An integrated workflow to perform reservoir and completion parametric study on a shale gas reservoir

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Abstract

The main objectives of this paper are to assess the long-term and short-term production based on both reservoir parameters and completion parameters of shale gas reservoirs. The effects of the reservoir parameters (permeability and the initial reservoir pressure) and completion parameters (fracture geometry, stimulated reservoir volume, etc.) on the short-term and long-term production of shale gas reservoirs were investigated. The currently used approach relies mainly on the decline curve analysis or analogs from a similar shale play to forecast the gas production from shale gas reservoirs. Both these approaches are not satisfactory because they are calibrated on short production history and do not assess the impact of uncertainty in reservoir and well data. For the first time, this study integrates initial production analysis, probabilistic evaluation, and sensitivity analysis to develop a robust workflow that will help in designing a sustainable production from shale gas plays. The reservoir and completion parameters were collected from different available resources, and the probability distributions of gathered uncertain data were defined. Then analytical models were used to forecast the production. Two well evaluation results are presented in this paper. Based on the results, completion parameters affected the short-term and long-term production, while the reservoir parameters controlled the long-term production. Long-term well performance was mainly controlled by the fracture half-length and fracture height, whereas other completion and reservoir parameters have an insignificant effect. Stimulation treatment design defines the initial well performance, while well placement decision defines well long-term performance. The findings of this study would help in better understanding the production performance of shale gas reservoirs, maximizing production by selecting effective completion parameters and considering the governing reservoir parameters. Moreover, it would help in accomplishing more effective stimulation treatments and define the potentiality of the basin.

Keywords Unconventional shale gas · Long-term and short-term production · Reservoir and completion parameters · Probabilistic approach

Introduction

Gas shale can be defined as any tight, fine-grained, organic-rich, gas self-sourced sedimentary formation. Gas shale contains all elements of a petroleum system and is a source rock, which provides hydrocarbons (Huaqing et al. 2018; Ma

et al. 2018; Xianggang et al. 2018; Mahmoud et al. 2019; Wei et al. 2019; He et al. 2019). As high as fifty percent of gas by weight can be formed through the maturation of organic material within the shale. The generated gas is trapped within shale adsorbed in the organic/clay material or free inside pores. As shale is relatively impermeable and the rate of hydrocarbon generation far exceeds the rate of outflow, hydrocarbons accumulate within shale formations. Thus, unconventional shale will trap most of the gas/oil in spite of their high pressure due to the low permeability (Dejam 2019a).

Shale has nanoscale pores with dimensions ranging from several nanometers to few micrometers (Qiu et al. 2019a, b; Tan et al. 2019). Due to the nanoscale pores, the flow regime in the shale matrix is defined by slip flow and transition flow (Fig. 1). Hence, the Darcy flow model is not

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Fig. 1 Flow regimes as per Knudsen in the microscopic porous medium [1]

applicable to the shale rock matrix, and the shale permeability is expected to be in the order of nano-Darcy (Blasingame 2015; Dejam et al. 2017a, b). However, Darcy flow occurs both in the open natural fractures and fissures and in the induced fractures of the shale formation.

