Case Study

ENERGY

How to Forecast Production When There is No Declining Rate

Objective

Our client was producing from a gas reservoir. For the purposes of reserves determination, and optimization of future development, the client requested that we determine the following:

- Original Gas-in-Place
- Forecast of future production (recoverable reserves)

Background

The first three wells came on production in 2001, and an additional 3 wells in 2007 (Figure 1). The only other data supplied were:

- production rates,
- flowing wellhead pressures;
- initial reservoir pressure in 2001,
- reservoir pressure in 2007, obtained just before one of the 2007 wells was placed on production.

There was no decline in the rate. No petrophysics or geological information was provided.

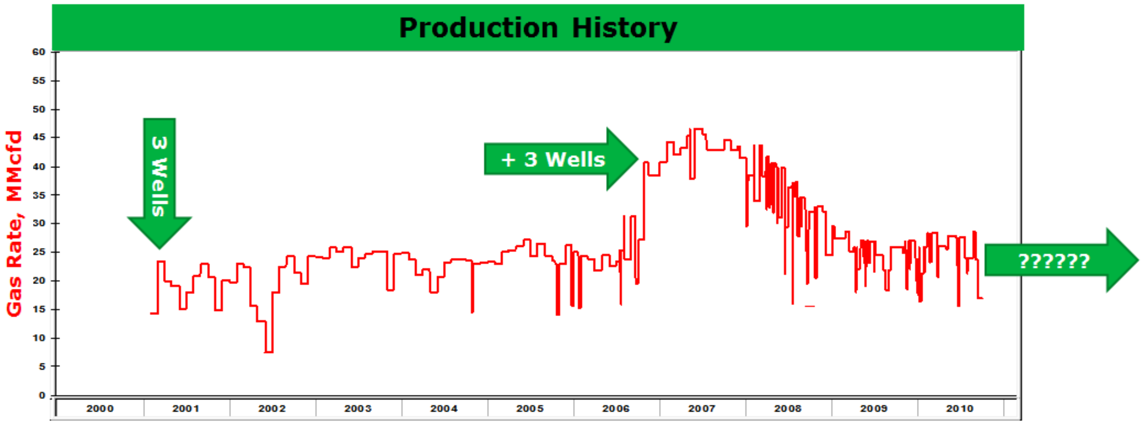

Figure 1: Production History

Methodology

The lack of reservoir engineering and geological data was overwhelming: no logs, no cores, no porosity, no permeability, no net pay, no saturations, no area. Normally, these parameters are required starting points for any reservoir engineering study, which would encompass history matching of the production using a simulator, and subsequently forecasting different production scenarios.

Moreover, there was no decline in production rate from which recoverable reserves could be forecast.

The saving grace that enabled this study to succeed was that the daily flowing pressures were available.

The classical equations of flow describe the relationship between flowing pressure and flow rate, for a given reservoir description. In other words, the combination of flow rates and flowing pressures contains information about the reservoir, in particular, its size as well as the deliverability potential of the well. Therefore, Rate Transient Analysis has the potential to yield our objectives, namely to extract the reservoir volume and deliverability from the supplied flow rates and flowing pressures.

The IHS Harmony™ software contains a series of reservoir engineering tools, ranging from simple Decline and Volumetrics to sophisticated Rate Transient Analysis (RTA) and Numerical Simulation. However due to the absence of information, only a few of these could be used.

1. Static Material Balance
2. Conversion of wellhead flowing pressures to bottomhole conditions
3. Flowing Material Balance (FMB)
4. Type Curve Matching (RTA)
5. Deliverability Forecasting (analytical models)

The Static Material Balance was possible because we happened to have one static reservoir pressure measured in 2007. If this had not been available (as is often the case) then a Static Material Balance could not have been performed. Nonetheless, the rest of the Analyses 2. to 5. would proceed independently, and yield all the required answers. In other words, the Static Material Balance is a bonus. It is a welcome bonus, because, as an independent analysis, it can be used to corroborate the other analyses.

