CO_2 SEQUESTRATION IN DEPLETED OIL AND GAS RESERVOIRS: A PROPOSED WORKFLOW FOR ASSESSING RESERVOIR SUITABILITY IN THE GULF OF MEXICO CASE STUDY APPLIED TO SOUTH EUGENE ISLAND 330

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ABSTRACT

Several factors make depleted oil and gas reservoirs attractive as potential CO_2 sequestration sites. These reservoirs contained extremely large volumes of hydrocarbons for geologic periods of time, and the existing infrastructure of wells, pipelines, etc. make sequestration of large volumes of CO_2 practical. In this work, we take advantage of the data collected during exploration and production of a mature Gulf of Mexico oil field, South Eugene Island Block 330 (SEI 330), to implement a workflow developed to assess potential sites for sequestration. As part of this workflow, we utilize detailed structural mapping, original hydrocarbon column heights, pressure data and production history to identify the structural and/or dynamic controls on seal capacity initially acting on a field and those activated during production. We then determine the effect these will have during CO_2 injection and over the timescales required for effective sequestration. We have developed this workflow in the context of dynamic geomechanical models that predict the pressure capacity of reservoir bounding faults that might be prone to reactivation due to CO_2 injection. Using the example of an actual depleted oil reservoir, SEI 330, we present an initial draft of a sequestration assessment workflow. This workflow examines the initial state and production evolution (including faulting, compaction and porosity loss) of the reservoir to predict the amount of CO_2 that might be safely sequestered in the field.

INTRODUCTION

Storage of CO_2 in geologic formations is proposed as a means of stabilizing greenhouse gas concentrations in the atmosphere. In order for geologic CO_2 sequestration to be an effective tool in the stabilization of atmospheric CO_2 concentrations, a goal of sequestering on the order of 10 Gt $C0_2$/y through sequestration must be met by mid-century (based on current emissions projections). Currently, pilot CO_2 sequestration projects such as Weyburn and Sleipner are sequestering on the order of 1 Mt CO_2/y. These pilot projects are important testing grounds for issues that will be faced as we move towards widespread sequestration implementation. It is important to look forward to the future of CO_2 sequestration, and continue to evaluate the potential of as many large-capacity repositories as possible.

The three geologic storage options available for CO_2 sequestration are unmineable coal seams, deep saline aquifers, and mature oil and gas fields. In the future, it will likely be necessary to exploit all of these options in order to make a significant impact on global atmospheric CO_2 concentrations. However, this paper focuses on evaluating mature oil and gas fields as potential storage sites based on their geomechanical properties. Mature oil and gas fields offer a number of benefits over the other storage options during the development stage of widespread CO_2 injection operations. Depleted hydrocarbon fields have extensive databases, partially in place infrastructures, and the possibilities for value-added benefits from enhanced oil recovery (EOR) and possibly enhanced gas recovery (EGR). The initial cost-reducing aspects unique to depleted oil and gas fields are essential in the promotion of widespread CO_2 sequestration operations. Oil and gas fields have also contained large volumes of buoyant fluids for geologic periods of time, which means that at least in the past they had adequate seal integrity. The fact that hydrocarbon production is occurring suggests that the reservoir has a certain level of porosity and permeability as well as a reasonable capacity, which suggests that injection of CO_2 into the reservoir may be possible.

In this paper, we want to evaluate how geomechanics influence the storage capacity and seal integrity of a reservoir through the lifetime of the field. In order to do so, we are developing a workflow that integrates data from field exploration and development, hydrocarbon production, and finally CO_2 injection and completion stages of the field. In creating this workflow, we seek to answer the following questions:

- What were the trap and seal mechanisms governing initial hydrocarbon capacity?
- What is the effect on the caprock of the buoyancy pressure when CO_2 replaces oil and/or gas and how will this affect the reservoir capacity?
- How has depletion affected the reservoir properties and seal capacity?
- How will the injection process influence the wellbore, reservoir, and seal?

The purpose of creating a workflow for assessing reservoir suitability is to standardize the process by which sequestration sites are chosen and to make it easier to compare the potential of several different sites in a similar setting.

We are developing this workflow in the context of the regional challenges faced in evaluating sequestration sites in the Gulf of Mexico. The first step is to examine an individual field that encompasses a number of properties characteristic of other fields in this region. For our case study, we have chosen to use South Eugene Island Block 330 (SEI 330). SEI 330 is a mature field that has been in production since 1972 and is accompanied by a substantial dataset. The initial capacity of the field was controlled by several different mechanisms that are important in many fields in the Gulf of Mexico.

GULF OF MEXICO

The Gulf of Mexico offers all the advantages related to depleted oil and gas reservoirs for CO_2 sequestration. First, the Gulf of Mexico is one of the most extensively studied oil and gas provinces in the United States. Because of this, there are substantial datasets available for many different fields. This data includes 3D seismic surveys and data collected from existing wells, including well logs and pressure data. The producing reservoirs have been structurally interpreted and their physical properties characterized. Production history also provides important constraints for the reevaluation of fields as well as information on the effects of depletion on the reservoir properties, seal integrity, and wellbore stability. Moreover, the industry partners that produce in the Gulf of Mexico have standard workflows or best practices that they have developed specifically for evaluating reservoirs in the region for production. These workflows can be reworked and extended in order to include the assessment of CO_2 sequestration potential in the standard reservoir evaluation process. In this paper, we modify a Fault Trap and Seal Integrity Analysis Workflow to incorporate steps relevant in the examination of reservoir suitability for sequestration.

The U.S. Gulf Coast and the Gulf of Mexico also have an impressive infrastructure built around the petroleum industry. Figure 1 illustrates the extensive pipeline infrastructure in the area. There are many oil and gas pipelines offshore in the Gulf of Mexico and many more extending onshore. The infrastructure has evolved in such a way that the region is capable of transporting massive amounts of fluids over far distances. Figure 1 also shows that there are several potential point sources at which anthropogenic CO_2 can be captured for storage in the Gulf of Mexico. These include power plants, chemical plants, refineries, and industrial plants. While transporting CO_2 over long distances may be unfavorable in many cases, it could be made worthwhile through incentive programs and the value-added benefits of EOR and less likely EGR. Furthermore, in the future we may have no other choice but to sequester as much CO_2 as possible wherever it can be safely and effectively stored.

