Journal of Petroleum Science and Engineering 143 (2016) 245–257

Contents lists available at ScienceDirect

Journal of Petroleum Science and Engineering

journal homepage: www.elsevier.com/locate/petrol

Probing diagnostic fracture injection tests in unconventional reservoirs

J. Wallace [a], C.S. Kabir [b,*], C. Cipolla [a]

[a] Hess Corporation, 1501 McKinney Street, Houston, TX 77010, USA
[b] CS Kabir Consulting, Sugar Land, TX 77479, USA

ARTICLE INFO

Article history:
Received 3 July 2015
Received in revised form
24 January 2016
Accepted 29 January 2016
Available online 10 February 2016

Keywords:
Diagnostic fracture injection testing
Unconventional reservoirs
Fracture closure pressure
Reservoir pressure
Fluid leakoff

ABSTRACT

Diagnostic fracture injection tests (DFIT) are commonly used to characterize stress and reservoir properties in unconventional reservoirs. Although simple in concept, interpreting DFIT results can be difficult because several factors can cause results to deviate from ideal DFIT behavior. Some examples of non-ideal DFIT behavior include steep pressure declines after shut-in, absence of pseudo-linear and pseudo-radial flow, and excessive storage indications. Such deviations from ideal DFIT behavior challenge our ability to estimate formation properties reliably. Potential drivers of non-ideal behavior include heterogeneous rock properties, complex rock/fluid interaction, multiphase effects, and natural fractures.

The objective of this study is to investigate how these factors can impact DFIT results and interpretations. A comprehensive approach was taken using a combination of pressure transient analysis, frac modeling, analytical leak-off modeling, and detailed numerical simulation of DFIT behavior. The application was for a horizontal well, completed in a shale gas reservoir, which included an actual field DFIT. Detailed modeling included full wellbore transients and storage, hydraulic behavior through induced fractures, as well as complex interactions between rock, fluids, and natural fractures. It was determined that the actual DFIT showed indications of a complex network created by the pump-in. Closure pressure estimates were found to be reliable, between the simulation cases and DFIT analysis. However, a consistency check on initial reservoir pressure had to be used to obtain reasonable estimates compared to the simulation input. Finally, estimates of reservoir conductivity were highly uncertain compared to the actual simulation inputs. Furthermore, the actual DFIT estimates of reservoir pressure and conductivity were found to be overoptimistic. In fact, the estimated ultimate recovery using DFIT-based permeability-thickness product turned out to be more than twice the estimated ultimate recovery using the integrated core, log, and a pressure-buildup test.

1. Introduction

DFITs have become one of the most common formation tests in unconventional reservoirs. This well test involves fracturing into the formation, measuring the fracture closure pressure for stress, and using the additional post-closure falloff pressure to estimate reservoir properties. The low leak-off and moderate brittleness of these reservoirs allows for efficient fracturing with a limited injectant volume. In practice, DFITs can be completed in less than two weeks, for a fraction of the time and cost of running a buildup test. There is also less risk in running a DFIT, compared to running build-up tests, because any formation damage from the small volume pump-in can easily be bypassed by the large volume fracture treatment. However, running a buildup test requires long-term stable flowing conditions before shut-in, and requires several weeks of shut-in; which can result in significantly delayed production revenue.

Soliman and Kabir (2012) have reviewed many of the various DFIT interpretation methods. In short, most modern DFIT analyses are based on variations of Nolte's (1979) original work. Nolte's original formulation for DFIT analysis has the following limiting assumptions:

1) Constant fracture height with symmetric bi-wing geometry
2) Elastic continuum
3) Constant injection with a power-law fluid
4) Continuous, stable propagation of fluid during pumping with immediate growth arrest when pumping is stopped
5) Fracture closes freely

These conditions require the wellbore to be aligned with a principal stress direction (Haimson and Cornet, 2003). This

* Corresponding author.
E-mail addresses: jwallace@hess.com (J. Wallace), shahkabir@gmail.com (C.S. Kabir), ccipolla@hess.com (C. Cipolla).

