Chapter 2
Tight Gas Reservoirs Characterisation for Dynamic Parameters

Tight gas reservoirs might be very different in term of reservoir characteristics, and it is challenging to adequately determine the reservoir dynamics parameters such as the effective permeability of matrix and natural fractures, relative permeability, skin factor, hydraulic fractures size and conductivity and fluid gradients in the reservoir. Similar to the conventional gas reservoirs, the reservoir characterization tools such as well testing, logging, core analysis and formation testing are commonly used and run in tight gas reservoirs. However due to the tight formations complexity, heterogeneity and very low permeability, use of the acquired data to obtain meaningful results may not be well understood in term of determining the well and reservoir parameters and predicting the well production performance [13, 14]. This chapter presents the methods for determination of the effective permeability of non-fractured, hydraulically fractured and naturally fractured tight formations.

2.1 Welltest Analysis in Tight Gas Reservoirs

The conventional method of pressure build-up test data analysis is to plot the transient pressure (P) and its derivative (P':$-d[\Delta P]/d[\mathrm{Log}((t_p + \Delta t)/\Delta t)]$) versus time on Log–Log scales to identify the radial flow regime and determine the reservoir permeability (KAPPA engineering 2011). Diagnosis of the radial flow regime is critical in quantitative welltest interpretation, since reliable values for reservoir permeability and skin factor can be estimated when radial flow regime is established in the reservoir [3, 9].

A pressure transient test breaks into several flow regimes, each seeing deeper in the reservoir than the last [9]. Depending on well completion type, completion configuration, reservoir geological and geometric attributes, different flow regime might be revealed on diagnostic plots of pressure transient data analysis in vertical, horizontal or multi-fractured wells [5]. In pressure transient tests, the pressure derivative curve can indicate the different flow regimes: the slope of +1 shows wellbore storage effect, the slopes of −0.5, +0.5, +0.25 and +0.36 indicate

N. Bahrami, *Evaluating Factors Controlling Damage and Productivity in Tight Gas Reservoirs*, Springer Theses, DOI: 10.1007/978-3-319-02481-3_2,

spherical, linear, bi-linear and elliptical flow regimes respectively, and the slope of zero indicates radial flow regime.

In multi-fractured tight gas wells, the main reservoir flow regimes are the early time linear flow regime (slope of +1/2 on pressure derivative) perpendicular to the hydraulic fractures inside Stimulated Reservoir Volume (SRV), followed by the early-time elliptical flow regime towards the drainage area of the linear flow (slope of +1/3 on pressure derivative), and then the early-time boundary dominated flow when drainage area around the hydraulic fractures is depleted. After depletion of SRV, gas flow is provided by the untreated rock surrounding SRV, which acts as boundary. The early time boundary dominated flow effect is then followed by the late-time linear flow regime and then late-time elliptical flow regime inside the untreated reservoir rock towards the SRV around the multi-fractured well. Finally at very late-time when pressure disturbance propagates deep enough into the reservoir, a pseudo radial flow regime is established with slope of zero on pressure derivative [4]. The linear and elliptical flow regimes may be the dominant flow regimes in tight gas wells with significantly long time duration and the radial flow regime may not be reached, due to the very low reservoir permeability, heterogeneity, hydraulic fractures, natural fractures, permeability anisotropy, and reservoir geometry [18, 2].

The early portion of welltest data during pressure build-up tests is normally affected by wellbore storage and skin factor. In tight gas reservoirs, the low permeability slows down the reservoir response to the pressure disturbance during transient testing, which causes the wellbore storage effect to be significantly long [12]. As a result, tight gas reservoirs typically require a relatively long pressure build-up testing time to reach the late time pseudo radial flow regime, which is often not practical. In addition, the need for hydraulic fracturing to obtain commercial flow rates in tight gas reservoirs adds to the complexity of the problem and makes analysis of the pressure transient data more difficult. Therefore, welltest analysis using the conventional techniques may fail to provide reliable results.

2.2 Permeability Estimation in Hydraulically Fractured Tight Gas Wells

The main challenge with welltest analysis of the tight gas wells is that the testing time cannot be long enough to reach radial flow regime. However for a multi-stage fractured horizontal tight gas well, if both of the linear flow and elliptical flow regimes are detected on the Log–Log diagnostic plot, they can be used in welltest analysis to estimate reservoir characteristics.

