Potential Formation Damage: An Integrated Reservoir Characterization Study of the Naturally Fractured Carbonate Middle Duperow Formation at the Kevin Dome, Montana*

Minh C. Nguyen[1,5], Morteza Dejam[2], Mina Fazelalavi[3], Ye Zhang[1], David W. Bowen[4], and Philip H. Stauffer[5]

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[1]Department of Geology and Geophysics, University of Wyoming, Laramie, Wyoming, USA (minh.nguyen@uwyo.edu)
[2]Department of Petroleum Engineering, University of Wyoming, Laramie, Wyoming, USA
[3]Energy Research Section, Kansas Geological Survey, Lawrence, Kansas, USA
[4]Department of Earth Sciences, Montana State University, Bozeman, Montana USA
[5]Earth and Environmental Sciences Division, Los Alamos National Laboratory, Los Alamos, New Mexico, USA

Abstract

In this study, we integrate geologic and engineering data of a naturally fractured carbonate reservoir at the Kevin Dome, Montana. Well test data are correlated with core description, geochemical and lithology study to determine the flow behavior and communication within the injection test interval and to the surrounding area. Based on a dual-continuum geologic model, numerical brine injection simulations are carried out to validate the interpretation results from our well test analytical models and forecast the probability of CO_2 injection success using current reservoir properties. As a result, our well test analytical models as well as lithology/core description suggest that fluid flow may be mainly restricted to the injection interval and the assumption of radial (horizontal) flow may be appropriate. The well test models also indicate that there is potentially formation damage with a positive skin factor although prior to brine injection well tests, well stimulation through acid treatment was performed. Our numerical simulation results appear to confirm this formation damage by showing additional pressure buildup in the injection data during later test periods. To explain this, acid may have dissolved dolomite then dolomite or calcite may have been formed again further into the matrix/fracture system. Another possible explanation is mechanical clogging of the fractures due to acid dissolving dolomite and dislodging fine grains. Our work also predicts that if no additional well stimulation is performed, the project will have a lower probability of successfully injecting 1 million tons of CO_2 into the Middle Duperow formation over 4 years.

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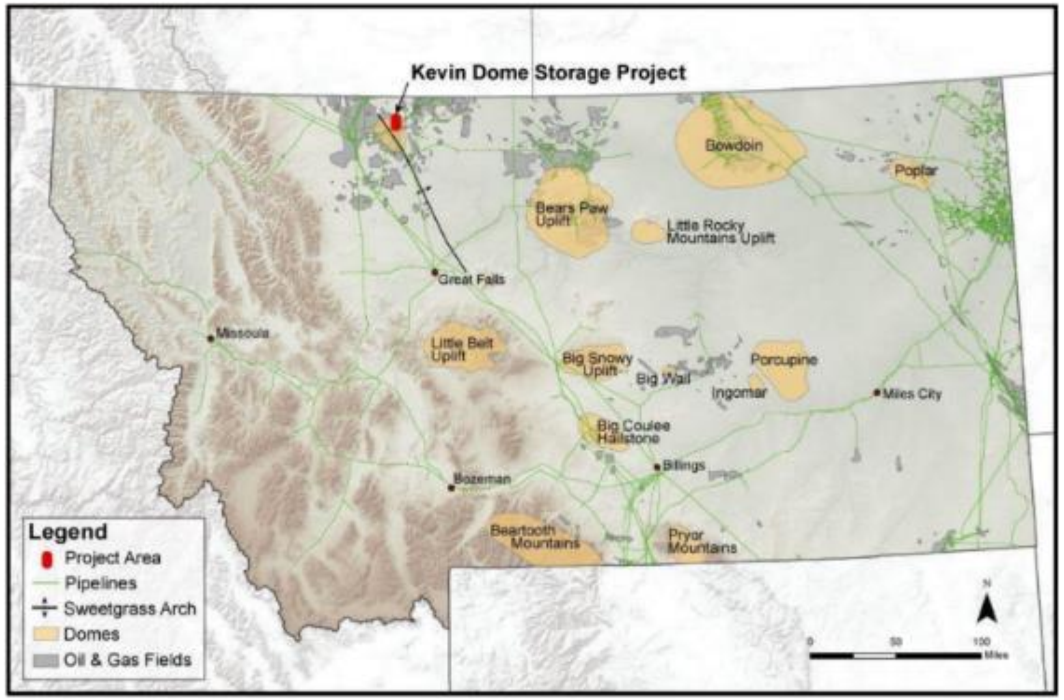
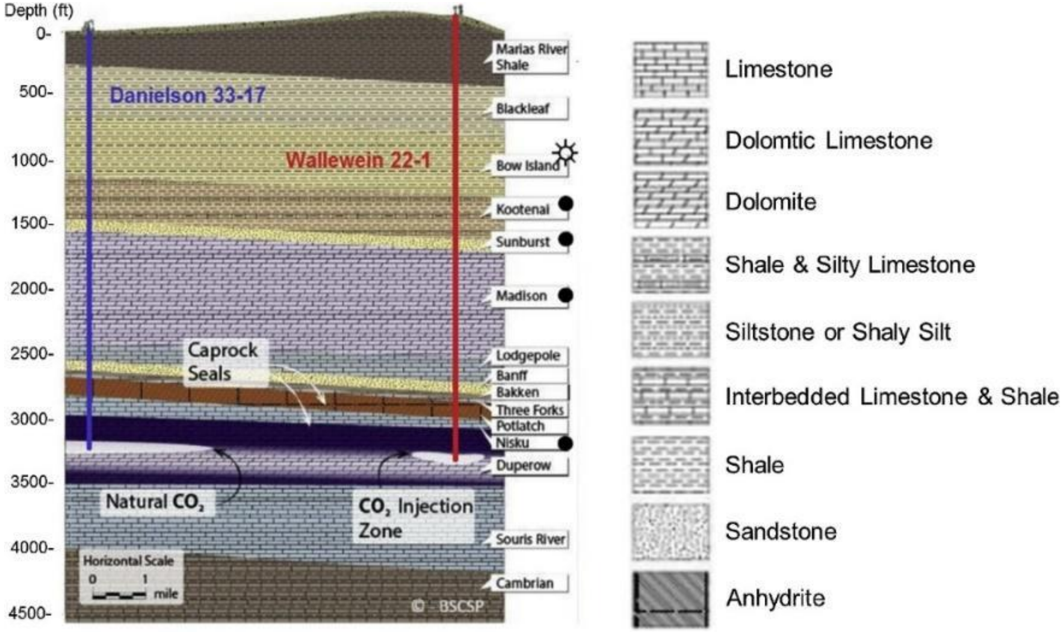
Introduction

