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Linking microseismic event observations with geomechanical models to minimise the risks of storing CO₂ in geological formations

J.P. Verdon^{a,*}, J-M. Kendall^a, D.J. White^b, D.A. Angus^c

^a*Department of Earth Sciences, Wills Memorial Building, University of Bristol, Bristol, U.K..*

^b*Geological Survey of Canada, 580 Booth, Ottawa, Canada.*

^c*School of Earth & Environment, University of Leeds, Leeds, U.K..*

Abstract

For carbon capture and storage (CCS) in geological formations to be scientifically viable, we must be able to model and monitor the effects of geomechanical deformation on the integrity of the caprock. Excess deformation may open fractures, providing pathways for CO₂ leakage from the reservoir. An acceptable geomechanical model must provide a good match with field observations. Microseismic activity is a direct manifestation of mechanical deformation, so can be used to constrain geomechanical models. The aim of this paper is to develop the concept of using observations of microseismic activity to help groundtruth geomechanical models. Microseismic monitoring has been ongoing at the Weyburn CO₂ Storage and Monitoring Project since 2003. We begin this paper by presenting these microseismic observations. Less than 100 events have been recorded, documenting a low rate of seismicity. Most of the events are located close to nearby producing wells rather than the injection well, a pattern that is difficult to interpret within the

*Corresponding author

Email addresses: `James.Verdon@bristol.ac.uk` (J.P. Verdon),
`gljmk@bristol.ac.uk` (J-M. Kendall), `Don.White@NRCan-RNCan.gc.ca` (D.J. White),
`D.Angus@leeds.ac.uk` (D.A. Angus)

conventional framework for injection-induced seismicity. Many events are located in the overburden. Without geomechanical simulation it is difficult to assess what these observations mean for the integrity of the storage formation. To address these uncertainties we generate numerical geomechanical models to simulate the changes in stress induced by CO₂ injection, and use these models to predict the generation of microseismic events and seismic anisotropy. The initial geomechanical model that we generate, using material properties based on laboratory core measurements, does not provide a good match with either event locations or S-wave splitting measurements made on the microseismic events. We find that an alternative model whose reservoir is an order of magnitude softer than lab core-sample measurements provides a much better match with observation, as it leads shear stresses to increase above the production wells, promoting microseismicity in these areas, and generates changes in effective horizontal stresses that match well with S-wave splitting observations. This agreement between geophysical observations and a softer-than-lab-measurements reservoir model highlights the difficulties encountered in upscaling lab scale results. There is a strong need to link geomechanical models with observable manifestations of deformation in the field, such as induced seismicity, for calibration. Only then can we accurately assess the risks of leakage generated by mechanical deformation.

Keywords: Geological carbon storage, Weyburn, Carbon dioxide, Passive seismic monitoring, Geomechanical modelling

1. Introduction

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Storage of CO₂ in deep geological formations such as saline aquifers and mature hydrocarbon reservoirs provides a technique that can immediately reduce mankind's greenhouse gas emissions while continuing to meet the

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world's energy needs. As we consider the development of large scale stor- 5
age sites – the EU has proposed that at least 12 CCS sites should be in 6
operation by 2015 – it is clear that monitoring programs will be required 7
to demonstrate that CO₂ is safely stored, and also that effective modelling 8
tools should be developed to predict the fate of injected CO₂ (Bickle et al., 9
2007). It is necessary not just to model the flow of CO₂ through the sub- 10
surface, but also the mechanical deformation that CO₂ injection can induce. 11
There are a host of uncertainties that beset the accurate modelling of sub- 12
surface processes, which means that models can only be trusted when they 13
provide a good match with observations made at the site. This is why Di- 14
rective 2009/31/EC of the European Parliament, on geological storage of 15
CO₂, states that ‘the minimum conditions for site closure and transfer of 16
responsibility includes [...] the conformity of the *actual* behaviour of the 17
injected CO₂ with the *modelled* behaviour’ (E.U. Parliament and Council, 18
2009). For reservoir flow modelling, the accuracy of a model is confirmed 19
by history matching with known wellhead pressures, CO₂ breakthrough at 20
observation wells (Giese et al., 2009), and matching the plume shape with 21
that inferred from 4D seismic monitoring (Arts et al., 2004; Bickle et al., 22
2007). 23

Injection of CO₂ will increase the pore pressure in the reservoir, deform- 24
ing both the reservoir and sealing caprocks. Excess deformation can com- 25
promise caprock integrity through the formation or reactivation of fractures 26
or faults. It is therefore important to model the geomechanical impact of 27
CO₂ injection. Geomechanical models can also be used to ensure that CO₂ 28
injection does not induce earthquakes on nearby faults. Just as fluid flow 29
models are matched with observations, so we must do so with geomechanical 30
models to ensure that they are accurately representing reality. There are 31
several techniques that can be used to constrain geomechanical models, such 32

as surface deformation, 4D seismic observations and microseismic activity. 33
At In Salah, Algeria, CO₂ injection has produced surface deformation, which 34
has been imaged using satellite based InSAR methods (Onuma and Ohkawa, 35
2009). The magnitude and geometry of the surface deformation provides a 36
constraint to guide geomechanical models (Rutqvist et al., 2009). Increases 37
in P-wave travel time detected during 4D seismic surveys have been used to 38
image deformation in the overburdens of depleting reservoirs (Hatchell and 39
Bourne, 2005). However, this technique has yet to be applied to a CO₂ stor- 40
age site, where, presumably, the expansion of the reservoir would compress 41
the overburden, reducing P-wave travel times (e.g., Verdon et al., 2008b). 42

In this paper we will demonstrate how microseismic activity can be used 43
to constrain geomechanical models. Movement of faults and/or fractures 44
will generate seismic energy. Although analogous to earthquakes, event 45
magnitudes in and around reservoirs are significantly lower, so they are 46
termed *microearthquakes* or *microseismic events*. The seismic waves that are 47
produced by such events can be detected by geophones placed in boreholes, 48
or larger arrays at the surface. Events are located using methods derived 49
from conventional earthquake seismology. Given that microseismic events 50
will be induced by stress and pressure changes caused by CO₂ injection, 51
they represent an observable manifestation of geomechanical deformation 52
that can be used to constrain mechanical models. 53

Seismic waves generated by microseismic events and recorded on geo- 54
phones near the reservoir will travel through the rocks that are directly of 55
interest (as opposed to controlled source seismics, where waves must travel 56
through the whole of the overburden to and from the surface). As such, 57
wave propagation effects can also provide information about geomechanical 58
processes. Of particular interest is seismic anisotropy, where the veloci- 59
ties of waves are dependent on their direction of travel and polarisation. 60

It is well known that seismic velocities and anisotropy are modulated by 61
non-hydrostatic stress changes (e.g., Nur and Simmons, 1969; Zatsepin and 62
Crampin, 1997; Teanby et al., 2004b; Verdon et al., 2008a), so observations 63
of shear wave splitting – a key indicator of anisotropy – made on waves 64
generated by microseismic events can also be used to inform geomechanical 65
models. 66

1.1. The Weyburn CO₂ Monitoring and Storage Project 67

The Weyburn field in Saskatchewan, Canada, has been producing oil 68
since 1954. Waterflooding was initiated in the 1960s to maintain production 69
levels, and horizontal infill wells were drilled in the 1990s. Injection of CO₂ 70
began in 2000, which boosted oil production back to 1970s levels. Approxi- 71
mately 3 million tonnes of CO₂ are injected each year in a supercritical state. 72
The CO₂ injection program has included a research component, testing and 73
examining the abilities of various monitoring techniques to image CO₂ in 74
the subsurface. The results of this research are of great significance for the 75
CCS community. 76

