Abstract

Gas well performance can deteriorate or improve as a result of changes in inflow and outflow. Early detection of such changes allows timely recognition of their impact on the production forecast and, if necessary and justified, timely execution of remedial activities. This article will demonstrate how comparison of subsequent surface pressure build-up (S-PBU) periods reveals either onset of formation water production and/or liquid loading and that can be use to estimate WGR. The S-PBU data can also be transformed into a dynamic inflow performance relation (D-IPR). It will be demonstrated how the evolution of this D-IPR reflects changes in inflow performance either due to impairment or due to stimulation. In addition, the D-IPR provides an independent measure of the gas production rate prior to shut-in. And best of all, this data is abundant, typically free of charge and easily digestible.

Introduction

Figure 1 shows an example of a surface pressure build-up observed after shutting-in gas well X-1 which illustrates three consecutive stages:

1. Early-time: the frictional pressure drop across the wellbore decreases almost instantaneously as the gas production at surface stops.
2. Mid-time: the gas after-flow from the reservoir re-pressurizes the wellbore; also known as the wellbore storage period.
3. Late-time: the bottom-hole pressure equilibrates with the reservoir pressure; this is known as the pressure transient period during which the pressure differential across the reservoir gradually dissipates.

The pressure transient periods are routinely used by reservoir engineers to perform pressure transient analysis (PTA) to derive reservoir properties such as permeability, reservoir boundaries, dual porosity characteristics, hydraulic fracture effective length etc. In PTA the wellbore storage period is also matched in conjunction with radial flow estimation to assess the wellbore skin. PTA is best performed making use of bottom hole pressure data as the surface pressure data is impacted by evolution of both the wellbore temperature profile and the liquid holdup profile during the shut-in period. Methods have been introduced to correct for these wellbore temperature and holdup variations, see Fair (2002). The accuracy of the
calculated bottom-hole pressure is generally adequate in terms of absolute pressure values e.g. used for material balance purposes, but can be insufficient for the small pressure variations that are essential for PTA, see Spyrou (2013).

In terms of PTA, the wellbore storage period and the variations in wellbore temperature and liquid holdup are considered a nuisance. A downhole shut-in tool and pressure measurement are used where possible to eliminate the disturbances introduced by the wellbore. Also, PTA typically requires long shut-in periods to distill reliable reservoir information. In this paper, it will be demonstrated that short duration gas well surface pressure build-up (S-PBU) data contains significant surveillance value not so much in terms of reservoir performance but in terms of well performance.

The goal of gas reservoir and well surveillance is to monitor reservoir and well performance. Figure 2 shows a schematic of a gas well draining a gas reservoir and introduces the parameters that feature in the rest of this paper. The average reservoir pressure $P_{\text{res}}$ (bara) is typically used to construct material balance plots to derive the connected gas volume and possibly aquifer pressure support, while the near-wellbore reservoir pressure $P_{\text{res, nw}}$ (bara) together with the inflow resistance $A$ (bar$^2$/10$^3$Sm$^3$/d) and the bottom-hole pressure BHP (bara) controls the gas inflow rate $Q_{\text{gas}}$ ($10^3$Sm$^3$/d) via the Forchheimer inflow relation assuming Darcy inflow:

$$P_{\text{res, nw}}^2 - \text{BHP}^2 = A\cdot Q_{\text{gas}}$$
where $A$ is inversely proportional to the reservoir permeability times net height product and increases with increasing wellbore skin. In this paper, it will be demonstrated how surface pressure build-up data can be used to detect changes in inflow resistance. The completion volume $V$ (m$^3$) determines the time required to re-pressurize the wellbore after production is shut-in and it will be shown how this information can be used to provide a rough measure of gas rate in absence of any other source of information.

A high water-gas ratio $WGR$ (m$^3$/10$^6$Sm$^3$) is indicative of formation water influx which can result in a production problem associated with either a surface water handling constraint, water cross-flow during extended shut-ins and/or increasing inflow resistance as water inflow replaces gas inflow. The liquid holdup $HU$ (-) is proportional to this $WGR$ and increases due to liquid loading if $Q_{gas}$ drops below the so-called critical gas rate $Q_{min}$ (10$^8$Sm$^3$/d) required to lift liquids to surface. This paper will present how S-PBU data can be used to detect a significant increase of liquid holdup due to increasing $WGR$ or due to liquid loading, and how $WGR$ can be estimated based on distinct characteristics of consecutive S-PBU records.