- The Big Sky Carbon Sequestration Partnership's Kevin Dome project is one of US DOE's Regional Carbon Sequestration Partnership Phase III Development projects (Onishi et al., 2019)

- The target reservoir is the middle Duperow, a Devonian carbonate (mixed dolostone and limestone) interval of ~100 ft (30 m) thickness

- Our research goal is to utilize the existing samples and data at this site to contribute to the understanding of CO_2 storage in naturally fractured carbonate reservoirs.

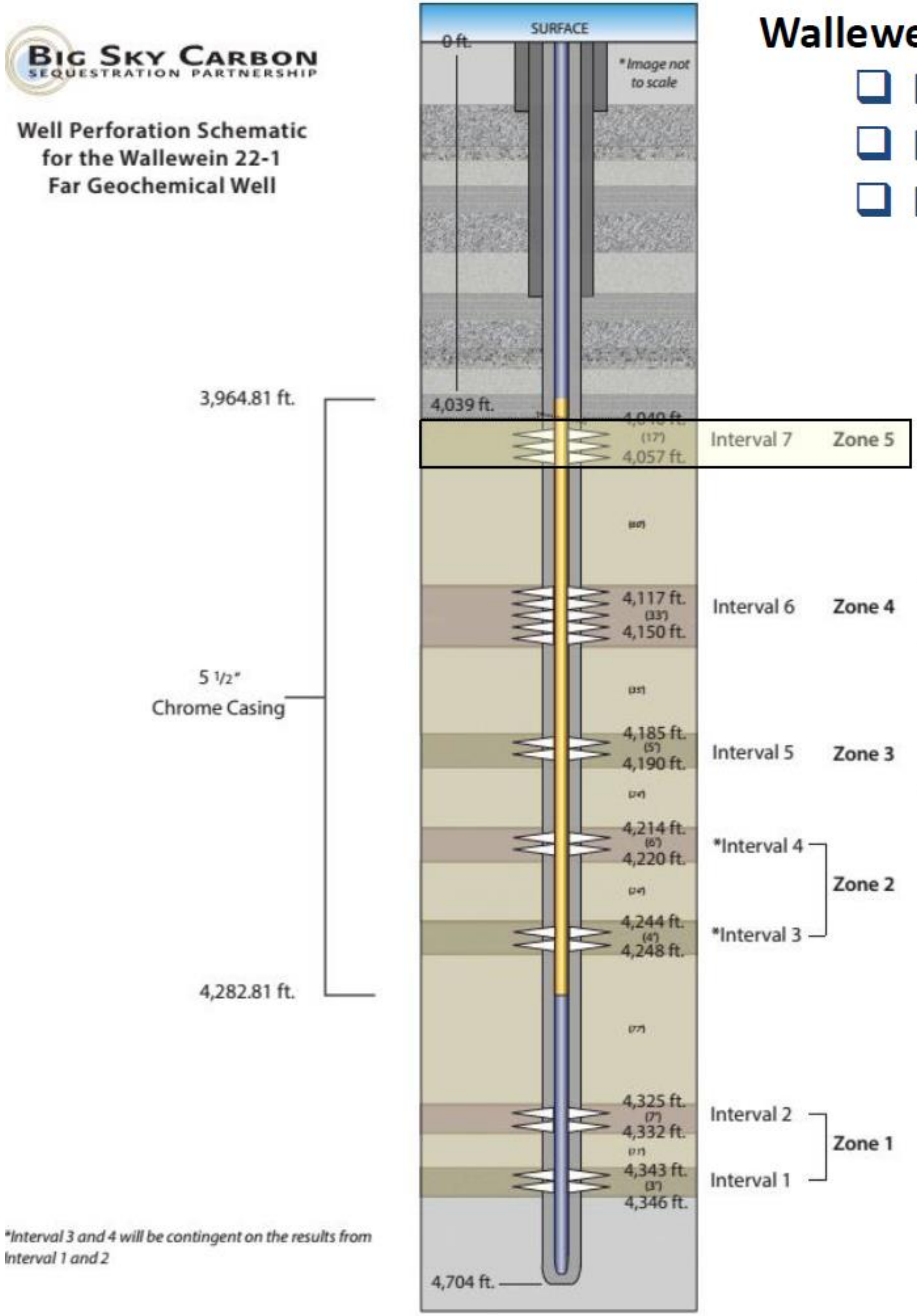


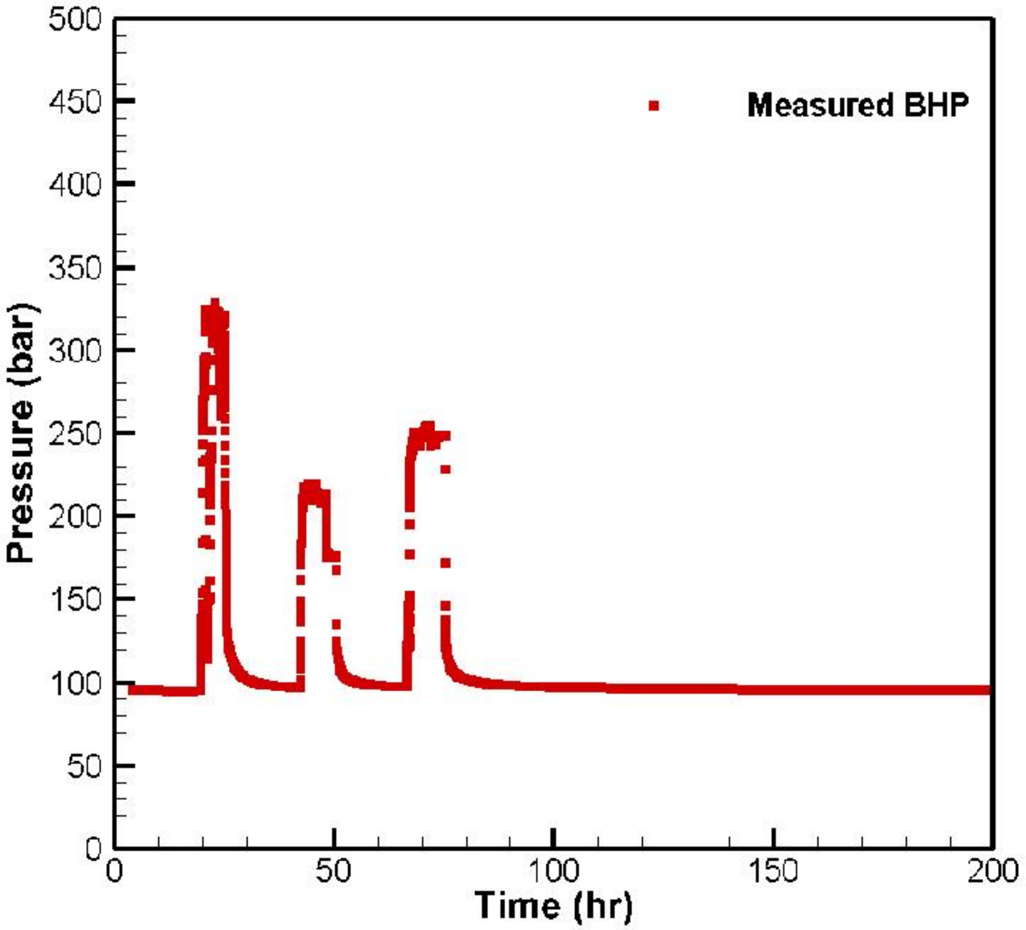


Disclaimer: This graphic is a generalized representation of the subsurface at Kevin Dome.
The horizontal and vertical scale are independent of one another to fir the view on a single page. Surface infrastructure not to scale