1. Static Material Balance:

The initial reservoir pressure was known. In addition, a static pressure was measured in one of the new wells before it was placed on production in 2007. This allowed a 2-point Material Balance calculation to be performed, which yielded an Original Gas-in-Place (OGIP) of 285 BCF (Figure 2). Most material balance calculations contain numerous data points, but only two were available in this case. The quality of the resulting calculation of OGIP could not be substantiated by additional points. However, this value will act as an independent confirmation of the subsequent analysis of the flowing pressures and rates using RTA.

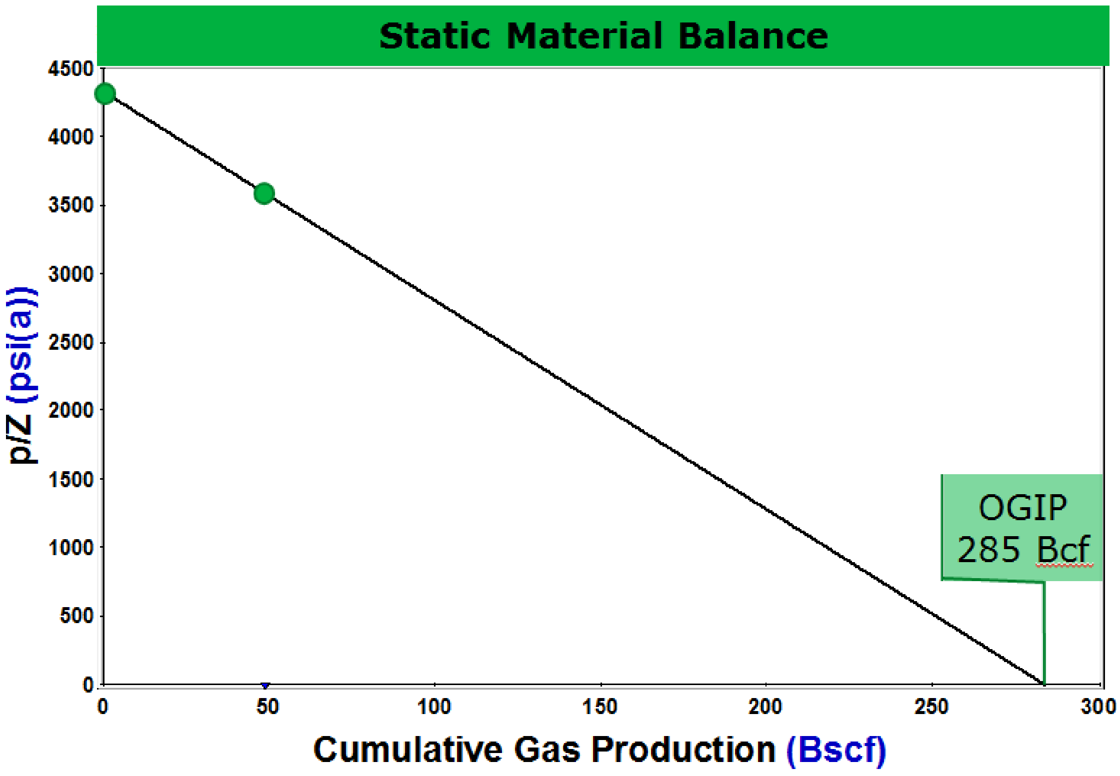

Figure 2: Static Material Balance (2-point)

2. Conversion of Wellhead Pressures to Bottomhole

The wells were producing dry gas with minimal water (of condensation), and the wellhead pressures were measured continuously. The client confirmed the nominal tubing size, and the depth of the reservoir. Using the tools in Harmony, the wellhead pressures were converted to bottomhole flowing pressures for use in RTA. The calculated bottomhole pressures are shown in Figure 3.

2. Flowing Material Balance (FMB)

At the heart of Rate Transient Analysis lies the Flowing Material Balance. This technique was pioneered by IHS Markit. It is an extremely powerful method for determining Original-Hydrocarbons-in-Place, and its development is fully documented in the referenced publications and technical videos (see References). As shown below, it is derived by combining the equation for boundary-dominated flow with the static material balance. For simplicity it is derived in terms of single phase liquid flow (Equation 4) but it is subsequently applied to gas flow (Equation 5).

