Measurement and modeling of stress changes caused by underground pressurization of gas

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ABSTRACT
Underground storage of gas allows us to store energy when supply exceeds demand, and quickly deliver energy when needed. In Ontario, natural gas is stored in spent reservoirs during reduced demand (typically summer) and delivered in winter. Renewable wind and solar energy is produced inconsistently, but excess energy can be stored underground as compressed air. In both, pressurized gas is injected into subsurface formations – changing the effective stresses in and around the storage formation or cavern. To maximize capacity, operators want to maximize pressure, while avoiding hydraulic fracturing. Here we describe two modeling studies. In the first, data was obtained from a deep borehole, providing indirect observations of the geomechanical response of the caprock. In the second, open boreholes intersected thin caprock units above the reservoir, allowing gas flow into a shallower unit. At both sites, the mechanical response of the caprock was modeled using combined two-phase flow and geomechanical models.

RÉSUMÉ
Le stockage souterrain de gaz nous permet d’emmagasiner de l’énergie lorsque l’approvisionnement dépasse la demande et de fournir de l’énergie lorsque nécessaire. En Ontario, le gaz naturel est emmagasiné dans des réservoirs épuisés, en période de demande réduite (généralement l’été) puis libéré en hiver. L’énergie renouvelable tel que l’énergie solaire ou éolienne ont une production variable, mais peuvent aussi être emmagasinée sous terre dans des systèmes de stockage sous pression. Dans les deux cas, un gaz doit être injecté à l’intérieur d’une formation, ce qui modifiera les pressions de la formation ou de la caverne. Pour maximiser la capacité, les opérateurs veulent optimiser la pression et éviter la fracturation hydraulique. Nous décrivons ci-dessous, deux études, dans le premier cas, les données ont été obtenues à partir d’un forage, ce qui nous a fourni des observations sur la réaction géomécanique du caprock. Le second étude, un forage ouvert, entre coupant l’unité du caprock, permis au gaz de migrer. La réponse mécanique du caprock a été modélisée à l’aide d’un modèle de flux ainsi que géomécanique.

1 INTRODUCTION
There are many applications where subsurface injection of pressurized gas is important. Underground natural gas storage (UGS) is a long-established technique for storing natural gas. Compressed air energy storage (CAES) is used to store energy from renewable energy supplies such as wind and solar, which provide an inconsistent supply of energy. Both UGS and CAES balance energy supplies with energy demands, making for a more efficient and less volatile energy system. In terms of geomechanical processes, geological sequestration of CO₂ is entirely analogous.

The reliability of UGS comes from the established sealing properties of gas reservoirs over geological time scales, and from a thorough understanding of flow and mechanical processes in and around the storage pool. This technical understanding is particularly important if an operator wishes to increase the maximum storage pressure beyond the naturally occurring discovery pressure of a gas reservoir (delta pressuring), or for storage in engineered aquifer or salt cavern systems.

We were hired to examine the impact of increasing maximum operating pressure (MOP) in a large number of gas storage pools, where gas is injected into subsurface storage formations at pressure. This may considerably impact the effective and total stress in the overlying caprock. To efficiently solve this coupled geomechanical problem, we chose to combine a gas and liquid (two-phase) flow model and a geomechanical model in series. Two-phase flow models were developed and calibrated with data collected on-site, and by inference and interpolation from data collected at nearby pools in the same formations. The mechanical response of the caprock to the simulated delta pressuring was then modeled, allowing assessment of the induced stresses in formations surrounding the reservoir.

In this paper, we highlight modeling results and field measurements from two pools, which exemplify the geomechanical response to pool pressurization and movement of gas in the subsurface. The Silurian age pinnacle reefs are close to one another, and have been safely operated for decades. The ground surface elevation is roughly 200 mASL (metres above sea level), and the minimum depth to both pools is roughly 500 m. The caprock consists of relatively thin anhydrite and shale units, overlain by a somewhat more permeable carbonate unit, a thin anhydrite, and a salt unit. In both cases, the historical data set includes local data on key properties (permeability and porosity) of the reservoir and caprock material, additional property data (retention curves, mechanical properties) from surrounding reefs, and micro-fracture test results (at one of the pinnacle reefs).

