Aeon Petroleum Consultants Quarterly Newsletter

Aeon Petroleum Consultants is a professional engineering firm registered in the State of Texas. We specialize in estimating resources and reserves. Our intent on publishing this newsletter is to highlight topics of interest to those involved in estimating, reviewing, or reporting oil and gas resources and reserves.

In this issue, we will discuss the following:

- Aeon Petroleum Consultants website
- Methods of Estimating Reserves and Resources
  - Deterministic
  - Stochastic
- How to Calculate Static Bottom-Hole Pressure from Surface Wellhead Pressure for a Dry Gas Well

We hope to make this quarterly newsletter informative and useful. If there are any topics you would like us to discuss in future newsletters, please contact us on our website and let us know.

Aeon Petroleum Consultants Website

The website for Aeon Petroleum Consultants can be found at:

www.aeon-petro.com

The website contains topics and items that should be of interest to those estimating, reviewing or reporting oil and gas resources and reserves. Besides listing the services that Aeon Petroleum Consultants can provide to the oil and gas industry, there are items available for download, software created by Aeon Petroleum Consultants available for download or demo, videos, and resource and reserve guidelines for viewing and download.

Check out our offerings here:

https://aeon-petro.com/supplement/shop/

Please feel free to contact us regarding our services, software, or items you would like us to discuss in these newsletters.

Methods of Estimating Reserves and Resources

There are basically two methods used to estimate oil and gas reserves or resources; deterministic and stochastic. In a given area it is possible that both methods might be used, depending on the available data.

The deterministic method is used where the range of uncertainty of the data is narrow or where production data or pressure decline data is available. Narrowing the range of uncertainty requires a large amount of data which, in turn, involves drilling a number of wells. The reserves or resources are estimated by direct calculations of fixed data values (area, thickness, porosity, etc.). Reserves or resources for producing wells are usually calculated using production decline or pressure decline trends.

The stochastic method (also referred to as the Monte Carlo method) is used when there is a wide range of uncertainty in the input data. A wide range of uncertainty would be expected in an exploration area where few, if any wells have been drilled. As an example, the calculation for oil or gas reserves and resources requires values for area, thickness, porosity, water or hydrocarbon saturation, formation volume factor, and recovery factor. For sparsely drilled areas, the ranges of each of these variables could be quite wide. Since there is no fixed value for each of these variables, a direct calculation is not possible. So, the stochastic method uses ranges and distributions of each variable as input. The ranges for input variables are usually specified at the 1^{st} and 99^{th} percentile values (referred to as P_{01} and P_{99}). The input distributions are typically normal, log-normal, or uniform statistical distributions and are determined by observation. Once the ranges and distributions of each variable are determined, the method estimates reserves or resources by statistically generating each of the variables and calculating a result. These calculations are repeated thousands of times. An average estimate of reserves or resources can be calculated as the average of these calculations.

Regardless of the method used, reserves are typically reported as proved, proved-plus-probable, proved-plus-probable-plus-possible and abbreviated as 1P, 2P, and 3P, respectively. The 1P, 2P, and 3P reserves are associated with the likelihood of recovery as the 90th (P_{90}), 50th (P_{50}), and 10th (P_{10}) percentiles, respectively. In other words, there is a 90% chance the proved reserve estimates will eventually be recovered, 50% chance of recovering the 2P, and a 10% chance of recovering the 3P.

Resources are reported as either prospective resources (undiscovered) or contingent resources (discovered). Prospective resources use the symbol "U", while contingent resources use the symbol "C". prospective resources are reported as 1U, 2U, and 3U corresponding to the 90th, 50th, and 10th percentile likelihood of recovery. Similarly, contingent resources are reported as 1C, 2C, and 3C for the 90th, 50th, and 10th percentile likelihood of recovery. Because prospective resources are undiscovered (they might not have wells drilled or may not have been tested), there is usually a determination of risk associated with the resource estimates. The risks associated with prospective resources are source, migration, trap, and seal. These refer to a potential source of hydrocarbon generation, a migration pathway from the source to the reservoir, the possibility of a reservoir trap, and the ability of the trap to retain hydrocarbons. The risk factor is calculated by multiplying each of these individual risks together. Each of the estimates (1U, 2U, and 3U) are multiplied by the risk factor to obtain "Risk Adjusted" 1U, 2U, and 3U estimates.