Welltest analysis of hydraulically fractured tight gas wells requires plotting of the pressure transient data and the derivatives on the Log–Log diagnostic plot: $d(p)/d(t^{1/2})$ is defined as the linear flow derivative, $d(p)/d(t^{1/3})$ is defined as the elliptical flow derivative, and $d(p)/d(\ln[t])$ is defined as the radial flow derivative.

Then the pressure derivative values for linear flow, elliptical flow and radial flow regimes can be determined as shown in Fig. 2.1: m_{LF} from zero slope line on linear derivative, m_{Ell} from zero slope line on elliptical derivative and m_{RF} from zero slope line on radial derivative [15, 10].

The linear flow and elliptical flow regimes are both controlled by K and X_f. The solution of the diffusivity equation for infinite acting elliptical flow has been proposed for non-fractured horizontal oil and gas wells [15]. Modifying and re-deriving the elliptical flow equation for a hydraulically fractured horizontal gas well, and integrating that with the linear flow equation can provide the hydraulic fracture size and reservoir permeability as follows:

$$X_f = \frac{573}{K^{0.89}\,(\phi\mu C_t)^{0.5}}\left(\frac{qT}{h * n * m_{Ell}}\right)^{1.39} \tag{2.1}$$

$$K = \left(\frac{40.99qT}{h * n * X_f * m_{LF}}\right)^{2}\frac{1}{\varphi\mu C_t} \tag{2.2}$$

Solving the two non-linear equations simultaneously can provide the two unknowns K and X_f. In the above equations, P is pressure (psia), t is time (hrs), q is gas flow rate (MSCFD), B is formation volume factor, h is reservoir thickness (ft), μ is viscosity (cp), φ is porosity (fraction), C_t is total compressibility, T is reservoir temperature (R), K is reservoir permeability (md), and n is number of fractures.

On the pressure build-up diagnostic plots for a multi-stage fractured horizontal tight gas well, if only the linear flow regime is detected and the testing time is not long enough to reach elliptical and radial flow regimes, then alternative methods such as using the second derivative of transient pressure should be used to proceed with welltest analysis and predict a theoretical radial flow regime. The theoretical radial flow should be predicted to estimate m_{RF} value, assuming an infinite

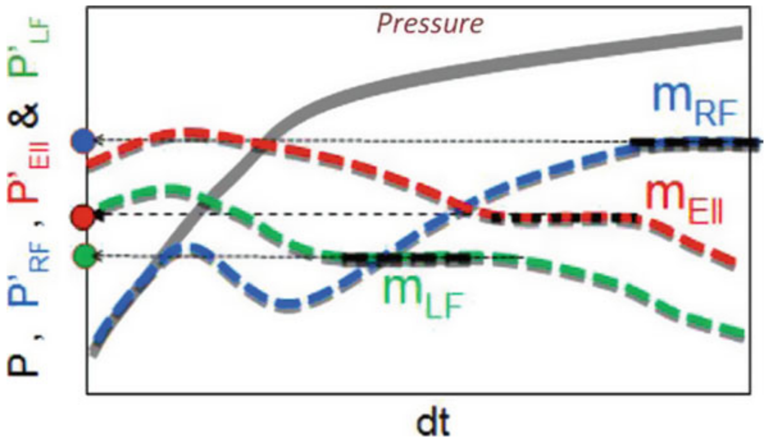

Fig. 2.1 Welltest analysis using the pressure derivatives

stimulated reservoir volume [4]. Using value of the linear flow derivative, m_{LF}, and the value of m_{RF} from the theoretical radial flow prediction, the reservoir permeability and hydraulic fracture half-length size can be estimated as follows:

$$K = \frac{1637 * Q_g * T}{2.3 * m_{RF} * h * n} \tag{2.3}$$

$$X_f = \frac{40{\cdot}99\, Q_g\, T}{h * m_{LF} * n} \sqrt{\frac{1}{K\varphi\mu C_t}} \tag{2.4}$$

Permeability estimation using the method may have significant uncertainties, due to some assumptions in predicting the theoretical radial flow regime.