The Weyburn reservoir, at a depth of ~1430m, consists of an upper Marly 77
dolostone and lower Vuggy limestone layer, of Carboniferous age, with a 78
combined thickness of 30-40m. The reservoir is over- and underlain by thin 79
evaporite layers, which provide the primary seal, while a secondary seal is 80
provided by the overlying Mesozoic Watrous shale layer. Controlled source 81
seismic monitoring combined with reservoir fluid flow modelling has been 82
successful in imaging the plumes of CO₂ migrating away from the injection 83
wells (White, 2009). In 2003 it was decided to examine the feasibility of using 84
microseismic monitoring to image the injection of CO₂ in one pattern of the 85
field. Weyburn is the first – and currently the largest – CCS site to have 86
deployed a microseismic event detection array. Microseismic arrays have 87
also been installed at the Aneth oil field CCS-EOR pilot site, Utah (Zhou 88

et al., 2010), and recently at the In Salah CCS site, Algeria (Mathieson 89
et al., 2010). 90

A recording array of 8 triaxial geophones was cemented in a disused 91
vertical production well approximately 50m from a vertical CO₂ injection 92
well. Horizontal production wells trending to the NE are located to the NW 93
and SE of the injection well. The setup for microseismic monitoring can be 94
seen in Figure 1. The geophones were spaced at 25m intervals at depths 95
between 1181-1356m. The geophones were switched on in August 2003, and 96
CO₂ injection began in January 2004. Excepting two short periods where 97
the array was shut down for technical reasons, recording has been continuous 98
until the present. The passive seismic experiment is divided into two phases 99
– Phase IB which began in August 2004 and ran until October 2004, and 100
Phase II, which has run from September 2005 until 2010. 101

2. Observed microseismicity 102

Further information on the microseismicity observed at Weyburn can be 103
found in Maxwell et al. (2004), White (2009) and Verdon et al. (2010b). 104
To locate detected seismic triggers, a 1D P- and S-wave velocity model was 105
computed using a dipole sonic velocity log from a nearby well. Locations 106
were calculated by matching observed P- and S-wave arrival times with ray- 107
tracing through the model, and the propagation azimuth was determined 108
using first arrival P-wave hodogram analysis. 109

Event locations are marked in Figure 1. 68 triggers were detected dur- 110
ing Phase IB that were from microseismic events (rather than completion 111
shots or drilling noise) and could be reliably located. This represents a very 112
low rate of seismicity. Events have magnitudes of -1 to -3, and events of 113
magnitude -2 are detectable at 500m from the array, which suggests that 114
the small number of events recorded is not an artifact of high noise levels. 115

During Phase II, 18 events were detected in October 2005, and 21 in January 2006. As of 2006 no further events have been detected. There is no evidence to suggest that increases in reservoir noise, or equipment failure, are to blame for the lack of seismicity post 2006, as other activities such as drilling and well completions continue to be detected. The lack of seismicity post 2006 means that CO₂ is moving through the reservoir aseismically. This may indicate that either little deformation is occurring, or that deformation is occurring in a more ductile manner, such that microseismic events are not generated. Verdon et al. (2010a) have shown that CO₂ injection can generate similar amounts of seismicity to water injection, so it is unlikely that it is the lower bulk modulus and/or viscosity of CO₂ alone that has generated the low seismicity rates.

There is a range of dominant frequencies in the events detected, from as low as 20Hz to 150Hz (Verdon et al., 2010b). Because the recording environment at Weyburn is relatively noisy, and because many events have low (20Hz) dominant frequencies, errors in event location are often large (up to 100m in depth). Furthermore, perturbations to the velocity model of $\pm 250\text{ms}^{-1}$ can change event locations by 75m N-S, 20m E-W and 70m vertically. Nevertheless, these relatively large location uncertainties do not affect our principal conclusions.

The hypocenters plotted in Figure 1 show that most of the events are located near to the production wells to the NW and SE. Conventional wisdom dictates that as pore pressures increase around the injection well, effective normal stress will decrease, moving the stress state (often plotted in Mohr circle notation) closer to the Mohr-Coulomb failure criteria. As a result, microseismic events will initially be located around the injection site, and will move outwards radially to track the pressure pulse (e.g., Shapiro, 2008, and references therein). At production wells, the pressure drawdown will

increase the effective normal stress, reducing the likelihood of shear failure. 144
Therefore the observations made here, with events located near producing 145
wells, and few events at the injector, were not expected. 146

Many events appear to be located above the reservoir. Although the 147
large depth errors mean that some of these events could actually be located 148
within the reservoir interval, it seems that much of the microseismic activity 149
is occurring in the overburden. Does this indicate top-seal failure and the 150
migration of CO₂ into the overburden? Stress arching effects – where part 151
of the load induced by CO₂ injection is taken up by stress transfer into the 152
over-, under- and sideburdens – can also lead to seismicity in the overburden 153
(e.g., Angus et al., 2010), without any transfer of fluid or of pore pressure 154
between the reservoir and caprocks. This underscores the importance of 155
having a good understanding of the potential geomechanical behaviour of 156
the storage site in different hypothetical circumstances. It is probable that 157
fluid migration or a pore-pressure connection into the overburden will be 158
documented by a different spatial and temporal pattern of microseismicity 159
compared to stress arching effects – geomechanical models will be necessary 160
to distinguish them. 161

2.1. Anisotropy 162

The seismic energy recorded on the geophones will have travelled only 163
through rocks in and near the reservoir. As such, wave propagation ef- 164
fects such as S-wave splitting (SWS) induced by seismic anisotropy can be 165
attributed to the physical properties of these rocks. This means that micro- 166
seismic events make ideal shear-wave sources for SWS analysis (Verdon and 167
Kendall, 2011), because there is no need to account for the anisotropy of all 168
the rock between the surface and the reservoir interval, as with SWS mea- 169
sured using 9-component reflection seismic surveys (e.g., Luo et al., 2005, 170
2007). In hydrocarbon reservoirs, anisotropy is usually caused by the pres- 171

ence of aligned fracture sets. By forward modelling the effects of fractures 172
and sedimentary fabrics, it is possible to invert measurements of SWS for 173
combinations of fracture geometries that best fit the observed data (Verdon 174
et al., 2009). The SWS detected by the geophones was measured using the 175
semi-automated technique developed by Teanby et al. (2004a), using cluster 176
analysis to ensure a stable result. 177

Of the 544 possible SWS measurements during Phase IB, (68 events \times 178
8 geophones) only 30 provided reliable results, quite a low success rate for 179
SWS analysis. This is partly related to the fact that the low frequency of the 180
waveforms causes the S-wave arrivals to be contaminated by P-wave coda, 181
and partly related to the fact that the S:N ratio of the waveforms is not 182
very good. The measurements are plotted in Figure 2a. The measurements 183
are inverted for the strikes and fracture densities of two vertical fracture 184
sets – this approximates the observations made on core samples regarding 185
aligned fractures in the reservoir (Brown, 2002). Fracture density refers to 186
the nondimensional term given by Hudson et al. (1996). To visualise the 187
results of the inversion we plot the normalised rms misfit between forward 188
modelled and observed splitting as a function of the two fracture strikes and 189
densities (Figure 2b & 2c). The 90% confidence intervals are marked in bold 190
– the inversion finds well constrained fracture strikes of 150° and 42° . The 191
fracture densities are less well constrained because they trade off against 192
each other, but all successful inversion results imply that the fracture set at 193
 150° (F1) has a higher fracture density than the set at 42° (F2). 194