Here we show that substantial pressure increases were possible without compromising caprock integrity or infringing on regulatory requirements and best practices. This has improved the capacity and deliverability of these gas storage operations.
In Canada, most jurisdictions apply Canadian Standards Association Z341 (CSA Z341) to regulate the technical aspects of natural gas storage (CSA, 2014). This standard allows delta pressuring up to a maximum pressure at or below 80% of the fracture gradient; defined as “the pressure gradient that, when applied to subsurface formations, causes the formations to fracture physically.” It is unclear from this whether the fracture breakdown pressure or fracture closure pressure should be applied, but conservatism requires us to acknowledge that weak planes may exist in the formation that we do not encounter in a fracture test, meaning the fracture closure pressure, which does not give credit for the tensile strength of the rock, is the relevant criterion. This condition requires that gas pressure be less than or equal to 80% of the minimum principal stress. To meet this standard, the operator must estimate how changes in the pressure of stored gas and movement of gas drive changes in total and effective mechanical stress in the caprock above the storage pool.

The United States’ regulatory environment is more complex, with federal regulation of some aspects of gas storage at interstate facilities, and a wide variation in state regulatory requirements. In the past only surface facilities have been under federal oversight, but in response to the Aliso canyon blowout (Conley et al. 2016), federal authorities are beginning to exercise rulemaking authority over downhole tubing and casing (PHMSA, 2016).

Regardless of local regulations, gas storage operators are concerned with the local stress regime in the vicinity of their reservoirs, and must operate within safe limits that provide a buffer for uncertainty and heterogeneity of stress and property distributions in the subsurface.

3 MODELING PLAN

This project required an evaluation of the potential for gas propagation in the caprock, and the geomechanical response to pressure change in the storage reservoir and connected secondary storage zones. Two models were used to understand the mechanical behavior of each storage pool: a two-phase flow model (TOUGH2, Equation of State Module 3, modified to include the properties of alternative gases and brine, Pruess et al. 1999) and a mechanical (FLAC3D, Itasca 2009) model. Rutqvist and Tsang (2003) first suggested that TOUGH2 could be combined with FLAC3D, leveraging the strengths of each code. They showed one possible application, coupling these models to simulate the hydraulicmechanical response of caprock during CO2 sequestration. Walsh et al. (2015) combined these codes in a different way to characterize damage development and flow in an excavation. These models may be combined in diverse ways to address many problems.

To model a UGS reservoir, TOUGH2 was used to develop a flow model of the system, generating a pore pressure field for input into FLAC3D. The FLAC3D model was used to assess the impact of the changing pore pressures on stress in storage and caprock formations.

4 IN-SITU STRESS

The in-situ stress is the primary factor determining the fracturing pressure and therefore the safe MOP of a UGS reservoir. Lam and Usher (2011) presented the best available synopsis of the regional stress regime. Based on their report, the minimum horizontal principle stress ($\sigma_h$) in this region and depth is 1 - 1.2 times the vertical stress ($\sigma_v$), while the maximum horizontal principle stress ($\sigma_h$) is likely between 1.5 and 2.1 $\sigma_v$. The orientation of the maximum principle stress is approximately ENE. A series of micro-fracture tests at one of the pools confirmed that $\sigma_h$ is close to lithostatic ($\sigma_l$).

The complete stress tensor could not be obtained from testing. To manage this uncertainty, the horizontal principle stresses were both assumed to be equal, and close to the lithostatic stress gradient. This is likely conservative with respect to the potential for tensile hydraulic fracturing, but produces a state of low shear stress. To assess the potential for shear failure, cases in which $\sigma_v$ was set to 2.5 $\sigma_h$ were also simulated. Shear failure was found to be an unlikely failure mode, and these results are not discussed further here.

5 STORAGE POOL A

Storage Pool A was discovered in December 1970 at a pressure of 6082 kPa (882 psia), and produced until August 1972, when it was shut-in at a pressure of 865 kPa (125 psia), having produced 152 Mm$^3$ (5.3 bcf) of natural gas. Use of the pool for gas storage began in 1975. Pool A is of interest due to the installation of a pore pressure monitoring system in the water saturated caprock formations directly above the buried pinnacle reef. At the time this model was prepared, the pool operated at a delta pressure gradient of 0.73 psi/ft (16.5 kPa/m). It has since been delta pressured to 0.76 psi/ft.

5.1 Field Program

In 2013, a site characterization field program was completed by Geoform. This work included drilling and coring one borehole to approximately 490 m deep, providing much needed information about the caprock formations. Core was sampled and tested for mechanical properties, retention properties, permeability, and geochemistry. Field hydraulic testing provided in-situ measurements permeability for these very low permeability units. To record the evolution of pressure in the caprock during pressure cycling, datalogger probes were installed in seven intervals. This data has been used for model development and analysis.