Wallewein #22-1 Zone 5 Injection Test Data & Analysis

- Day 1: Step-Rate Test (SRT)
- Day 2: Injection Test
- Day 3: Injection Test





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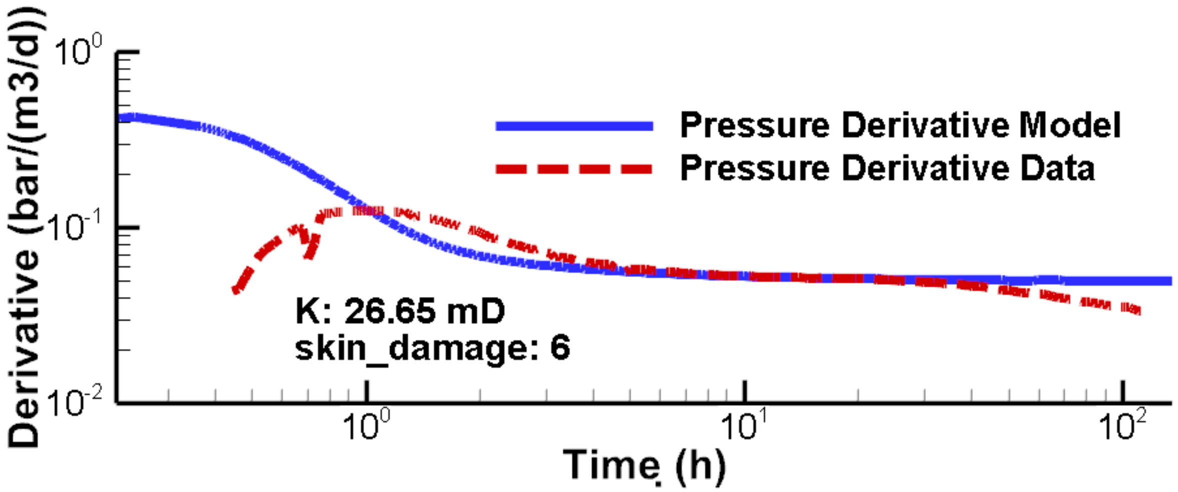
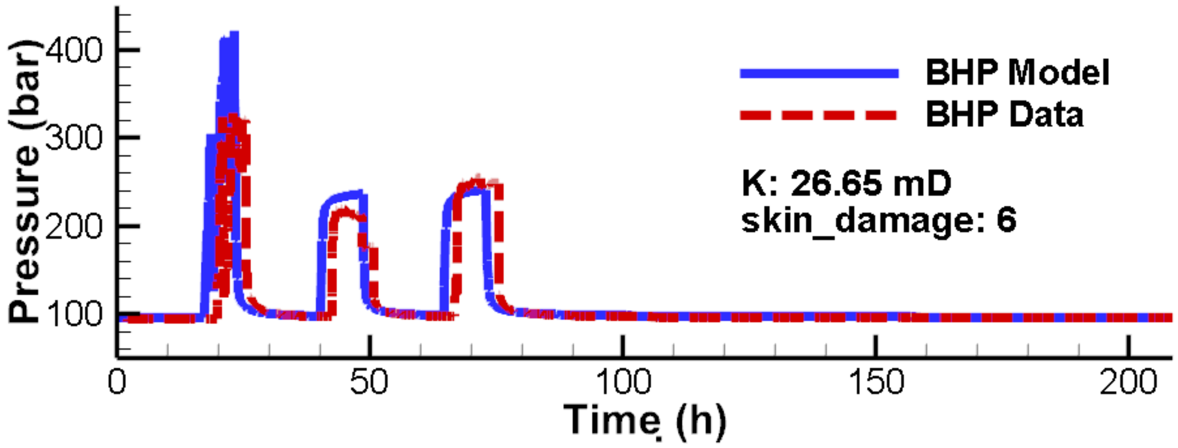
Well Test Analysis – Full Penetration





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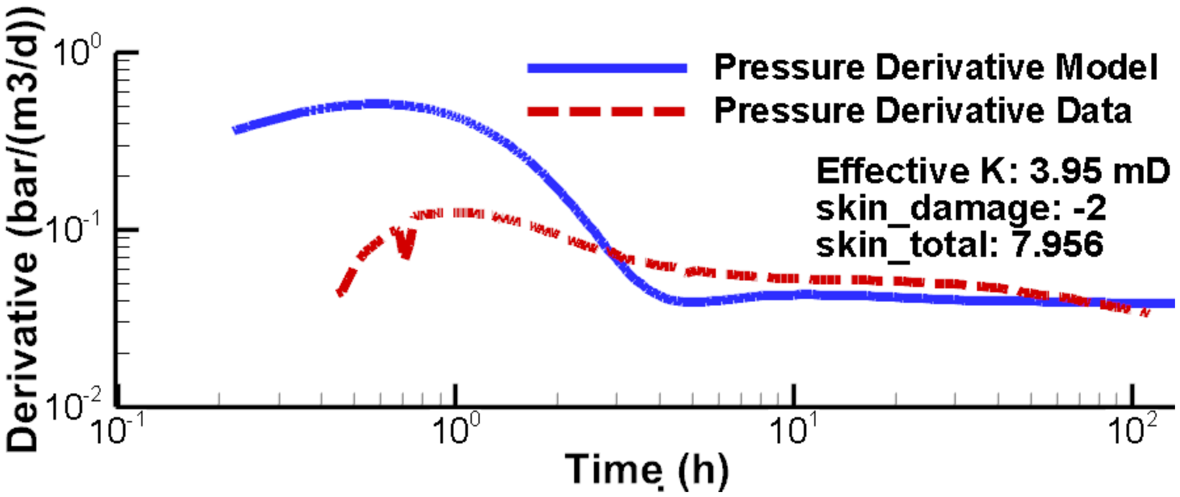
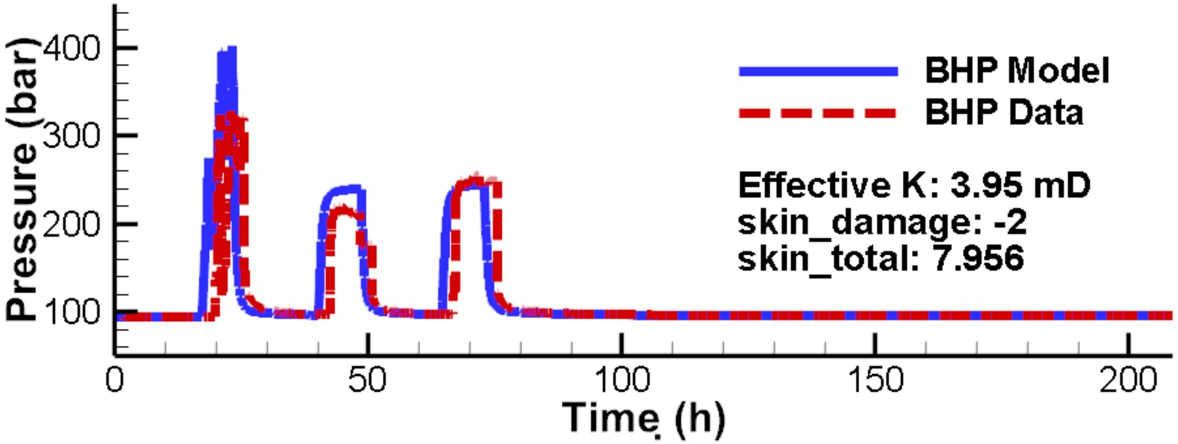
Well Test Analysis – Partial Penetration