The observed splitting is a path averaged effect, which includes contri- 195
butions from all the portions of the rock through which the waves have 196
travelled. The waves from some of the events, which are located in the 197
reservoir, will have travelled through both reservoir and overburden rocks, 198
while waves from events in the overburden will have travelled through the 199

overburden only. As such, the observed splitting will contain contributions 200
from both the overburden and reservoir, and it will be difficult to decom- 201
pose these effects. Previous work on the reservoir interval has indicated the 202
presence of fractures sets striking at 40° and 148° (Brown, 2002), matching 203
closely the fracture sets inferred from SWS observations. No such data is 204
available for the overburden. However, Brown (2002) found that the NE 205
striking set (F2 here) is the more pervasive set, while the SE set (F1 here) 206
is weaker. This contrasts with the inversion of SWS observations, which 207
suggest that the F1 set is the more dominant. 208

The above indicates that the observations made during microseismic 209
monitoring do not provide a wholly satisfactory match with expectations. 210
The event hypocenters are generally located around the horizontal produc- 211
tion wells, and some appear to be in the overburden, rather than around 212
the injection well as expected. These locations cannot be explained with- 213
out resorting to some form of geomechanical modelling, and it is important 214
to determine whether the seismicity in the overburden represents fluid mi- 215
gration or merely stress transfer. Seismic anisotropy is also sensitive to 216
non-hydrostatic stress changes, so such geomechanical models may also help 217
understand why the observations of seismic anisotropy do not fully match the 218
observations made on boreholes and core samples made by Brown (2002). In 219
the following section we develop a simple geomechanical model to represent 220
the deformation caused by injection into the Weyburn reservoir. 221

3. Geomechanical modelling 222

While widely used for civil engineering applications, finite element me- 223
chanical modelling is still a developing technique in the earth sciences. The 224
state of the art is to couple together an industry-standard reservoir flow 225
simulator with a finite element mechanical solver (Dean et al., 2003). The 226

reservoir flow simulation provides the pore fluid pressures, fluid densities 227
and compressibilities, which are used as the loading for the geomechanical 228
simulations. 229

There are a number of methods with which to couple together the flow 230
and mechanical simulators (Dean et al., 2003). The simplest is with a one- 231
way coupling, where the results from the flow simulation at user-defined 232
timesteps are used as the loading for a geomechanical model, with no feed- 233
back to the flow simulator from the geomechanical results. This approach 234
is appropriate where the deformation is slight enough that it does not cause 235
significant variation in porosity and/or permeability. Where deformation 236
is large enough to moderate the flow properties, changes in porosity and 237
permeability must be returned to update the fluid flow simulation. 238

The most effective balance between numerical accuracy, computational 239
time, and the functionality provided by industry-standard software, is found 240
in an iterative method, where the fluid flow simulation and geomechanical 241
model are solved iteratively until a convergent value for the change in pore 242
volume is found for each timestep (Dean et al., 2003). This is the method 243
we use to model the CO₂ injection at Weyburn, coupling together a MORE 244
(by Roxar Ltd) fluid flow simulation with an ELFEN (Rockfield Ltd) ge- 245
omechanical model via a Message Passing Interface (MPI, also by Rockfield 246
Ltd). 247

3.1. Fluid flow simulation 248

The fluid flow simulation only has to simulate the reservoir. Because 249
the reservoir is laterally extensive with little topography, it is appropriate 250
to model it as a flat layer with a structured mesh. We set up the injection 251
and production wells to approximate the pattern at Weyburn where mi- 252
croseismic monitoring has been deployed. 4 horizontal wells are modelled, 253
trending parallel to the y axis. In between the production wells are 3 vertical 254

injection wells with a spacing in the y direction of 500m. The horizontal 255
wells are completed over a length of 1400m in the reservoir. To reduce com- 256
putational requirements we model only half of the reservoir, and complete 257
the simulation by assuming that the model is symmetrical about the x axis. 258
Therefore the figures in this work show only the half of the reservoir that 259
has been simulated. 260

The region enclosed by the wells is approximately 1.5×1.5 km. However, 261
we extend the model to 4.4km in the x direction and 4km in the y direction in 262
order to avoid the influence of edge effects. The reservoir is 40m thick, and 263
for the purpose of fluid flow simulation is split into the upper Marly and 264
lower Vuggy layers. The modelled porosities are 0.25 for the Marly layer 265
and 0.15 for the Vuggy layer, and the permeabilities are $\kappa_x=5$ mD, $\kappa_z=4$ mD 266
for the Marly layer, and $\kappa_x=10$ mD, $\kappa_z=7$ mD for the Vuggy layer. These 267
values are chosen as representative of geological models of the reservoir, 268
which show heterogeneity typical of carbonate systems. Nevertheless, these 269
values provide a reasonable match with observed pressures and injection 270
rates, although the simulation has not been history matched in any way. 271

The mesh through the well region has a spacing of 60×50 m ($x \times y$), with 272
an increasingly coarse mesh used away from the wells. The flow regime is as 273
follows: For one year there is no injection in order to ensure that the model 274
has stabilised; after this the field is produced, representing the pressure 275
drawdown during oil production at Weyburn, reducing the pore pressures 276
from 15 to 10MPa. The three vertical wells then begin to inject CO_2 , for a 277
period of 1 year, increasing the pressure to ~ 18 MPa, while the pressure is 278
still below 15MPa at the producers. This provides an approximation of the 279
state of the field after 1 year of injection (i.e., by the end of 2004, the end 280
of Phase IB). The CO_2 injection rate at each well is 100MSCM/day. The 281
pore pressures, which provide the loading for the geomechanical model, at 282

the end of the simulation are plotted in Figure 3.

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3.2. Geomechanical model

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The geomechanical model must include both the reservoir and the surrounding over- and underburden. The geometry of the reservoir in the geomechanical model must be the same as for the fluid flow modelling. However, the internal mesh need not be the same, as we are able to interpolate between the simulators. For the geomechanics we use a mesh spacing of $60 \times 50 \times 20$ m ($x \times y \times z$) in the reservoir, coarsening away from the wells. The top of the reservoir is at 1430m. The overburden is modelled to the surface. As with the reservoir, the units in the overburden are assumed to be flat and laterally continuous layers, modelled with a regular grid. The underburden is modelled to a depth of 2480m, 1km below the base of the reservoir. The non pay rocks are divided into 4 units: the evaporite units bounding the reservoir both above and below, the overlying Watrous shale, while the remainder of the overburden above the Watrous, and the underburden below the lower evaporite layers are modelled with uniform representative properties. The properties of these layers further from the reservoir do not significantly affect the stress evolution in and around the reservoir with which we are concerned, so treating them in this manner is not an issue.