**Outflow Performance**

In a stable flowing gas well, the pressure drop across the wellbore between the tubing head pressure (THP) and BHP is determined by $Q_{gas}$ together with the wellbore hydrostatic parameter $B$ (-) and friction parameter $C$ (bar$^2$/10$^3$Sm$^5$/d$^2$) via the Cullender-Smith (C-S) outflow relation:

$$BHP^2 = B \cdot THP^2 + C \cdot Q_{gas}^2$$  \hspace{1cm} (2)

Ignoring the underlying complexity, shut-in or closed-in tubing head pressure (CITHP) data can be converted into shut-in of closed-in bottom-hole pressure (CIBHP) data by setting $Q_{gas} = 0$ in eq. (2):

$$CIBHP = B^{0.5} \cdot CITHP$$  \hspace{1cm} (3)

where the hydrostatic parameter $B$ can be approximated for dry gas by:

$$B_{dry} = e^{0.0683 \cdot SG_{dry} \cdot TVD / (THT + BHT + 273) - Z}$$  \hspace{1cm} (4)

and $SG_{dry}$ is gas specific gravity (air=1), TVD is true vertical depth (m), THT and BHT are tubing head
and bottom hole temperature (degC) and Z is gas deviation factor (-). Bdry mainly depends on TVD and SGdry and typically varies between 1.3 and 1.8. The combination of Eqs. (3) and (4) provides an estimate of CIBHP typically within 1-2% of actual values. Higher accuracy can be achieved by correcting for the gradual reduction of the wellbore temperature (approximated by FTHT and FBHT) following shut-in which effectively increases Bdry and reduces CITHP, see Fair (2002). Such temperature correction is available in commercial PTA software.

Oden (1980) accounts for the presence of associated water and condensate whilst flowing by increasing the effective gas specific gravity from SGdry to SGwet, as following:

$$SG_{wet} = 0.8157 \cdot (SG_{dry}/0.8157 + 10^{-3} \cdot WGR + 0.8 \cdot 10^{-3} \cdot CGR)$$

where CGR is condensate-gas ratio (m³/10⁶Sm³) and the relative density of water and condensate are assumed fixed at 1.0 and 0.8 (water=1). For example, in case WGR and CGR both equal 100 m³/10⁶Sm³ Eq. (5) will turn SGdry=0.6 into SGwet=0.75. This higher SGwet then turns the dry gas Bdry into a wet gas Bwet, as following:

$$B_{wet} = B_{dry} \cdot (SG_{wet}/SG_{dry})$$

For example, assuming Bdry=1.50 Equation (6) results in Bwet=1.66. Assuming THP=50 bara, Eq. (2) then dictates BHP at Qgas =0 of 61.2 and 64.4 bara for Bdry and Bwet respectively which means that in this example case the associated liquids increase the hydrostatic head whilst flowing by 3.2 bara or 28% from a dry 11.2 bara to a wet 14.4 bara.

Note that a more representative value for Bwet can be derived by matching Eq. (3) to outflow curves generated using commercial software. This is illustrated in Figure 3 which shows the outflow points calculated for a high WGR of 1000 m³/10⁶Sm³, together with the C-S dry gas outflow curve and the C-S wet gas outflow curve matched against the calculated outflow points; the hydrostatic component of the outflow curves is described by Bdry=1.39 and Bwet=2.62 respectively.
Data Quantity, Quality and Collection

Figure 4 plots 1 year of real-time THP and $Q_{\text{gas}}$ data for gas well X-1. This data set contains 30 shut-in periods of which most are relatively short (several hours) and unscheduled. Based on reviewing a large number of producing gas wells, the number of yearly shut-in’s per well typically varies between 10 and 100 providing an abundance of potential gas well performance surveillance moments.