The Gulf of Mexico can provide a substantial storage capacity for the sequestration of CO_2. According to the Gulf of Mexico OCS Regional Office of the U.S. Department of the Interior Minerals Management Service (MMS), the total proved reserves in the Gulf of Mexico as of 2000 are 14.93 billion barrels (Bbbls) of oil (includes crude oil and condensate) and 167.3 trillion cubic feet (Tcf) of gas (Crawford et al., 2000). This equals approximately 45.36 Bbbls of oil equivalence that is or was contained in 1050 fields and considered commercially recoverable. By comparison, sequestering 1 Gt carbon (~1/3 of the goal for annual sequestration) requires storage of about 46.6 Bbbls CO_2 at reservoir conditions (assumes density of CO_2 at 500 kg/m^3). Therefore, full fluid replacement of proven reserves in the Gulf of Mexico (as determined in 2000) with CO_2 would satisfy a third of the sequestration goal for one year. Likewise, production in the Gulf of Mexico for 2000 equates to about 1.4 Bbbls of oil equivalence (Crawford ed al., 2003). If CO_2 were sequestered at the same rate as production in the Gulf of Mexico (1.4 Bbbls CO2/y), which is overly optimistic, about 1% of the global target for sequestration could be met annually. While these numbers can seem disheartening, they illustrate the need to closely examine all possible sequestration sites and to standardize the evaluation process so that a large number of sites can be assessed in an efficient way.

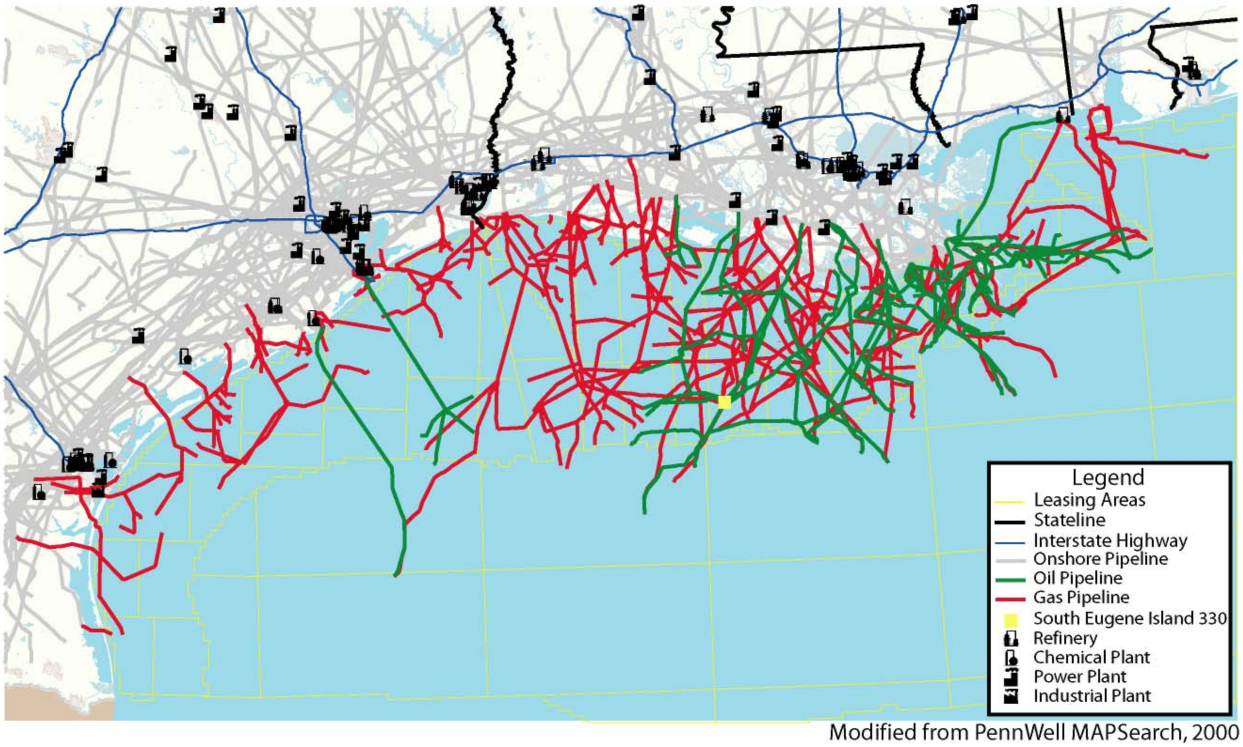

Figure 1: Oil and gas infrastructure in the Gulf of Mexico and U.S. Gulf Coast and potential sources for CO_2 capture.

Many of the largest fields in the Gulf of Mexico may be prime candidates for sequestration and CO_2 EOR operations. Carbon dioxide EOR is mainly reserved for mature fields (Gielen, 2003). Of the 81 largest fields in the Gulf of Mexico, 84% have been in production for more than 25 years. The production of these fields has declined dramatically over the years. For example, SEI 330, which began production in 1972, reached peak production of oil in 1976 with about 3 MMbbls/month and of gas in 1977 with about 15 Bcf/month. In 2000, SEI 330 was averaging about 630 thousand barrels/month of oil (~20% of peak production) and 2 Bcf/month of gas (~13.5% of peak production) (Crawford et al., 2000). It seems likely that this field could be a candidate for EOR operations. It is also important to note that extensive CO_2 EOR operations in the Gulf of Mexico could significantly increase the amount of proven reserves by making more oil commercially recoverable.

There are a number of factors that make the Gulf of Mexico a positive site for developing a regional workflow for the evaluation of CO_2 sequestration potential. Extensive datasets are available that are crucial in building comprehensive pictures of potential storage sites. The current petroleum industry infrastructure and the number of CO_2 sources near the Gulf Coast are integral steppingstones in the building of a complete CO_2 sequestration infrastructure. There is a significant capacity for storage in the region as well as a large potential for value-added benefits from CO_2 EOR.

SOUTH EUGENE ISLAND BLOCK 330

South Eugene Island Block 330 is located offshore of Louisiana, about 270 km southwest of New Orleans. The field is part of a salt-withdrawal, plio-pleistocene mini-basin. Most of the reservoirs in the field are in the hanging wall of the major basin-bounding normal growth fault. The hydrocarbons are trapped by rollover anticlines created during the salt-withdrawal related faulting. SEI 330 is mature field that began production in 1972 with an extensive dataset, including a recent 3D seismic survey, numerous well logs, bottom-hole pressure readings, and pressure tests (leak-off tests and formation integrity tests).