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The geomechanical model is solved for a poroelastic regime, where deformation is dependent on the Young's modulus (E), Poisson's ratio (ν) and porosity (ϕ) of the rocks, as well as the compressibility of the pore fluid, which is assumed to be brine in all of the non-pay rocks. The material properties for each unit are given in Table 1, based on core sample work by Jimenez et al. (2004). The boundary conditions are that the top of the model is a free surface, and the planes at the sides and base of the model are prevented from moving in a direction normal to the boundary, although

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they are free to move within the plane of the boundary (i.e. at the $x - z$ 311
boundary, nodes can move vertically (z), and horizontally in the x direction, 312
but not in the y direction). 313

4. Results 314

During the production phase of the simulation, the pore pressure draw- 315
down increases the effective stress in the reservoir, while there is a small 316
amount of extension in the overburden. During the injection phase, the ef- 317
fective stress decreases at the injection well as the pore pressure increases. 318
The inflation of the reservoir causes a small amount of compaction in the 319
overburden. Plots of the changes in effective stress in and around the reser- 320
voir can be found in the online supplementary material. The stress changes 321
in the overburden are small, most of the load induced by injection is taken 322
up by the reservoir. We are most interested in what these stress changes 323
mean for induced seismicity, as this will allow us to compare our model to 324
the microseismic observations made at Weyburn. Therefore we develop a 325
method to map modelled stress changes into predictions about the likelihood 326
of generating induced seismicity. 327

4.0.1. Induced Seismicity 328

We have not modelled discrete surfaces on which failure may occur. The 329
area of rock stimulated by a microseismic event is typically on a sub-metre 330
scale, whereas the elements we use in geomechanical modelling have dimen- 331
sions of $\sim 50\text{m}$. Therefore, in order to generate predictions about micro- 332
seismic event locations we need a way of approximating the likelihood of a 333
microseismic event occurring in a particular model element. To do so we 334
use the concept of the fracture potential, as described in Eckert (2007). 335

The likelihood of a material to experience brittle shear failure can be 336
expressed in terms of a fracture potential, f^p (Connolly and Cosgrove, 1999). 337

The fracture potential describes how close the stress state is to crossing the 338
 Mohr-Coulomb envelope described by 339

$$\tau = m\sigma'_n + c, \quad (1)$$

where τ is the shear stress and σ'_n is the effective normal stress acting on 340
 the rock, and m is the coefficient of friction and c is the cohesion of a plane 341
 in the rock. m is often given in terms of an angle of friction, 342

$$m = \tan \phi_f. \quad (2)$$

The shear stress, τ is related to the differential stress, q , which is the differ- 343
 ence between maximum and minimum effective stress, by 344

$$\tau = q/2 = \frac{\sigma'_1 - \sigma'_3}{2}. \quad (3)$$

In the shear failure regime, f^p describes the ratio between the actual differ- 345
 ential stress and the critical differential stress at failure, 346

$$f^p = \frac{q}{q_{crit}}. \quad (4)$$

The critical differential stress is given by 347

$$q_{crit} = 2(c \cos \phi_f + p \sin \phi_f), \quad (5)$$

where p is the mean principal effective stress, 348

$$p = (\sigma'_1 + \sigma'_2 + \sigma'_3)/3. \quad (6)$$

By substituting equation 5 into equation 4, the fracture potential is then 349
 given by 350

$$f^p = \frac{q}{2(c \cos \phi_f + p \sin \phi_f)}. \quad (7)$$

To compute the fracture potential we use equation 7. In the caprock, we 351
 use $c=5\text{MPa}$, $\phi_f=45^\circ$, while in the reservoir we use $c=3.5\text{MPa}$, $\phi_f=40^\circ$. Be- 352
 cause little can be known about preexisting planes of weakness on which brit- 353
 tle shear failure, and therefore microseismicity, will occur, these are rather 354

arbitrary, generic values. However, we are only interested in relative changes 355
in f^p , i.e. whether injection causes f^p to rise or to drop, increasing or de- 356
creasing the likelihood of shear failure and microseismic activity. As such, 357
sensitivity analysis shows that the choice of value for these parameters is 358
not particularly important. 359

In Figure 4 we plot the evolution of fracture potential through time at 360
selected points in the reservoir and overburden. From Figure 4 we note 361
that fracture potential increases in the reservoir during production, while it 362
is relatively unchanged in the overburden. Once injection begins, fracture 363
potential remains relatively constant at the production wells, but decreases 364
at the injection wells. In the overburden there is an increase in fracture 365
potential, albeit limited in spatial extent, above the injection well, with 366
little evolution of f^p elsewhere in the overburden. In Figures 5a and 5b we 367
plot maps of the fracture potential in the reservoir and overburden after 1 368
year of injection. 369

In general, there are some qualitative comparisons that can be made 370
between this model and the observations made at Weyburn. For instance, 371
the fact that across most of the reservoir fracture potential is not increased 372
by injection matches with the lack of seismicity recorded. Also, this model 373
suggests that fracture potential should be higher at the production wells 374
than at the injection wells, which matches the observations that the ma- 375
jority of events occur close to the producers. However, this model can not 376
explain why in reality many events are located in the overburden above the 377
producing wells – the model suggests that there is little evolution of f^p in 378
the overburden, and the only place it does increase is directly above the 379
injection well. The suitability of this model can also be assessed through a 380
comparison of the seismic anisotropy that it predicts. 381

4.0.2. Seismic Properties

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To compute the seismic properties based on the stress changes we use 383
the rock physics model developed by Verdon et al. (2008a) and calibrated 384
by Angus et al. (2009). Non-hydrostatic stress changes serve to generate 385
anisotropy by preferential closing of cracks perpendicular to the maximum 386
stress direction, while cracks perpendicular to the minimum stress stay open. 387
Because the majority of the raypaths for the detected S-wave arrivals are 388
through the overburden, we are most interested in the anisotropy generated 389
in this region. The shear-wave splitting patterns generated in the overburden 390
of this model are plotted in Figure 5c. Splitting patterns generated in the 391
reservoir can be found in the online supplementary material. No significant 392
splitting patterns develop in the overburden. Some splitting does develop in 393
the reservoir (see supplementary material), but with a fast direction parallel 394
to the horizontal well trajectories. The lack of anisotropy in the overburden, 395
and anisotropy with fast direction parallel to wells in the reservoir, does 396
not match with the observations made above, where an anisotropic fabric 397
was observed in the overburden, striking to the NW, perpendicular to the 398
horizontal well trajectories. 399

We conclude that this initial model, whose material properties were 400
based on core measurements from the field, does not provide a good match 401
with the observations of microseismic activity and seismic anisotropy in the 402
field. The question to ask, then, is why this should be? One potential 403
answer lies in the fact that rock physics measurements on cores represent 404
the intact rock, whereas the reservoir is dominated by fractures, which pro- 405
vide key fluid-flow pathways in the reservoir, and, as the name – the Vuggy 406
Formation – suggests, vugs. Core scale measurements can only account for 407
microscale properties – features that are much smaller than the core size. 408
The effects of meso and macro scale features, that are a similar size as, or, 409

in the case of fractures, larger than the cores will not be accounted for in 410
core analysis. The presence of fractures and vugs can significantly soften 411
the elastic stiffness of the reservoir. Because the overburden has far fewer 412
fractures, and no vugs, we keep their properties the same while reducing the 413
stiffness of the reservoir. 414

4.1. A softer reservoir? 415

For the updated model, we reduce the Young's modulus of the reservoir 416
to 0.5GPa, while keeping all the other properties the same as for the first 417
model. The trends of effective stress evolution during injection are similar 418
as for the previous model, with increasing pore pressure reducing effective 419
stress at the injection site, and inflation of the reservoir causing compaction 420
in the overburden. However, because in this case the reservoir is softer, more 421
stress can be transferred from the reservoir to the overburden. As a result, 422
the changes in effective stress within the reservoir are reduced, while stress 423
changes in the overburden are amplified. Plots of the effective stress changes 424
in the softer model can be found in the online supplementary material. 425