As shale gas reservoirs are very tight, they have to be drilled horizontally to produce economically. Large fractures must be created along these horizontal wells to produce commercially from shale gas reservoirs. The geometry of the created fracture(s) depends on many variables, including the pumping rate and pressure, pad volume, fluid viscosity, proppant concentration, in situ stress, and rock fabric (Dejam et al. 2018; Kou and Dejam 2018; Zhang et al. 2018; Olayiwola and Dejam 2019; Dejam 2019b). Ideally, a fracture grows in the same plane as the well in both length and height and can reach other formations with higher in situ stress barriers. A fracture continues to grow in length until the end of the pumping treatment. The resulting fracture is planar and extends in a bi-wing manner away from the wellbore. Hence, they are normally called bi-wing, planar, or simple fractures (Smith and Montgomery 2015). Other fracture geometries may occur due to many reasons, including the existence of natural fractures and low-stress anisotropy (Sayers and Le 2010). Due to micro-seismic activities, four possible fracture geometries can be present in hydraulically fractured reservoirs (Mattar et al. 2006; Gomaa et al. 2017). As the performance of a well in shale reservoirs is highly influenced by the geometry of the fractures created and the hydraulic fracture signal is inseparable from the reservoir signal, it is essential to understand the complexity of the fractures. Moreover, a complex fracture geometry is sought in stimulation treatment because it not only connects more rock surface area to the wellbore but also enhances the effective permeability of the reservoir by activating more natural fractures and fissures. Such a complex fracture geometry is identified as a stimulated reservoir volume (SRV). Although the effect of an SRV on a conventional reservoir is minor, it is significant in shale gas reservoirs. Gomaa et al. (2017) have shown that the fracture complexity can be controlled by controlling the viscosity of the fracturing fluid. SRV creation can extend far beyond the induced fractures, and this can be detected from the micro-seismic activities (Ehlig-Economides and Economides 2011). An SRV is created when the

fracturing water is imbibed by the high capillary shale, preventing fractures from closing and acting as a conduit for the hydrocarbons to flow to the induced fracture (Anderson et al. 2010). Other studies have also examined the role of the fracture fluid in determining the extent of production. Only quarter to half of the pumped fluid is recovered in shale stimulation operations, with the rest of the fluid remaining trapped in the reservoir. In actual practice, it is generally considered a bad sign to recover more stimulation treatment fluid (Gomaa et al. 2014).

Published reports indicate that researchers have extensively studied and modeled the effects of adsorption of shale gas and coalbed methane. Fan et al. (2018) have shown that the micropores highly affect the gas adsorption in shale gas reservoirs (Fan et al. 2018). The approach they used will help better estimate the gas content in shale gas reservoirs. Zhao et al. have shown that there is a critical pore size that affects the adsorption of coalbed methane during the water injection process (Zhao et al. 2018a). Wang et al. (2017) have studied the effects of the competitive adsorption of methane and carbon dioxide on the adsorption of shale gas (Wang et al. 2017). They found that the organic pores (pores in organic matter) have a higher adsorption capacity for CO₂ compared to methane although the self-diffusion of methane is larger than that of CO₂. In addition, they indicate that the direction, i.e., whether the adsorption is horizontal or vertical, has a major effect on the adsorption capacity. Horizontal adsorption is higher than vertical adsorption.

Many empirical, analytical, and numerical solutions to analyze production data in porous formations are available in the published literature. Arps was the first to analyze declining rates in producing wells empirically (Arps 1945). His models predict the future rate and the expected ultimate recovery (EUR) based on the production history of the wells as long as the production is stable and a BDF (boundary dominated flow) has prevailed. In shale formations, transient flow typically lasts for years and the application of Arps's equations during this period tends to overestimate future production. Conventional well test analysis methods are currently used to analyze the production from shale gas reservoirs. Well test analysis requires long shut-in periods to analyze shale, and this method is not practical because of the unavailability of suitable shut-in periods. Hence, rate transient analysis is more commonly used to analyze shale reservoirs (Blasingame and Lee 1988; Ilk et al. 2008). Other methods have been suggested for the analysis of production from shale such as diagnostic analysis of production data (Ilk et al. 2010), deterministic workflow (Clarkson et al. 2011), and a generalized workflow that incorporates all transient analysis methods (Clarkson 2013).

The amount of gas held in shale gas sources exceeds that of conventional reservoirs. Commercial production of gas from unconventional resources has been made difficult

due to many technical challenges. The advances in drilling and hydraulic fracture treatment have helped enhance the recovery by exposing more of the reservoir to the wellbore. However, production analysis leads to a non-unique solution for parameters such as the fracture half-length and permeability due to the lengthy transient period that a shale reservoir expresses.

