Analyzing Well Performance 98

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This paper addresses the widespread need of oil field operators to continually verify that wells are being produced as close to their optimum capacity as possible, and in the most cost-effective manner. The analysis is to be made based on data obtained at the surface without entering the wellbore and must yield an accurate representation of conditions that exist within the wellbore, at the bottom of the well, at the sandface and within the reservoir. As such it is not an easy task since fairly complicated processes are involved in the flow of gas, oil and water mixtures in wellbores and a number of operators are often confused by the apparently contradictory evidence which one may obtain. The objective of this paper is to present in simplified terms some of the basic concepts of well performance analysis and to recommend a procedure to be followed in obtaining, organizing and analyzing the data assisted by a user friendly software program: AWP98.

The Problem

The question that must be answered is:

> "Is the well producing all the fluid that it is capable of producing without problems ?"

The producing bottomhole pressure (PBHP) should be less that 10% of the static bottomhole pressure (SBHP) to insure that the maximum production is being obtained from the well. This requires measurement of both the producing and the static bottomhole pressures. The PBHP must be obtained while the well is being produced at normal conditions and the SBHP must be obtained when the well has been shut-in long enough that the bottomhole pressure in the wellbore has stabilized.

Well performance is defined as the relationship between fluid flow rate and the pressure drawdown between the wellbore and the formation pressure. This relation may take several forms (which are all approximations of the actual behavior) the most common of which are:

Productivity index : PI = Flow Rate/ Drawdown expressed in Bbl/day per psi

Inflow Performance Relation: IPR = functional relation between flow rate, Flowing BHP and Static BHP, the most common of which is Vogel's relation.

In order to answer the question above, it is thus necessary to be able to determine what is the current well performance and to compare it to what we consider it should be for the particular well.

The vast majority of operators try to approach this complicated problem with a minimum of effort and information without realizing that the likelihood of reaching a correct analysis is greatly diminished. As seen by the relations above there must be a minimum of information that must be secured in order to make an intelligent assessment of the well's performance. The AWP98 program allows the operator to determine the well's inflow performance relationship. A well may be producing at 20%, 50% or 80% of the maximum flow rate. From the flow rate obtained from an accurate well test and measuring the corresponding PBHP and SBHP allows the operator to determine the percentage of maximum production that is being obtained from the well and to estimate the maximum production rate that is available from the well when the PBHP is reduced to zero.

What Must Be Known For Analysis

Ideally we should have a complete description of the well's history and characteristics, reservoir fluid properties, reservoir performance, geology, etc.. In practice however we must have at least an accurate description of the wellbore and artificial lift system: depths, sizes, completion hardware, operational parameters, etc. Preferably this information should be summarized on a wellbore diagram since this will provide us with the ability to visualize the wellbore conditions and the relationship between various elements, for example: is the pump above the perfs? does liquid exist above the pump? is gas flowing up the annulus? what are the pressures at the pump intake, the gas/liquid interface and the perfs?

Well Test

Since the analysis is to be based on the well's performance it is vital to have ACCURATE well test information which corresponds to the time frame of the analysis. It is not uncommon to see operators analyzing wells using month-old test data or test data which is erratic.

Well tests should reflect the STEADY STATE performance of a well. The flow rate has to be stabilized and GOR and WOR should be consistent with past performance. It is thus important to maintain accurate historical records (spreadsheets are ideal for this) of well test data annotated with any changes or unusual conditions.

Static BHP

The static bottom hole pressure (SBHP) represents the energy available to move the fluid from the reservoir to the wellbore. It is one of the key factors in the analysis of well performance. If we do not know how much energy (pressure) is available from the reservoir, we cannot determine how efficiently we are producing the well. Unfortunately it is also one of the least known quantities and it is commonly ignored by production personnel since it is supposed to be a value pertinent only to "Reservoir Performance" that can be estimated only from complicated transient pressure tests.