Figure 2 depicts a structure contour map of SEI 330 and the eastern part of SEI Block 331(SEI 331) that was created at Pennzoil from 3D seismic and well data (Finkbeiner et al., 2001). It shows the structural complexity for one of the deeper sand layers, the OI sand (in literature based from Pennzoil data) also known as the I1 sand (in ExxonMobil data). The relationship between hydrocarbons in these fields and SEI Block 314 (SEI 314), the field to the north of SEI 331, will also be discussed in the upcoming section. The general structural configuration of the field is as follows. A complex basin-bounding fault zone runs approximately WNW-ESE and dips to the SSW, with throws across the fault of ~500 m in the ESE and ~300 m in the WSW (SEI 314). Several smaller faults propagate off the main fault zone in an approximately east to west direction with some dipping towards the north and others towards the south. These faults have throws of up to 100-150 m. A syncline separates SEI 330 in the east from SEI 314/331 in the west (just off the map).

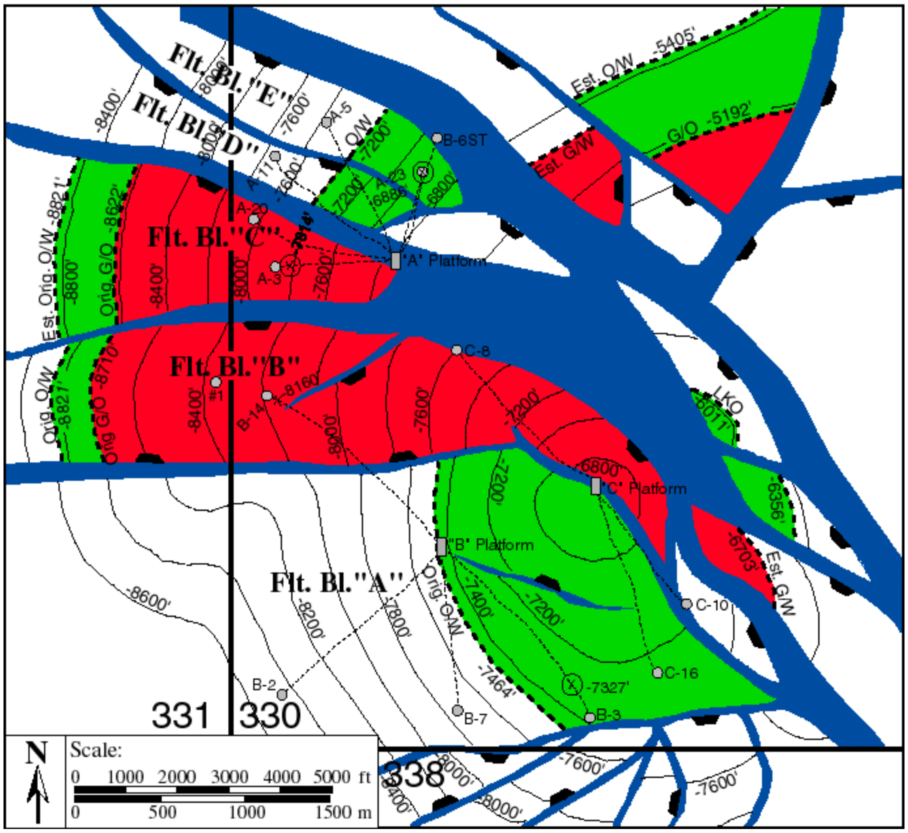

Figure 2: Structure contour map of the OI (I1) sand in SEI 330 and part of SEI 331. Faults are shown in blue, gas columns red and oil columns in green. The depth contours are in feet. Well paths are also shown with dashed lines. Fluid contact information from well data is shown with thick dashed lines. The different fault blocks (A-E) are labeled. The map is taken from Finkbeiner et al. (2001).

Several researchers have studied the field over the years. Alexander and Flemings (1995) examined the three phases of the depositional setting relating to salt mobilization, salt-withdrawal, and the waning of salt-movement. Alexander and Handschy (1998) used fault plane profiles across many of the second order faults in the field to make interpretations about reservoir communication. By integrating pressure and geochemistry data, they inferred that in most cases, juxtaposed sand windows of the same sand layer were nonsealing, while juxtapositions of two different sands were often sealing. Gordon and Flemings (1998) and later Stump and Flemings (2000) studied the hydrodynamic evolution of the field and sources of overpressure. Losh et al. (1999 and 2001) analyzed fluid migration in the field using geochemistry, structural interpretations and pressure data. Finkbeiner et al. (2001) investigated the roll of dynamic seal constraints on the hydrocarbon column heights in the most highly over-pressured fault blocks. We will further explore this study later in this paper.

We have chosen to study this field in more detail because the previous studies have brought a number of interesting, yet unresolved, questions to light about topics such as the relationships between fault blocks, fluid migration, sources of overpressure and controls on hydrocarbon column heights. Many of these studies are also based on the structure maps generated by Pennzoil over a decade ago (Figure 2). Currently, structure maps based on a newer 3D seismic survey are being created using the advanced interpretation tools now available. We will reevaluate SEI 330 based on these new structural interpretations and see if this affects the interpretations that were made in the previous studies.

DEVELOPING A GEOMECHANICS BASED WORKFLOW

It is imperative to approach any assessment of CO_2 storage potential in the Gulf of Mexico from a geomechanical perspective. In order to look at seal capacity and integrity in relation to geomechanics, we need to examine the reservoir and seal characteristics through the lifetime of the reservoir (Figure 3). Many of the trapping mechanisms in the region depend on fault seal. So through the workflow it is necessary to (1) determine the initial state of the trapping and sealing mechanisms, (2) examine the effect of production on the seal and reservoir properties, and (3) investigate the injection and sequestration effects during the CO_2 enhanced production and sequestration of CO_2. The steps in developing our geomechanical sequestration site assessment in the Gulf of Mexico are to (1) define the roles reservoir geomechanics play during the lifetime of a field, from exploration to sequestration, and (2) determine the necessary steps involved in characterizing the critical geomechanical effects influencing sequestration suitability of a field.

Applying this strategy to SEI 330 will guide us through the steps and data necessary to include in our geomechanical assessment of reservoir suitability for CO_2 sequestration in the Gulf of Mexico. From there, we will integrate these steps into a standardized workflow that can be applied to other fields in the region and act as a building block for workflows to be developed in other oil and gas regions.