Flow equation:

$$p_i - p_{wf} = \frac{N_p}{c_o N} + b \times q \qquad \text{Equation 1}$$

Material Balance:

$$p_i - \overline{p}_R = \frac{N_p}{c_o N} \qquad \text{Equation 2}$$

Subtracting:

$$\overline{p}_R - p_{wf} = b \times q \qquad \text{Equation 3}$$

Rearranging: oil:

$$\overline{p}_R = p_{wf} + b \times q \qquad \text{Equation 4}$$

gas:

$$\left(\frac{\overline{p}}{z}\right)_R = \left(\frac{p}{z}\right)_{wf} + b \times q \qquad \text{Equation 5}$$

Using Equation 5, the average reservoir pressure ($\overline{p}$) that exists in the reservoir at any time can be calculated from the flowing pressure (pwf) and the flow rate (q), if the value of b is known. It is shown in the references, that "b" is related to the well's Productivity Index and can be obtained by simply plotting q/Δp (or q/Δψ for gas) vs Np/Δp (or Npa/Δψ for gas), all of which are obtained from the production data. This procedure can be applied to each of the wells. Note that the q and Δp refer to a specific well. The Np , on the other hand, can be used in two modes:

a) If it represents the production from the well, the resulting OGIP is that well's drainage volume
b) If it represents the total production from the whole reservoir, the resulting OGIP is the volume of the whole reservoir.

Using the first well as an example, Figure 3 displays the flow rate (red curve) and the flowing pressures (black curve) for that well. Using Equation 5, the value of $(\frac{\overline{p}}{z})_R$ is calculated. This represents the average pressure in the reservoir. From here on, the problem is treated like a traditional Static Material Balance. The $(\frac{\overline{p}}{z})_R$ that has just been calculated using, Equation 5, is plotted against Np, where Np is the total production of the whole reservoir (from all six wells). The intercept on the x-axis is the OGIP of the reservoir. The answer is 275 BCF. Repeating the same process for each of the other wells yields similar answers.

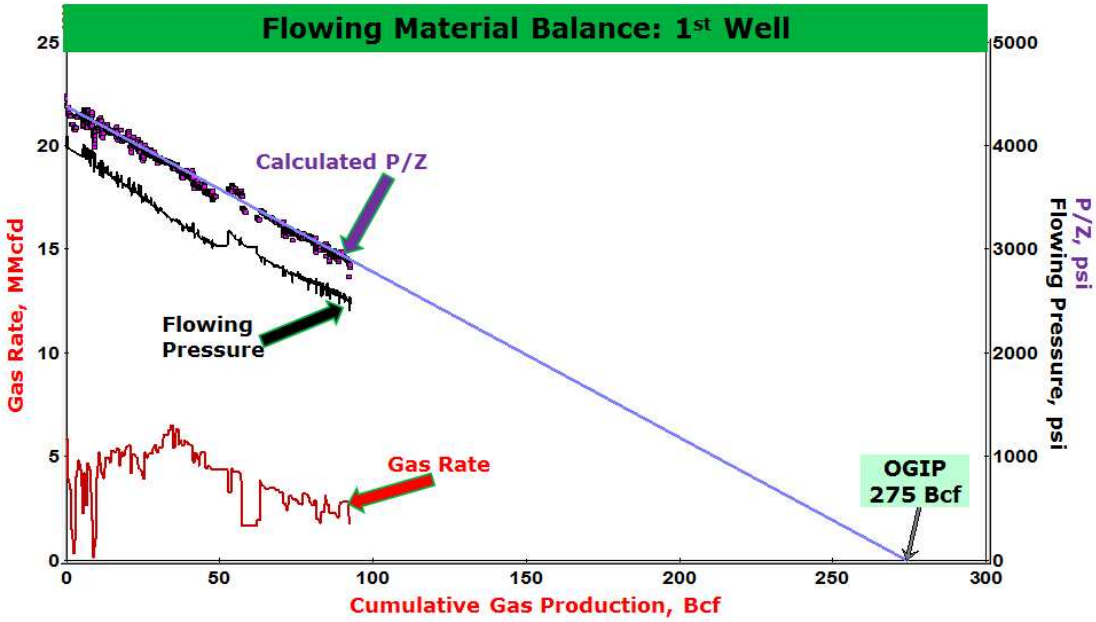

Figure 3: Flowing Material Balance (Using Total Production of six wells)

4. Type Curve Matching (RTA)

Another analysis tool available in Harmony is Type Curve Matching. Because this is a gas reservoir, the first thing to be done is to convert pressure (p) to pseudo-pressure (ψ), time (t) to pseudo-time (t_a) and cumulative production (N_p) to pseudo-cumulative production (N_{pa}) and use these pseudo-variables in place of the originals. The type curves consist of plotting $q/\Delta\psi$ vs material balance pseudo-time t_{ca}. Material balance pseudo-time t_{ca} is defined as N_{pa}/q.

