ESTIMATION OF WILDCAT WELL DRAINAGE AREA FROM WELL TEST DATA

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Estimation of wildcat well drainage area is extremely important for seismic data validation, reserves estimation and further field development planning in general.

There are several methods available in practice for drainage area estimation [1]. Some of them depends on continuous recording of bottom hole pressures during prolonged production period (Reservoir Limit Test), while others observe pressure behavior in neighbor wells (Interference Test).

Application of such methods on prospect plains is quite limited due to absence of surface network infrastructure for prolonged production or physical absence of neighbor wells at all.

However, sometimes even a rough estimation of drainage area needed at early stages of field exploration. It becomes more important when geological model constructed on early stages of exploration disagrees dramatically with production data from real well drilled on prospect plain.

Therefore, we developed method which would help reservoir engineers to estimate drainage area of wildcat well from test data. To understand better its practical applications and theoretical background, we would illustrate it with following example.

In 1977, during seismic surveys in Rostov Region, promising geological structure with approximate area of 3.52 square kilometers was discovered. Further wildcat drilling in 1983 confirmed that structure is productive and contains natural gas reservoir.

We would use well test data from first productive wildcat well on this field to demonstrate practical application of the method.

Initial reservoir data represented by petrophysical and reservoir fluids data given in **Tables 1** and **2**.

Table 1 – Petrophysical data

Reservoir Interval, meters	Parameter	Numerical Value
1310.6-1332.6	Net pay thickness, meter	22.0
	Effective porosity, fraction	0.17
	Initial gas saturation, fraction	0.70
	Initial water saturation, fraction	0.30

Table 2 – Reservoir fluids data

Parameter	Numerical Value
Formation volume factor: - gas - water	 0.006915 1.00
Gas compressibility factor	0.8465
Viscosity, cP: - gas - water	 0.0165 0.67
Compressibility, $(kgf/cm^2)^{-1}$: - gas - water - formation	 0.00756 4.594×10^{-5} 5.508×10^{-5}
Density, kg/m^3: - gas - water	 111.59 1004.82

Well test operations were conducted as the flow-after-flow test with final build-up – **Figure 1**.

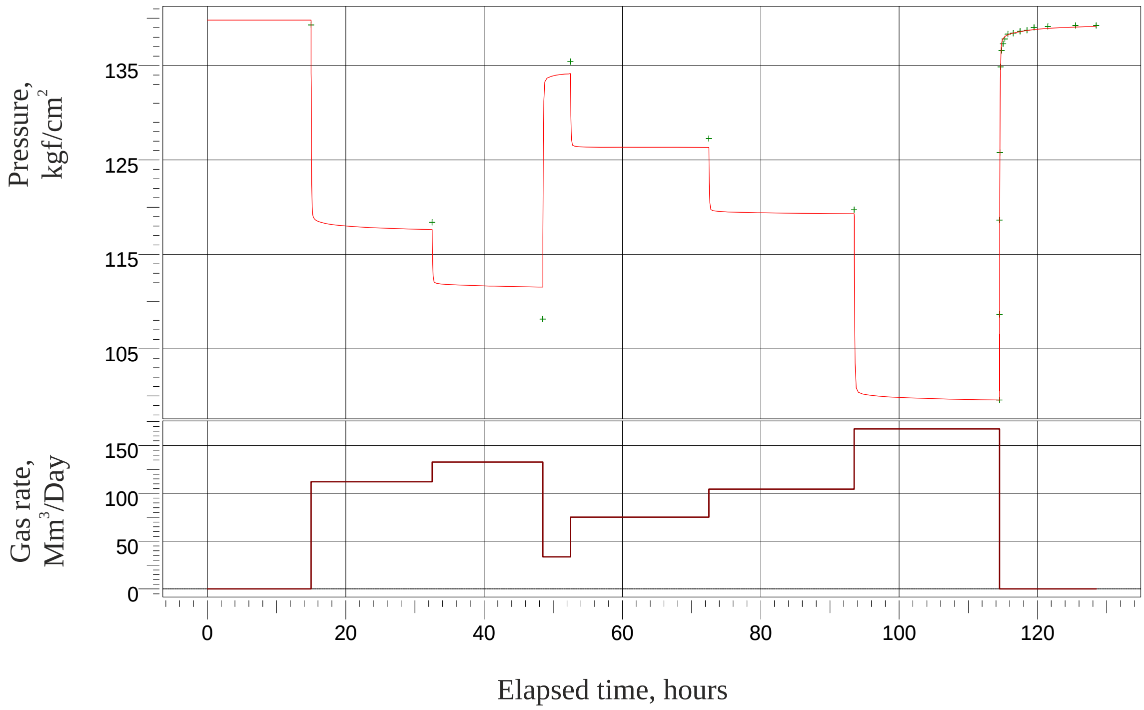

Figure 1 – Rate-pressure history during well test

Analysis of the final build-up was performed by the means of Gringarten-Bourdet type-curves and sustained by straight-line analysis on semi-log plot – **Figures 2** and **3**.