A realistic estimate of SBHP is necessary for well performance analysis. Every effort must be made to obtain representative values which can be used in estimating Productivity Index or IPR relations. Otherwise these relations are totally meaningless. One way to obtain realistic SBHP data is to institute a policy to routinely make static fluid level <u>measurements any time that any well in a field</u> is shut in for any reason (workover, repair, equipment failure) and to interpret these static fluid level measurements in terms of bottom hole pressure. What is required is at least an estimate within 10-15% of the actual stabilized pressure. More accuracy is not required considering the uncertainties of the other data that we commonly have available. Such an estimate would be far better that the values which are commonly guessed by production personnel.

Producing BHP

This quantity is the key element in determining the flow behavior of the well. A steady value of PBHP is an indication of stabilized conditions. A varying value of PBHP is an indication that the behavior of the well is changing and its current performance may not be representative of the "normal behavior" of the well. This is especially important in reservoirs produced by secondary recovery methods. A variation in PBHP may also indicate the acquired data is inaccurate. The need for measurement of casing pressure and casing pressure buildup rate with maximum precision cannot be over-stressed.

A stabilized value of PBHP combined with the SBHP is required to calculate the well drawdown and estimate the PI or the IPR of the well. If the PBHP is small compared to the SBHP (say 10 to 15%) then we are probably producing the well at 80-90% of its maximum rate. If the PBHP is only 50% of the SBHP then we can produce fluid at a greater rate from the reservoir if we are able to increase the drawdown by lowering the PBHP.

It thus should be clear that in order to be able to make a judgment about how efficiently we are producing a well we must know BOTH the Static and the Producing bottom hole pressures and have the results of an accurate Well Test. If any of these three parameters are missing or are grossly inaccurate we will reach the wrong conclusion.

It is a fact that virtually all oil operators undertake fluid level measurements in pumping wells. Unfortunately a large number of these measurements are only used to answer the question: "**Is there fluid above the pump intake**" thus ignoring the potential of converting these measurements into Well Performance Analysis and answering the key question :"**What is the well's actual performance**".

The following calculations are based on the assumption that all operators have access to at least a strip-chart type of fluid level instrument which is in good condition and a pressure gage with sufficient accuracy to measure casinghead pressure within +/- 5 psi and also measure the casing pressure build-up rate with sufficient accuracy.

Calculation of PBHP

The following relates to calculation of Producing Bottom Hole Pressure in wells which have an open annulus from the casinghead to the perforations so that a bottom hole pressure calculation can be based on the addition of a measured casing head pressure, plus the calculated gas column pressure and the fluid column pressures. This thus covers at least 95% of all wells produced by pumping (beam, ESP and PC) the remaining 5% corresponds to those wells that are completed with packers.

Calculation of PBHP requires a knowledge of the distribution of fluids (oil, water and gas) in the annulus. The following basic concepts have been established from many years of experience and are generally accepted:

In a well producing at STEADY state conditions (stable flow rate, GOR and WOR) the following is accepted:

1- A stable fluid level and casinghead pressure are an indication of a stable PBHP.

2- The liquid above the pump intake consists of 100% oil, regardless of the well test WOR.

3- The liquid below the pump intake will contain a % of water greater than the well test WOR due to water holdup. For practical purposes the gradient of this liquid can be assumed to be the gradient of the produced brine.

4- In a well producing with a closed casinghead valve and exhibiting a constant casing head pressure, the fluid column in the annulus below a gas/liquid interface, which is above the pump intake, consists of 100% liquid.

5- In a well producing with the casing annulus flowing gas into a flow line at constant pressure, the fluid column below the gas/fluid interface consists of a gas/liquid mixture with gas bubbling through the liquid all the way from the perforations to the gas/fluid interface. This is defined as a **Gaseous Liquid Column**.

6- The flow rate of gas bubbling through the liquid, the annular area and the liquid properties determine the % of liquid which is present in a gaseous annular liquid column. The larger the gas flow rate, the smaller the % of liquid present in the gaseous liquid column. For high gas rates, both liquid and gas can be produced out of the casing valve so that there is not a definite gas/liquid interface in the annulus.