Nowadays, real time gas rate and surface pressure and temperature data is routinely acquired and stored a few times per minute which is adequate for the purposes presented in this paper. A tool was build that retrieves all consecutive PBU periods for a specific well and then facilitates comparison and further analysis as described below. The accuracy of modern digital pressure gauges tends to be better than 0.1 bara which again is sufficient for the purposes presented in this paper. The most commonly observed practical problem is that the data is compressed to save bandwidth and storage capacity. This can inadvertently result in insufficient data frequency and resolution, and is observed in quite a few of the examples presented below. In those cases surveillance value can be maximized by changing the compression settings.

Another common problem is that the well is shut-in up-stream of the digital pressure gauge which translates into zero data during shut-in. This can be fixed by either moving the gauge up-stream of the shut-in valve or by actuating an alternative valve down-stream of the pressure gauge.

Compare and Analyze Surface Pressure Build-Up Periods

Eq. (3) only applies if the wellbore is filled with gas because the presence of a liquid column affects the hydrostatic pressure component and distorts the pressure build-up until the liquid has drained back into the reservoir. This is clearly illustrated in Figure 5 which shows an example of consecutive S-PBU periods for well X-2 that experiences water breakthrough with increasing WGR in periods #1/2/5 ($\sim$2000 m$^3$/106Sm$^3$ in #5), is successfully treated by water shut-off in period #64, and suffers water breakthrough again in period #86. The pressure range across which pressure build-up is distorted is denoted $\Delta$ (bara) and increases from 3 to 30 bara with increasing WGR.
The multi-phase redistribution process that distorts the S-PBU is described cartoon-style in Fig. 6: following shut-in the liquid and gas in the wellbore separate resulting in a gas column sitting on top of a liquid column. In the mean time wellbore re-pressurization has commenced and shifts the entire gas-liquid pressure profile towards higher values. As the liquid column pressure profile approaches the reservoir gas pressure profile the gas inflow from the reservoir will slow down disproportionately as the liquid column diminishes the effective drawdown. Eventually the liquid column pressure will locally exceed the reservoir gas pressure resulting in even less gas inflow and onset of liquid drainage. Once the entire liquid column has drained Eq. (3) with $B_{\text{dry}}$ applies.

The time required for draining the liquid column depends on the liquid column height, the near-wellbore reservoir quality and height, the wellbore trajectory and the presence of fractures, and can range
from less than one hour to more than one week. The surface pressure build-up during the liquid drainage phase is typically 3-30x slower than before the liquid drainage phase. Note that the liquid column in a gas well will eventually drain away unless the well is connected to a water producing layer with higher pressure than the gas reservoir; in that case a standing liquid column will remain and water cross-flow will occur during shut-in. The latter inevitably causes kick-off problems in case of an extended shut-in period.

The onset of liquid loading also increases the liquid content of the wellbore and causes a similar distortion of the S-PBU. Liquid loading occurs when $Q_{\text{gas}}$ reduces below $Q_{\text{min}}$. This is illustrated in Figures 7 and 8 which depict S-PBU’s for wells X-3 and X-4 with and without liquid loading. $\Delta$ reflects the liquid column that has been building during the liquid loading period. Hence a higher $\Delta$ means a higher BHP and hence a lower $Q_{\text{gas}}/Q_{\text{min}}$. This is clearly observed in Figure 8 where $\Delta$ of 1, 3 and 10 bara correspond to $Q_{\text{gas}}/Q_{\text{min}}$ of 0.91, 0.73 and 0.06 respectively.
Figure 9 shows a series of S-PBU periods for well X-5 which first demonstrates onset of liquid loading from #80 to #163, followed by unloading due to continuous foam injection from #163 to #243. Note that the presence of foam distorts the shape of the S-PBU in a different fashion as before: instead of a change in slope the surface pressure reaches a plateau which is sustained for about 1 hour until pressure builds up to the undistorted long term value. Figure 10 shows another example for well X-6 which displays the same characteristics where the plateau value with foam injection lasts for 2-4 hours. The probable explanation is that foam and gas do not segregate as quickly as water and gas and that a column of foam collects in the wellbore which only reaches the perforated reservoir interval after hours.