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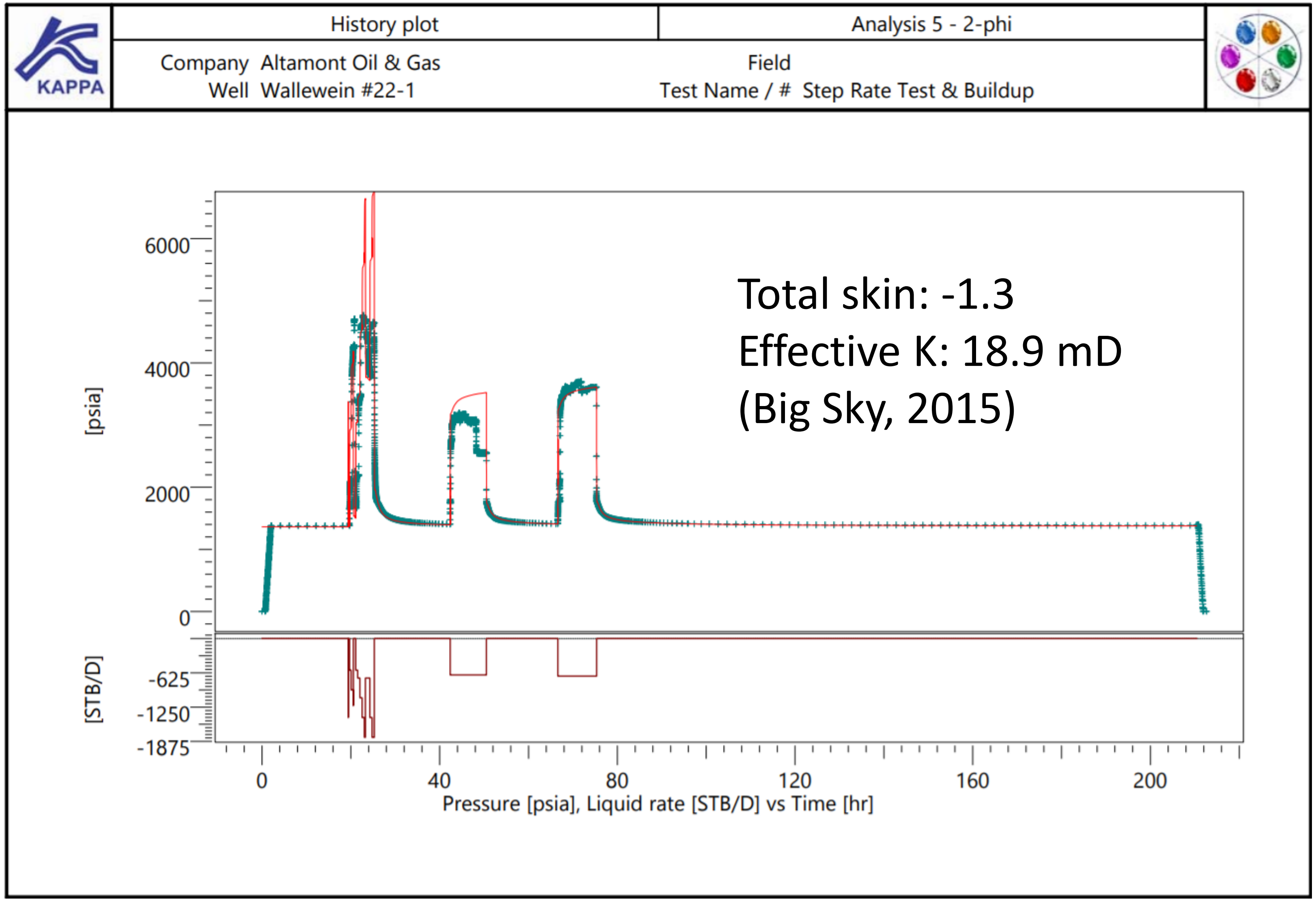