http://dx.doi.org/10.1016/j.petrol.2016.01.039
0920-4105/

Nomenclature

A	area (ft^2)
A_{frac}	fracture area (ft^2)
a	unit conversion coefficient
a_2	unit conversion coefficient
a_{inj}	water activity of the injectant
b	unit conversion coefficient
C_I	fracturing fluid filtrate leak-off coefficient (ft/min^0.5)
C_{II}	reservoir leak-off coefficient (ft/min^0.5)
c_f	formation compressibility (1/psi)
C_t	total leak-off coefficient $c_t =$ total compressibility (1/psi)
d	permeability loss coefficient (1/psi)
G_c	G-function value at closure
h	formation height (ft)
$J1$	joint set number one
$J2$	joint set number two
k	permeability (md)
k_i	initial permeability (md)
L	linear-flow regime
M	mobility (md/cp)
M_r	reservoir fluid mobility (md/cp)
M_f	fracture fluid filtrate mobility (md/cp)
pv	pore volume (ft^3)
pv_i	initial pore volume (ft^3)
p	pressure (psia)
p_i	initial pressure (psia)
$p_{closure}$	closure pressure (psia)
p_c	closure pressure (psia)
p_{net}	net pressure (psia)
p_{mech}	mechanical pressure (psia)
p_{pore}	pore pressure (psia)
$q_{leakoff}$	leak-off rate (ft^3/min)
R	universal gas constant (ft^3 psi /R/mol)
S_{hmax}	maximum horizontal stress (psi)
S_{vert}	vertical stress (psi)
S_{hmin}	minimum horizontal stress (psi)
T	temperature (ºF)
t	time (min)
t_c	closure time (days)
V_m	molar volume (ft^3/mol)
w	fracture width (in.)
x_f	fracture half-length (ft)
$\Delta\sigma$	change in local stress (psi)
$\Delta p'$	effective pressure change (psi)
Δp	pressure change (psi)
φ	porosity (fraction)
φ_i	initial porosity (fraction)
$\sigma_{fracture}$	fracture stress (psi)
μ	viscosity (cp)

assumption is reasonable for conventional reservoirs; however, unconventional reservoirs present challenges because they are very tight, relatively brittle, and are usually naturally fractured. This assumption is challenged even further because most DFITs in unconventional reservoirs are pumped through the toe of a horizontal well. Near-well fissuring is more likely, because of high wellbore shear stresses in horizontal wells in addition to a confluence with highly anisotropic rock. Bottomhole pressures at these conditions can far exceed the overburden stress of the formation, resulting in horizontal fractures along bed-parallel joints. Dominant fractures that grow out of the near-well zone, can still be affected by the wellbore orientation, growing somewhat longitudinal to the wellbore (Deeg et al., 1997; Weijers et al., 2000). Once these dominant fractures propagate away from the wellbore, they will turn towards the S_{hmax} direction, opening against the S_{hmin}. However, residual net pressures can still easily be 100 psi to over 1000 psi (Daniels et al., 2007). Thus, residual fracture pressure can still be high enough to create a secondary fracture system. These conditions can create considerable variation in DFIT falloff behavior. A result of this variation is the potential for misinterpretation of formation properties. The objective of this study is to investigate the effect of several potential drivers of complex, non-ideal DFIT behavior and to determine how this behavior can impact stress and reservoir property estimates.

2. Problem statement

As an introduction to the main focus of this paper, an actual DFIT in a recent shale gas well in the Utica play is analyzed using pressure-transient analysis (PTA). The DFIT was pumped through a single set of perforations at the toe of a horizontal well, which had a lateral length of 4600 ft. This shale gas reservoir was completed at a vertical depth of 9000 ft. Subsurface characterization of this shale reservoir confirms that it is brittle, has an effective porosity around 5–7%, and a matrix permeability of about 2E-4 md (Bertoncello et al., 2014). Formation stress follows a normal faulting nature, with the wellbore azimuth oriented slightly west of the S_{hmax} azimuth. A microseismic test at this location confirmed that transverse fractures dominated the midfield region (Cipolla and Wallace, 2014). The DFIT pump-in included a total pump volume of 120 bbl of clean water with 3% KCl, pumped at an average rate of 8.27 bpm for 14.5 min. Fracture breakdown and stable propagation was confirmed before shut-in, and the wellhead pressure was continuously monitored both during injection and after shut-in. Pressure falloff monitoring continued for 9 days.

2.1. Shale characteristics

Shale, for the purpose of this study, follows Fishman's description (Fishman et al., 2013) of hydrocarbon source rock that is dominated by mudstone facies and usually trends toward being either organic-rich or calcite-rich. In either case, shale has a significant amount of organic content, ranging from roughly 2% to over 10%. Rock samples were taken in the same formation as that of the field DFIT example. Rock properties include the following characteristics: brittle rock with high calcareous content, roughly 4–6% porosity, with most of this porosity in the organic matter. Fig. 1a is a scanning electron image of a sample of this rock, as discussed by Bertoncello et al. (2014). While the clay material has an ultralow porosity, the organic matter has significant porosity, and is surrounded by additional intergranular porosity. As shown by Al Duhailan et al. (2013), bed-parallel micro-fractures should be found in source rock because of volume expansion from hydrocarbon generation. Apaydin et al. (2012) demonstrate how important these micro-fractures can be to unconventional reservoir performance. Therefore, a significant factor in DFIT behavior is how the high-pressure injectant permeates, fractures, leaks off, and then imbibes into the rock.