Practical Surveillance for Carbon Capture and Storage using Analytical Methods and Flow Simulation

Richard Baker, BRE Group; Alexander LaFreniere, McDaniel & Associates; Jesse Prefontaine, S&P Global

Summary

The application and economics of Carbon Capture and Storage (CCS) in saline aquifer critically depends on large scale permeability. Monitoring injection rates and pressure allows us to have an early warning system and allows us to improve reservoir characterization. In this paper we focus on the diagnostics and flow simulation of the Saline Aquifer, Quest Project. In particular we focus on injectivity as well as history matching bottomhole injection pressures and rates over a five year period. This paper will be useful for project as an analogy in CCS.

When we examine the Shell Quest project using a full field model, we note the following

- There is an increase in reservoir pressure in Cambrian aquifer.
- There is a gradual degradation of injectivity in two wells 8-19 and 7-11
- During shut in or slow down of injection rates there are very large changes in injectivity before and after. These changes in injectivity are irreversible in some cases.

High injectivity is critical for Carbon Capture and Storage (CCS) projects. The advantage of analysing these CCS injectors, are that they have high frequency pressure and rate data as well as temperature is available.

Observations of Injectivity

Figure 1 shows the injection rates and BottomHole Flowing Pressures (BHFP) over a 3.5 year period for the Quest (Cambrian) injector 8-19 on approximately a daily basis.
The injectivity index we use here will be the simplified version (rates/BHFP). Note that the injectivity degrades substantially with time. Also note after three injection slowdown or shut-in periods there is a dramatic and sudden decrease in injectivity as shown on figure 2.

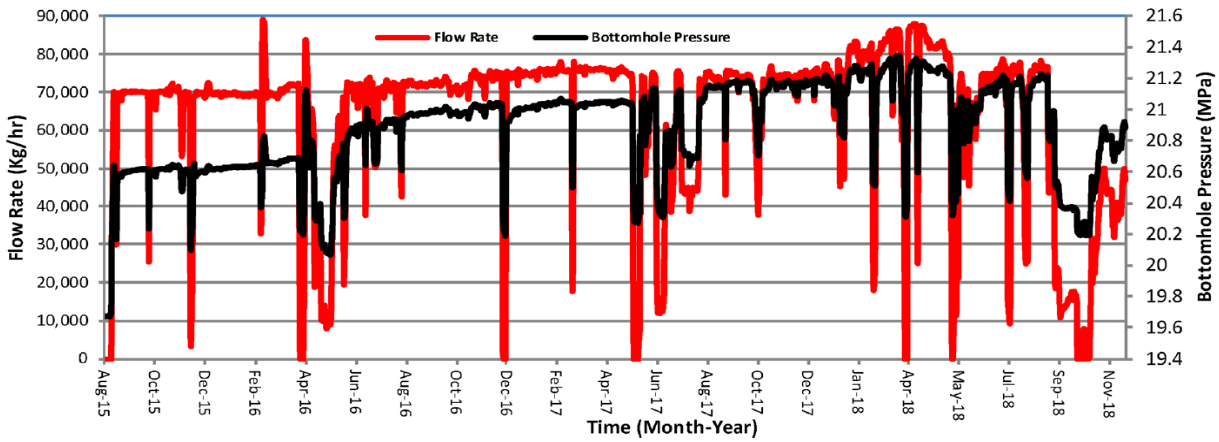

Figure 1: Injection well average daily flow rate and bottomhole pressure with time (3.5 years)

A gradual decrease in injectivity decrease is commonly associated with waterfloods or CO2 miscible EOR floods with WAG process. Generally, the decrease in injectivity in waterfloods and CO2 miscible EOR floods is thought to be due to injecting dirty water, fines migration or multiphase interference effects in WAG processes. Changes in injectivity in CO2 injectors in saline aquifers have been attributed to salt precipitation.