![Figure 9—Selected S-PBU periods for well X-5 illustrating liquid loading and foam injection](image1)

![Figure 10—Selected S-PBU periods for well X-6 illustrating liquid loading and foam injection](image2)

**Determine WGR based on S-PBU**

In case liquid loading is absent ($Q_{gas}$ exceeds $Q_{min}$) but a pressure distortion can be recognized, the surface PBU and $\Delta$ can be used to estimate WGR using one of the following methods:
\( \Delta \) is translated into a value of WGR by dividing the liquid volume in the wellbore over the gas volume at standard conditions, where the liquid volume \( V_{\text{liq}} \) (m\(^3\)) follows from:

\[
V_{\text{liq}} = (\pi/4) \cdot \text{ID}^2 \cdot 10 \cdot \Delta / \cos \Phi
\]

(7)

Where ID and \( \Phi \) are the tubing internal diameter (m) and the deviation (deg) across the bottom section of the wellbore where the liquid column accumulates. The gas volume at standard conditions \( V_{\text{gas}} \) (Sm\(^3\)) at shut-in follows from the actual gas volume \( V_{\text{gas},a} \) (m\(^3\)) by assuming \( Z=1 \) (see below) and zero friction:

\[
V_{\text{gas}} = V_{\text{gas},a} \cdot \text{FTHP} \cdot (1 + B_{\text{dry}}^{0.5})/2
\]

(8)

Where \( V_{\text{gas},a} \) equals \( V \) minus \( V_{\text{liq}} \), and FTHP is the flowing THP (bara). For a monobore completion and \( V_{\text{liq}} \ll V_{\text{gas}} \), one then derives:

\[
\text{WGR} = 10^7 \cdot \Delta \left[ \text{AHD} \cdot \cos \Phi \cdot \text{FTHP} \cdot (1 + B_{\text{dry}}^{0.5})/2 \right]
\]

(9)

where AHD is the along hole depth (m). This WGR value represents an upper limit as slip between the liquid phase and gas phase flowing up the tubing increases the liquid fraction relative to the gas fraction. A value \( \Delta \) of 1 bara can easily be observed if accurate pressure gauges are used and data is acquired and stored at sufficient frequency. Eq. (9) with \( \Delta = 1 \) bara, AHD=3000 m, \( \Phi = 0 \) deg, FTHP=10-100 bara and \( B_{\text{dry}} = 1.5 \) thus translates into a minimum detectable WGR of \( \sim 300-30 \) m\(^3\)/10\(^6\)Sm\(^3\).

\( \Delta \) is translated into a value of \( B_{\text{wet}} \) assuming that \( \Delta \) corresponds to the difference between the wet and dry gas C-S outflow curve at \( Q_{\text{gas},0} \) as illustrated in Figure 3, and \( B_{\text{wet}} \) is then used to calculate \( S_{G_{\text{wet}}} \) and WGR. \( B_{\text{wet}} \) follows from:

\[
\Delta = \text{FTHP} \cdot (B_{\text{wet}}^{0.5} - B_{\text{dry}}^{0.5})
\]

(10)

This results in:

\[
B_{\text{wet}} = B_{\text{dry}} \left[ \text{FTHP}/(\text{FTHP}-\Delta) \right]^{2}
\]

(11)

For the example in Figure 5, \( \Delta \) is \( \sim 30 \) bara in period #5; with FTHP=80 bara and \( B_{\text{dry}} = 1.5 \), one derives \( B_{\text{wet}} = 3.84 \). Now, the value of \( B_{\text{wet}} \) is translated into a value of \( S_{G_{\text{wet}}} \) using Eq. (4) as following:

\[
S_{G_{\text{wet}}} = S_{G_{\text{dry}}} \cdot \ln(B_{\text{wet}})/\ln(B_{\text{dry}})
\]

(12)

For \( S_{G_{\text{dry}}} = 0.6 \), one calculates \( S_{G_{\text{wet}}} = 1.99 \). WGR is then calculated using Eq. (5) as 1700 m\(^3\)/10\(^6\)Sm\(^3\) of the same order of magnitude as the well test value of \( \sim 2000 \) m\(^3\)/10\(^6\)Sm\(^3\). For comparison, Eq. (9) results in WGR=1100 m\(^3\)/10\(^6\)Sm\(^3\) i.e. of the same order of magnitude.