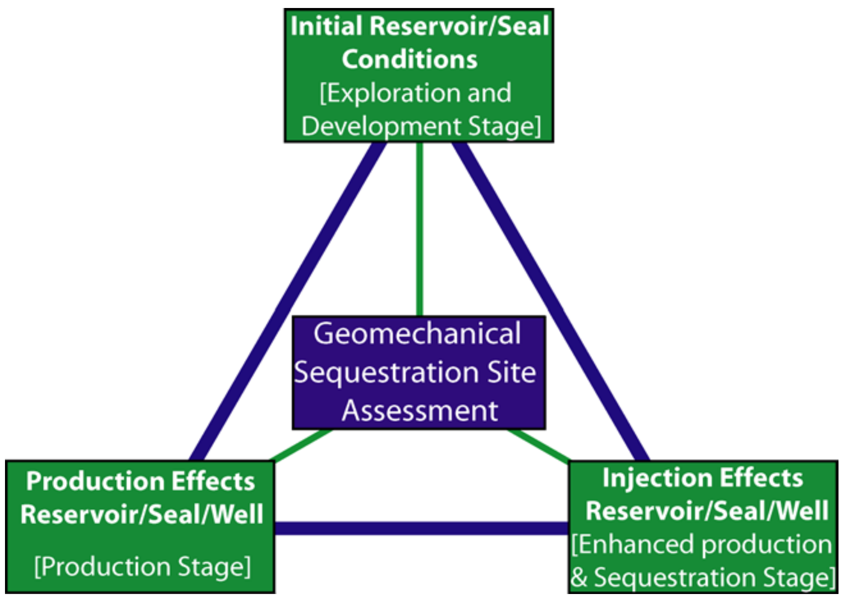

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Figure3: The strategy for building a geomechanical sequestration site assessment is to integrate data from the three stages in the lifetime of a field.

INITIAL CONDITIONS OF THE RESERVOIR AND SEAL

Trap and Seal Mechanisms

Five different trap and seal mechanisms have been identified as controls on the hydrocarbon fill in different reservoirs in the area of SEI 330. Some reservoirs are controlled by structural mechanisms that result in volume limitation for hydrocarbon fill. However, others are controlled by more complex dynamic mechanisms. The hydrocarbon columns in these reservoirs are pressure-limited. Figure 3 illustrates these structural and dynamic mechanisms in their simplest form.

The “fill to spill” mechanism is a geometric control, by which the trap fills with hydrocarbons until a synclinal spill point is reached, defining the reservoir capacity. This is a common mechanism that controls fill in the shallower sands of SEI 314/331, which are the blocks adjacent to SEI 330 in the northwest and west directions respectively and are separated from SEI 330 by a syncline. The hydrocarbons spill from the northwest to the southeast into SEI 330.

Another structural mechanism controlling hydrocarbon capacity in both SEI 330 and SEI 314/331 is across fault leakage (Alexander and Handschy, 1998). This most often occurs when there is sand on sand juxtaposition of the same sand layer across a fault. Primarily, this occurs near the fault tips where the displacement across the faults is minimal. In many cases, when two different sand layers are juxtaposed across a fault it acts as a seal.

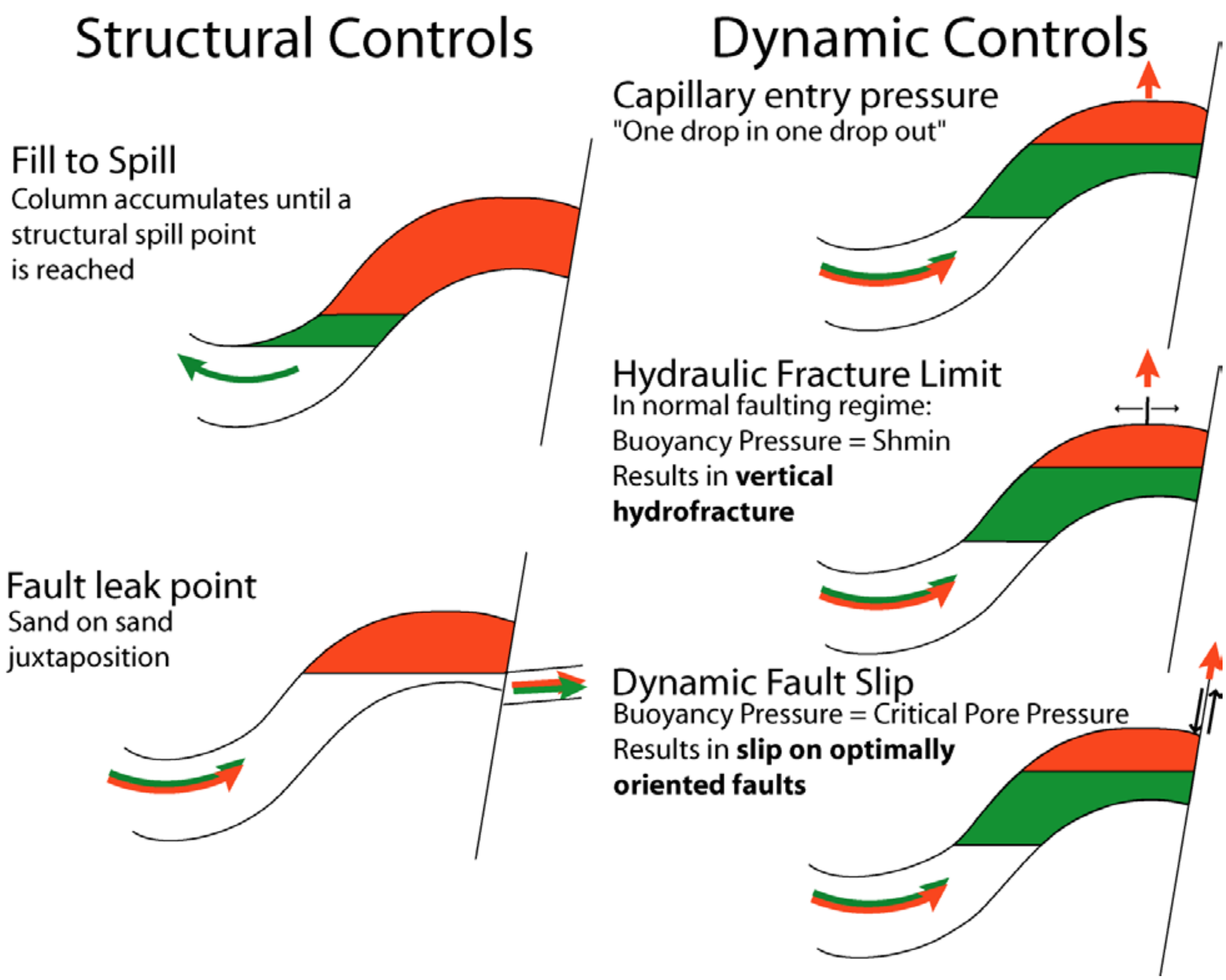


Figure 4: Hydrocarbon fill controls and sealing mechanisms acting in SEI 330 oil and gas reservoirs. Different mechanisms are explained more fully in the text.