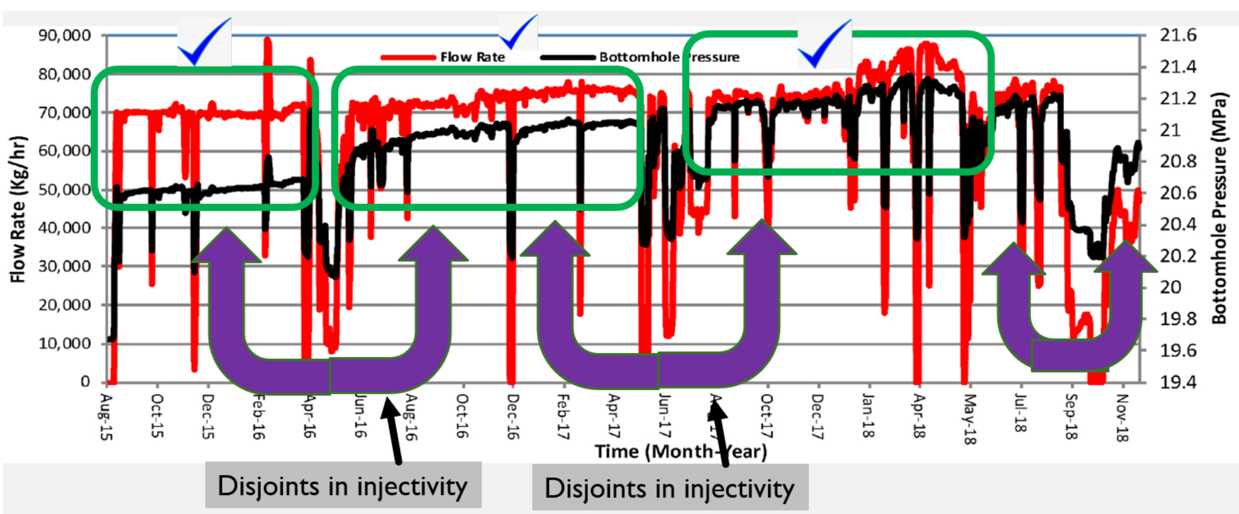

Figure 2: Injection well 08-19 average daily flow rate and bottomhole pressure with time (3.5 years) with annotation for gradual and sudden losses on injectivity

Tawiah 2020[1] exhaustively looked at possible changes in injectivity for the Quest project due to changes in fluid properties, non-Darcy flow and relative permeability. Tawiah clearly shows an inverse relationship between bottomhole injection temperature and injectivity. Tawiah1 attributes changes in flow due to thermally-induced micro-fractures. Shokri 2021[2], attributed the Aquistore project has similar thermal fracturing effects. We would agree that thermal injection induced

fractures have a very large impact on the Quest injectors. However, the focus of this paper is on the decrease of injectivity overall and the sudden changes in injectivity. A common explanation of this decrease in saline aquifer injection is salt precipitation near wellbore.
It was noted that an injector in this field was believed to experience halite precipitation and a subsequent degradation of injectivity[3]. The well underwent a hot water wellbore remediation treatment, and the injectivity of the well. However, as described later in this paper, the injectivity doesn't necessarily return to its original state.

There are two explanations for the decrease of injectivity either reservoir pressure or decreased permeability in the area around the injector could explain the loss of injectivity. A full field flow simulation and a more detailed single well model was done to investigate those phenomena. The full field simulation shows that it is unlikely that reservoir (aquifer) pressure alone could cause the decrease in injectivity. Similarly, it is unlikely salt precipitation near wellbore alone is responsible for the observations.
To understand the mechanisms and approximate future performance of a CCS project we need to start simple.

Material Balance

A material balance was conducted using the 2020 Shell Quest annual progress report3 and other publicly available information. An estimated pore volume of 14.3 billion m3 of pore volume and an initial reservoir pressure of 19.7 MPa were used. This was then used in conjunction with publicly available injection volumes to generate a material balance. Analyzing from August 2015 to August 2020, the average reservoir pressure was found to rise by 584 kPa (Figure 3). When compared to falloff test results for Shell's 2020 annual progress report, the material balance results corroborated the resultant pressures at the time of the pressure tests. With this validated, the next step was to estimate the injectivity of the wells.