7- Closing the casing valve in a well producing gas from the casinghead will result in an increase in casinghead pressure. The casing pressure increase vs. time is a measure of the casinghead gas flow rate. The faster the increase, the greater the gas flow rate. Over short periods of time (less than 10 minutes) the casing pressure increase vs. time should be a straight line.

8- Keeping the casing valve closed in a well which normally produces gas from the casing will cause the fluid level in the annulus to be depressed as the casinghead pressure increases. In all cases the fluid level will drop to the pump intake if the casing valves remain closed for a sufficient period of time. During fluid level depression the PBHP may increase significantly above its normal value if tubing flow is limited by pump capacity.

9- A high fluid level in a well which is producing gas from the annulus is not necessarily an indication of a high producing BHP. Correct estimation of the PBHP can be made only taking into account the gas present in the annular gaseous liquid column and computing an equivalent **Gas-Free** fluid level. Measurements have been made in pumping wells where the annular fluid column consisted of only 10-15% liquid.

10-Very accurate PBHP can be calculated from measurement of casinghead pressure by installing a back-pressure regulator in the casinghead flow line and causing a controlled increase in pressure until the fluid level stabilizes just above the pump intake. Once stabilized conditions have been re-established, the measured casinghead pressure will then constitute the major component of the pump intake pressure and the PBHP can be calculated with great accuracy.

These facts have been applied to develop accurate methods for calculation of PBHP which are implemented automatically in various modern digital fluid level instruments. However since the majority of operators still use the classic strip chart fluid level instruments, the program AWP98 was developed to perform the PBHP calculation from readings obtained with strip chart data.

The calculation takes into account the PVT properties of the gas, oil and water on computing the densities of the fluids and the corresponding gradients and moreover it accounts for the effect of gaseous liquid columns by correlating the casing pressure buildup rate with the liquid fraction.

Calculation of SBHP

Estimates of the static formation pressure can be obtained from fluid level measurements in wells that have been shut in for a period of time sufficient for the wellbore pressure to approach the pressure at the drainage radius of the well. Ideally such pressure is best obtained by continuous measurement of fluid level and casing pressure during a pressure buildup test. Automatic fluid level instruments are used routinely for this purpose and yield results comparable to those obtained from bottom hole pressure gages.

The reality is however that pressure buildup tests are performed rarely since they may involve significant loss of production which in the eye of management is not justified by the improved knowledge of pressure or wellbore damage.

It is however recommended that an effort be made to compile information that will allow the operator to make accurate estimates of the SBHP for wells in a given reservoir by using all indications of a static liquid level supported by the formation pressure. This may include static fluid level surveys in wells shut in for maintenance or repair, undergoing workovers, swabbing operations, kill fluid density requirements, injectivity tests and of course bottom hole pressure surveys.

Just as in the case of Producing Bottom Hole Pressure calculation, in order to calculate the SBHP it is necessary to know the distribution and composition of wellbore fluids. This involves applying the following concepts that have been developed through experience:

1- When a pumping well is shut in at the surface, formation fluids will continue to flow into the well and will accumulate in the annulus. The rate of this "after flow" will decrease as the BHP increases, and eventually will stop. This effect contributes to what is known as wellbore storage effect.

2- It is not possible to accurately predict the WOR during the after flow period. Normally it is assumed that the WOR will remain unchanged from the WOR determined from well tests.

3- Fluid level and casing pressure measurement as a function of time during the shut in period generate good estimates of liquid and gas after flow, which can be used in buildup interpretation.

4- In general the liquid that was present in the annulus when the well was producing will remain in the annulus during the buildup and will be added to the after flow fluid. Occasionally it has been observed in high GOR wells that during the buildup the liquid level in the annulus decreases during the buildup. This is caused by the gas after flow causing sufficient pressure increase to displace the liquid into perforations connected to relatively low pressure stringers. This is especially the case when dealing with long perforated intervals.

5- In order to accurately calculate the pressure at static conditions it is necessary to have information regarding the producing fluid level, producing casing pressure, well test, etc. In other words a SBHP can only be computed if a PBHP survey has been performed prior to shutting-in the well.

