Abstract

Hydraulic fracture stimulation is commonly conducted in tight gas reservoirs to improve the deliverability. The typical sequence of events during the initial completion of a tight gas well is to conduct a hydraulic fracture treatment, flow back on clean-up for 2-4 days, shut-in to run pressure gauges and then conduct an extended flow and buildup test. The extended flow period can vary from a few hours to a few days and the subsequent buildup can vary from a day to several weeks. Fracture treatments in the Western Canadian Sedimentary Basin (WCSB) increasingly utilize CO₂ or Nitrogen to assist in the flow-back of these treatments. A CO₂ charged frac can flow back for a day or more, before burnable (reservoir) gas is seen at surface and at this point, there is typically 40+% CO₂ in the total gas. In many cases, this is the first gas rate reported by the testers. When conducting a pressure transient analysis, current industry practice is to ignore the CO₂ volume injected.

WCSB operators and regulators continue to push for shorter test durations due to economic and environmental concerns. The objective of this paper is to investigate the impact of ignoring CO₂ injection on post-frac pressure transient analysis, and to provide guidelines on when the pressure transient analyst should take into account the injected CO₂ volumes.

Introduction

The usage of CO₂ in fracture stimulation has been studied extensively. The practical use of CO₂ in hydraulic fracturing has been available since the 1960's. It was initially pumped with the frac fluids in a ratio adequate to gas lift the liquid back to surface after the treatment. Later, higher CO₂ ratios (50-75%) were used. Recently, liquid CO₂ has been used as the fracturing fluid for proppant transport. A CO₂-based stimulation can reduce much of the damage related to fracturing fluids. The use of CO₂ can provide a fracture fluid recovery mechanism that is independent of reservoir pressure. It is unique because CO₂ can be pumped as a liquid and then vaporizes to a gas and flows from the reservoir, leaving no liquid or chemical damage.

Pressure transient analysis is typically performed on the post-frac buildup to estimate reservoir parameters, such as initial reservoir pressure, permeability, effective fracture length, and deliverability potential etc, based on bottomhole pressure measurements and concurrent surface measurement information, such as wellhead pressure(s), and gas, oil and water rates, etc.

Industry Practice in the WCSB

A typical tight gas reservoir, vertical well completion in the WCSB commences with a hydraulic fracture treatment. Proppant volumes are rarely below 40 tonnes and frequently exceed 100 tonnes. Fluid volumes are proportionate to the sand volumes and can exceed 200 m³. The cleanup flow back times will vary from operator to operator (based on liquid and sand recovery) but are
typically 2 to 4 days. Once burnable gas has been reported and liquid and sand volumes (if any) have fallen to acceptable levels, the well is shut-in to run pressure recorders to monitor the extended flow and buildup test. The extended flow test duration will also vary, and will be driven by tie-in costs, proximity to residents, emissions, etc. Where infrastructure exists and the tie-in costs are minimal, it is not uncommon to see a 4-hour flow followed by 16-hour buildup (some Alberta operators have interpreted this to be, the ERCB regulated, minimum testing sequence) 5.

After a CO₂ charged fracture stimulation treatment is completed (typical injection duration is about 2 hours), the well is opened to flow back on cleanup. Naturally, the first few hours of flow will see gas composed of close to 100% CO₂ going through the test facilities. A common field practice is to wait until burnable (reservoir) gas is seen at surface before recording any gas rates. At this point, there is typically 40+% CO₂ in the total gas stream. The CO₂ content will then gradually decline as reservoir gas makes its way to the wellbore.

Current industry practice in well test interpretation is to ignore the CO₂ volume injected during the frac, and any reported CO₂ flow back volumes/rates. If separator readings are not reported prior to seeing burnable gas at surface, the analyst has no choice but to use only the gas volumes/rates reported after burnable gas is identified. On the other hand, in situations where CO₂ rates are being calculated and included in the operators’ field notes, it is not uncommon to see an interpretation based on all of the production rate history (including the produced CO₂) being used to develop the pressure buildup derivative, but with no consideration of the injected volumes.