5.2 Model Setup

Figure 1 shows the grid and property distribution in the cross-sectional Pool A model, showing the structure of the reef and cap formations. The shale and anhydrite caprock is very tight, with permeabilities on the order of $10^{-20}$ m$^2$ (10$^{-5}$ md) or less. The carbonate formation directly above the reef is divided into an upper zone with a permeability of $1.4 \times 10^{-21}$ m$^2$, and a lower zone with permeability of
5.5x10^{-18} m^2. The reef itself has an average permeability of 7.2x10^{-15} m^2 (7.2 md) based on core analysis.

Below these underpressured units, measured pressures are near hydrostatic.

The carbonate formation above the reef, isolated from the storage pool by relatively thin layers of anhydrite and shale, is over-pressured with respect to hydrostatic. The genesis of this overpressure is uncertain. It is close to the pool discovery pressure, and may have been naturally present. Alternatively, it may be a long-term consequence of the decades-long storage operation, as gas slowly seeps from the reservoir into the overlying carbonate. We have conservatively assumed the second explanation is true, and the properties of the thin anhydrite and shale caprock units, have been calibrated to fit the observed overpressure. The Sept. 2013 pressure profile from the calibrated model is shown in Figure 3. The modeled pressure distribution in the overlying caprock units is reasonably close to the measured distribution, with the exception of the shallower underpressured units.

Figure 3. Modeled and measured pore pressure profiles above pool during September 2013 pressure minimum.

While Figure 3 represents a single point in time, the orange line in Figure 2 shows the time series of average fluid pressure in the carbonate formation above the reef. The model predicts pressures in the carbonate unit move toward equilibrium with the average storage pressure, tracking the average pressure during the preceding 4-5 years. This calibrated model allows small quantities of gas to seep into the lower part of the overlying carbonate during the decades-long operational period of the pool. The overpressure in this formation has implications for the effective stress and fracture gradient.

The pressures from TOUGH2 were imported into the previously initialized FLAC3D model. Figure 4 shows the model results for a 0.73 psi/ft delta pressure, from both TOUGH2 and FLAC3D. The top panel shows the gas saturation, the second shows the saturation averaged pore pressure which was exported to FLAC3D, the third shows the resultant total stress distribution (horizontal), and the final panel shows the calculated percent fracture gradient. Fracture gradient was calculated using the maximum fluid phase pressure (not average pressure).

5.3 Model Results

Pool inventory between 1983 and 2013 was used to calculate average gas injection/withdrawal rates, to develop the CH$_4$ source/sink term (see top of Figure 2). For the first 23 years the model used a simplified source term based on stabilized inventories, allowing the model to run quickly while matching the stabilized pressures and establishing a reasonable pressure history.

Figure 1. Grid and properties, Pool A model

Figure 2 also shows measured and modeled storage pressures (see insert in figure). In general, the model does a good job of matching the storage pressure history, particularly given that the pressure prediction is very sensitive to the production rate.

Figure 2. Methane source term and modeled and measured pool pressure, Pool A

Figure 3 shows a measured pressure profile above the gas storage pool (caprock), taken in Sept. 2013 at minimum pressure. A multilevel packer system had been installed for three months and pressures in most test intervals were approaching equilibrium with the formation. The measurements show underpressures in shallower units (recall the surface elevation is 200 mASL), which have likely developed over geologic time and are perhaps linked to glaciation during the past 120 ka (Neuzil, 2014).
The maximum percent fracture gradient was 65.4% at 0.73 psi/ft. Increasing the pressure gradient to 0.8 psi/ft, by increasing injection and extraction rates, raised the maximum fracture gradient to 71.4%. In both cases, this maximum occurred at the top of the reef. This model, in combination with the excellent field measurements at this location, suggests that it may be possible to increase the maximum pressure beyond 0.8 psi/ft, as infrastructure is upgraded to handle higher pressures.

5.4 Indirect Measurement of Stress Change

Dataloggers were installed in seven intervals above the storage reservoir to record the evolution of fluid pressure in the cap during reservoir pressure cycling, and provide an early warning should the increased storage pressure cause detrimental pressure changes in the cap. Figure 6 shows pressures from six dataloggers. Data from the seventh, installed at -160 mASL, is difficult to interpret due to pronounced underpressure in the adjacent formation, which may be causing the packer to leak.