\( \Delta \) is used to match WGR (and \( B_{\text{wet}} \)) assuming that \( \Delta \) corresponds to the difference between the wet and dry gas C-S outflow curve at \( Q_{\text{gas},0} \) as illustrated in Figure 3. In the example of Figure 3, \( \Delta \) of 22 bara requires WGR=1000 m\(^3\)/10\(^6\)Sm\(^3\) and corresponds to \( B_{\text{wet}} = 2.62 \). This outflow matching method is considered most representative. A study to establish the accuracy of the different methods will be carried out in future.

**Calculate and Compare Dynamic Inflow Performance Relations**

If one ignores wellbore friction, the rate at which THP increases \((d\text{THP}/dt)\) can be used to calculate the gas rate flowing into the bottom of the tubing. Utilizing Eq. (3) and assuming \( Z=1 \) for convenience, one derives:

\[
Q_{\text{gas}} = V \cdot (d\text{THP}/dt) \cdot (1+ B^{0.5})/2000
\]

(13)

where \( t \) denotes time (days). Note that \( Q_{\text{gas}} \) refers to bottom hole conditions as the gas rate at surface is zero; this bottom hole gas flow is referred to in PTA literature as after-flow. In this paper \( V \) is taken as the completion volume only i.e. \( V \) does not include the volume of any natural or hydraulic fractures. Setting \( Z=1 \) introduces an error that varies with pressure and temperature i.e. varies across the wellbore.
For the examples in this paper the average error across the wellbore ranges from 5% at lower pressure (below 50 bara) to 10% at higher pressure (above 100 bara). Future tool development will incorporate Z when calculating $Q_{\text{gas}}$.

Plotting the BHP calculated via Eq. (3) against $Q_{\text{gas}}$ from Eq. (13) then results in a so-called dynamic inflow performance relation (D-IPR). This process is illustrated in Figure 11 for well X-7. The three stages that were observed in the S-PBU can again be recognized: the early-time or high-rate part reflects the dissipation of wellbore friction; the mid-time or medium-rate part corresponds to the wellbore storage phase and reflects inflow performance and liquid drainage, while the late-time or low-rate part represents the pressure building back up to the average reservoir pressure. In most gas wells analyzed to date, the wellbore storage phase of the PBU could be successfully matched against the inflow performance parameters of Eq. (1) i.e. $A$ and $P_{\text{res, nw}}$, see Fig. 11.

![Figure 11—Illustrating calculation of D-IPR based on S-PBU and matching of D-IPR against Forchheimer inflow relation for well X-7](image)

Figure 12 shows the surface PBU’s and corresponding dynamic IPR’s for well X-8 before and after a hydraulic fracture stimulation treatment. The stimulation treatment results in a two-fold reduction of the dynamic inflow resistance $A$ which corresponds to a productivity improvement factor (PIF) of 1.5.

![Figure 12—D-IPR of well X-8 before and after hydraulic fracture stimulation](image)
A significant liquid column will impact the S-PBU and therefore also the D-IPR. Figs. 13 and 14 show the D-IPR curves corresponding to the S-PBU curves in Figs. 7 and 10: the same pressure distortion \( \Delta \) can be recognized in both plots. Figures 13 and 14 show that despite the presence of a liquid column the pressure build-up prior to the onset of liquid drainage is still governed by the same dynamic inflow resistance \( A \). The dynamic \( A \) derived from PBU’s has been compared to the static \( A \) derived from multi-rate test data for a number of wells. Figure 15 demonstrates good agreement between these two measures of \( A \).
The dynamic IPR also provides a measure of the gas production prior to shut-in by reading off \( Q_{\text{gas}} \) at the anticipated BHP. This can provide a value for gas rate even in the absence of any gas metering. Calculated and measured values of \( Q_{\text{gas}} \) have been in reasonable agreement, see Figure 11, where the wellbore friction prior to shut-in was small compared to the wellbore hydrostatic.