In well test analysis, the pseudo-pressure data/derivative is plotted versus pseudo-time. In order to correct the buildup data to account for rate variations in the drawdown sequence, a superposition time function is applied6. As a consequence of superposition, the trends that we see in the buildup derivative are heavily influenced by the rate history that precedes the buildup. Of course, the shape of the derivative has a direct effect on our interpretation of the well test, because it reflects the reservoir signal.

**Discussion**

A schematic of the flow rate and time sequence for a fracture treatment, and a flow and buildup test are depicted in Figure 1. The final buildup period (Δt) of the injection/shut-in/flow/buildup sequence shown in Figure 1 can be analyzed using superposition. If, for the sake of simplicity, the short shut-in period (to run recorders) is ignored, the radial flow superposition equation during the buildup takes the form of:

\[
\Delta P = 162.6 \frac{B \mu}{kh} \left[ q_i \log \left( \frac{t_f + t_u + t_p + \Delta t}{t_f + t_u} \right) + q_f \log \left( \frac{t_p + \Delta t}{\Delta t} \right) \right]
\]

For linear flow (such as into a hydraulic fracture), the log function is replaced by the square root function. Note also that q_i is negative.

From this equation, it can be seen that for specific values of q_i, q_f, t_f, t_u, and Δt, the longer the flow period (t_p), the smaller the impact of the injection portion (q_i) t_f appears to be. However, when the flow period is short, the impact of the injection portion appears to be significant and should not be ignored.

In order to study the effect of ignoring CO₂ injection and flow back volumes/rates on post-frac pressure transient analysis, synthetic data sets were generated using an infinite conductivity fracture model (assuming an infinite, homogeneous reservoir, and that the effect of gas composition change on fluid properties is insignificant).

The following reservoir parameters were used to generate the synthetic data sets.

- Net pay: 10 m
- Porosity: 10%
- Water Saturation: 20%
- Initial Reservoir Pressure: P_i = 10000 kPa
- Permeability to Gas: k = 0.1 mD
- Effective Frac Half-Length: x_f = 30 meters
- Dimensionless Wellbore Storage Constant: C_D = 1000

**Synthetic Case Studies**

Two cases were studied, a long flow, and a short flow. Synthetic data were generated for the complete frac/cleanup/flow/buildup sequence. However, when it came to analyzing the synthetic buildup pressures, two different methods were used. These different methods (scenarios 1 and 2) of analyzing the same data set were created in order to study the effect, on the analysis, of including or ignoring the CO₂ injection volumes:

- Scenario 1: include CO₂ injection and all flow back volumes/rates.
- Scenario 2: ignore CO₂ injection; use the total measured gas rates (including CO₂ flow-back volumes).

**Case 1 - Long Cleanup, Long Flow and Buildup Test**

Frac/cleanup/flow/buildup sequence: 2-hour CO₂ Injection, 2-hour shut-in, 24-hour cleanup, 3-hour shut-in (to place downhole recorders), 48-hour flow, 144-hour buildup. Scenario 1 includes the CO₂ injection period when calculating the superposition time function. The pressure derivative plotted versus superposition pseudo-time is shown in Figure 2.

Scenario 2 uses the same pressure data set as Scenario 1, but for the purposes of the analysis, it ignores the CO₂ injection period. The pressure derivative plotted versus superposition pseudo-time for this Scenario is shown in Figure 3.

The comparison plot for both Scenarios is plotted in Figure 4. It shows the effect on the analysis of ignoring CO₂ injection. Figure 4 illustrates that for a long flow test, ignoring the CO₂ injection will cause a small deviation in the late-time pressure derivative. Analysis of the derivative, ignoring CO₂ injection, will likely result in the analyst overestimating permeability, and consequently the deliverability forecast will be optimistic.