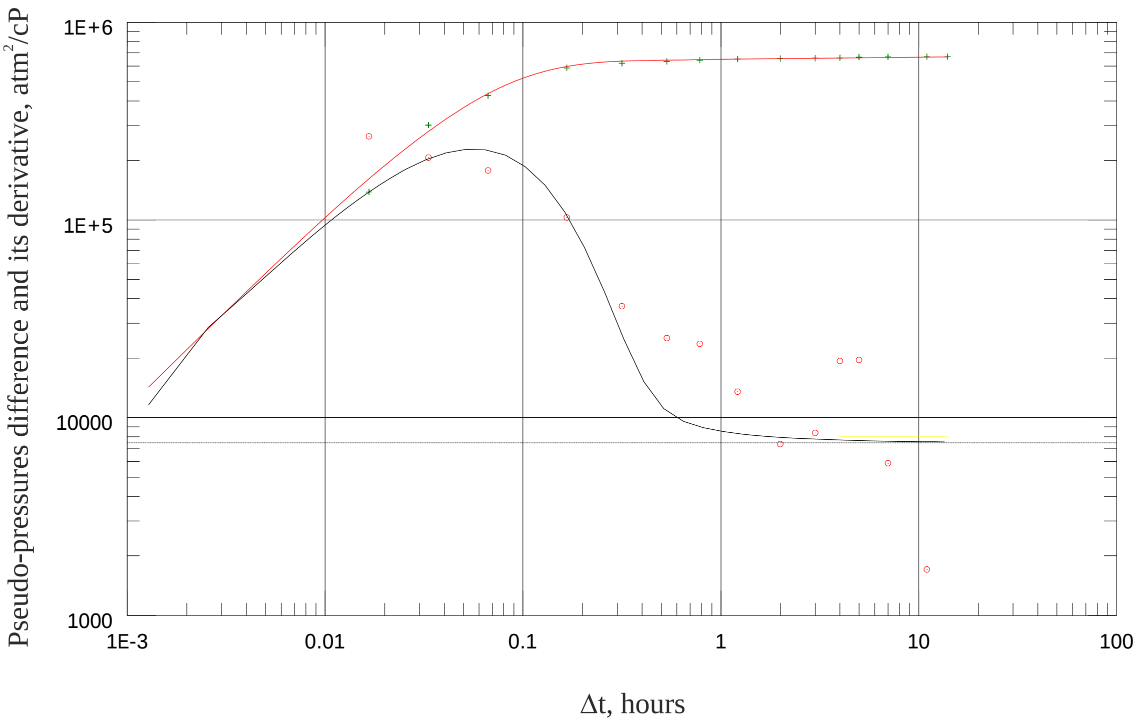

Figure 2 – Final build-up on log-log plot with type-curve matching

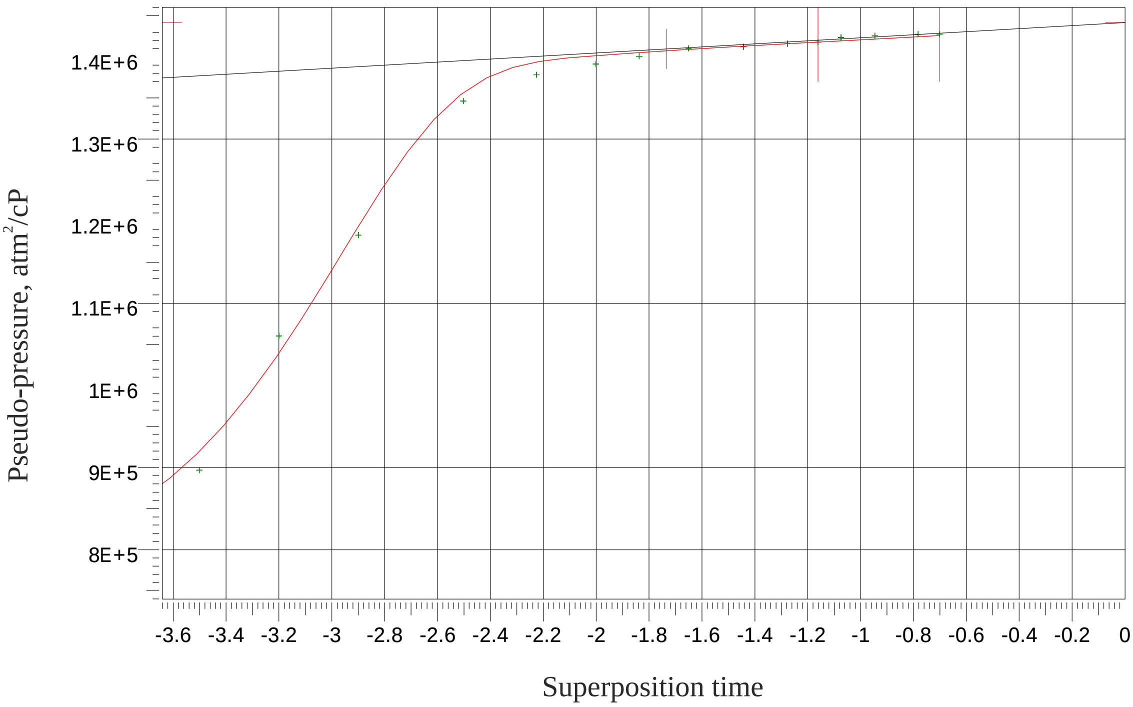

Figure 3 – Final build-up on semi-log plot with straight-line analysis

One can notice relatively low frequency of pressure data during final build, there is a simple technical reason behind it. At the time when well test had been conducting

(1983) almost all USSR governmental oil and gas exploration agencies were equipped with Bourdon Tube Pressure Recorders. Data was read manually from pressure charts with the help of comparators, therefore its frequency was always low on such build-ups.

Nevertheless, pressure behavior on log-log plot, in our case, can be fairly analyzed and validated with the help of semi-log plot. It matches best to homogeneous infinite-acting reservoir what is the case for almost all wildcat well tests, due to relatively short build-up times. Corresponded results of log-log plot analysis presented in **Table 3**.

Table 3 – Results of well test analysis

Parameter	Numerical Value
Initial reservoir pressure, kgf/cm^2	139.798
Reservoir temperature, ^{o}C	+45
Average permeability, mD	20.7
Skin factor: - constant skin - total skin - non-Darcy flow coefficient, (Mm3/Day)$^{-1}$ - drawdown loss due to skin, % of total drawdown	 +21.1 +37.9 0.1 82.53
Wellbore storage coefficient, m^3/(kgf/cm^2)	0.08
Radius, meter: - investigation - drainage	 146.62 boundaries not reached during build-up
Drainage area, km^2: - actual - expected	 boundaries not reached during build-up 0.774

In our case, parameter of main interest is expected drainage area, which lies within the scope of this work. Below we will discuss reasons behind its estimation and method of estimation itself.

As we know, well test analysis procedure ends up with average pressure calculation and construction of inflow performance relationship. It is necessary to made proper choice of production rates under which well would be operated or stimulation strategy in case of low performance.