**Discussion**

The surface pressure build-up (S-PBU) and dynamic inflow performance relation (D-IPR) should primarily be considered as tools to detect changes in gas well inflow or outflow performance by comparing consecutive S-PBU and D-IPR periods. This allows early identification of changing well conditions which can trigger either additional surveillance (e.g. production logging or well testing) or remediation (e.g. stimulation, water shut-off, deliquification, sand clean-out). These changes in gas well performance can be readily spotted by most production engineers or can be programmed for pattern recognition as part of exception based surveillance efforts.

In addition S-PBU and D-IPR help estimate well parameters such as inflow resistance (\( A \)), water-gas ratio (WGR), and gas rate (\( Q_{\text{gas}} \)) in absence of other relevant surveillance data such as multi-rate well test data. Acquiring such surveillance data can be challenging due to logistics and cost issues, especially in case of offshore unmanned platforms or subsea wells. However, the well parameters derived should be used with caution. This pertains both to the WGR derived from \( \Delta \) in S-PBU and/or D-IPR as well as to the \( A \) and \( Q_{\text{gas}} \) derived from D-IPR. Also note that assuming \( Z=1 \) did introduce a small but significant error (5-10% in examples) which will be rectified in future versions of tools.

The volumetric estimate of WGR using Eq. (9) assumes no-slip between the gas phase and the liquid phase which should result in a conservative i.e. too high value of WGR. The approach that derives \( S_{\text{wet}} \) via Eq. (12) and WGR using Eq. (5) could be more representative. The most reliable estimate is produced by matching \( \Delta \) against outflow curves for varying WGR. The WGR values calculated to date have been of the same order of magnitude as well testing values. Obviously, WGR can only be inferred as long as \( Q_{\text{gas}} \) exceeds \( Q_{\text{min}} \).

The D-IPR calculation is based on a number of assumptions. Most important, fluid friction is ignored, phase redistribution is ignored, temperature changes are ignored and the wellbore volume is assumed known and constant. Ignoring fluid friction is justified in case of low gas rate and large tubing but could affect the initial phase of wellbore storage in case of high gas rate or small tubing. Ignoring temperature
changes during PBU is also justified in case of low gas rate but could impact both the mid-time and late-time analysis results in case of high enough gas rate. The impact of both fluid friction and temperature has been small in cases investigated so far. Transient multiphase flow calculations would be able to provide more insight regarding the influence of fluid friction and wellbore temperature.

Phase redistribution is described by Stegemeier (1958) for the case of gassy oil wells and has been investigated in detail by Fair (1981) and Olarewaju (1989). Essentially, in the extreme case of a closed wellbore the process of gas and liquid segregation causes an increasing surface as well as bottom hole pressure: Figure 16 illustrates the process of flipping the gas and liquid content of a wellbore closed at top and bottom, and highlights that the magnitude of phase redistribution can be significant. Please keep in mind that Fig. 16 assumes the most extreme initial situation of liquid on top of gas, and ignores the impact of liquid drainage and pressure build-up. Al-Darmak (2006) states that the evolution of the incremental pressure is determined by the velocity of (Taylor) gas bubbles rising in liquid which is about 0.25-0.45 m/s for practical completion sizes and results in 2-3 hours for a 3000 m deep well. This is a conservative number considering that the flow regime in most gas wells is annular rather than bubble flow. OLGA simulations for 3000 m deep gas wells indeed indicate much faster segregation of the liquid and gas phases, typically within 0.5-1 hour. This is also in line with the S-PBU field data which indicate full drainage of the liquid column within hours.