Figure 6 shows that, despite cycling pool pressure between 3.5 and 8.2 MPa, the fluid pressure measured in the caprock did not change significantly. The gradual pressure rise apparent in ports 2, 3, and 4 is due to equilibration between the initial fluid pressure in the packed-off section of borehole and the formation fluid pressure. Port 1, in the relatively permeable lower part of the overlying carbonate unit shows virtually no change during this time, as equilibration was much more rapid.

Even at the scale of Figure 6, small perturbations are evident in some of the pressure time series. To highlight these perturbations, a cubic spline fitting the overall trend of the pressure recovery curve was subtracted from the data to remove the recovery trend, highlighting the small pressure fluctuations – as shown in Figure 7. Plotted in this way, there is clearly a relationship between pressure changes in the storage pool and smaller pressure changes in the cap. The observed pressure response is virtually instantaneous, and the pressure perturbations are inversely proportional to the pool pressure changes.

Given the very low permeability of the caprock units, the fluid pressure response measured by these sensors is likely not due to changes in formation pressure, but rather to mechanical deformation of the wellbore acting on the fluid in the isolated interval. The same forces will act on pores in the adjacent formation, causing similar pressure changes, though surely of a different magnitude. Clearly, that the observed pressure fluctuations are not caused by movement of fluid, but rather by mechanical deformation of the wellbore as stress in the caprock changes.

There are no similar pressure fluctuations in Port 1, in the lower carbonate, closest to the storage reservoir. The permeability of this unit is approximately three orders of magnitude higher than other units, which allows any mechanically induced pressure fluctuations in the borehole and formation to dissipate much more rapidly. Alternatively, very low gas saturations in the borehole and adjacent pores would eliminate the hydromechanical pressure response (e.g. Walsh et al., 2012).
It is possible to model the observed mechanical response of the borehole to stress changes, and thereby use fluid pressure changes in the borehole as a proxy measurement for changes in rock stress; however, this effort was beyond the scope of the current project. Nevertheless, the observed pressure fluctuations do provide a valuable qualitative confirmation of the modeled stress changes.

6 STORAGE POOL B

The much larger Pool B is located roughly 4 km (2.5 miles) west of Pool A, with a similar overall structure and geological setting. It was discovered in 1952 at a well head pressure of 6,153 kPa (892 psia). The depth to crest is 502.9 m, translating to a discovery gradient of 11.8 kPa/m (0.52 psi/ft). After producing 629 Mm$^3$ (22.2 bcf) of natural gas, the pool was designated a natural gas storage area in 1962 and currently operates between cushion and maximum pressures of 2,413 kPa and 7,960 kPa (measured at well head). Figure 8 shows the three dimensional structure of the tops of four units, the storage formation (reef), the flanking carbonate (which has a relatively porous dolomitized zone), the overlying carbonate (predominantly dolomite above the reef), and the overlying salt (not present directly above the pool).

At Pool B there are gas pressure measurements from secondary storage zones in the flanking carbonate and a small incipient reef (see Figure 10). Eight wells are cased into the shallower overlying carbonate. Uncased below
this point, they provide a high permeability connection between the storage formation (reef) and the overlying carbonate, bypassing the shale and anhydrite caprocks. During drilling, gas shows were recorded in the overlying carbonate in many wells (see Figure 9). These gas shows and the cross connections between the overlying carbonate and the reservoir, mean that this unit likely acts as a secondary gas storage zone. Based on mapped gas/oil and oil/water contacts an oil saturated zone approximately 10 m thick exists at the base of the reef.

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In the small incipient reef to the west of the reservoir, pressure responds rapidly to increasing pressure in the reservoir, with peaks that almost equal the reservoir pressure. The response to pressure drops is less direct, never dropping below roughly 4.5 MPa (bottom hole).

In October 2015 an observation well in the upper part of the overlying carbonate was completed. The data suggest that there is little connection between pressures at this location and the pressure in the reservoir.

Figure 11 shows the TOUGH2 and FLAC3D model grid in plan view. A comparison between the two grids shows the enhanced refinement of the FLAC3D grid, required to meet more stringent mesh quality requirements. As the flow and mechanical models are based on the same geological structure and property distribution, it was possible to interpolate pressures from the coarser TOUGH2 grid to the FLAC3D grid with a minimal loss of accuracy. The estimated principle stress direction, is expected to lie between E13°N and E30°N in this area (Lam and Usher, 2011; World Stress Map, 2014). To model this the principle stress tensor (assumed to be oriented E23°N) was rotated 23 degrees and the resultant stress tensor was calculated and applied to the model boundaries.