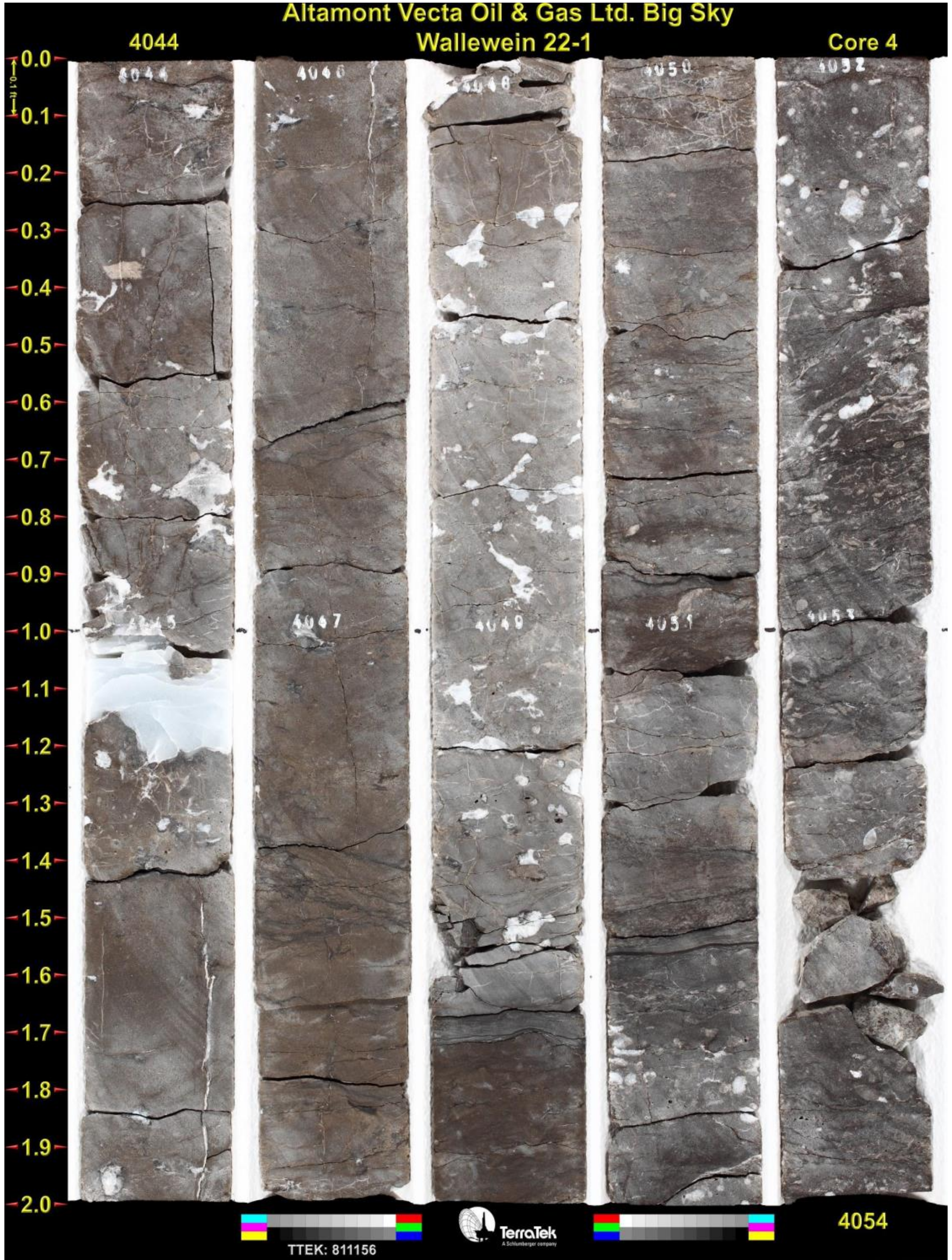
Well Test Results Contradict Previous Report