Figs. 7 and 8 show humps in the S-PBU records which could be ascribed to phase redistribution after shut-in of these liquid loaded wells. The humps are most pronounced in case of advanced liquid loading when the liquid column in the well is largest. Stegemeier (1958) argues that the pressure humps increase as the liquid fraction in the wellbore increases and shows that they decrease as the reservoir quality improves. Figure 17 shows 3 S-PBU periods for well X-9: #1 represents moderate WGR and stable flow, #2 represents high WGR and advanced liquid loading, while #3 reflects high WGR and early liquid loading. S-PBU periods #2 and #3 exhibit pressure humps of ~6 bara and ~2 bara respectively, proportional to the liquid column height Δ of ~60 bara and ~20 bara respectively.
The observation of the pressure plateau in case of foam injection probably reflects the reduced downward velocity of foam compared to water. Based on the S-PBU field data it appears that water will reach the bottom of a 3000 m well with 1 hour, while foam could take at least several hours. This type of S-PBU surveillance data will help diagnose foam deliquification performance, complimentary to acoustic liquid level monitoring, see McCoy (2009).

A fixed mechanical wellbore volume is a fair assumption in absence of significant natural or hydraulic fractures. If conductive fractures are present they could effectively increase the wellbore volume and thereby impact the wellbore storage phase of the S-PBU. Given the same S-PBU data, a larger effective wellbore volume translates into a lower $A$ and a larger $Q_{\text{gas}}$. Hence the current fixed mechanical wellbore volume results in conservative (high) values for $A$ and (low) values for $Q_{\text{gas}}$. The comparison of the calculated $Q_{\text{gas}}$ with the $Q_{\text{gas}}$ measured just before shut-in could be used to derive the effective wellbore volume. The examples examined to date have not highlighted significant fracture volumes: Fig. 15 demonstrates that the dynamic and static values for $A$ are in reasonable agreement.

The D-IPR’s shown in Figs. 11, 13 and 14 all show a good demarcation between the wellbore storage phase and the pressure transient phase of the build-up period. In those cases a near-wellbore reservoir pressure can be assigned that, together with the dynamic $A$ will match the wellbore storage phase. Fig. 12 shows D-IPR’s where this demarcation becomes less evident. This is expected for tight gas reservoirs where the reservoir pressure transient part becomes significant. The limits of this type of D-IPR analysis are yet to be clearly established.

When tracking gas well inflow performance it is much more relevant to monitor the inflow performance relative to a well defined near-wellbore reservoir pressure than relative to a time dependent transient reservoir pressure. When $A$ is calculated using $P_{\text{res}}$ instead of $P_{\text{res, nw}}$, $A$ tends to be overestimated because it then reflects a combination of inflow performance and reservoir performance. In reservoir simulators where wells are located in sizable reservoir blocks the inflow resistance by necessity must capture both inflow performance plus the transient reservoir pressure inside the “well” block resulting in a value of $A$ that increases with block size. By monitoring the D-IPR derived $A$ relative to the near-wellbore reservoir pressure one directly monitors how wellbore skin is affected by impairment, stimulation, water breakthrough etc. For example, Fig. 12 shows a reduction of $A$ following hydraulic fracture stimulation.

The process of liquid segregation and drainage may be clear in concept but has escaped detailed modeling so far. Dousi (2006) and Hu (2010) present examples of transient multi-phase modeling. More
such modeling should improve insight into the details of the PBU process and facilitate better utilization for surveillance purposes.

This paper has elaborated the value of S-PBU for gas well surveillance. No doubt, oil well S-PBU data could bring significant surveillance value as well. In oil wells the situation is more complicated due to incomplete liquid drainage and the presence of 3 distinct fluid phases i.e. gas, oil and water. Nonetheless, oil well S-PBU data is just waiting to be explored e.g. to detect changes in BS&W and/or GOR.

Conclusions

1. The comparison of gas well surface pressure build-up (S-PBU) periods can be used to identify changes of liquid holdup that reflect either increasing water-gas ratio (WGR) or liquid loading. The liquid holdup in the wellbore after shut-in translates into a pressure distortion across a range $\Delta$. In case the gas well is not liquid loading $\Delta$ can be used to guestimate WGR. In gas wells that receive foam injection S-PBU’s can be used to track foam performance.

2. The wellbore storage part of the S-PBU can be transformed into a dynamic inflow performance relation (D-IPR) which can then be matched by a combination of inflow resistance ($A$) and near-wellbore reservoir pressure ($P_{res, nw}$). Changes of these inflow parameters will reflect either impairment or stimulation. The pressure distortion range $\Delta$ is clearly visible in the D-IPR as well. The dynamic inflow resistance calculated from D-IPR data is in reasonable agreement with the static inflow resistance derived from multi-rate testing data. Also the gas rate prior to shut-in estimated based on the D-IPR tends to be in reasonable agreement with the measured gas rate provided that the wellbore friction prior to shut-in is small compared to the wellbore hydrostatic pressure.