Figure 12 shows the model grid and property distributions for the two models on the A-A’ cross section (location shown in Figure 11). Vertically, the model extends from the elevation -200 m ASL down to -473 m ASL. The 3D representation of the geological structure of the Pool B and host rock is based on drilling logs, geological cross sections and 3D seismic inversion. The TOUGH2 cross-section shows different permeability zones within the reef, which reflect the data from transient pressure testing of the reservoir (see Figure 13).
Eight uncased well segments extend from the reef into the overlying carbonate, crossing the thin shale and anhydrite caprock formations. These high-permeability connections are represented by vertical columns of model elements assigned a high vertical permeability. Figure 14 provides a detail of the reef showing the distribution of well features. These features approximate the eight wells, in terms of their capacity to transport gas between the reef and the overlying carbonate. The vertical permeability of the well features is high, reflecting the very high flow capacity of an open wellbore. The horizontal permeability of the wellbores is scaled to represent the effective surface area of the wells open in the overlying carbonate.

In the overlying carbonate, the pressure rises gradually over the decades of operation, eventually reaching an equilibrium pressure, with small fluctuations in response to the pool pressure cycles. There are currently no available pressure observations in this formation, but the conceptual model is the best fit to the available information.

The pressure response in the incipient reef follows that in the storage reef, with a reduced amplitude and some delay. Peak pressure in the incipient reef is similar to that in the primary storage reef, but minimum pressures do not fall nearly as low as those in the storage pool. The model was able to reproduce this complex behavior, caused by gas entering and exiting solution as a function of pressure, changing the permeability to gas of the flow connection between the pool and the incipient reef.

6.2.2 Mechanical Model Results

In the Pool B pool, open boreholes intersecting two thin caprock units immediately above the reservoir allowed gas flow into the shallower overlying carbonate unit. The presence of these open boreholes significantly impacted the modeled fracture gradients. Model scenarios were developed to simulate current operations at the pool with permeable connections representing all boreholes currently uncased into the overlying carbonate. The highest fracture gradients were predicted to occur at the location of open boreholes, as a result of the propagation of reservoir pressures to this shallower zone. Two wells were identified which had the highest predicted fracture gradients, due to having the shallowest casing set depths in the overlying carbonate.
An updated model was developed in which permeable elements representing these wells were removed, to reflect plans to plug and abandon these wells. Under current MOP, with all current wells, the maximum fracture gradient is estimated to be 76.8%. If permeable connections at the two wells with the shallowest casing depths are removed, the maximum estimated fracture gradient is reduced to 72.0%. Increasing the maximum delta pressure to 0.76 psi/ft increases the maximum fracture gradient to 73.7%, and a further increase to 0.80 psi/ft increases the maximum fracture gradient to 78.1%.

To evaluate the impact of some key, but uncertain, model parameters, a number of other sensitivity cases with alternate parameter sets were assessed. These sensitivity cases included increasing the caprock permeability, increasing the pool compressibility, increasing the gas saturation in the overlying carbonate, and using alternate material properties to represent the overlying carbonate (permeability, capillarity, and mobility weighting functions).

The model results showed that a pressure increase to a maximum delta pressure of 0.80 psi/ft would be feasible, and would not exceed 80% of the fracture gradient, in compliance with regulatory requirements. This conclusion is predicated on the plugging and abandonment of the two wells with the highest fracture gradients. Figure 16 shows fracture gradients in the overlying carbonate in plan section. The connection between wells open in the overlying carbonate and the highest fracture gradients is very apparent.

Uncertainty was managed through conservative, but plausible, assumptions, based on the available evidence. The use of all available field data to calibrate and confirm model predictions fostered confidence in the model. At Pool A, pore pressure measurements in a borehole above the pool provided qualitative confirmation of model predicted stress changes, and offered a potential method to estimate stress changes by the proxy measurements of pore pressure changes or borehole deformation. At Pool B, modeling allowed us to identify optimal candidate wells for abandonment. This hydromechanical modeling procedure allowed us to establish the safety of increased operating pressures. This will allow the operator to increase storage capacity by 10% or more, and eventually to increase deliverability.

7 CONCLUSION

We have described two similar models investigating gas flow and geomechanical processes in UGS operations. In both, multiphase fluid flow and rock mechanical models were combined to quantify subsurface processes which occur when gas is injected into deep formations.

8 REFERENCES