6- Since most of the uncertainty about SBHP calculation is related to the composition of the liquid column in the wellbore at stabilized conditions, the most accurate results will be obtained when the height of such column is at a minimum. Thus if a conventional pressure buildup test is to be performed on a well, it is recommended that in preparation for the test, the producing fluid level be depressed to near the pump intake, by means of a back pressure regulator, as described above. If a single point SBHP test is to be performed, improved accuracy will be obtained if the casing valves are closed-in until the liquid level is depressed to the pump. Then the well is shut in and the pressure and liquid level allowed to stabilize (it may take several days) and the computed SBHP will be more accurate since there will be a minimum of liquid in the wellbore.

7- Since most reservoirs are inhomogeneous and often faulted, it is most likely that wells in the same reservoir will exhibit different SBHP depending on their location within the reservoir and their position relative to injectors or other producers. Thus SBHP is to be considered more a well property than a reservoir property that can be expressed as a single "average" value.

These concepts have been applied in developing software for automatic calculation of SBHP using digital fluid level instruments, and are also implemented in the AWP98 software. Details can be found in the Bibliography given at the end of the paper.

The AWP98 Software

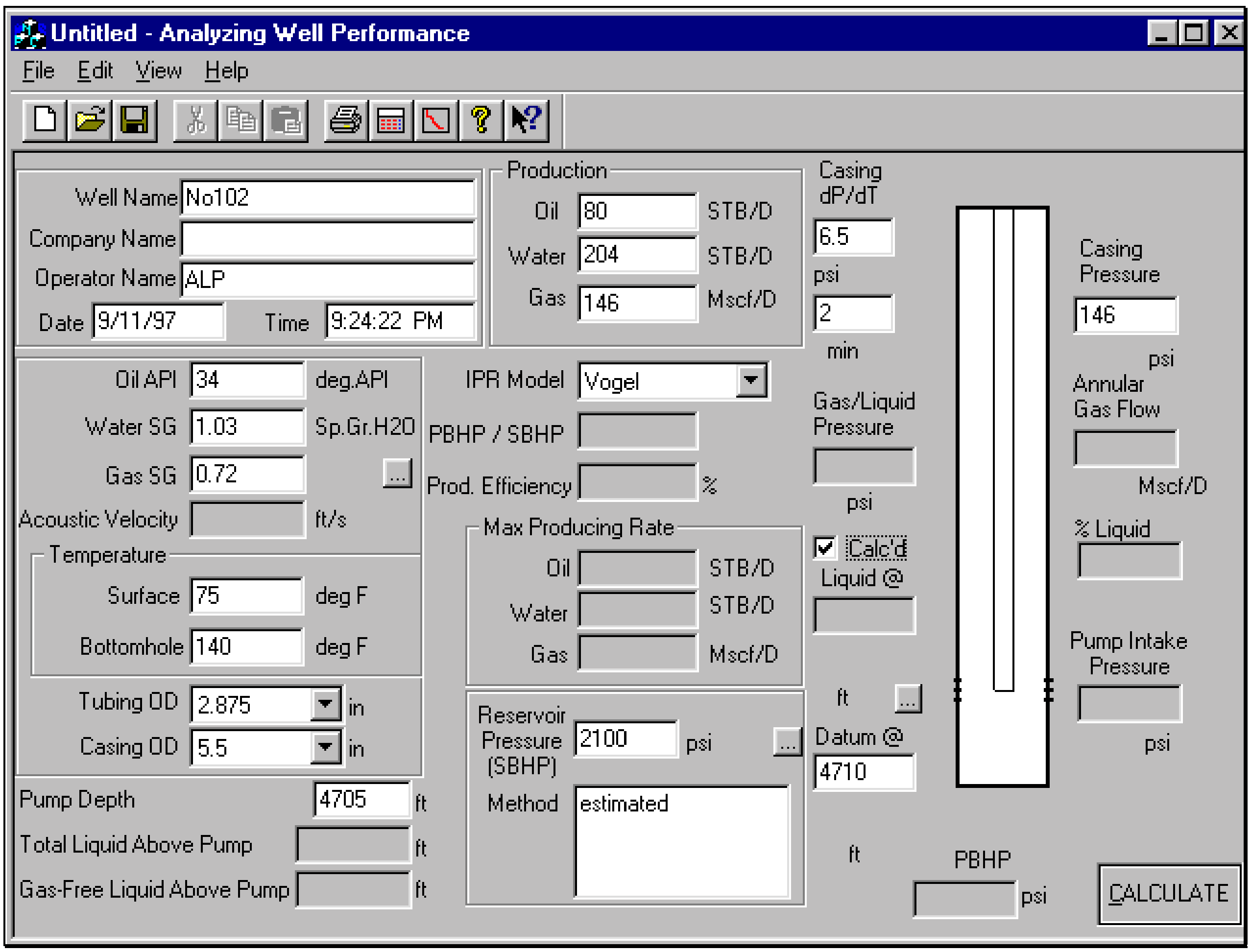
The objective of this program is to provide some guidance for obtaining a meaningful interpretation of fluid level data for the analysis of well performance. The program was designed with a user-friendly graphical interface which uses a data input form organized to represent a wellbore diagram. This facilitates visualization of the fluid distribution and the depth relationship between pump intake, perforations and fluid level. The user is required to obtain and enter all the pertinent data and is warned when important data is missing and offered to use default values if the necessary data is unknown.