The fracture potentials for the softer model are computed as for the first 426
model, using the same Mohr-Coulomb failure criteria. The evolution of f^p 427
through time at selected points in the reservoir is shown in Figure 6. As with 428
the stiffer reservoir, the fracture potential increases during the production 429
phase. As more stress is transferred to the overburden, fracture potential 430
also increases here. Once injection begins, the fracture potential in the 431
reservoir is reduced at the injection well, and remains relatively unchanged 432
at the producing wells. In the overburden above the injection well, after 433
a transient increase in f^p , the fracture potential is reduced in this region, 434
returning to pre-production values. In contrast, the fracture potential in the 435
overburden above the production wells sees an increase after injection, and 436
this increase is maintained throughout the injection period. In Figures 7a 437

and 7b we plot maps of the fracture potential in the reservoir and overburden 438
after 1 year of injection, and the increase in f^p in the overburden above the 439
producing wells is clear. 440

The evolution of fracture potential for the softer model implies that in- 441
jection now increases the probability of fracturing in the overburden above 442
the *production* wells, and reduces the probability of fracturing around and 443
above the injection well. This provides a much better match with observa- 444
tions made at Weyburn, where events occur in the reservoir and overburden 445
near the horizontal production wells, but few if any events are found near 446
the injection well. In particular, this model shows how stress transfer into 447
the overburden which, as noted by Segura et al. (2010) is promoted by a 448
softer reservoir, can generate increases in shear stress, and therefore a greater 449
likelihood of microseismicity, above the horizontal production wells. 450

The shear wave splitting patterns generated in the overburden of the 451
softer model are plotted in Figure 7c. The splitting patterns in the reser- 452
voir are available in the online supplementary material. Little splitting is 453
developed in the reservoir. However, in the overburden a coherent splitting 454
pattern develops where the fast directions are orientated parallel to the well 455
trajectories above the production wells (the y axis), while above the injec- 456
tion wells the fast directions are orientated perpendicular to this (parallel 457
to the x axis). 458

From the recorded data we observed an anisotropic fabric with a fast 459
direction striking to the NW, perpendicular to the NE well trajectories. 460
This splitting was measured on waves recorded by geophones sited between 461
depths of 1181-1356m alongside the injection well, from microseismic events 462
located in or above the reservoir. Therefore, with most of the raypath is in 463
the overburden, the splitting they experience will image the anisotropy of 464
the rocks between event locations and the geophones, i.e., of the caprocks 465

above the injection site. As such, the predictions from the model, with 466
fast directions orientated perpendicular to the well trajectories above the 467
injection well, provide a good match with observations made in Section 2.1, 468
where the dominant fabric was observed striking to the NW, perpendicular 469
to the NE well trajectories. 470

It appears, therefore, that the model with a reservoir that is an order 471
of magnitude softer than laboratory rock physics measurements produces 472
event location and seismic anisotropy predictions that provide a much better 473
match with observations than the original model. This model implies that 474
the microseismicity observed in the overburden at Weyburn is caused by 475
stress transfer through the rock frame, rather than a pore fluid connection 476
or CO₂ leakage. 477

5. Discussion 478

Event locations at Weyburn suggest that there is microseismicity in the 479
overburden. This observation could be a cause for concern, as it could be 480
inferred that the events represent either CO₂ leakage, or at least elevated 481
pore-pressures being transferred into the overburden. Either would imply 482
that pathways exist for CO₂ to migrate out of the reservoir. Nevertheless, 483
controlled source 4-D seismic monitoring has not shown any evidence for 484
fluid migration into the overburden. However, without geomechanical mod- 485
els, there can be no alternative explanation for why the events are found 486
where they are. 487

A representative geomechanical model shows that, if the reservoir is 488
softer than measured in core samples, deviatoric stress will increase in the 489
overburden, increasing the likelihood of shear failure and thereby of micro- 490
seismic activity, especially above the producing wells. In contrast, if there 491
were pore-pressure connections, or buoyant fluid leaking into the overbur- 492

den, one might anticipate that microseismicity would be located above the 493
injection well, where pore pressures are highest and most of the buoyant CO₂ 494
is situated. This has been observed during hydraulic fracturing where CO₂ 495
was used as the injected fluid (Verdon et al., 2010a). At Weyburn events are 496
located above the producing wells, suggesting that the former is the case – 497
a softer than anticipated reservoir is transferring stress into the overburden, 498
inducing microseismicity. The anisotropy generated by such stress transfer 499
also matches the observations of anisotropy made at Weyburn, furthering 500
our confidence in this second, softer model. 501

It is therefore worth asking whether we are putting the hydraulic in- 502
tegrity of the caprock at risk with these microearthquakes? Unfortunately 503
this question is difficult to answer, as even active faults and fractures do 504
not necessarily act as conduits for fluid flow, and there is no way of knowing 505
how well connected any fractures in the caprock may be. The fact that there 506
are few events, most of which are of low magnitude, suggests that there are 507
not many large scale fractures in the overburden. Furthermore, there has 508
been no seismicity detected more than 200m above the reservoir (Figure 509
1b), which would be well within the detectability threshold of the geophone 510
array, implying that if any fractures are being stimulated by CO₂ injection, 511
they do not extend far into the caprock system. Most importantly, the suite 512
of integrated geophysical and geochemical monitoring systems deployed at 513
Weyburn do not indicate any leakage, so it would appear that any fracturing 514
generated by microseismicity in the overburden is not currently providing a 515
pathway for leakage. By continuing to monitor the field it will be possible 516
to ensure that this remains the case. 517

The reduction in stiffness we use to produce the match with observa- 518
tions is large – from 14 to 0.5GPa. This is done to show the changes that a 519
softer reservoir can produce *in extremis*. In this case the changes to fracture 520

potential and shear wave splitting introduced by a softer reservoir are clear 521
for the reader to see. As the stiffness is reduced from 14GPa, the trends 522
that we have highlighted gradually establish themselves. It is well known 523
that the presence of fractures and vugs in a reservoir will mean that core 524
sample measurements are overestimates of the true, *in situ* values. How- 525
ever, an order of magnitude overestimate is perhaps too much to attribute 526
entirely to the presence of fractures and vugs. It is at this point that we 527
should remind ourselves that what we are dealing with here is a simplified 528
representative model, useful for determining the principal controls on reser- 529
voir stress changes, and the directionality of stress changes introduced by 530
varying material parameters. In this case, we suspect that the Young's mod- 531
ulus is overestimated by an unknown amount, and we know that reducing 532
it will produce a stress path closer to that inferred from microseismic ob- 533
servations. This paper has demonstrated the importance of groundtruthing 534
geomechanical models with geophysical observations from the field. To de- 535
termine more exactly how much the Young's modulus needs to be reduced 536
to get a good match with observation will probably require a more detailed 537
model that provides a better match with the details of the reservoir geology, 538
and a more precise way of determining how much of an increase in fracture 539
potential is needed to generate microseismicity. 540

6. Conclusions 541

Monitoring of induced microseismicity has been conducted since 2003 in 542
one pattern of the Weyburn CO₂ Storage and Monitoring Project. Event 543
hypocenters indicate that most of the microseismicity is located around the 544
nearby horizontal production wells, and not around the injection well as 545
anticipated. Although the errors in vertical location are large, it appears 546
that many events are located in the overburden. Observations of anisotropy 547

made by measuring the splitting of S-waves also do not match with expectations based on core sample and borehole log work. Overall, the low rate of seismicity suggests either that there is little geomechanical deformation occurring, or that deformation is generally occurring aseismically.