A unified workflow for the analysis of the gas production from unconventional resources is not available in the literature, and all the previous analyses are subjective and depend on the analyzed cases. Until now, there is no single systematic approach in designing stimulation treatments for the shale gas reservoirs. Treatment parameters (such as lateral length, number of stages, and the conductivity of fracture) are subjective. In addition, there is high uncertainty in estimating reservoir and stimulation parameters such as permeability, initial pressure, and fracture half-length. The novelty in this study includes the integration of initial production analysis, probabilistic evaluation, and sensitivity analysis for the first time. The proposed workflow consists of various approaches that fits different data sets. Therefore, it can be easily generalized and applied to any shale gas play.

The objective of this paper is to evaluate the key parameters of reservoirs and wells that affect shale gas production. Reservoir parameters such as porosity, permeability, and the initial reservoir pressure will be evaluated. The completion parameters that will be investigated are well spacing, well length, fracture geometry, etc. Finally, an integrated production analysis workflow will be developed to be used as a guide for the production analysis from shale gas reservoirs.

Methodology

The proposed production analysis workflow consists of three major stages as shown in Fig. 2. They are (1) Stage 1: the initial production analysis, (2) Stage 2: the production evaluation using a probabilistic approach, and (3) Stage 3: parametric sensitivity.

In the initial production analysis stage, two wells in an unconventional shale gas reservoir were studied. The appropriate rate transient analysis is performed using IHS Harmony and Kappa Saphir, two software packages specially developed for the rate and pressure transient analysis. The software packages were used to analyze the available production and pressure data.

In the probabilistic evaluation stage, the probability distribution function is defined to obtain the completion parameters. Some parameters are more precise, while others have some level of uncertainty. For example, the well length and the reservoir temperature are more precise than the rock permeability and the fracture half-length. Reservoir parameters, such as permeability, porosity, initial pressure, and the reservoir extent, were evaluated. Completion parameters,

Fig. 2 Proposed workflow

including the number of fracture clusters, horizontal well length, well spacing, fracture height, fracture half-length, and fracture conductivity were also assessed. The main objective of the probabilistic evaluation stage is to reduce the uncertainty of unknown well and reservoir parameters. After the probability distributions of the parameters are defined, Monte Carlo simulation was used to construct the stochastic samplings of the parameters. Monte Carlo picks random samples for each parameter. The samples are then used to run the Composite Model numerous times. Thus, the uncertainties of the collected parameters are adequately reflected.

The model used in this paper considers the homogenous porosity, isotropic dual region permeability, well location in the center, constant pressure step, and shale lithology. The two main outcomes of the previous steps are the probabilistic production forecast and the probability distribution of the final parameters. The probabilistic forecast captures the likely production range of the subject well. The probability distribution of the final parameters would redefine the initial probability in light of the production forecast. In order to accomplish this task, @Risk (MS Excel add-in) or IHS Harmony was used. @Risk can define the probability distribution of each collected parameter and create Monte Carlo samplings. IHS Harmony can run the composite model and provide results.

In the sensitivity analysis stage, the impact of the well and reservoir parameters on gas production is investigated. A workflow similar to that used in the probabilistic evaluation is used, except that the probabilistic distribution of the final reservoir parameters is used. The sensitivity of the well and reservoir parameters would be repeatedly verified to obtain the production. In order to accomplish these tasks, IHS Harmony was used as the main tool.

Results and discussion

In this study, two multi-fractured horizontal wells drilled in a gas window of a shale gas basin were investigated. The two wells are producing the same fluids, and they are located close to each other.

The uncertainty of a range of parameters, such as fracture height (h_f), fracture half-length (x_f), number of fractures, reservoir permeability, reservoir initial pressure, and fluid properties, was investigated. In multi-fractured horizontal wells drilled in a shale gas reservoir, the unknown parameters are more than the known parameters. Fracture height is the most uncertain parameter among them because an accurate or direct method to determine the fracture height in horizontal wells is not available. The fracture height in vertical wells can be determined using temperature and acoustic, pulsed neutron, or radioactive tracer surveys in a straightforward manner (Dobkins 1981; Anderson et al. 1986; Ahmed 1988; Velez et al. 2012; Goyal et al. 2017). Even though the fracture height in multi-fractured horizontal wells can be determined through well testing and simulation, a direct method such as in the case of vertical wells is not available. To reduce the uncertainty in the determination of the fracture height, it is considered as equal to the formation thickness.