2.3 Estimating Permeability of the Natural Fractures

Natural fractures may contribute the most to total gas production from tight gas reservoirs, and therefore identification of their characteristics is essential for well production performance evaluation.

The basic dynamic characteristics of the natural fractures are fracture storativity and interporosity flow coefficient, which can be estimated from welltest analysis. Then using the parameters, natural fractures permeability can be estimated as follows [22]:

$$K_f = \delta \frac{K_m}{\lambda} r_w^2 \tag{2.5}$$

$$\delta = 4(1/a_X^2 + 1/a_Y^2 + 1/a_Z^2) \tag{2.6}$$

where K_m is matrix permeability, K_f is fracture permeability, r_w is wellbore radius, δ is shape factor, and λ is interporosity flow coefficient. a_x, a_y and a_z are matrix block size respectively in x, y and z directions. In the case of Kazemi model ($a_\chi \gg a_z$ and $a_y \gg a_z$), the shape factor, δ, is considered to be $4/a_z^2$. The shape factor can be estimated from image log fracture spacing (a_z); matrix permeability can be estimated from core analysis; and the interporosity flow coefficient can be estimated from welltest analysis if dual-porosity, dual-permeability response is clearly observed on pressure build-up diagnostic plots [7].

However in tight gas reservoirs, due to the long wellbore storage effect and also the tightness and heterogeneity of the reservoir rock, pressure build-up diagnostic plots may not be able to show the dual porosity dual permeability response. Hence, estimating the interporosity flow coefficient and fracture permeability from such welltest data might not be feasible, and the conventional approaches might fail to characterize the fracture parameters in tight gas reservoirs.

Permeability of natural fractures for tight gas reservoirs can be estimated based on Kazemi model that assumes parallel layers of matrix and fracture in a uniform fracture network model [23] and averaging the reservoir permeability based on thickness of matrix and fracture layers [7, 9]:

$$K \cdot h_{Average} = \sum_{Matrix}^{m=1....n} (K_m \, * \, a) + \sum_{fracture}^{f=1....n} (K_f \, * \, b) \tag{2.7}$$

$$h = (n * \mathrm{a}) + (n * \mathrm{b}) \tag{2.8}$$

where K_f is permeability of a natural fracture, b is average fracture aperture, a is average matrix block thickness, K is welltest permeability, K_m is average permeability of the matrix blocks, h is reservoir thickness, n is number of fractures intersecting the wellbore across the reservoir, φf is fracture porosity (fraction), n * a is cumulative matrix block thickness, and n * b is cumulative fracture aperture. By combining Eqs. 2.6 and 2.7 using the assumption of $a \gg b$, $K_f \gg K_{welltest}$ and $K_f \gg K_m$ for tight gas reservoirs, following simplified equation can be written:

$$K_f = K_{welltest} * \frac{a}{b} \tag{2.9}$$

Since Eq. 2.8 is based on simplified models and assumptions, using some correction factors might provide more realistic relationship between fracture dynamic parameters. Considering the correction factors, average permeability of natural fractures ($K_{f,average}$) can be expressed in the following generalized form:

$$K_{f,\,average} = C_1 * K_{welltest} * \left(\frac{a_f}{b_f}\right)^{C_2} \tag{2.10}$$

Where $K_{welltest}$ is welltest permeability, b_f is average fracture aperture, a_f is average fracture spacing, and C_1 and C_2 are the correction factors. For a tight gas reservoir, average permeability can be estimated from welltest analysis, fracture spacing and fracture aperture can be approximated from image log processing, and the constants C_1 and C_2 can be determined from sensitivity analysis using reservoir simulation models, or as matching parameter during field history matching.

