate, q, from the instant of
opening the well to production, then there would be no restrictions on the length of producing time, \(t_p\), before shutting the well in [2].

2.1. Pressure build up curve

A build up curve can be divided into three regions. An early-time region during which a pressure transient is moving through the formation nearest the wellbore. A middle-time region during which the pressure transient has moved away from the wellbore and into the bulk formation. And a late-time region, in which the radius of investigation has reached the well’s drainage boundaries [3].

2.2. Reservoir model

In general, there are several reservoir models that are important in determining the pressure derivative curve that matches the Pressure Build Up analysis, which are homogenous reservoir, double porosity reservoir and double permeability reservoir. The Double Porosity model assumes a reservoir that is not homogeneous but consists of a rock matrix with high storability and low permeability and fissures that have low storability and high permeability. In the Double Permeability Reservoir model, it is assumed that a reservoir with 2 layers with different permeability where the first layer has a higher transmissibility than the second layer. A-1 Well is a homogenous reservoir. Homogenous reservoir is the simplest model by assuming the same porosity, permeability and thickness values [4]. The permeability value is assumed to be isotropic which has the same value in all directions [5].

2.3. Reservoir boundary

In general, reservoir boundaries are divided into 2 types, which are Infinite Boundary and Fault. Infinite boundary, assumed an unlimited reservoir limit or boundary from the reservoir cannot be detected during a pressure survey. Fault is a type of reservoir boundary with the presence of faults located at a certain distance from the production well. The fault can only limit 1 direction of the reservoir (single sealing fault), or can be in the form of a limit on 2 reservoir directions (intersecting faults, two parallel faults), or bound systems with closed system (circle and rectangular) types where the tests have detected the entire boundary of the reservoir [5].

2.4. Deliverability test method

One of the objectives of the well testing work is to determine the ability of a layer or formation to produce [6]. The definition of deliverability of a gas well is the ability of the well to produce with a constant flow rate at a certain pressure. The production capability of a well can be known for each of the different bottom flow pressures (\(P_{wf}\)). There are various deliverability testing methods, which are Flow After Flow Test (Conventional Back Pressure Test), Isochronal Test, and Modified Isochronal Test. The most basic equation is used as a conventional analysis (C and n) to determine the ability of a gas well in production (deliverability) based on Rawlins-Schellhardt's empirical equation. This equation is one of the most widely used methods to describe the downhole performance of a gas well. The maximum price of gas rate is called Absolute Open Flow (AOF), which occurs when the bottom pressure of the well (\(P_{wf} = 0\)), but in the calculation of AOF occurs when the bottom pressure of the well (\(P_{wf}\)) is equal to atmospheric pressure (\(P_{wf} = 14.7 \text{ psia}\)).

2.5. Inflow performance relationship

Inflow Performance Relationship is a study of the performance of fluid flow from a reservoir to a wellbore, where this performance will depend graphically on the Productivity Index (PI). The Productivity Index of a well is expressed in graphical form known as the Inflow Performance Relationship (IPR) curve. This IPR curve is made in the form of the relationship between the wellbore pressure (\(P_{wf}\)) to the flow rate of well production (q). In order to be able to determine this IPR curve, q, \(P_{r}\), and \(P_{wf}\) data are obtained from the results of the well test.

IPR (Inflow Performance Relationship) is one of the important indicators to determine the productivity of a well. IPR itself is a plot between \(P_{wf}\) and q. So, from the IPR graph we can know that
for each desired flow rate how much flow pressure is needed. IPR can also be used to see the maximum flow rate of a well. The maximum flow rate gas well is also called AOF or Absolute Open Flow value. This AOF value is obtained when Pwf is zero [6].

Pressure Build Up Test analysis needs reservoir data, production data, Petro physical data, and other additional data that support the analysis of Pressure Build Up. A-1 well data is obtained from PVP test results, logging interpretation, and well correlation in the same field. In the Pressure Build Up analysis, a reservoir data is needed [7].

Table 1. Reservoir data.

| Parameter           | Value  | Unit   |
|---------------------|--------|--------|
| Well Radius         | 0.583  | Ft     |
| Net Pay             | 500    | Ft     |
| Porosity            | 0.4    | Fraction |
| Reservoir Temperature | 124    | °F     |
| Formation Compressibility | 1.22E-05 | 1/psi |
| Gas Compressibility | 0.91   | cuft/sec |
| Gas Viscosity       | 0.013  | Cp     |
| Gas Gravity         | 0.562  |        |

Analysis carried out using software has a working sequence that starts with preparing supporting data such as fluid viscosity, compressibility of rocks, formation volume factors, thickness of productive layers, porosity, and well radius. The next stage is the selection of the reservoir model which is then followed by the model analysis process. If the results of the reservoir model selection show that the actual curve and the model curve are matched or aligned, then pressure derivative graphs and Horner graphs can be obtained with reservoir parameters resulting from the calculation of the software. The results of these calculations can then proceed to the calculation of IPR (Inflow Performance Relationship) to determine the productivity or potential of the well by determining its maximum production.