Although the principal application of the program is envisioned for interpretation data obtained with strip-chart fluid level instruments, it is also useful in verifying the analysis obtained with digital fluid level recorders. In addition, the AWP98 program produces an output file in text format which can be imported into most spread sheet and data base software which can be used to effectively manage the data and develop historical trend graphs.

Description

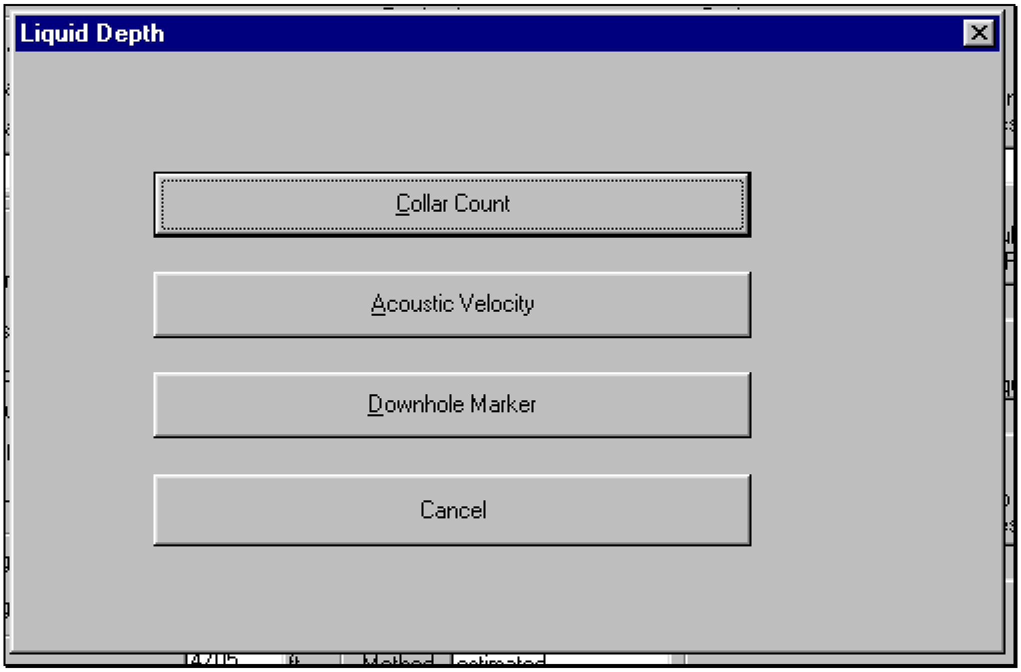
The AWP98 program uses data forms for input of the data and display of results. The following is the main form. Data is input into the fields with white background. Calculated values are displayed in the fields with gray background.