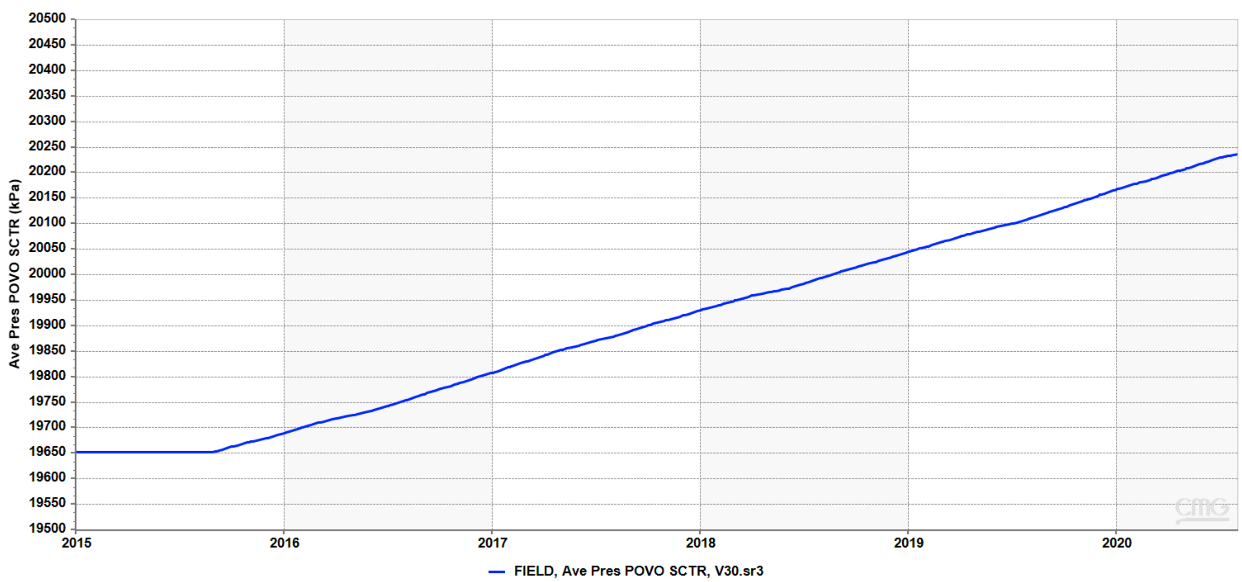

Figure 3: Field-level material balance results – average reservoir pressure vs time

Basic Darcy's Law Calculation

Preliminary bottom hole injection pressure is estimated assuming a pseudo steady-state radial isothermal Darcy flow. This analytical methodology assumes that the CO2/brine has advanced far enough into the reservoir for the pressure gradient to be dominated by CO2 flow properties, and the brine saturation behind the front is assumed to be close to irreducible. This methodology does not take into account pressure buildup in the reservoir over time and represents an instantaneous estimate of injectivity.

Using publicly available rate and bottomhole pressure data, the goal of this evaluation was to evaluate whether the assumption of steady-state flow is reasonable. Focusing on the 08-19 injector well, three characteristic periods of flow were evaluated (Figure 4). In all three flow periods the Darcy's law results showed a constant bottomhole flowing pressure, contrary to the increasing trend seen in observed well data (Figure 5).

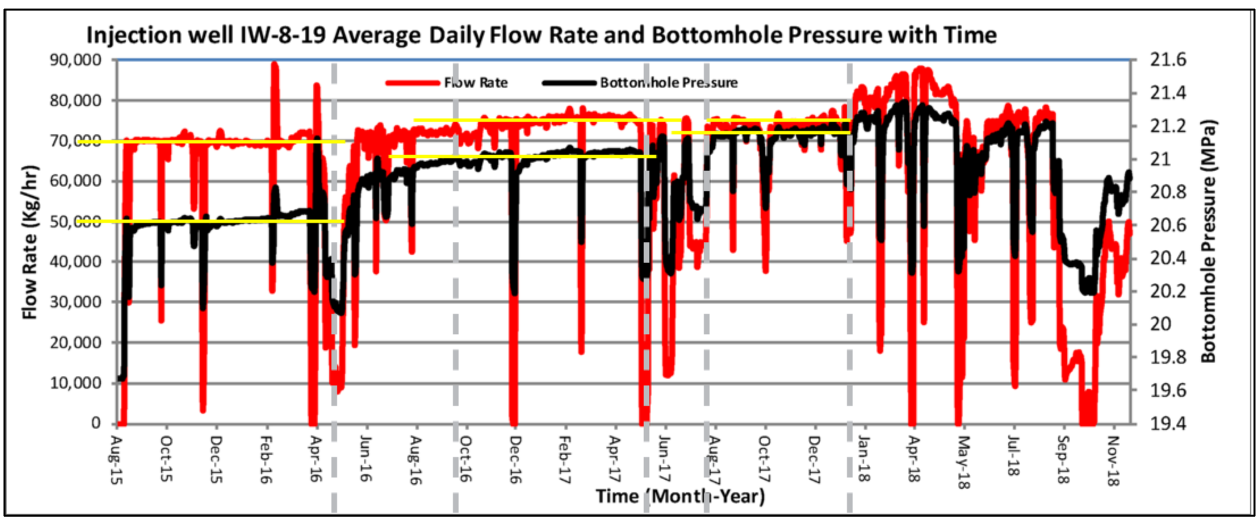

Figure 4: Historical injection rates and bottomhole pressures of injection well 08-19