3. The pressure build-up period should be analyzed in more detail using transient multiphase flow simulators to get better grip on fluid friction, phase redistribution and liquid drainage.

Acknowledgements

We want to acknowledge Lynn Rowlan from Echometer for pointing out the possibility of constructing a dynamic inflow performance relation based on surface pressure build-up data, Intesar Mahmood for testing early versions of the Excel data repository during his internship, and Simon Trin from NAM for his thorough review and discussion over PTA implications of the presented workflow.

Nomenclature

- $A$: Forchheimer inflow resistance (bar$^2$/10$^3$Sm$^3$/d)
- $AHD$: Along Hole Depth (m)
- $B$: C-S gas hydrostatic parameter (-)
- $B_{dry}$: C-S dry gas hydrostatic parameter (-)
- $B_{wet}$: C-S wet gas hydrostatic parameter (-)
- $BHP$: Bottom Hole Pressure (bara)
- $BHT$: Botton Hole Temperature (degC)
- $C$: C-S gas friction parameter (bar$^2$/10$^3$Sm$^3$/d$^2$)
- $C_{wet}$: C-S wet gas friction parameter (bar$^2$/10$^3$Sm$^3$/d$^2$)
- $C-S$: Cullender-Smith
- $CGR$: Condensate-Gas Ratio (m$^3$/10$^6$Sm$^3$)
- $CITHP$: Closed-In Tubing Head Pressure (bara)
- $D-IPR$: Dynamic Inflow Performance Relation
- $FTHP$: Flowing Tubing Head Pressure (bara)
- $HU$: Liquid Hold-up (-)
<table>
<thead>
<tr>
<th>Symbol</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>$P_{res}$</td>
<td>Average reservoir pressure (bara)</td>
</tr>
<tr>
<td>$P_{res, nw}$</td>
<td>Near-wellbore reservoir pressure (bara)</td>
</tr>
<tr>
<td>$PTA$</td>
<td>Pressure Transient Analysis</td>
</tr>
<tr>
<td>$Q_{gas}$</td>
<td>Gas rate ($10^3$Sm$^3$/d)</td>
</tr>
<tr>
<td>$Q_{min}$</td>
<td>Minimum stable gas rate ($10^3$Sm$^3$/d)</td>
</tr>
<tr>
<td>$SG$</td>
<td>Dry gas specific gravity (air=1)</td>
</tr>
<tr>
<td>$SG_{wet}$</td>
<td>Wet gas specific gravity (air=1)</td>
</tr>
<tr>
<td>$S-PBU$</td>
<td>Surface Pressure Build-Up</td>
</tr>
<tr>
<td>$THP$</td>
<td>Tubing Head Pressure (bara)</td>
</tr>
<tr>
<td>$THT$</td>
<td>Tubing Head Temperature (degC)</td>
</tr>
<tr>
<td>$V$</td>
<td>Completion volume (m$^3$)</td>
</tr>
<tr>
<td>$V_{gas}$</td>
<td>Completion gas volume at standard conditions (Sm$^3$)</td>
</tr>
<tr>
<td>$V_{gas, a}$</td>
<td>Completion gas volume at actual conditions (m$^3$)</td>
</tr>
<tr>
<td>$V_{liq}$</td>
<td>Completion liquid volume (m$^3$)</td>
</tr>
<tr>
<td>$WGR$</td>
<td>Water-Gas Ratio (m$^3$/10$^6$Sm$^3$)</td>
</tr>
<tr>
<td>$Z$</td>
<td>Gas deviation factor (-)</td>
</tr>
<tr>
<td>$\Delta$</td>
<td>Range of PBU distortion (bara)</td>
</tr>
<tr>
<td>$\phi$</td>
<td>Wellbore deviation (deg)</td>
</tr>
</tbody>
</table>

**References**