As data is input, the program constructs the wellbore diagram on the right side of the form. This diagram changes according to the values input. Calculated values are updated only when the CALCULATE button is selected. At this point, all the known values have been entered. The user has also selected the choice of having the program calculate the fluid level by checking the ellipsis by the Liquid box. This means that further input is required.

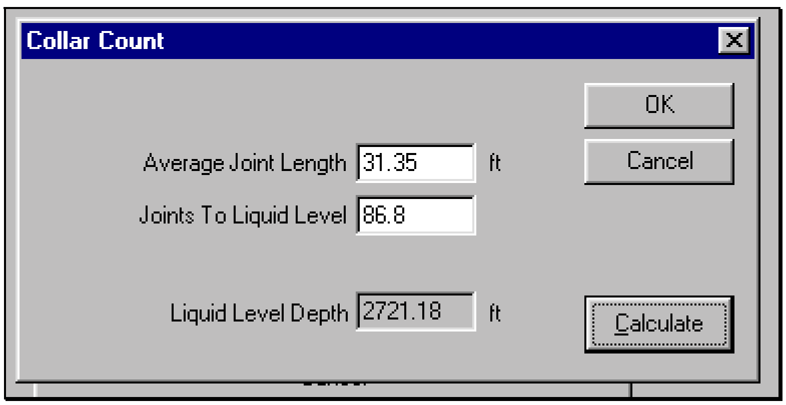


Notice that the user is required to enter a value for the Static Bottom Hole Pressure, even if it is only an estimate.

When the fluid level is calculated the following form is displayed. The user selects one of the buttons that describes the method to be used to calculate the liquid level. The most common choice is by inputting the result of a collar count from an acoustic strip chart.