@250 mD and 0.25 Krco2

	Period 1	Period 2	Period 3
Rate m3/day	940,000	1,000,000	1,030,000
Pwf Actual (MPa)	20.6	21	21.2
Pwf from Darcy's Law 30C (MPa)	20.7	20.8	20.9
Pwf from Darcy's Law 60C (MPa)	20.6	20.6	20.7

Figure 5: Steady-state Darcy's law validation for injection well 08-19

There can be multiple explanations for this behavior: a degradation of injectivity over time manifests in a reduction of permeability or an increase in skin, an increase in reservoir pressure necessitates the higher injection pressure to achieve an equivalent rate, or a combination of factors.

Pressure buildup was later analyzed using analytical material balance calculations on a closed system, and ultimate finite difference compositional flow simulation.

If we use this simple method, there is no way to history match the trends and granularity of the Quest project injection data. A numerical flow simulation is needed.

Simulation Overview

The simulation models three CO_2 injectors in the Quest CO_2 sequestration project. Quest captures and injects 1.1 Mtpa of CO_2 into the Basal Cambrian Sands aquifer. Shell is a carbon sequestration project without an EOR component. Public Alberta Knowledge Sharing portal as well as independent geological modelling was used to construct and history match a simulation model. The simulation is a multi-well, compositional, isothermal, non-geomechanically coupled model that incorporates solubility, multiphase effects including hysteresis, but not mineralization. Sensitivities were explored to develop an understanding of key input parameters on plume geometry, migration, and bottomhole pressure vs rate.

Gridding

The grid used for full field model had grid block sizes of 100m x 100m x approximately 2m in height (20 vertical layers, with total thickness of approximately 40m).

The grid is designed to have the smaller finer grid-blocks described above in the near well bore region injector CO_2 plume area. The model uses uses a pore volume multiplier in the outer blocks reach a total pore volume of 138 E9 BBL. This is a very large volume which is larger than the largest giant oil reservoirs in the world. However very large volumes are support by both material balance and the full filed simulation model, during the static reservoir pressure match. The model uses a closed boundary, no analytical aquifer or infinite aquifer is coupled to the model.

History Matching

To history match the simulation three different classes of parameters were considered; outer boundary/pore volume, static property scaling, and near-wellbore modifications through time.
These three classes of parameters controlled the match as follows:

- The total pore volume manipulated to generate an overall pressure buildup that honors the average reservoir pressure increase seen between initial and extrapolated fall-off data, using a material balance analysis as an estimation/check.
  - To conserve grid blocks, deploying more grid blocks in the plume/saturation change area near-wellbore, and less gridblocks far-field in the pressure affected area.
- Static property scaling was used to transform core data to large-scale permeability and porosity, matching plume scale and shapes based on 4-D seismic and Shell's internal flow simulation plume geometries.

o The depositional environment was honored, a reduction in Kv/Kh moving upwards resulted in the best plume geometry match.

• Near-wellbore permeability was increased in perforated blocks to get the model to run, and decreased in the blocks surrounding the well to increase injection pressures and cause fall-off pressures to more closely match. This modification is believed to replicate the effects of thermally-induced micro-fractures.

Conclusions

1. There are very large volumes in place for the saline aquifer
2. During shut in or slow down of injection rates there are very large changes in injectivity before and after. The cause of those changes are unknown
3. There is a gradual degradation of injectivity in two wells 8-19 and 7-11
4. Thermally-induced micro-fractures are believed to cause high permeability in near wellbore region.

Acknowledgements

The authors would like to acknowledge Krystina Edwards of Highwood Emissions Management, and Dylan Lougheed of Saga Wisdom for their support and contributions.

References

1. Tawiah, P., et al. *International Journal of Greenhouse Gas Control 92* (2020): 102843
2. Rangriz-Shokri et al. *Non-Isothermal Injectivity Considerations for Effective Geological Storage of CO2 at the Aquistore Site* (2019). SPE-196118
3. Shell Canada Ltd. *Quest Carbon Capture and Storage Project 2020 Annual Status Report* (2020)