Breakdown Pressure of Green River Shale With sc-CO2 and Water Monitored Using X-ray Computed Tomography (MR13B-0072)

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Introduction

- The very steep drop in the first 30-40 months of producing gas wells (Fig. 1) supports that natural and induced fractures are the main production contributors in this period.
- Aqueous fracturing disadvantages: liquid loading, long flowback periods and swelling and dispersion of some clay minerals.
- Properties of supercritical CO_2: Greater adsorption capacity in shale (Fig. 2), inducing thermal stress when it expands, and unique physical properties.
- Understanding fracture behavior (e.g. breakdown pressure) is important for fracturing job design and fracturing avoidance during CO_2 sequestration and stimulation jobs.

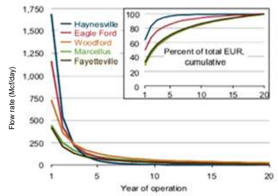


Figure 1: Gas wells production profile for different shale basins in the US (U.S. Energy Information administration (2013)

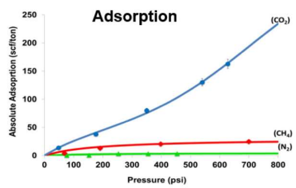


Figure 2: CO2 adsorption capacity compared to other gases for shale(Aljamaan, 2015)

Background

Breakdown pressure models

Breakdown pressure model	Review	Reference
Classical model	Performs well when there is no permeation	(Hubbert and Willis, 1972)
Classical + Poroelastic model	Accounts for fluid permeation to matrix	(Haimson et al., 1968)
Point stress model	might explain wellbore size effect	(Ito and Hayashi, 1991)
Fracture mechanics based model	Accounts for wellbore size Modified model: might justify pressurization rate influence	(Abou-Sayed et al., 1978 ; Rummel, 1987)

Factors influencing breakdown pressure

- Rock properties
- Fluid properties
- State of stress
- Pressurization rate
- Borehole size

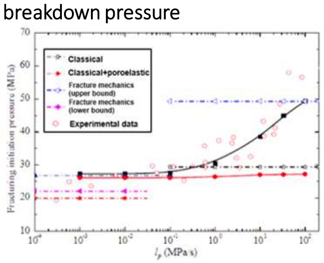


Figure 3: Modified after Zhang et al. (2017b)

CO2 fracturing experiments for shale

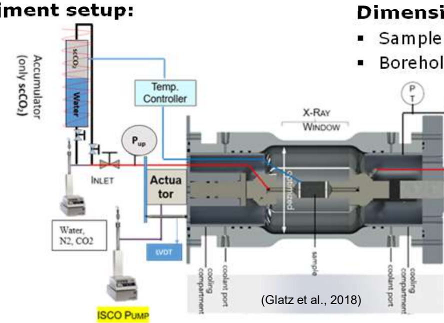
$CO_{2\,BDP} < Water_{BDP}$ $CO_{2\,BDP} > Water_{BDP}$

Paper	Rock Types	sample dimensions (in)	Stresses	Breakdown pressure results	Fracture status
Bennour et al., 2015	shale	6.7" * 3.35"	Uniaxial	l-CO2 < oil < water	Water: parallel to bedding l-CO2: unstable fracture
Li et al., 2016	shale - Green River	2" * 1"	Triaxial	l-CO2 > N2 > water	------
Zhang et al., 2017a	shale	7.87"	Triaxial	sc-CO2 < l-CO2 < water	Fracture complexity: sc-CO2 > l-CO2 > water

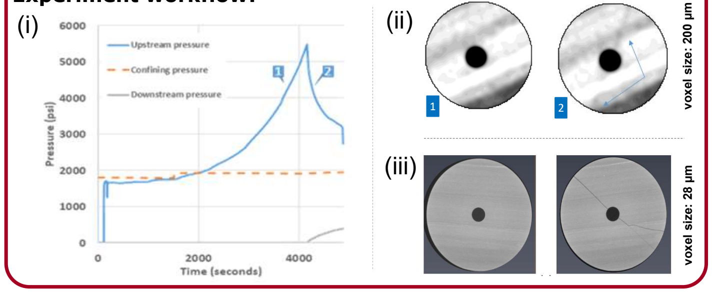
Experimental Setup and Methodology

Experiment setup:

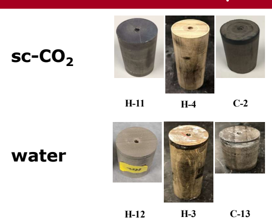
Dimensions:
- Sample: 1.3 - 2″ x 1″
- Borehole: 1″ x 1/8″



Experiment workflow:



Experimental Work



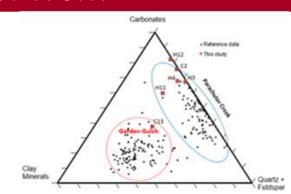
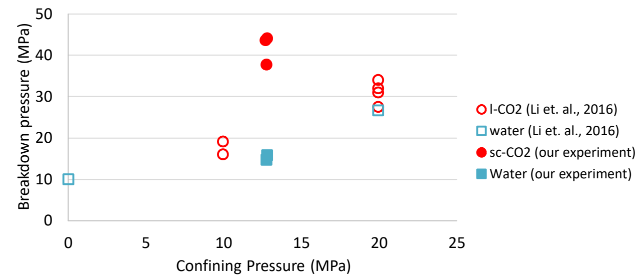


Figure 5: Mineral composition of Green River shale along with tested samples– Modified after Burnham and McConaghy (2014)

Sample	Fluid used	pb (g/cc)	Dimensions (L*D)	Formation	Depth (ft)	Summary
H 11	sc-CO2	2.21	2″ × 1″	Parachute Creek	2344.1	Fracture observed
H 4		1.97	2.8″ × 1″	Parachute Creek	485.9	Fracture observed
C 2		2.3	1.9″ × 1″	Parachute Creek	7495.3	Fracture observed
H 12	Water	2.21	1.9″ × 1″	Parachute Creek	2344.3	Fracture observed
H 3		2.04	2.8″ × 1″	Parachute Creek	485.7	Fracture observed
C 13		2.6	1.5″ × 1″	Garden Gulch	10486	Failed (leakage at 8870 psi)

Results



Modified after Li et al., (2016)

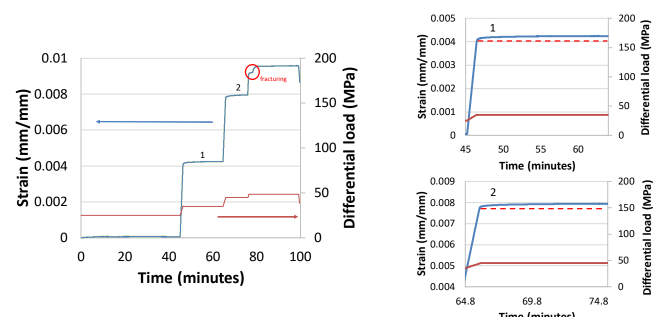
Possible explanations for large BP for sc-CO2 treated samples:
- Different mineral composition: larger ductility than Li et al., (2016) samples
- Reaction to kerogen: large total organic content
- Viscoplastic behavior: observed during experiments

H 11 (sc-CO2)   H 12 (water)

sc-CO2 treated sample:
- 30 degree from bedding
- Slightly branched fracture

Water treated sample:
- Parallel to bedding
- One main fracture

C2 short term creep during sc-CO2 fracturing:



Conclusions

- A general trend of large breakdown pressure and unstable fracture propagation for sc-CO2 treated samples was observed.
- sc-CO2 reaction to kerogen is expected to increase ductility of samples and hence result in larger breakdown pressure magnitudes.
- Mineral composition variation plays a major role in breakdown pressure.
- Fracture complexity evaluation is limited as sample size decreases.

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