One dynamic seal controlling mechanism is the capillary entry pressure (CEP), which is a physical property of the caprock. The CEP is the ability of the caprock to resist the migration of hydrocarbons through its pore space (Schowalter, 1979). Three factors control the CEP: the size of the pore throats, the hydrocarbon-water interfacial tension, and wettability (Schowalter, 1979). Laboratory experiments performed on core samples, such as mercury-air capillary pressure tests, provide good estimates of the CEP. This dynamic mechanism can be described by the phrase "one drop in equals one drop out." The caprock can only support a certain buoyancy pressure exerted by the hydrocarbon column. If another "drop" of hydrocarbon enters the system, the buoyancy pressure at the top of the reservoir exceeds the CEP of the caprock. The excess pressure is released by squeezing a "drop" of hydrocarbon out of the top of the reservoir into the caprock. We speculate that the reservoirs that have no apparent structural controls and that have large hydrocarbon columns may be controlled by the CEP of the caprock. They have large buoyancy pressures at the top of the reservoir, yet not enough pressure to exceed the theoretical hydraulic fracturing limit or dynamic fault slip limit.

The hydraulic fracture limit is another pressure-related control on the amount of buoyant fluid a reservoir can accommodate. When the fluid pressure in a reservoir reaches the magnitude of the least principal stress, the rock hydraulically fractures. In the case of a normal faulting regime such as the Gulf of Mexico, the least principal stress is the minimum horizontal stress, S_{hmin}. The hydraulic fracture opens in the direction of S_{hmin} and propagates vertically. When this occurs at the crest of an anticlinal reservoir, the fluid is able to leak-off into the caprock. This mechanism generally influences reservoirs that have an extremely over-pressured initial water phase.

In many cases the third pressure-dominated control on reservoir capacity, the dynamic fault slip limit is reached before the hydraulic fracture limit can be exceeded. As hydrocarbons accumulate in an over pressured sand, the fluid pressure at the top of the reservoir may increase such that it reaches a critical pressure, P_p^{crit}. Above the P_p^{crit}, Coulomb failure criterion predicts slip on faults that are optimally oriented in the local stress field. When slip occurs, the newly activated fault planes acts as conduits for fluid flow. The migration of fluids out of the reservoir decreases the buoyancy pressure at the crest below the P_p^{crit}. The sediments in the Gulf of Mexico are pliable so that the fault can easily repair itself and act as a seal again, allowing pressure to buildup (Finkbeiner et al., 2001). The P_p^{crit} can be defined by the following equation in a normal faulting regime:

$$P_p^{crit} = [S_{hmin} - f(\mu)*S_v]/[1-f(\mu)] \quad (1)$$

where

$$f(\mu) = [(\mu^2+1)^{1/2}+\mu]^{-2} \quad (2)$$

In the above equations, μ is the coefficient of sliding friction, S_{hmin} is the magnitude of the minimum horizontal stress (the least principal stress), and S_v is the magnitude of the vertical stress (the greatest principal stress). In their study of SEI 330, Finkbeiner et al. (2001) interpret that Fault Block A is likely controlled by the dynamic fault slip limit.

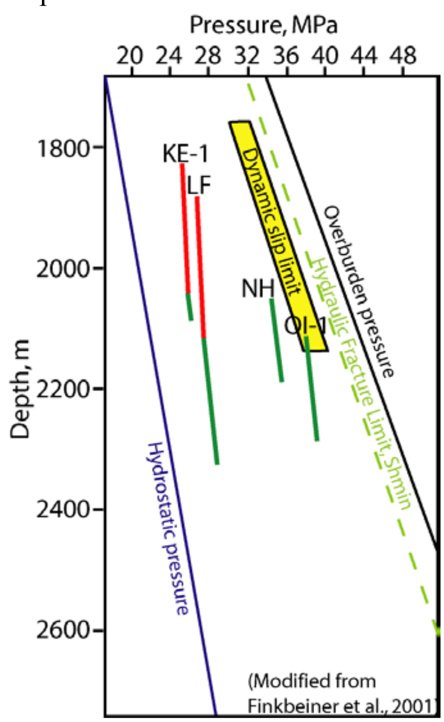


Figure 5: Pressure vs. depth plot of Fault Block A, modified from Finkbeiner et al., 2001. The blue line is hydrostatic pressure (0.010 MPa/m), the black line is the overburden pressure, S_v, (0.021 MPa/m) (derived from the density log), the green dashed line is the hydraulic fracture limit or least horizontal stress, S_{hmin}, (interpolated from leak off tests and formation integrity tests), and the yellow box is the dynamic slip limit, P_p^{crit}, (calculated from the overburden stress and the least horizontal stress over a range of coefficients of friction between 0.3 and 0.6). Oil columns are shown in green and the gas column in red. The pressure at the top of the OI-1 sand in fault block reaches the dynamic fault slip limit, suggesting that this reservoir is controlled by dynamic fault slip. Other shallower sands (KE-1, LF) in the same fault block are not limited by the dynamic fault slip or hydraulic fracture limit.

Figure 5, modified from Finkbeiner et al. (2001), illustrates this interpretation. It is a pressure vs. depth plot for Fault Block A. This figure illustrates the fluid pressures of several different reservoir layers in the fault block One observation is that NH and OI-1 sands appear to have a higher initial water-phase pressure than the shallower sands, indicating that they are very highly over-pressured. Another observation is that the shallower sands have very large gas caps, while the NH and OI-1 sands have no gas cap. Finally, the pressure at the top of the OI sand lies within the range of P_p^{crit} for $0.3<\mu<0.6$, suggesting that dynamic fault slip is the mechanism acting to control the hydrocarbon accumulation in that reservoir. However, the shallower sands, except possibly the NH sand, are not controlled by this mechanism

Dynamic Limits on Seal Capacity and Buoyancy of CO_2

If the trap and seal mechanism is controlled structurally by a spill point or fault leak point, then there is a volumetric limit on the reservoirs capacity to store CO_2. However, if the capillary entry pressure, hydraulic fracturing limit, or dynamic slip limit is the overriding control on seal capacity then it is necessary to evaluate the dynamic limit of the seal with respect to the buoyancy of CO_2. Figure 6 illustrates that the buoyancy of the reservoir fluid determines the volume that can be retained by a seal that is dynamically constrained. The buoyancy pressure at the top of the reservoir is a function of the initial aquifer pressure, fluid density and column height. In Figure 6A, at T0, no hydrocarbons are in the system and the pressure at the top of the reservoir lies on the aquifer pressure gradient. As a reservoir fills over time from T0-T3, the fluid pressure at the top of the reservoir structure increases falling along the hydrocarbon pressure gradient. Once the buoyant force reaches the pressure limit of the seal, the controlling mechanism takes over, releasing any excess fluid pressure through capillary leakage, hydraulic fracturing, or fault slip. Because of the different densities of oil, CO_2 and gas at reservoir conditions, a dynamically constrained reservoir has less capacity for CO_2 than for oil, but more capacity for CO_2 than for gas (Figure 6B). In sequestration projects, there will be a time-dependent, complex combination of different fluids that will dictate the seal capacity and integrity of dynamically constrained reservoirs. For this reason, it is important to have a geomechanical model and reliable structural model that can help in the prediction of the maximum sustainable pressure and the fluid pressures at the top of the reservoir structure.