As with the FMB analysis, the data for one well, $q/\Delta\psi$, can be plotted against that well's individual t_{ca}, or against the total reservoir's t_{ca}, to yield the individual well's drainage volume or the total reservoir volume (OGIP). Figures 4 and 5 show type curve matches for two different wells, resulting in the total reservoir OGIP. For demonstration purposes both the Agarwal and the Blasingame type curves have been used.

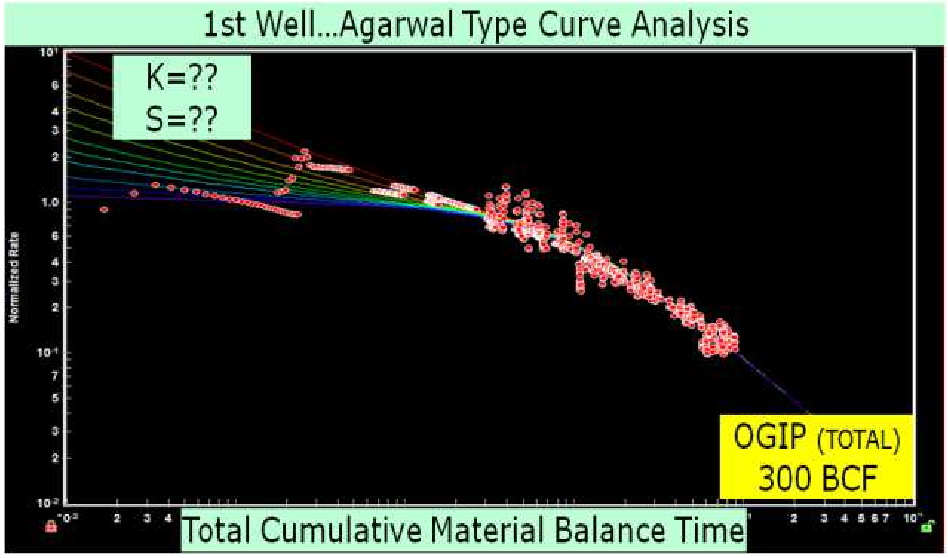

Figure 4: Agarwal Type Curve, Well 1

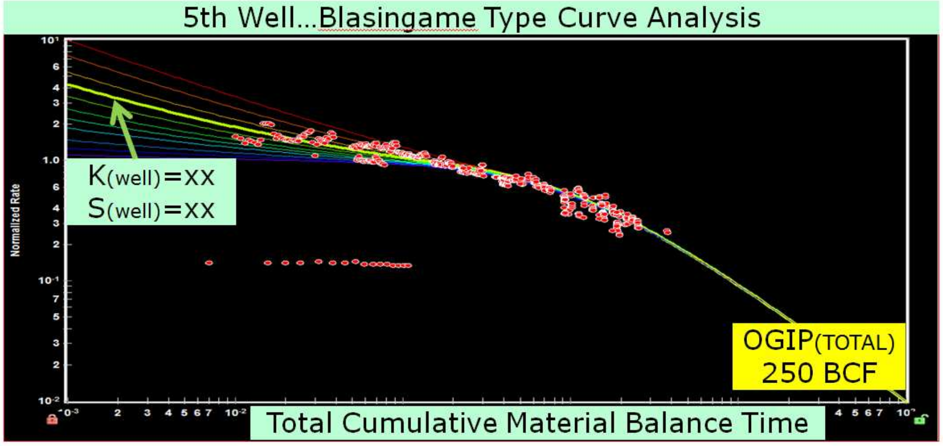

Figure 5: Blasingame Type Curve Analysis, Well 5

In type curve analysis, the permeability and skin can be determined from the early time data. In Figure 4, the early time data is too scattered to be of any use. In Figure 5, the early time data has been matched to a specific type curve, and in principle, the permeability and skin for that well could be determined if the petrophysical parameters (net pay, porosity, etc.) had been known.