The fracture half-length can be determined using gas well production data analysis. Long-term production data are required to determine accurate values of the fracture half-length. Several techniques and methods, such as production analysis, can be used to determine the fracture half-length

(Bybee 2004; Barree et al. 2005). Advisory systems built based on field experience in tight reservoirs to predict the fracture half-length have produced results that match well with those obtained from production data analysis (Wei and Holditch 2009). Micro-seismic monitoring can be used to determine the fracture half-length (Le Calvez et al. 2005). Production logging and production data can be integrated to evaluate the post-fracturing operation success (Jung 2017). Production history matching using proxy models has been used to characterize the fractures and production from shale gas reservoirs (Kim et al. 2017).

Regarding the permeability of a reservoir, two permeability values are of interest. They are the non-stimulated rock permeability or the outer permeability, and the stimulated rock permeability or the inner permeability. The maximal inner permeability is estimated from the linear flow behavior using Eq. (1) (Spivey and Lee 2013):

$$\left(\frac{p_i - p_{wf}}{q} \right) = m_L \sqrt{t} + b_L S_f \quad (1)$$

where p_i is the initial reservoir pressure, p_{wf} is the bottom-hole flowing pressure, q is the gas flow rate, m_L is the slope of the linear flow region, t is the time, b_L is the intercept, and S_f is the fracture face skin. The outer permeability of the stimulated reservoir volume (SRV) can be estimated using the diagnostic fracture injection test (DFIT).

Accurate initial reservoir pressure can be determined using post-closure analysis. If the direct measurement of the pressure is not available, an estimation can be used from nearby wells. The upper limit of the initial pressure should not exceed the fracture gradient pressure, and lower limit can be considered as that estimated from the pressure build-up test.

For a near-critical fluid such as condensate gas, a full PVT study on an early bottom-hole sample is highly recommended. If it is not available, the equation of state (EOS) calibrated using a recombined wellhead sample can be used.

In this paper, two wells drilled in a shale gas reservoir were analyzed. The two wells have produced for several months at a high gas/oil ratio. The reservoir temperature is 270 °F, the flowing bottom-hole pressure was set to be a minimum of 100 psi, the reservoir length is 4812 ft, and the reservoir width is 1300 ft. The reservoir height is 93 ft, and the reservoir rock bulk density is 2.5 g/cm³.

Initial production analysis

The first step in data analysis is to convert the surface readings to bottom-hole values. This was achieved by uploading the well configurations along with the fluid properties and the production history to the well performance simulator PROSPER. Subsequently, the normalized rate versus the

normalized material balance time was plotted to identify the flow regimes. Material balance pseudo-time (t_{mb}) can be calculated using Eq. (2):

$$t_{mb} = \frac{\mu_i C_{ti}}{q} \int_0^t \frac{q}{\bar{\mu} \bar{C}_t} dt \quad (2)$$

where μ is the gas viscosity, C_t is the total compressibility, and q is the gas flow rate. The calculated pseudo-time is normalized to obtain the maximum material balance time (MBT). The rate is divided by pseudo-pressure (P_p) calculated using Eq. (3).

$$p_p = \frac{\mu_i}{\rho_i} \int_{p_i}^p \frac{\rho}{\mu} dp \quad (3)$$

where ρ is the gas density. By dividing the rate by p_p , the highest normalized rate is obtained. Two flow regimes, namely bilinear flow, and linear flow were clearly identified with no sign of transition to boundary dominated flow (BDF) (Fig. 3). The bilinear flow attributed to fracture cleanup, lasted for 2 months, recovering about 13.5% of the fracturing fluid pumped into the reservoir during the fracturing operations. Subsequently, the stabilization of the gas/water ratio (GWR) was observed producing 50 bbl/MMscf of gas, indicating that the well cleanup period has ended. As only a linear flow exists, the minimum SRV and the maximum SRV permeability can also be estimated.