It should be noted that there is a significant difference between prospective and contingent resources, as prospective resources are undiscovered and contingent resources are discovered. Therefore, the difference between 1U and 3U is typically larger than the difference between 1C and 3C. It should also be noted that no amount of risk adjustment can be made to change prospective resources into contingent resources. Nor can any adjustment be made to prospective or contingent resources to change those estimates into reserves.

How to Calculate Static Bottom-Hole Pressure from Surface Wellhead Pressure for a Dry Gas Well

Static reservoir pressure is important for the calculation of production rates and pressure used in P/z versus cumulative production trends. Since well typically do not have bottom-hole pressure gauges installed, it is necessary to calculate the bottom-hole pressure using surface pressure readings.

As one moves down the wellbore from surface to reservoir, there is an increase in both pressure and temperature. Also, with a change in pressure and temperature is a change in gas compressibility (z-factor). With an assumption of no fluid in the wellbore, a formula has been developed that takes into account all these effects and allows one to calculate bottom-hole pressure from surface shut-in wellhead pressure as follows:

$$P_{BH} = P_{WH} * e^{\left(\frac{0.01875\gamma_g * H_{GC}}{z_{ave} * T_{ave}}\right)}$$

where,

P_{BH} = bottom hole pressure (psia)
P_{WH} = wellhead pressure (psia)
γ_g = gas gravity (air = 1)
H_{GC} = height of gas column (reservoir depth - vertical feet)
z_{ave} = average z factor
T_{ave} = average temperature (^{o}R)

Since z_{ave} is unknown until the bottom-hole pressure is calculated, it is initially estimated and calculations performed iteratively until a constant value is reached.

For low-pressure wells less than 2,000 feet, the formula can be used “as is” to calculate the bottom-hole pressure. However, for deeper and/or higher-pressure wells, the height of the gas column or vertical feet between the surface and the reservoir is typically halved and the formula applied to the upper half and again to the lower half.

The use of this formula is best illustrated by solving an example. Given below is an example problem:

Data:

P_{WH} = 1,875 psia
H_{GC} = 5,400 ft
Gas gravity = 0.720
Wellhead temperature = 68 ^oF
Reservoir temperature = 112 ^oF

Solution:

Calculate the temperatures in ^oR:

Wellhead temperature = 68 + 460 = 528 ^oR
Reservoir temperature = 112 + 460 = 572 ^oR

Calculate the mid-point depth and temperature:

Mid-point depth = 5,400 / 2 = 2,700 ft
Mid-point temperature = (528 + 572) / 2 = 550 ^oR

Set up a table (or use Excel) to iteratively calculate the upper half of the wellbore until a constant value is obtained. Input the initial z_{ave} as the z-factor calculated at the surface pressure and the mid-point temperature. Shown below is a table for the upper half of the wellbore.

P_{WH} (psia)	HGC (ft)	Gas Gravity	z_{ave}	Tave (^oR)	P_{BH} (psia)
1,875	2,700	0.72	0.680	539	2,071
1,875	2,700	0.72	0.675	539	2,073
1,875	2,700	0.72	0.675	539	2,073

Notice that by the third iteration a constant value of z_{ave} was obtained.

Now that the pressure at the mid-point has been calculated, we can calculate the lower half of the wellbore as shown in the table below.

P_{WH} (psia)	HGC (ft)	Gas Gravity	z_{ave}	Tave (°R)	P_{BH} (psia)
2,073	2,700	0.72	0.738	561	2,264
2,073	2,700	0.72	0.736	561	2,264
2,073	2,700	0.72	0.736	561	2,264

So, the bottom hole pressure is 2,264 psia.

However, let's see what it looks like when we calculate using the entire wellbore instead of dividing the calculations in half. The table below shows the results of these calculations.

P_{WH} (psia)	HGC (ft)	Gas Gravity	z_{ave}	Tave (°R)	P_{BH} (psia)
1,875	5,400	0.72	0.714	550	2,257
1,875	5,400	0.72	0.706	550	2,262
1,875	5,400	0.72	0.706	550	2,262

The pressure calculated using the entire wellbore is 2,262 psia, only a difference of 2 psia. This equates to an error less than 0.1%.