5. Deliverability Forecasting, using Analytical Model

Before embarking on the deliverability calculation, the following is a summary of the learnings so far:

- The range of OGIP obtained from all the previous analyses was 250-300 Bcf, with an average of 285 BCF.
- The remaining gas-in-place is 192 Bcf (=OGIP 285 Bcf less gas produced to date 93 Bcf)
- The current reservoir pressure is 2660 psi (Figure 2: p/z=2930 at Gp=93)
- The current flowing pressure is 2400 psi (production data)

- The total current flow rate of all six wells is 25 MMcfd (production data)
- Permeability and skin are unknown and unknowable, because of the absence of petrophysical parameters. However, all indications are that the permeability is quite good:
    - The drawdown ($\overline{p}_R - p_{wf}$) is small (<10%)
    - The wells are obviously being choked to maintain constant rate
    - The wells have produced continuously and extensively at 10 MMcfd each, obviously under restricted flow conditions.
    - From the type curves, the time to reach boundary-dominated flow is less than 100 days.
    - The wells behave similarly, reflecting a reasonably homogeneous reservoir

In view of the good permeability, and recognizing that all the wells are producing from a common reservoir, a simple analytical model was created, consisting of a superwell in a homogeneous circular reservoir. The model parameters are given below:

- $\overline{p}_R =$ 2660 psi (current reservoir pressure)
- $p_{wf} =$ 2400 psi (current flowing pressure)
- q = 25 MMcfd (current flow rate)
- OGIP = 192 Bcf (Remaining-Gas-in-Place)
- Perm = Unknown
- Skin = Unknown

The permeability and skin are unknown. However, once boundary dominated flow is reached, the individual values of perm and skin and reservoir shape and other petrophysical properties are of no consequence; it is their combination (in the form of productivity index) that affects deliverability. Therefore, the permeability and skin were adjusted arbitrarily to replicate the current operating conditions, namely: a flow rate of 25 MMcfd at a flowing pressure of 2400 psi. Of course many combinations of perm and skin are possible, but they all will yield the same forecast. In effect, the model used is a "Tank type depletion". In such a system, the controlling variables are:

- the volume of the tank – known from RTA
- the compressibility of the fluid in the tank - assumed dry gas gravity = 0.65
- the productivity index - (q/ $(\overline{p}_R - p_{wf})$ all of which are known

Having set up the above simple analytical model in Harmony, the deliverability was forecast under numerous scenarios. Two examples are given below:

Scenario I: How long can production be maintained at 25 MMcfd without addition of compression (assume pipeline pressure = 1000 psi)? The result is shown in Figure 6. It shows that the current rate can be maintained for an additional 10 years.

Scenario II: Can the rate be increased to 50 MMcfd, and how long will it last, without adding compression? The result is shown in Figure 7. It shows that 50 MMcfd can be maintained for 4 years.

It is obvious that the Expected Ultimate Recovery (EUR) for these and any other scenarios can be determined by noting the cumulative production at any specified time or abandonment rate.