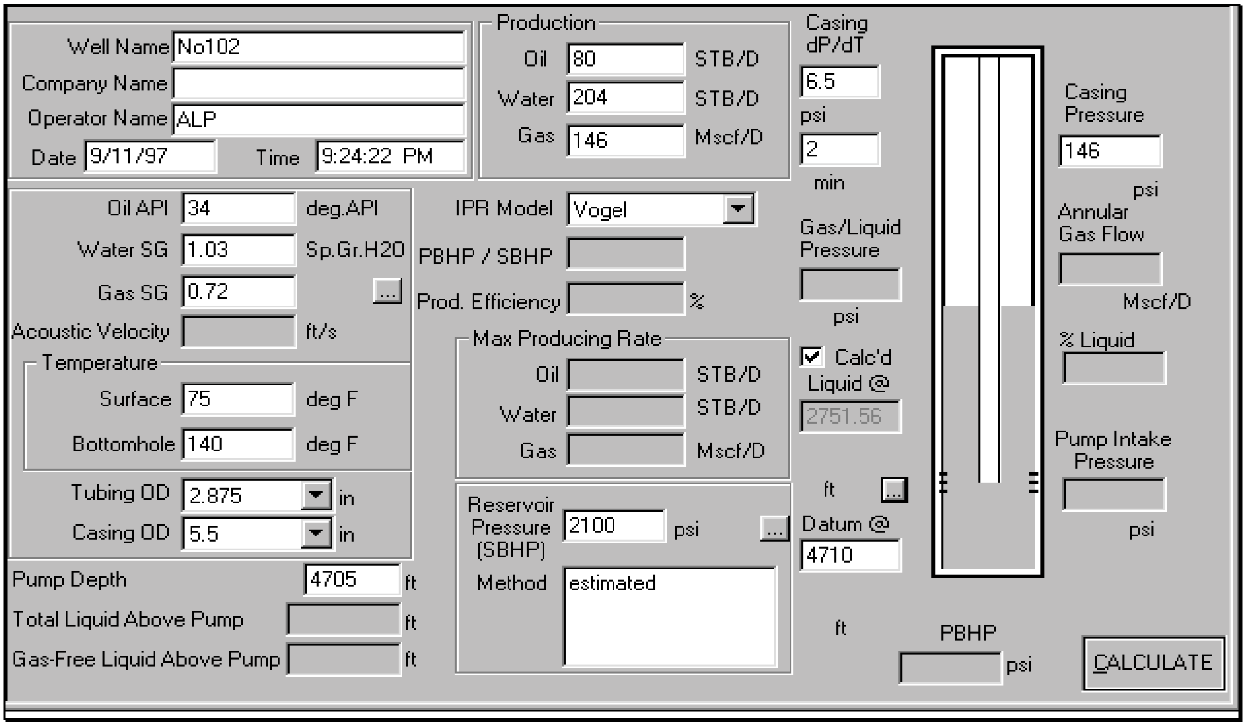


The collar count is entered in the following form, each of the other options has a corresponding input form.:

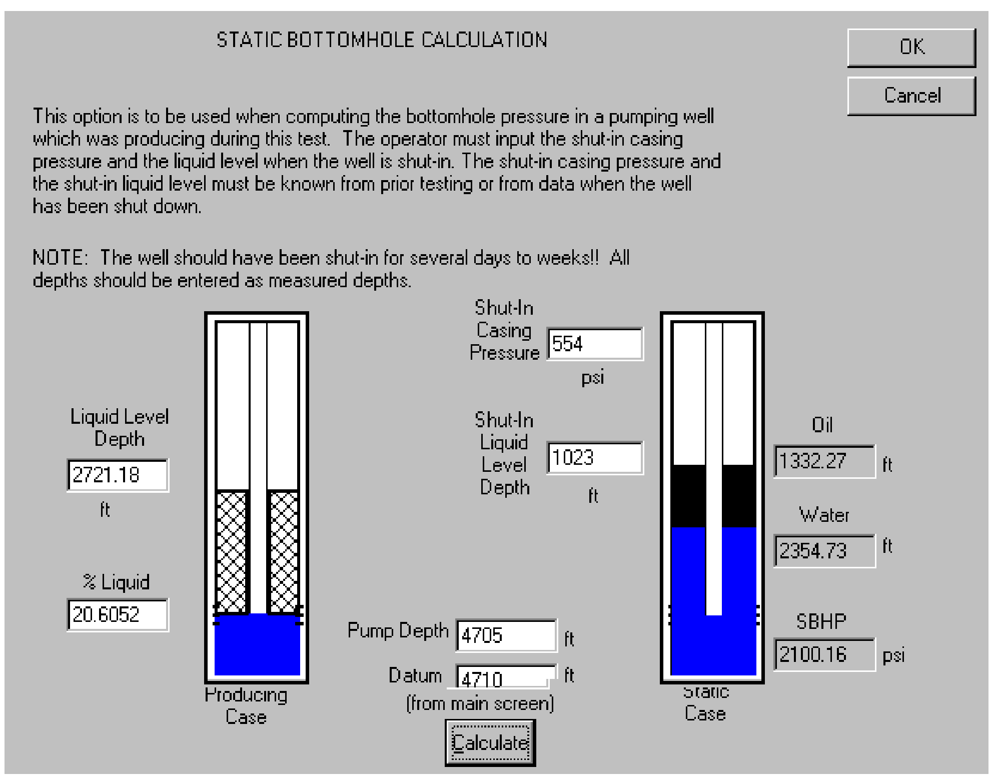


The fluid level depth is displayed once the Calculate button is selected.

Clicking OK returns to the main form, as shown below and the liquid level depth is now displayed on the form.