Core Sample

- Injection interval Zone 5
- This interval contains mainly dolomite (greyish materials) and anhydrite (small white blobs)
- Vertical fractures are observed from the core though their vertical extent is not extensive and not representative of the reservoir fractures



Hypothesis and Testing

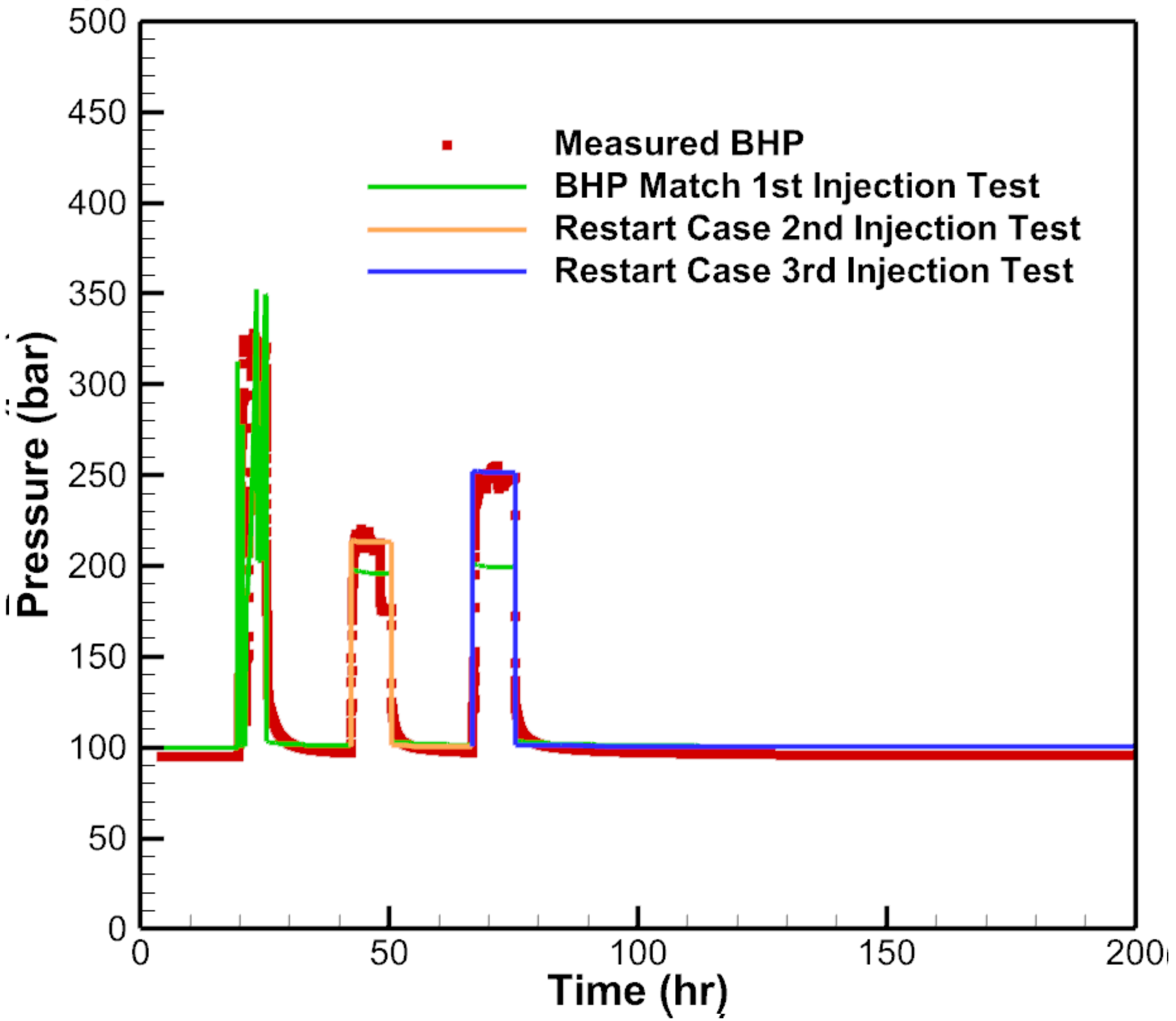
- *We hypothesize that formation damage at Wallewein 22-1 during injection well tests may have reduced the **near-wellbore permeability**, which will adversely impact future CO_2 injectivity at this well*.

- To test this hypothesis and validate the interpretation from the well test analytical models, we perform 3-D brine injection simulations using an improved dual-continuum flow model in which matrix and fracture properties are estimated based on the most recent characterization data collected at the site. (Zaluski, 2018)

- Geochemical speciation calculations are carried out to identify the likely in-situ reactions contributing to the observed pressure buildup during brine injection following the acidizing treatment.