**Case 2 – Short Cleanup, Short Flow and Buildup Test**

Nowadays, it is more common in the WCSB to conduct short tests due to economic and environmental concerns. A typical flow sequence consists of a 2-hour CO₂ Injection, 2-hour shut-in, 12-hour clean-up, 3-hour shut-in (to run downhole recorders), 4-hour flow and 16-hour buildup.

As in the previous case study, Scenario 1 includes the CO₂ injection. The pressure derivative plotted versus superposition pseudo-time is shown in Figure 5.

Scenario 2 uses the same pressure data set as Scenario 1, but for the purposes of the analysis, it ignores the CO₂ injection. The pressure buildup derivative plotted versus superposition pseudo-time is shown in Figure 6.
Comparing Figures 5 and 6 illustrates that ignoring CO2 injection will artificially create a significantly different trend in the late-time pressure derivative. In this example, the late-time trend in the derivative can be mis-interpreted as a limited reservoir, constant pressure boundary or interference from offset producer(s) etc., which is completely wrong, as this is synthetic data from an infinite reservoir.

Field Data Examples

Well # 1

The well was perforated in the Montney formation and hydraulically fractured, placing 35 tonnes of proppant, blended in 71 m$^3$ of fluid, and 71 x 10$^3$m$^3$ of CO2 gas, into the formation. A 43-hour cleanup flow was conducted and the burnable gas was detected after 15 hours cleanup (at a CO2 content of 85%). Then the well was shut-in (at a CO2 content of 10%) to run downhole recorders. Shortly thereafter, the well was opened to flow on a 60-hour single point test. The well was shut-in at a final gas rate of 41 x 10$^3$m$^3$/d. The pressures were monitored for 430 hours to conclude testing operations.

The total CO2 gas pumped during the frac treatment was 71 x 10$^3$m$^3$. It took 2 hours to complete the fracture treatment; therefore, the gas CO2 injection rate can be calculated to be 849 x 10$^3$m$^3$/d.

Analysis of Buildup

The buildup data was analyzed in two different ways. In Scenario 1 the injection of CO2 was taken into account in the superposition calculation, whereas for Scenario 2 the CO2 injection was ignored. The pressure derivative plotted for both Scenarios is shown in Figure 7. As with the synthetic cases, the Scenario 2 derivative falls below the Scenario 1 derivative.

Using a net pay of 11.5 m and a porosity is 5%, the history matching results, using a Fracture model, with and without the CO2 injected volumes, are shown in Table 1.

It can be seen, in a frac’d tight gas reservoir, that ignoring CO2 injection and flow back volumes/rates, will overestimate the reservoir permeability. Consequently, the deliverability forecast will be optimistic.

Well # 2

The candidate well was perforated in the Glauconitic formation. The well was hydraulically fractured, placing 35 tonnes of proppant, blended in 111 m$^3$ of fluid and 42 x 10$^3$m$^3$ of CO2 gas, into the formation. A 24-hour cleanup flow was conducted and the burnable gas was detected after 13 hours cleanup (at a CO2 content of 25%). Then the well was shut-in (at a CO2 content of 13%) to run downhole recorders. Shortly thereafter, the well was opened to flow on an 18-hour single point test. The well was shut-in at a final gas rate of 45 x 10$^3$m$^3$/d. The pressures were monitored for 168 hours to conclude test operations.

The total CO2 gas pumped during the frac treatment was 42 x 10$^3$m$^3$. It took 2 hours to complete the fracture treatment; therefore, the gas CO2 injection rate can be calculated to be 500 x 10$^3$m$^3$/d.

Analysis of Buildup

Applying the same methodology as in the previous cases (Scenario 1 includes injection, Scenario 2 ignores injection), the pressure derivatives are shown in Figure 8. As previously, the Scenario 2 derivative falls below the Scenario 1 derivative.

Using a net pay of 4.2 m and a porosity of 8.6%, the history matching results, using a Fracture model, with and without the CO2 injected volumes, are shown in Table # 2.

Again, ignoring CO2 injection volumes/rates, will overestimate the reservoir permeability. Consequently, the deliverability forecast will be optimistic.