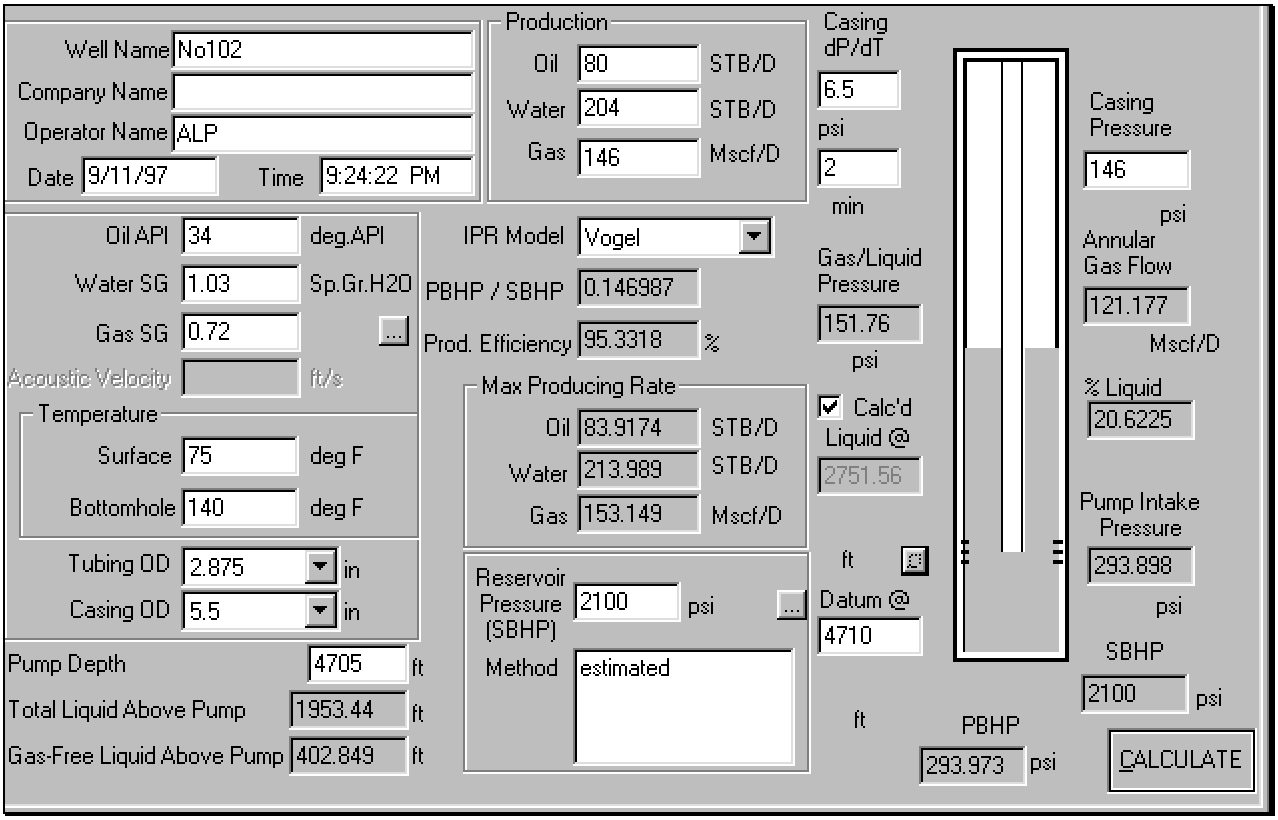


Often times the Static Bottomhole Pressure is not know. Knowledge of the producing bottomhole pressure is essential for analyzing well proformance. The program has the ability to calculate SBHP from shut-in liquid level and casing pressure measurements on the well. Clicking on the ellipsis next to the Reservoir Pressure field opens the form for calculation of the SBHP as shown below.



Clicking OK returns to the main form.

All the required data have been entered and the final calculations can be performed by selecting the Calculate button.



Interpretation of Results

The program has calculated the following values:

Pressure at gas/liquid interface	152 psi
Pressure at pump intake	294 psi
Producing BHP (pressure at datum depth)	294 psi
Annular gas rate	122 MCF/D
% Liquid in gaseous liquid column	21 %
Total Gaseous Liquid above pump	1953 feet
Total Gas-free Liquid above Pump	403 feet
Ratio of Producing to Static Pressure	0.14
Producing Efficiency	95 % (Vogel)
Maximum Flow Rate Possible	84 STBO/D

It can be concluded that the well is producing close to the maximum rate it can produce even though the fluid level survey indicates that there is a high fluid level (almost 2000 feet of fluid above the pump) but due to the high annular gas rate this fluid contains only 21 % liquid and thus exerts a relatively low back pressure on the formation.

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