In order to interpret these observations and understand what they mean for the risks of CO₂ leakage, it is necessary to construct geomechanical models of the injection process. For geomechanical models to be ‘trusted’, they must be matched with observations from the field. While there are many potential observables with which geomechanical models could be calibrated, the observations from Weyburn provide an opportunity to evaluate whether it is possible to match geomechanical models with observations of microseismicity.

We have generated a representative numerical geomechanical model of the Weyburn reservoir and surrounding units. This model couples together an industry standard fluid-flow simulator with a finite element mechanical solver. The initial model uses material properties based on core sample rock physics measurements, and does not do a good job of matching the microseismic observations. The most likely reason for this is that the stiffness of the reservoir has been overestimated. The presence of larger scale features such as fractures and vugs will not be accounted for in core sample analysis, and their effect will be to reduce the elastic stiffness of the unit, sometimes by quite a significant amount. By reducing the reservoir stiffness by an order of magnitude, we create a model that predicts that microseismic events will occur around the producing wells, and in the overburden above the producers. Although the reduction in stiffness we have made is perhaps overly large, our approach shows how geophysical observations in the field should be taken into account when developing geomechanical models.

Based on the inferences we have made from the geomechanical models,

we propose that the events in the overburden are not caused by fluid migra- 576
tion into, or pore pressure changes in the overburden, but by stress transfer. 577
S-wave splitting patterns generated by the softer model also match well with 578
observation. The discrepancy between laboratory measured static stiffness 579
and that needed to reproduce geophysical observations highlights the diffi- 580
culties that can be encountered in upscaling laboratory measurements for 581
use in field scale models. 582

This paper has presented a workflow that demonstrates how geomechan- 583
ical models can be linked with observations of microseismicity, improving 584
our interpretation of microseismic event locations and our confidence in our 585
geomechanical models. It is important to calibrate and groundtruth any 586
model of the subsurface, and microseismic observations, as a direct man- 587
ifestation of mechanical deformation, can provide an important constraint 588
for geomechanical models. The purpose of this paper is to demonstrate the 589
concept. At present, the state of the art in geomechanical modelling, and 590
in linking geomechanical models with geophysical observations, is proba- 591
bly not sufficiently advanced to fulfil the requirement that ‘the conformity 592
of the *actual* behaviour of the injected CO₂ with the *modelled* behaviour’ 593
(E.U. Parliament and Council, 2009) could be rigorously demonstrated in a 594
manner analogous to reservoir modelling of CO₂ distribution and 4D seis- 595
mic observations. Nevertheless, we anticipate that with more detailed and 596
advanced geomechanical models, and a more rigorous method for predicting 597
seismicity based on geomechanical models, further advances will be made. 598

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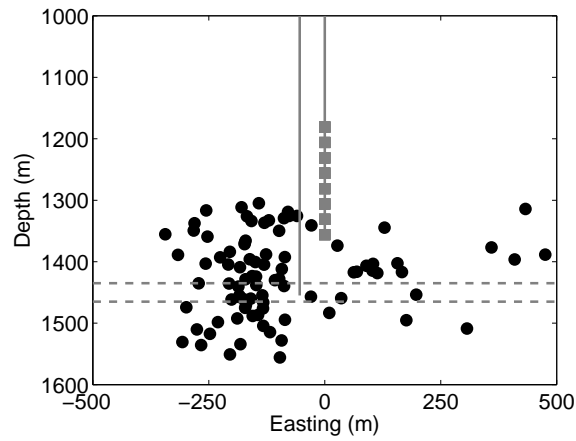
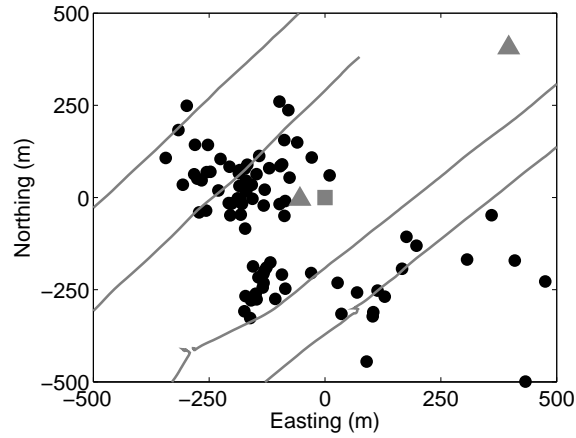
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<i>Unit</i>	<i>E (GPa)</i>	ν	ρ (kg/m ³)	ϕ	<i>Layer top (m)</i>	<i>Layer base (m)</i>
Overburden	5.0	0.25	2000	0.2	0	1210
Watrous	14.0	0.23	2000	0.1	1210	1410
Marly Evaporite	24.0	0.34	2700	0.05	1410	1430
Reservoir	14.5	0.31	2200	NA	1430	1470
Frobisher Evaporite	24.0	0.34	2700	0.05	1470	1490
Underburden	20.0	0.25	2500	0.1	1490	2490

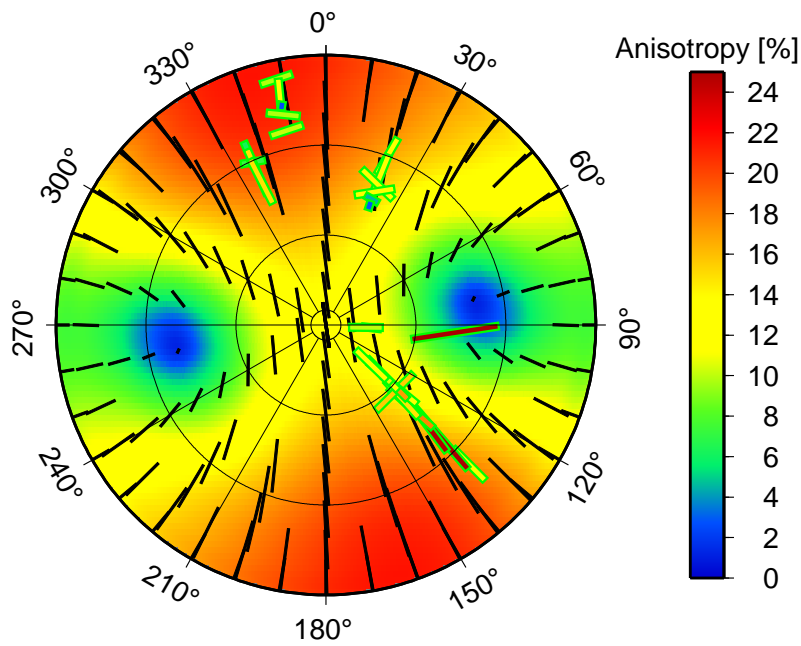
Table 1: Material parameters for the units of the Weyburn geomechanical model. All layers are saturated with water with $K=2.2\text{GPa}$ and $\rho=1100\text{kg/m}^3$, except the reservoir, whose porosity and fluid saturation are determined by the fluid-flow simulation.