Conclusion

1. If the extended flow test duration is longer than 48 hours, ignoring the CO2 injection volume in the post-frac pressure transient analysis appears to be insignificant; however, reservoir permeability will be overestimated, resulting in optimistic deliverability forecast.

2. If the extended flow test duration is shorter than 48 hours, ignoring the CO2 injection volumes can negatively impact the interpretation of the pressure transient analysis. The shorter the test duration, the larger the error.

3. For short flow test durations (i.e. <48 hours), it is recommended that testers carefully monitor and record the flow back of all gases for inclusion in the pressure transient analysis. Greater accuracy on the injection side is also incumbent on the frac service providers.

4. For post-frac pressure transient analysis, regardless of test duration, it is better to include CO2 injection and flow back volumes/rates in the analysis to obtain more accurate reservoir characteristics.

NOMENCLATURE

B = Formation Volume Factor
μ = Gas Viscosity [μ Pa.s]
p$\text{i}$ = Initial Reservoir Pressure [kPa]
pw = Wellbore Pressure [kPa]
Δp = p$\text{i}$ - pw [kPa]
P$\text{avg}$ = Average Reservoir Pressure [kPa]
k = Reservoir Permeability [mD]
h = Net Pay [meter]
x$\text{f}$ = Effective Fracture Half-length [meter]
C$\text{D}$ = Dimensionless Wellbore Storage Constant
t$\text{i}$ = Injection Time [hr]
t$\text{si}$ = Shut-in Time after Injection [hr]
t$\text{p}$ = Producing Time [hr]
$\Delta$t = Final Shut-in Time [hr]
$q_{\text{i}}$ = Injection Rate [e m$^3$/d]
$q_{\text{p}}$ = Producing Rate[e m$^3$/d]
$q_w$ = Gas Rate[e m$^3$/d]
ψ = Pseudo-Pressure [MPa$^2$/Pa.s]

REFERENCES

1. S.R.King, Liquid CO2 for the Stimulation of Low-Permeability Reservoirs; SPE paper 11616 presented at the 1983 SPE/DOE symposium on low permeability held in Denver, Colorado, March 14-16, 1983

2. Sam J.Garbis, The Utility of CO2 as an Energizing Component for Fracturing Fluids; SPE Paper 13794 September, 1986

Appendices

Tables:
Table 1: History matching results from both Scenarios for Well # 1.

<table>
<thead>
<tr>
<th>Scenario</th>
<th>P_{avg} (kPa)</th>
<th>k (mD)</th>
<th>x_f (m)</th>
<th>q_{g@1 Month} (e^3 m^3/d)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>26517</td>
<td>0.037</td>
<td>30</td>
<td>18.3</td>
</tr>
<tr>
<td>2</td>
<td>26518</td>
<td>0.058</td>
<td>27</td>
<td>24.0</td>
</tr>
</tbody>
</table>

Table 2: History matching results from both Scenarios for Well # 2.

<table>
<thead>
<tr>
<th>Scenario</th>
<th>P_{avg} (kPa)</th>
<th>k (mD)</th>
<th>x_f (m)</th>
<th>q_{g@1 Month} (e^3 m^3/d)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>25515</td>
<td>0.08</td>
<td>34</td>
<td>12.9</td>
</tr>
<tr>
<td>2</td>
<td>25359</td>
<td>0.10</td>
<td>20</td>
<td>16.0</td>
</tr>
</tbody>
</table>

Figures:

Figure 1: Injection/Flow/ Buildup Test – Rate/Time Sequence Diagram

Figure 2: Pressure derivative for synthetic long test (Scenario 1)

Figure 3: Pressure derivative for synthetic long test (Scenario 2)

Figure 4: Comparison plot for synthetic long test (Scenario 1 & 2)
Figure 5: Pressure derivative for synthetic short test (Scenario 1)

Figure 6: Pressure derivative for synthetic short test (Scenario 2)

Figure 7: Comparison plot for real field data example well # 1

Figure 8: Comparison plot for real field data example well # 2