It should also be noted that where there is significant in situ stress anisotropy, permeability of the natural fractures would be different in different directions [6]. The natural fractures that are aligned with maximum horizontal stress (perpendicular to the minimum stress direction) may have larger aperture and therefore greater permeability, compared with the natural fractures perpendicular to the maximum stress direction. As function of in situ stresses, the maximum permeability and horizontal permeability can be estimated as follows [5]:

$$K_{f,\max} = K_{f,average} * \left(\frac{\sigma_{\min}}{\sigma_{\max}}\right)^{\alpha/2} \tag{2.11}$$

$$K_{f,\min} = K_{f,\,average} * \left(\frac{\sigma_{\max}}{\sigma_{\min}}\right)^{\alpha/2} \quad (2.12)$$

where $K_{f,average}$ is average permeability of natural fractures, $K_{f,min}$ is permeability of the natural fractures that are perpendicular to the maximum stress direction, $K_{f,max}$ is permeability of the natural fractures that are perpendicular to the minimum stress direction, $\sigma_{\min}$ is minimum stress, $\sigma_{\max}$ is maximum stress, and α is a constant number that can be estimated from core analysis experiments and plotting permeability versus normal stress. For a typical tight gas reservoir in Western Australia, the value of α was estimated as -1.28 [5].

2.4 Relative Permeability Curves in Tight Gas Reservoirs

The major damage mechanisms in tight gas reservoirs such as phase trapping are found to be associated with relative permeability and capillary pressure curves. The damaging effects are reflected on gas and water relative permeability curves [8].

The relative permeability data for tight gas sands are extremely difficult to obtain by the conventional steady state flow analysis technique as it requires impractically very long stabilization time and flow rates are usually small [16]. However, an unsteady state technique can be applied in a core flooding experiment, in which the tight core samples are fully saturated with water (initial water saturation of 100 % for primary drainage), and then gas is flooded at constant volumetric flow rate to reach irreducible water saturation. During the core flooding experiment, the pressure differential across the core sample and volume of the produced water are recorded. Then the experimental core flood data can be input into a commercial core flooding data analysis software, in order to generate relative permeability curves by matching the core flood data for brine production and pressure differential [19].

For oil-gas system, relative permeability curve can be generated similarly. However if determination of gas-oil relative permeability may not be possible due to some limitations in the laboratory facilities when oil is used as liquid phase, then typical published oil-gas relative permeability data have to be considered in the reservoir simulation studies related to oil-gas system [17].

2.5 Pressure Measurement in Tight Gas Reservoirs

In order to measure the pressure of a formation, pressure gradient, and gas water contact, formation testing is used. To measure pressure of reservoir at each depth, the tool inserts to a probe into the borehole wall to perform a mini pressure drawdown and build-up by withdrawing a small amount of formation fluid, and then waiting for the pressure to build up to the formation pore pressure at that depth. Formation testers measure the pressure of the continuous phase in the invaded region, which is the pressure of the drilling fluid filtrate. Using the pressure measurements at different depths, gradient of pressure in the reservoir is determined, which can indicate reservoir fluid type and water-hydrocarbon contact [20].

In tight gas reservoirs, formation testing is challenging due to tightness of the reservoir rock, weak mud cake across the wellbore, and presence of large wellbore breakouts across the tight sand intervals. Although using advanced formation testing tools may help improve reservoir characterization of tight gas reservoirs [21], formation testing results in tight formations may still have some uncertainties. In good permeability zones, formation tests are effective and normal. However in the case of low reservoir permeability, the mud cake is often ineffective in preventing filtrate invasion, thus causing the measured pressure to be affected by wellbore pressure that might be higher than the actual formation pressure (supercharging effect). In testing of a very tight formation, even a large pressure drawdown may result in no flow from the reservoir (dry test). Tight gas reservoirs are often associated with bad-hole conditions (large wellbore breakouts) causing lost seals around the tool packer and failure during testing of the formation [20]. The formation testing measurements may also be influenced by the effects of capillary pressure in the case of liquid invasion into a gas bearing zone. As a result, the measured pressure might be different to the true formation pressure [1, 11].

2.6 Summary

The tight gas reservoirs dynamic parameters such as relative permeability, reservoir average permeability, and natural fractures permeability are the key factors that control production performance of tight gas wells. This section presented a new method of welltest analysis for more reliable estimation of the average reservoir permeability and a new correlation for estimating the permeability of natural fractures in tight formations.

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http://www.springer.com/978-3-319-02480-6

Evaluating Factors Controlling Damage and Productivity
in Tight Gas Reservoirs
Bahrami, N.
2013, XVI, 53 p. 37 illus., 14 illus. in color., Hardcover
ISBN: 978-3-319-02480-6