Next, the normalized gas production rate versus the square root of the gas production time was used to estimate the product of the fracture half-length and the square root of permeability ($x_f \sqrt{k}$) (Fig. 4). The slope of the straight line in Fig. 4 is 30 mD^{0.5}ft and it is the product $x_f \sqrt{k}$, according to Eq. 1. Also, Eq. 4 defines the maximum SRV

permeability using the time of the end of linear flow and fracture spacing. Finally, the minimum SRV was estimated by extrapolation in the flowing material balance time plot (Fig. 5).

$$k = \frac{1896 \phi C_i d_i^2}{t_{elf}} \quad (4)$$

The trilinear composite model was used to model production utilizing the input data extracted from straight-line analysis. The rectangular model with 45 equally spaced fractures was also used to model production. Initial completion parameters and the estimations of the straight-line analysis are used as initial input for the model, and regression of inner permeability, fracture half-length, and fracture conductivity was performed. The predictions of the model provided an excellent match with the production history as shown in Fig. 6.

Probabilistic evaluation

In this stage, the uncertainty overlooked in stage 1 is considered and evaluated. Each fixed parameter in the previous stage is now given an initial distribution (Table 1). Correlation between porosity and saturation was assumed to be a positive correlation, and that between the fracture numbers and fracture half-length was assumed to be a negative correlation. Next, a simulation was performed to refine the assumed distribution and to forecast the possible production. The initial and final distribution of the parameters is summarized in Table 1. Figure 7 shows P10, P50, and P90 forecast for Well 1 and Well 2. Fracture networks and fracture number are two of the major parameters that affect gas production from shale gas reservoirs (Xue et al. 2018).

Fig. 3 Normalized gas production rate versus material balance time (log–log scale)

Fig. 4 Square root time plot versus normalized gas rate

Fig. 5 Flowing material balance plot

Sensitivity analysis

The probabilistic analysis provides a better understanding of the likely completion and reservoir parameters. The mean value of the final distribution in Table 1 was fed to the created trilinear composite model to develop a base case scenario. Following that, the sensitivities of the main reservoir and the completion parameters were input into the model, and model was run for the equivalent of 30 years in order to determine the impact of each parameter. Results were plotted on both Cartesian and logarithmic scales and normalized to the base case maximum value to evaluate the performance from different angles. The following results were obtained from the sensitivity analysis.

The production is directly proportional to the fracture half-length. The longer the fracture half-length of the fractures formed, the higher the rate of production and the cumulative production. The ratio of the increase in the production to the increase in the fracture half-length is 1:2 (Fig. 8). The duration of the flow regimes is not affected by the fracture half-length.

The production is directly proportional to the number of fractures. More the fractures formed, the higher the initial rate of production and the cumulative production. The increase in the initial rate only lasts for at most a year. The ratio between the production increases after the equivalent of 30 years, and the fracture number increase

Fig. 6 Well production history match

Table 1 Initial and final distribution of uncertain completion parameters

Parameters	Initial distribution				Final distribution			
	Distribution type	Min	Max	Mean	Distribution type	Mean	P10	P90
Number of fractures	Triangular	32	63	48	Normal	47	57	38
Fracture half-length (ft)	Uniform	30	250	–	Log-normal	118	208	46
Fracture conductivity (N/A)	Uniform	5	300	–	Normal	21	32	16
Inner permeability	Uniform	90	400	–	Log-normal	162	290	117
Outer permeability	Uniform	20	90	–	Log-normal	25	34	20

Fig. 7 Forecasted Normalized Gas Rate Versus Normalized Time (Semi-Log Scale)

is 3:5 (Fig. 9). More the number of fractures, the shorter the transition period between the first linear flow and BDF.