3. Results and discussion
Based on the results of improving with Saphire software obtained derivative models matching as follows. PBU Test Analysis done by three times.

![Figure 1](image1.png)  
**Figure 1.** Pressure derivative analysis exported from 1st PBU.

![Figure 2](image2.png)  
**Figure 2.** Pressure derivative analysis exported from 2nd PBU.
The results of Sapphire v3.20 software interpretation indicate that the reservoir type suitable for well A-1 is Homogeneous and there is a one fault boundary. Table 2 below is the result of pressure derivative analysis on A-1 well 1st PBU, 2nd PBU and 3rd PBU.

Table 2. Results of Saphir analysis 1st PBU, 2nd PBU, & 3rd PBU.

| Parameter                  | Unit | 1st PBU | 2nd PBU | 3rd PBU |
|----------------------------|------|---------|---------|---------|
| Wellbore Storage Coefficient (C) | bbl./psi | 75      | 11.4    | 12      |
| Reservoir Pressure (Pi)    | psia | 690.39  | 629.88  | 587.828 |
| Skin (s)                   |      | 4.38    | 4.19    | 3.59    |
| Permeability (k)           | mD   | 110     | 110     | 110     |
| Fault (L)                  | ft   | 1800    | 1840    | 1640    |

Based on the results of improving with software obtained derivative models matching as follows. The third PBU was conducted on December 2017.

Figure 3. Pressure derivative analysis exported from 3rd PBU.

The A-1 well is a gas well, so to determine the ability of maximum flow rate of a well to produce or called AOFP (Absolute Open Flow Potential) a deliverability test is conducted. The deliverability test on the A-1 well uses IPR curve with the help of Prosper software using the C and n method. Below is the A-1, 1st PBU Well IPR curve:

Figure 4. IPR curve of A-1 well 1st PBU.

Figure 5. IPR curve of A-1 well 2nd PBU.
On the IPR curve above, the AOFP value is 201.421 MMSCF/day. Then IPR curve for 2nd PBU is also made, and the AOFP value is 170.787 MMSCF/day.

Based on the IPR curve, the A-1 Well 3rd PBU obtained an AOFP value of 156,770 MMSCF/day. Here is the A-1 well IPR curve in 3rd PBU:

Permeability in the A-1 Well doesn’t changed, which is 110 mD. The permeability value is considered excellent permeability because the reservoir has a large porosity of 40%. In A-1 Wells, the flow rate was increased from 22 MMSCF/day in December 2016 to 30 MMSCF/day in September 2017 and increased again to 38 MMSCF/day in December 2017. However, because the A-1 well is in a sandstone formation, when the flow rate is increased, it needs to be seen whether it will affect the level of formation damage due to sand problems. Through the results of well tests, it is known that the skin factor decreased, which indicates that the increase in flow rate does not cause any formation damage. This decrease in skin factor can be caused by the scale that is produced so that the sediment around the drill hole decreases.

AOFP of A-1 well in 2017 decreased, which can be caused by a decrease in initial pressure. In the pressure build up analysis it has been known that with the increase in flow rate, there is no damage to the formation of the well. Then the flow rate in A-1 well can still be increased up to 30% of the AOFP value according to PTK SKK MIGAS, so that the productivity of A-1 well can increase.

![Figure 6. IPR curve of A-1 well 3rd PBU.](image)

### 4. Conclusion

Based on the results of the well test analysis on well A-1, there are several conclusions which are:

- The skin factor decreased from 4.38 on 1st PBU to 3.59 on 3rd PBU, indicating no formation damage.
- The permeability value of three PBU tests remain constant, which is about 110 mD
- The reservoir pressure decreased from 690 psia to 587 psia, which can be the cause of decreased maximum flow rate, from 201.4 MMscf/D on 1st PBU to 170.8 MMscf/D on 2nd PBU to 156.7 MMscf/D on 3rd PBU.
- With increased flow rate from 22 MMscf/D on 1st PBU to 30 MMscf/D on 2nd PBU to 38 MMscf/D on 3rd PBU, based on PBU analysis, the change of flow rate doesn’t cause a damage on formation.

### Acknowledgments

The author’s gratitude is expressed to mentors for the guidance, and PT Kangean Energy for the data and new knowledge of Well Test. Thank you for all the institutions that helped. We also thank to AASEC 2019 who publishes this article, which in turn will benefit the society.
References

[1] D Abdassah 1993 Analisis Transient Tekanan (Bandung: Jurusan Teknik Perminyakan Institut Teknologi Bandung).
[2] M Sabet 1991 Well Test Analysis (Gulf Publishing Company, Texas).
[3] A Chaudhry 2001 Gas Well Testing Handbook (Elsevier Science, Burlington).
[4] U Nwamu 2013 Well Testing, Well Test Analysis (Dissertation, Petroleum Engineering, London Southbank University).
[5] C Ikoku 1984 Natural Gas Reservoir Engineering (Krieger Publishing Company, Florida).
[6] G G Kushtanova 2014 Well Test Analysis 31.
[7] T Ahmed 2000 Reservoir Engineering Handbook (Gulf Publishing Company, Texas).