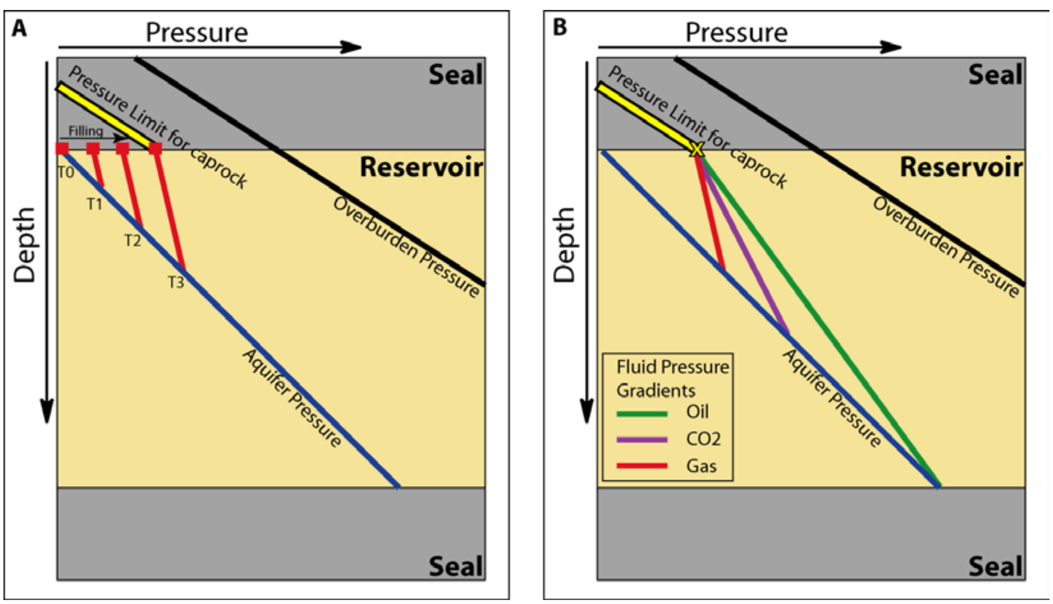


Figure 6: Effect of buoyant fluids on reservoir capacity in the presence of pressure-limited seals. A) Modified from Finkbeiner et al. (2001), the blue line is the aquifer pressure with depth and the red lines depict the changing fluid pressure with depth as the reservoir fills through time. When the buoyant pressure at the top of the hydrocarbon column reaches that of the pressure limit for the caprock no more hydrocarbons can be sustained and excess pressure is released through capillary leakage, hydraulic fracturing, of fault slip, depending on the control mechanism in the reservoir. B) This figure highlights the different buoyancies of oil, CO2, and gas and how this affects the volumes of these fluids that can be sustained by a pressure-limited seal.

PRODUCTION EFFECTS

The production of hydrocarbons from a reservoir implies that at the time of production there was sufficient porosity and permeability for large-scale fluid flow into a producing well; therefore it may be safe to assume a certain level of injectivity for the flow of CO_2 out of an injecting well into the reservoir. However, production may significantly alter the properties of the reservoir as well as the integrity of the seal. For these reasons, an important step in the evaluation of any reservoir is to characterize the effects of production on the reservoir properties, seal integrity and wellbore stability. Chan and Zoback (2002) and Zoback and Zinke (2002) observe that the stress evolution in a reservoir under production may lead to either stabilization or instability of the stress state. The stress path is defined by the change in the magnitude of the least principal stress with respect to the change in formation pressure within the reservoir during depletion. The stress path, **A**, can be calculated in two ways:

- Poroelastic theory: using the Biot coefficient, α, (α=1-K_b/K_g where K_g is the bulk modulus of the rock and K_b is the bulk modulus of the mineral grains) and Poisson's ratio, ν, (Figure 7A)

$$\mathbf{A} = \alpha\,[(1-2\nu)/(1-\nu)] \quad (3)$$

- In situ stress, S_{hmin}, and pore pressure, P_p, measurements (Figure 7B)

$$\mathbf{A} = \Delta S_{hmin}/\Delta P_p \quad (4)$$

Figure 7A, shows stress path calculations based on poroelastic theory and observed stress paths from different fields. Based on Coulomb failure criterion with μ =0.6, the stress path value, **A**, of the normal faulting line is roughly equal to 0.67. The red area shows the possible combinations of α and ν that can result in induced normal faulting. However poroelastic theory is not the preferred method of characterizing the stress path of a reservoir for two reasons: (1) significant inelastic deformation can occur during depletion that is not taken into account by this method and (2) values of ν and α are not always known (Chan and Zoback 2002). Another way to analyze the stress path is illustrated by Figure 7B. In this schematic, instead of plotting the stress path against α, the least principle stress is plotted against pore pressure, so that the slope of the line represents the stress path. The initial stress state can be either stable or active normal faulting, and are constrained in the shaded region. Within that region, the stress state can remain in normal faulting (dashed red line), become unstable (red line, slope of stress path is steeper than the normal faulting line), or stabilize (green, slope of stress path is shallower than the normal faulting line) depending on the slope of the stress path.