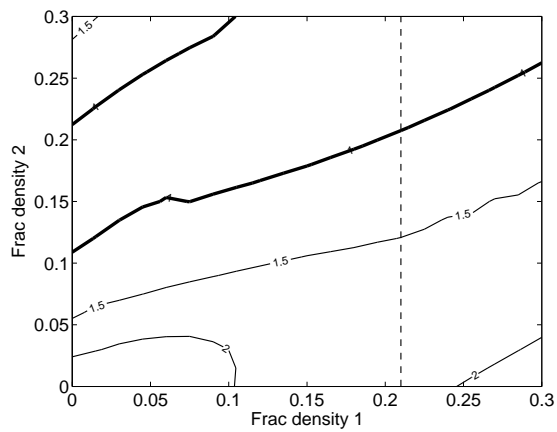
(a)

(b)

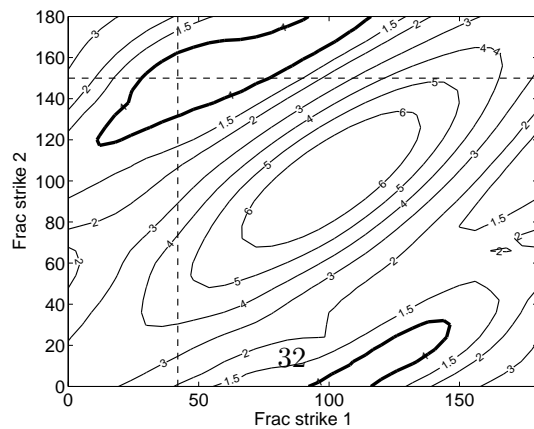
Figure 1: Event locations in (a) map view and (b) cross section. The observation geophones are marked by squares, and the vertical injection wells are marked by the triangles in (a) and the left-hand vertical line in (b). The horizontal production wells are marked in (a), and the reservoir interval is marked by the dotted lines in (b). The majority of events are located closer to the production wells than the injection well, and many are located in the overburden.



(a)



(b)



(c)

Figure 2: Results of the inversion of SWS measurements for the densities and strikes of two vertical fracture sets. In (a) we show an upper hemisphere plot of the SWS measurements (coloured ticks) along with the results from the best-fit model (contours and black ticks).

In (b) and (c) we plot the rms misfit surface as a function of fracture densities and of fracture strikes. (as per Verdon et al., 2009, 2010a; Verdon and Kendall, 2011). The best-fit model is indicated by the dashed lines and the dashed box in (b) and (c).

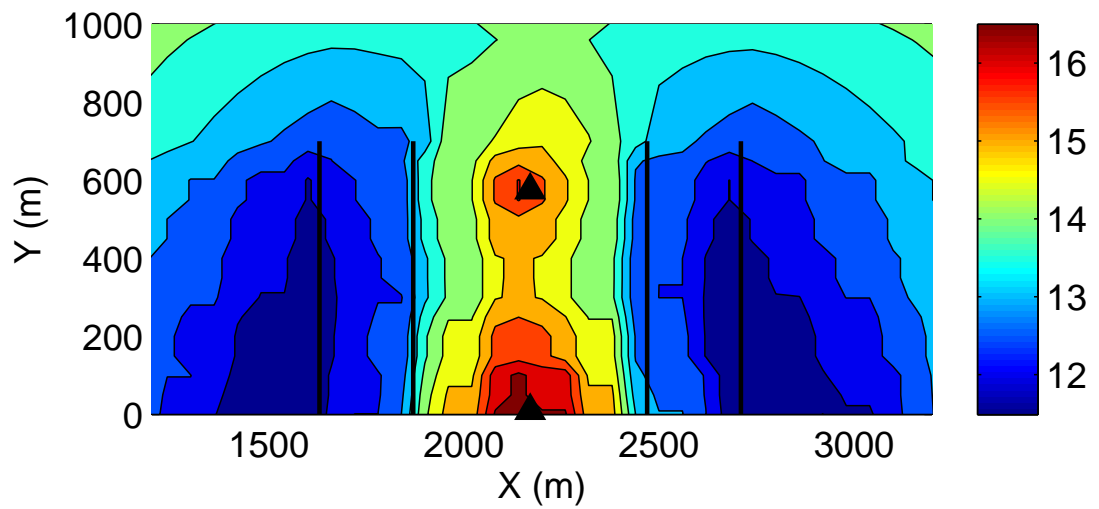


Figure 3: Map view of reservoir pore pressures (in MPa) after one year of injection computed by the fluid flow simulation of Weyburn. The vertical injection wells are marked by triangles, the horizontal producing wells by black lines. We have focused on the region of interest where production and injection occurs – the full model extends to $0 < x < 4400\text{m}$ and $0 < y < 2000\text{m}$ to include a ‘buffer’ area. Reflective symmetry along the x axis means that we can model only half the reservoir, and use symmetry arguments to complete the model.

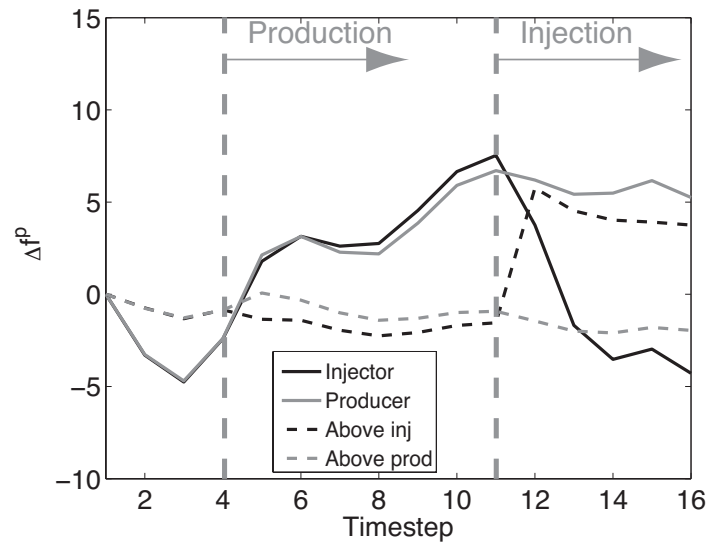
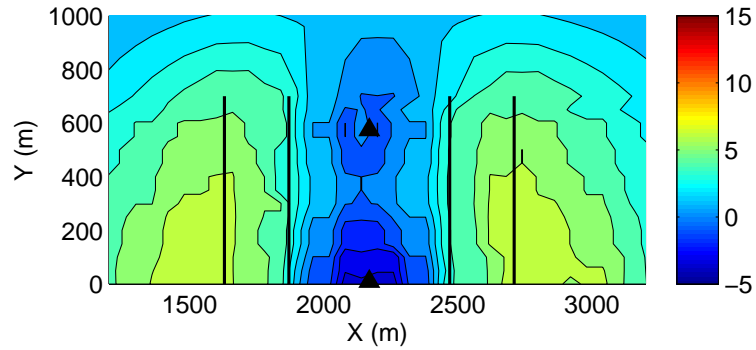
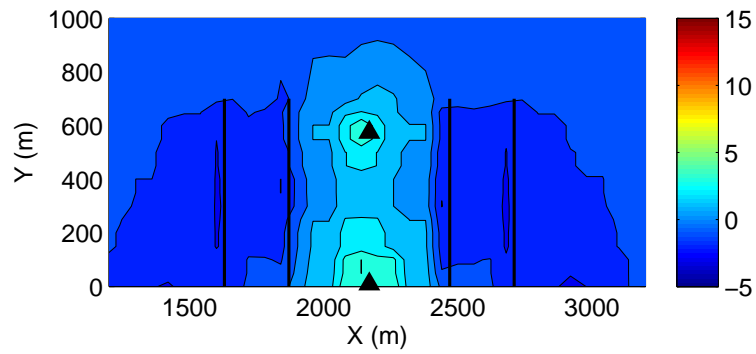