The production is directly proportional to the well length. However, the relationship weakens when the well

length is longer. The effect of longer wells appears after 1 year of production. The ratio between the increase in the production after 30 years and the longer well is 3:5

Fig. 8 Fracture half-length sensitivity

Fig. 9 Fracture number sensitivity

(Fig. 10). Longer wells delay the BDF regime and extend the linear flow regime.

The production is directly proportional to the fracture conductivity. However, the effect of more conductive fractures is negligible and is only apparent for the first few days lasting only for a few months (Fig. 11). Fracture conductivity does not affect the duration of the flow regimes.

The production is directly proportional to the well spacing. The effect of a larger spacing is initially negligible and is only apparent in the last few years of production. However, a small spacing that is really close to the fracture length shortens the well life significantly and thus decreases the production (Fig. 12). Well spacing does not affect the duration of the flow regimes.

The production is directly proportional to the fracture height. The higher the fractures formed, the higher the rate of production and the cumulative production. The ratio of the increase in the production and the increase in the fracture half-length is 1:1 (Fig. 13). The duration of the flow regimes is not affected by the fracture half-length.

The production is directly proportional to the inner permeability. The increase of production due higher permeability is negligible (Fig. 14). The effect of the higher permeability is initially significantly high and is apparent only in the first few months of production. A higher permeability shortens the initial linear flow regime.

The production is directly proportional to the outer permeability. The ratio of the change in production to the

Fig. 10 Well length sensitivity

Fig. 11 Fracture conductivity sensitivity

change in permeability is 4:5 (Fig. 15). The effect of the higher permeability is initially negligible and is apparent only after the first linear flow regime. A higher permeability shortens the transition between different flow regimes.

The production is directly proportional to the porosity. The effect of higher porosity is significant after the initial flow regime. The ratio of the change in production to the change in porosity is 1:2 (Fig. 16). The duration of the flow regimes is not affected by the change in porosity.

The production is directly proportional to the adsorption. The effect of higher adsorption is significantly high after the initial flow. The ratio of the change in production to the change in adsorption is 2:1 (Fig. 17). The duration of the

flow regimes is not affected by a change in the adsorption. Previous studies showed that gas adsorption is correlated with the TOC content and maturity (Zhao et al. 2018b).

Conclusions

After examining two different cases of gas wells in an unconventional gas play, the following conclusions are derived:

1. Cleanup period (bilinear flow) lasts for few weeks compared to months in other shale plays, and this can be attributed to the careful planning of drilling fluids.

Fig. 12 Well spacing sensitivity

Fig. 13 Fracture height sensitivity

2. Linear flow seems to last for few months at most, indicating a high permeability or intensive stimulation treatment.
 3. The probabilistic approach was the only way to estimate gas in place and stimulated reservoir volume because of the unclear indication of reservoir boundary.
 4. All cases indicate a limited fracture size (especially Well 2), and EUR can be doubled by doubling the fracture half-length.
 5. Different well and reservoir parameters have dissimilar effects on the performance and the duration of the flow regimes.
- In general, the completion parameters affect the initial short-term well performance, while the reservoir parameters impact the long-term well performance.
 - The transient flow regime is greatly affected by the fracture number, inner permeability, and well length.
 - The fracture conductivity affects the performance of the wells only for the first few days or weeks of production.
 - Outer permeability and well spacing affect only the BDF regime.
 - Adsorption affects performance during BDF flow and delays depletion.

Fig. 14 Inner permeability sensitivity

Fig. 15 Outer permeability sensitivity

- While the well spacing significantly affects the well life, its effect on EUR is minimal. However, well spacing does not affect the well performance.
6. Well performance is mainly affected by the fracture half-length, height, and number followed by the set of parameters including the porosity, permeability, and well length and then by the set of parameters including the well spacing, fracture conductivity, adsorption, and initial pressure.

Fig. 16 Porosity sensitivity

Fig. 17 Adsorption sensitivity

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