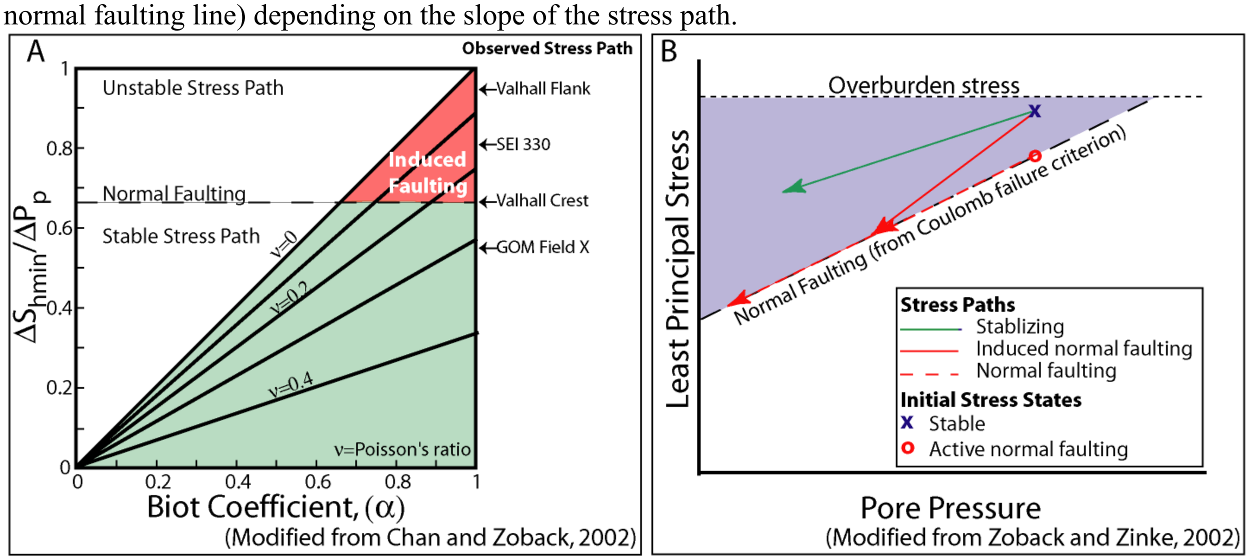


Figure 7: Variation of stress change with pressure. A) Theoretical poroelastic stress change as a function Biot coefficient and Poisson's ratio. The normal faulting line represents a stress path of A=0.67. Above this stress path, normal faulting will occur. Observed stress paths in different reservoirs are estimated on the right hand side of diagram. The Valhall field has inducted normal faulting (Zoback and Zinke, 2002), GOM field X has a stable stress path (Chan and Zoback, 2002), and SEI 330 has some induced faulting (Finkbeiner, 1998). B) Stress paths are a function of the least principal stress and formation pore pressure. The initial stress state can be stable or in active faulting (red dashed), the stress path can evolve to remain in faulting to stabilize (green), or to induce normal faulting (red solid).

Chan and Zoback (2002) investigate a field in the Gulf of Mexico with a stress path similar to that shown in green on Figure 7B. The Gulf of Mexico Field X (GOM Field X) is a Lower Miocene field located offshore of Texas on the continental shelf and is trapped by a rollover anticline associated with a growth fault. During depletion of the field, in situ stress and pore pressure measurements were made. These values are plotted in Figure 8A. Minifracs and leak-off tests constrain the magnitude of the least-principal stress, while drill-stem tests and remote formations tests were used to constrain the pore pressure. The estimated initial condition is shown with a red circle, because no initial determination of S_{hmin} was available. The stress path appears to be moving from a less stable stress state to more stable conditions. This implies that production is positively affecting the integrity of the reservoir and seal. However, injection into a field like GOM Field X may cause the stress path to again move toward normal faulting.

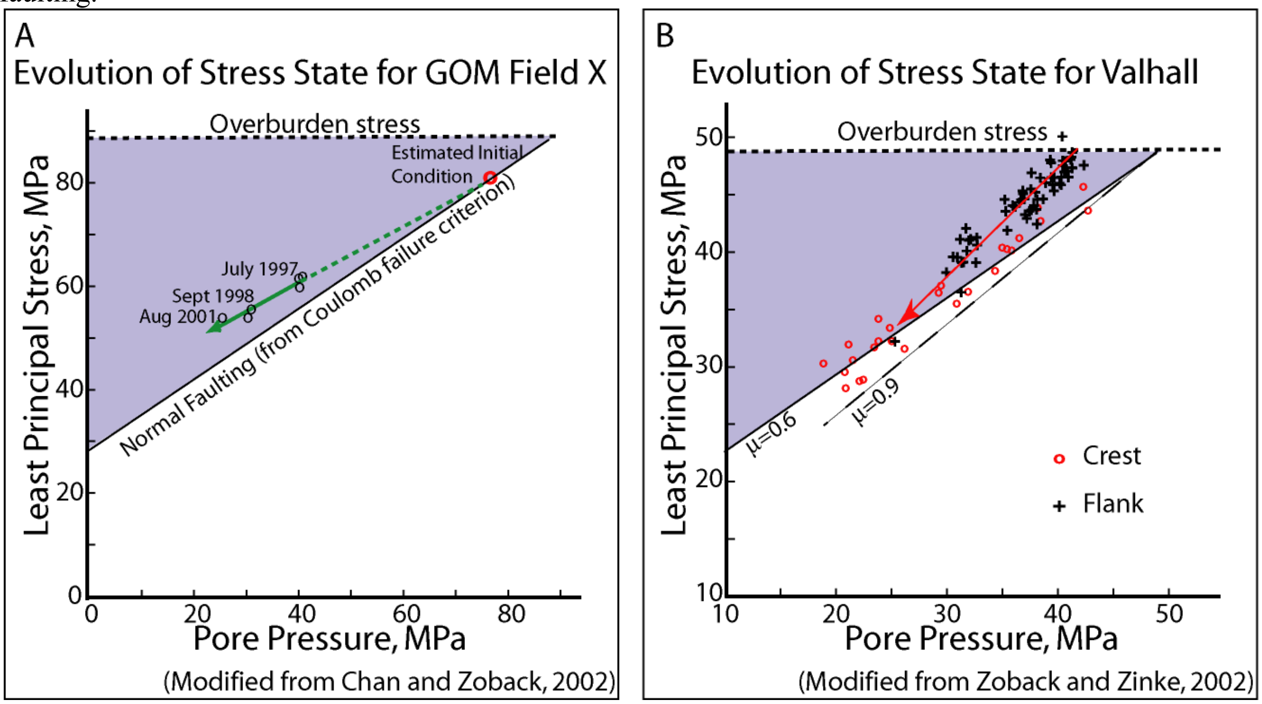
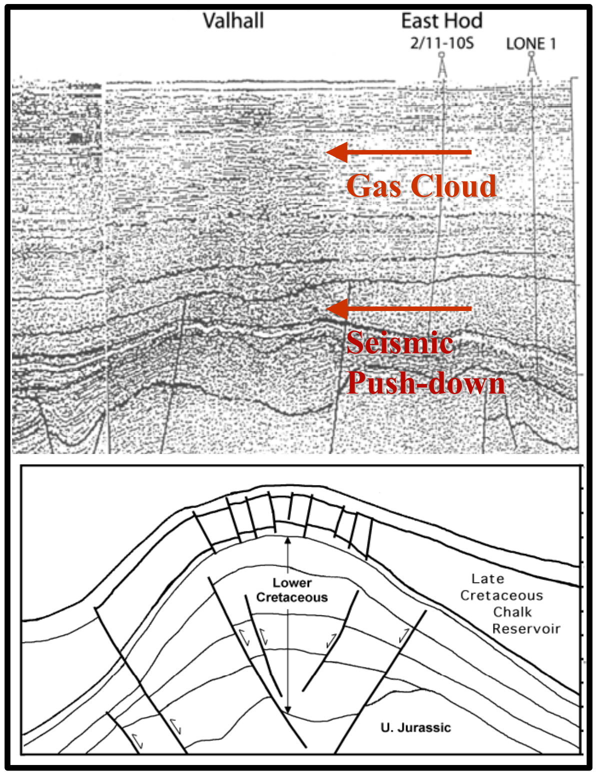