Generally, pseudo-steady state flow equation for calculation of average reservoir pressure, in case of natural gas reservoir, may be written in the following form [1]:

$$m(\bar{p}) = m(p_{wf}) + 0.1491\frac{T}{kh}\left(\log\frac{A/r_w^2}{C_A} + 0.351 + 0.87S\right)q_{sc} + 0.1296\frac{T}{kh}Dq_{sc}^2, \qquad \textbf{(1)}$$

where	$m(\bar{p})$	-	average reservoir pressure in terms of pseudo-pressure, atm^2/cP;
	$m(p_{wf})$	-	flowing bottom hole pressure in terms of pseudo-pressure, atm^2/cP;
	T	-	reservoir temperature, ^{o}K;
	k	-	average reservoir permeability, mD;
	h	-	net pay thickness, meter;
	A	-	drainage area, m^2;
	r_w	-	wellbore radius, meter;
	C_A	-	drainage area shape-factor;
	S	-	skin factor (constant skin);
	q_{sc}	-	gas rate under surface conditions, Mm^3/Day;
	D	-	non-Darcy flow coefficient, (Mm^3/Day)$^{-1}$.

We used above equation to estimate average reservoir pressure in our case, but since we did not reach boundaries during build-up, we could only use as a drainage area, the area from seismic data. Using 3.52 square kilometers as drainage area in equation **(1)** we would get average reservoir pressure equals to 140.399 kgf/cm^2.

As one can see from the **Table 3** this value is significantly higher than initial reservoir pressure, what is obviously not physical. Such situation may occur only in case of fluid injection into reservoir and couldn’t happen during withdrawal.

Let’s take a closer look to conceptions of initial and average reservoir pressures to better understand curiosity of this situation. Generally speaking, initial reservoir pressure is the pressure on the boundary of the well drainage area in undisturbed conditions (new well on newly discovered reservoir immediately after drilling). The average reservoir pressure, from the other hand, is, roughly speaking, some average pressure between boundary and well flowing pressures during prolonged well production with constant rate. It shows us how constant production affects pressure distribution in well drainage area and it's clear that it couldn't be higher then the boundary pressure, unless we are injecting fluids into reservoir with constant rate.