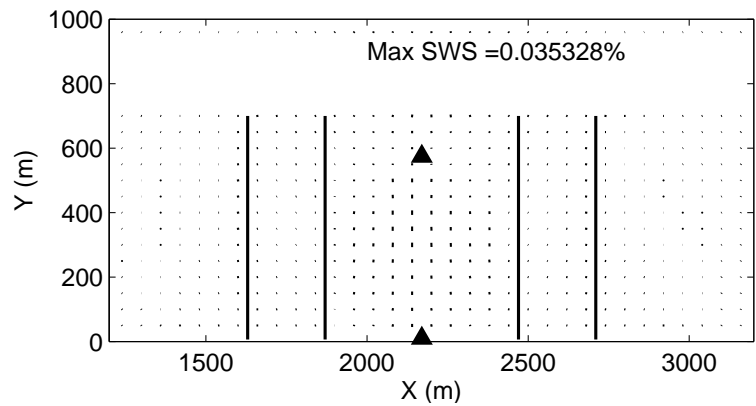
Figure 4: Percentage change in fracture potential in the Weyburn reservoir and overburden through time. f^p s in the reservoir injection well are marked by a solid lines, in the overburden by dashed lines. f^p s near the injection wells are marked in black, near the producers in gray. Fracture potential does not increase anywhere after injection begins (timestep 11) except in the overburden near the injection wells (black dashed line). Therefore this region should be most prone to microseismic activity.



(a)



(b)



(c)

Figure 5: Map view of microseismic and SWS predictions from the geomechanical model of the Weyburn reservoir. The injection and production wells are marked as per Figure 3. In (a) and (b) we plot the percentage change from the initial state of fracture potential in the reservoir and overburden after injection. In the reservoir (a), fracture potentials are largest at the production wells. In the overburden (b), there is a small increase in the fracture potential above the injection wells. In (c) we plot the modelled splitting for a vertically propagating shear wave in the overburden. Tick orientations mark the fast direction, tick lengths mark the splitting magnitude, and the maximum splitting values are given. Little SWS has developed, implying little differential variation of the horizontal principal stresses.

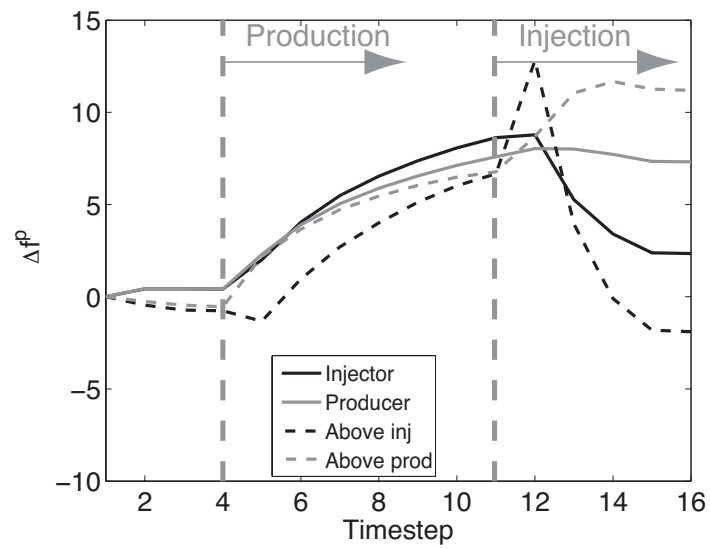
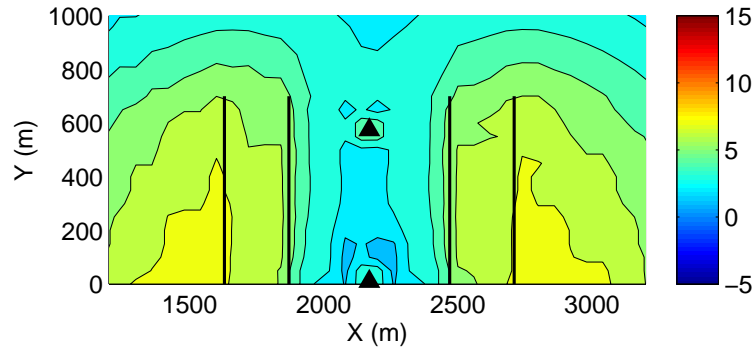
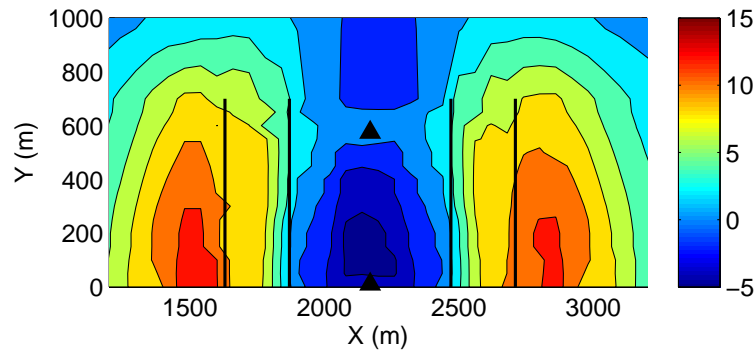


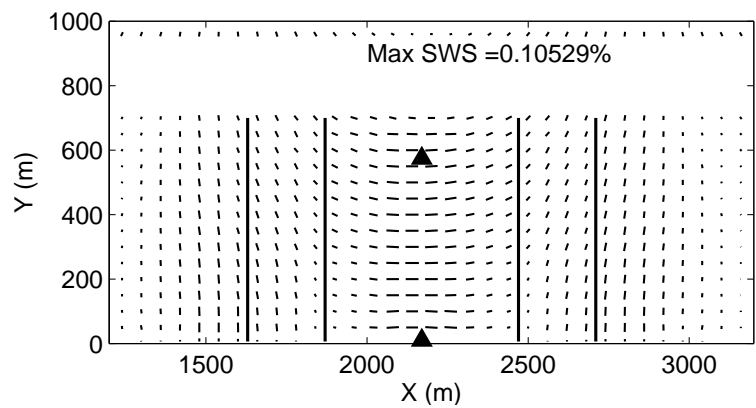
Figure 6: Percentage change in fracture potential in the softer Weyburn reservoir and overburden, as per Figure 4. After CO₂ injection begins (timestep 11), fracture potential is seen to increase in the overburden above the production wells (gray dashed line). After a transient increase, fracture potential above the injection well (black dashed line) decreases during injection.



(a)



(b)



(c)

Figure 7: Microseismic and SWS prediction from the softer model of the Weyburn reservoir. In (a) and (b) we plot the fracture potential in the reservoir and overburden after injection. Fracture potentials increase at the production wells and in the overburden above the production wells. In (c) we plot the modelled splitting for a vertically propagating shear wave in the overburden. Anisotropy develops, causing SWS in the overburden, with the fast direction above the injection site perpendicular to the horizontal well trajectories.