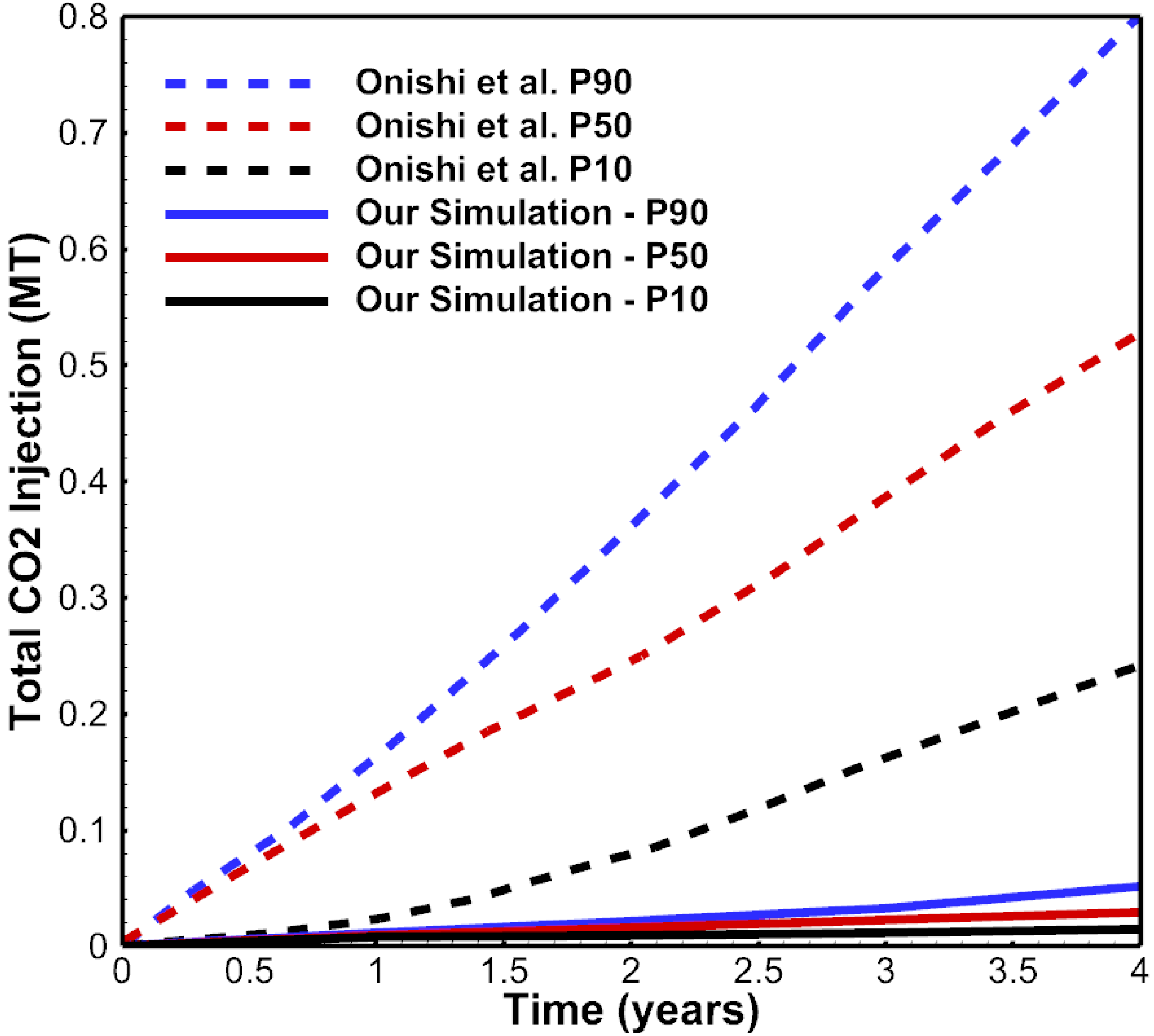
Results – Numerical Simulation

- In simulation scenarios where the near-wellbore horizontal permeability remains constant and there is no formation damage, BHP build-up during the second and third injection tests is similar (green solid line).
- Next, we consider simulation results that consist of changing k_h^w over time.
- Simulation results (orange and blue lines) show that permeability reduction (i.e., positive skin factor) during the injection tests can explain the observed pressure response
- A reduced permeability (compared to the first test) applied to the second injection test (orange solid line) has produced an improved fit to the observed pressure response during this test.



Results – Numerical Simulation

- Based on the formation damage observed during the second and third brine injection tests, k_h^w has been adjusted accordingly in a hypothetical CO_2 injection model.
- Our simulation results suggest that there is a lower probability of successfully injecting 1.0 MT of CO_2 into the Middle Duperow formation over 4 years compared to Onishi et al. (2019).
- This is likely because Onishi et al. (2019) used the fracture and matrix permeability range from regional parameter estimates in previous studies (Dai et al., 2014; Zhou et al., 2013) while we build our reservoir property model based on log and core measurements at Wallewein 22-1 (Zaluski, 2018)



Geochemical analysis of post-acid-test formation water

Sample	Wallewein 22-1 (mol/m3)	Amoco Chevron Gulf (mol/m3)	Snow Hollow #1 (mol/m3)
Ca	18.9	4.315	14.75
Mg	10.74	0.7471	2.44
Na	52.63	113.7	149.6
K	2.66	6.094	2.469
HCO_3	*	3.228	5.829
SO_4	31.02	0.5881	37.74
Cl	14.41	122.2	105
pH	6.3	6.0	8.2

- Baseline water chemistry samples were not collected before acid treatment
- We carry out a sensitivity analysis using water chemistry data from Wallewein 22-1 as well as from two analogous wells in the nearby Madison Limestone Formation

Saturation Index

Sample	Wallewein 22-1	Amoco Chevron Gulf	Snow Hollow #1
Calcite	0.5311	-0.6134	2.251
Dolomite	1.82	-0.6282	5.043
Gypsum	-0.1377	-1.959	-0.1266
Anhydrite	-0.3154	-1.413	0.2609
Halite	-5.001	-3.691	-3.725

- Saturation indices for select clogging minerals in log (q/k). a log(q/k) < 0 indicates a mineral will tend to dissolve, a log (q/k) > 0 indicates a mineral will tend to precipitate