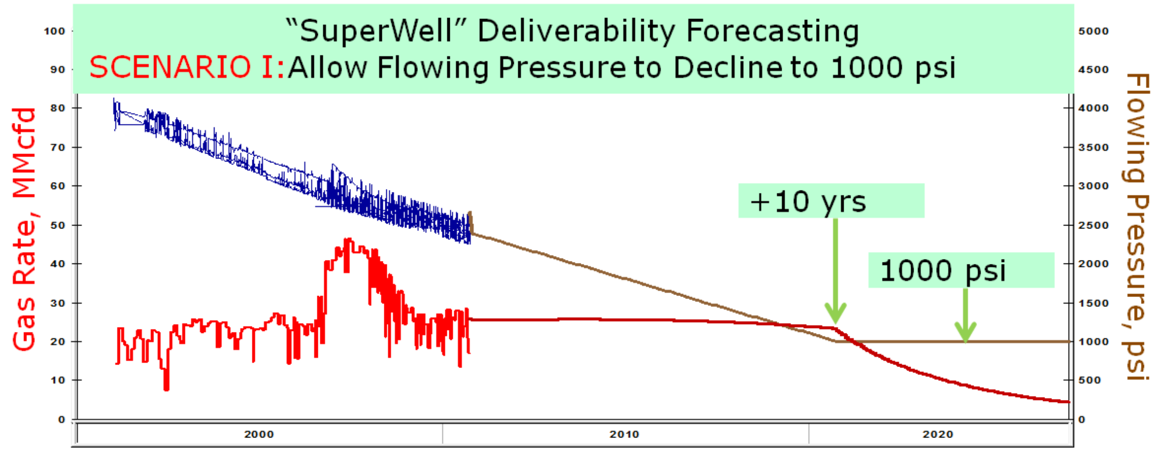

Figure 6: Forecast of Scenario I

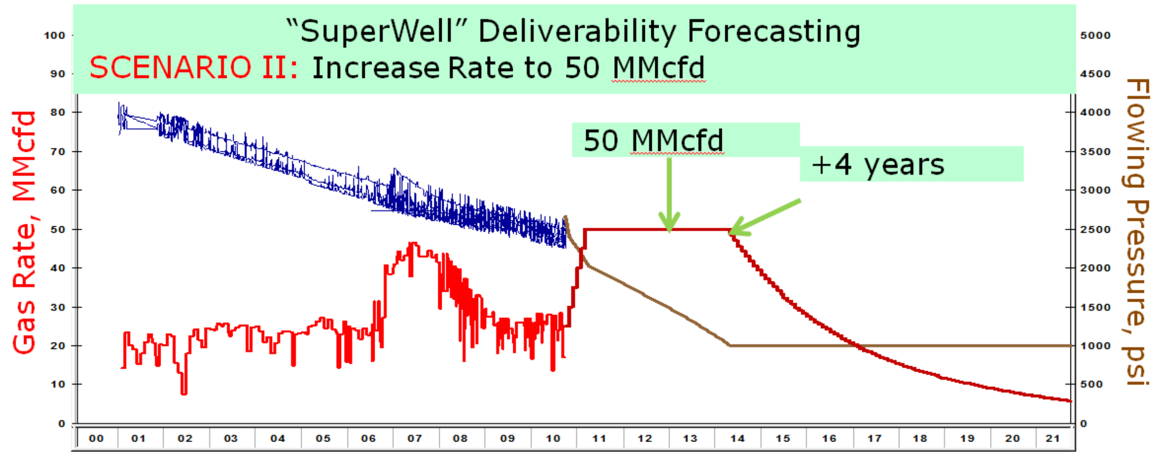

Figure 7: Forecast of Scenario II

Conclusions

Using minimum data (production rate and flowing pressure), the OGIP and production forecasts for several scenarios were determined with reliability, using simple tools:

- RTA Type Curves
- FMB
- Tank Type Depletion Model

The use of more sophisticated tools (simulators) is not warranted, because of the absence of fundamental data.

Nomenclature

b	=	inverse of productivity index	p_{wf}	=	wellbore flowing pressure
c	=	liquid compressibility	Δp	=	$p_i - p_{wf}$
EUR	=	expected ultimate recovery	$Perm$	=	permeability
FMB	=	flowing material balance	q	=	flow rate
N	=	original-oil-in-place	RTA	=	rate transient analysis
N_p	=	cumulative production	t	=	time
N_{pa}	=	pseudo-cumulative production	t_a	=	pseudo-time
$OGIP$	=	original-gas-in-place	t_{ca}	=	N_{pa}/q
p	=	pressure	z	=	real gas compressibility factor
p_i	=	initial reservoir pressure	ψ	=	pseudo-pressure
$\overline{p}_R$	=	average reservoir pressure	$\Delta\psi$	=	initial ψ - flowing ψ

References

1. Mattar L., McNeil, R., "The 'Flowing' Gas Material Balance", JCPT, Volume 37 #2, 1998
2. IHS Markit Technical Videos:
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3. Mattar, L. and D. Anderson: "Dynamic Material Balance (Oil or Gas-in-place without shutins)", Paper 2005-113 Canadian International Petroleum Conference, Calgary, June 2005.

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