Such dramatic disagreement between values of average and initial reservoir pressures suggests that reservoir lacks communication on its whole area and alternative methods of drainage area estimation should be implemented.

As we know, during radial infinite-acting flow, when the build-up time is significantly lower in comparison with times needed to pressure distortion reach reservoir boundaries, average reservoir pressure may be assumed to be equal to initial reservoir pressure [1].

Under this assumption we can rewrite equation (1) in the following form:

$$A = C_A r_w^2 \cdot 10^{\left(\frac{m(p_i) - m(p_{wf}) - 0.1296 \, T/kh \, D q_{sc}^2}{0.1491 \, T/kh \, q_{sc}} - 0.351 - 0.87 S \right)}, \qquad \textbf{(2)}$$

where $m(p_i)$ - initial reservoir pressure in terms of pseudo-pressure, atm^2/cP;

Drainage area estimated from equation **(2)** equals, in our example, to 0.774 square kilometers (**Table 3**), what is significantly lower than the value from seismic data.

It should be noted, that the main source of uncertainty in equation **(2)** is drainage area shape-factor, which hardly known during wildcat well testing. However, for the most practical cases it may be assumed to be equal to circle area shape-factor (31.62) for vertical wells; for horizontal wells, still, it should be assumed basing on trial and error approach.

Nowadays, natural gas reservoir studied in this work completely depleted and abandoned. Thus, we have opportunity to validate drainage area estimated from well test data by alternative means using production data.

Golan and Whitson suggested a method for approximating the drainage area of wells producing from a common reservoir [2]:

$$A_w = A_T\left(\frac{q_w}{q_T}\right), \tag{3}$$

where A_w - well drainage area, m^2;

A_T - total area of the field, m^2;

q_w - well flow rate, Mm^3/Day;

q_T - total flow rate of the field, Mm^3/Day.

These authors assume that the volume drained by a single well is proportional to its rate of flow. Generally speaking, drainage area of a single well would be dynamic parameter depending on the number of wells on the field and flow rate of a single well, i.e. reservoir communicates on its whole area.

However, we are already concluded that our reservoir of interest does not communicate on its whole area. Therefore, we should modify equation **(3)** in the following form to consider that fact:

$$A_w = A_T\left(\frac{G_{pw}}{G}\right), \tag{4}$$

where G_{pw} - cumulative gas production from well of interest until its abandonment, MMm^3;

G - gas initially in place for reservoir of interest, MMm^3.

Production data and results of calculation by equation **(4)** summarized in **Table 4**.

Table 4 – Estimation of well drainage area from production data

Parameter	Numerical Value
Cumulative gas production from well of interest until its abandonment, MMm^3	153.304
Gas initially in place for reservoir of interest, MMm^3	550.000
Total area of the field, km^2	3.52
Well drainage area from production data, km^2	0.981
Well drainage area from well test data, km^2	0.774
Relative deviation between methods, %	21.10

Analyzing data from **Table 4**, one can perfectly see that two methods agree well. The 21.10 % deviation is not so dramatic and may be caused by systematic errors in gas production measurements or another external factors rather than calculation algorithm itself.

Described example demonstrates perfectly that drainage area calculation algorithm suggested in this paper is extremely useful and provide reservoir engineers with reliable estimations at early stages of field exploration and development. It can be used further in seismic data validation, express reserves estimations and operative development planning.

Best results can be achieved with this method for reservoirs with medium range of permeability (10-100 mD). For low (less than 1 mD) and high (more than 100 mD) permeability reservoirs described method should be used with caution.

In high permeability reservoir, pressure distortion, caused by change of flow rate, travels quit fast. Thus, it is very likely that some boundaries have been felt during build-up and average reservoir pressure differs significantly from initial one. As one can see, equation **(2)** is the power function type, therefore small changes in reservoir pressure value affects greatly on drainage area value and in case of high permeability reservoir well drainage area can be seriously overestimated.

In low permeability reservoir, well drainage area is heavily completion dependent and controlled by hydrodynamics laws rather than geological setting. Simply put, for the vertical un-stimulated well, drainage area would be several feet around the wellbore, pressure difference on the boundary of drainage area would be almost negligible and inflow from whole reservoir area would take ages to compensate withdrawal from vicinity of the wellbore. Thereby, in un-stimulated tight reservoir well drainage area can be seriously underestimated.

References

1 Bourdet, D. (2002). *Well Test Analysis: The Use of Advanced Interpretation Models*. (Amsterdam: Elsevier).

2 Ahmed, T., McKinney, P.D. (2005). *Advanced Reservoir Engineering*. (Gulf Professional Publishing).