- All three water samples are evaluated for saturation of potential pore-clogging minerals: calcite, dolomite, gypsum, anhydrite, halite.
- Calcite is the only saturated phase. Therefore if chemical clogging were to occur, calcite would be the most likely candidate. Dolomite is not included because the kinetics of dolomite formation are slow and would not be applicable to the time scales being examined here.

Conclusions & Recommendations

- Two possible scenarios that could lead to a positive total effective skin factor and near wellbore permeability decline: **partial penetration** and **formation damage**
- Analytical models indicate a positive total skin factor, contradicting results of a previous study suggesting that the well was mildly stimulated.
- On the formation damage side based on our integrated analysis, high pressure brine injection may have mechanically clogged the fracture/matrix systems through anhydrite fines migration.
- Our geochemical study suggests that calcite precipitation may have occurred during pre-injection acid treatment, potentially also causing formation damage.
- Since acid treatment took place well in advance of brine injection tests, calcite precipitation and anhydrite dislodging are more likely to cause formation damage than high pressure injection.

Conclusions & Recommendations

- To address potential formation damage, we suggest that future GCS projects conduct a comprehensive geochemical study using baseline water chemistry samples before acid treatment to predict potential precipitation.
- Another prevention measure is to consider an alternative stimulation fluid such as EDTA.
- More precaution should be in place for fluid injection in GCS projects including BSCSP to avoid fracturing the rock formation and making it vulnerable to fines migration.
- A possible remediation plan for BSCSP is to inject a more basic solvent like NaOH or KOH into the formation to neutralize the acidic formation water and dissolve any possible calcite precipitation.
- Our work also predicts that regardless whether well stimulation is performed at the Wallewein 22-1, the project will have a lower probability of successfully injecting 1.0 MT of CO_2 into the Middle Duperow formation over 4 years compared to previous studies at the site which relied on regional parameters.

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