Figure 8: Evolution of the stress state for a field in the Gulf of Mexico and a field in the North Sea. A) The stress path for GOM Field X is moving away from normal faulting as depletion continues. B) There are two different stress paths evolving in the Valhall field. The flanks of the reservoir start out in a stable stress state and the stress path that evolves with depletion brings the flanks into a state of normal faulting. The crest of the reservoir begins and remains in a state of active normal faulting. The normal faulting line is shown for two possible coefficients of friction, μ.

The stress paths shown in red (solid and dashed) on Figure 7B are observed in the Valhall Chalk Reservoir in the North Sea. This reservoir, investigated by Zoback and Zinke (2002), is a faulted anticline. The caprock at the crest of the anticline was initially in a state of active normal faulting so that it followed the normal faulting stress path illustrated by the dashed red line in Figure 7B. The in situ P_p and S_{hmin} data for the crest are shown by red circles in Figure 8B. The faulting resulted in gas leakage out of the top of the reservoir. Evidence for this is seen in the seismic signature of a gas cloud and seismic pushdown of the anticlinal features in the seismic data (Figure 9). The flanks of the anticline had an initially stable stress state, but production in the field caused the stress state to move towards failure, following the solid red stress path illustrated in Figure 7B. The stress and pore pressure data taken in the reservoir during depletion, shown with black crosses in Figure 8B, trend towards the normal faulting lines calculated for both μ=0.6 and 0.9. The production-induced faulting resulted in increased microseismicity along the flanks of the anticline. A field like Valhall would likely not be suitable for CO_2 sequestration operations.



Modified from Zoback and Zinke, 2002

Figure 9: Valhall Chalk reservoir, North Sea is a faulted anticline reservoir with gas leakage from the crest. Production in the field resulted in normal faulting on the flanks of the anticline.

Clearly, depletion may result in complex changes influencing the state of stress and physical properties of a reservoir. These changes can alter the reservoir and seal capacity and integrity, and make the site unsuitable for CO_2 injection and sequestration. By integrating a geomechanical model, the knowledge of the initial reservoir and seal condition, and data taken during depletion, it is possible to better understand the changes a reservoir undergoes when its hydrocarbons are produced. The quantification of these changes is an important step in assessing a reservoir's suitability for CO_2 sequestration.

INJECTION AND SEQUESTRATION EFFECTS

After investigating the production effects on a field, we can make observations and predictions about the influence that injection will have on the reservoir, seal and well. Injection of fluids at high pressures can alter the stress state near the wellbore and in the reservoir. This can lead to hydraulic fracturing, failure on existing fracture planes, and damage to the injecting well. In reservoirs with low permeability, hydraulic fractures may provide the necessary permeability to enable large-scale fluid injection. However, increased permeability pathways, like hydraulic fractures and reactivated fracture planes, will focus the flow of CO_2. This may result in a reduction of sweep efficiency of the CO_2 in the reservoir, which can affect the success of sequestration and EOR projects. A geomechanical model provides insight into challenges such as these that could be faced during the injection phase.

An example of injection-induced fault reactivation is the Rangely Field in Colorado. During water flooding of the field from 1969 through 1973, microseimicity and reservoir pressures were measured (Figure 10) (Raleigh et al., 1976). Periods of water injection correlate with high reservoir pressures and increased seismicity, while times of fluid withdrawal are marked by a decrease in pressure and seismicity.

Seismicity rates are highest when the reservoir pressure exceeds the predicted critical pressure (Raleigh et al., 1976). While not all reactivated faulting is detrimental to the CO2 sequestration potential of a field, it is necessary to understand the mechanisms that are controlling this faulting to be able to assess the effect it will have on seal capacity and integrity.

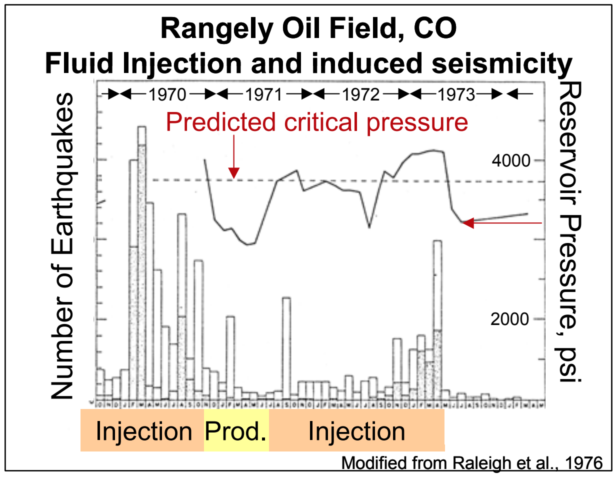


Figure 10: Time vs. Number of Earthquakes at Rangely Oil Field, CO. During water injection, seismicity is high. When the reservoir is being produced, the number of earthquakes decreases.

SUMMARY OF THE INITIAL GEOMECHANICAL WORKFLOW

After investigating the geomechanical controls on seal capacity at various stages in the lifetime of a field, we want to integrate that knowledge into a systematic workflow for assessing the geomechanical suitability for CO_2 sequestration. We will do this by reworking and extending a Fault Trap and Seal Analysis workflow. This is an appropriate starting point for evaluating reservoir potential in the Gulf of Mexico, a region dominated by fault trap and seal issues. We are still in the initial stages of workflow development, and Figure 11 shows the general outline we have established thus far. First, the business side of the problem is presented on the left had side. Here we state our underlying goal of efficient and long-term sequestration of CO_2 in depleted oil and gas fields. The middle section, Geomechanical Evaluation of Seal Capacity, is where we build a geomechanical model, evaluate the initial trap and seal conditions, and examine the effects of production on seal capacity. From there we can speculate about the possible effects that different injection scenarios might have on the seal capacity. The final section of the workflow takes inputs from the Geomechanical Evaluation of Seal Capacity analysis to assess the reservoirs suitability for sequestration. If a field is deemed satisfactory for CO2 sequestration, simulations will be run to test injection strategies, and to assess storage capacity and enhanced oil recovery possibilities in the field.

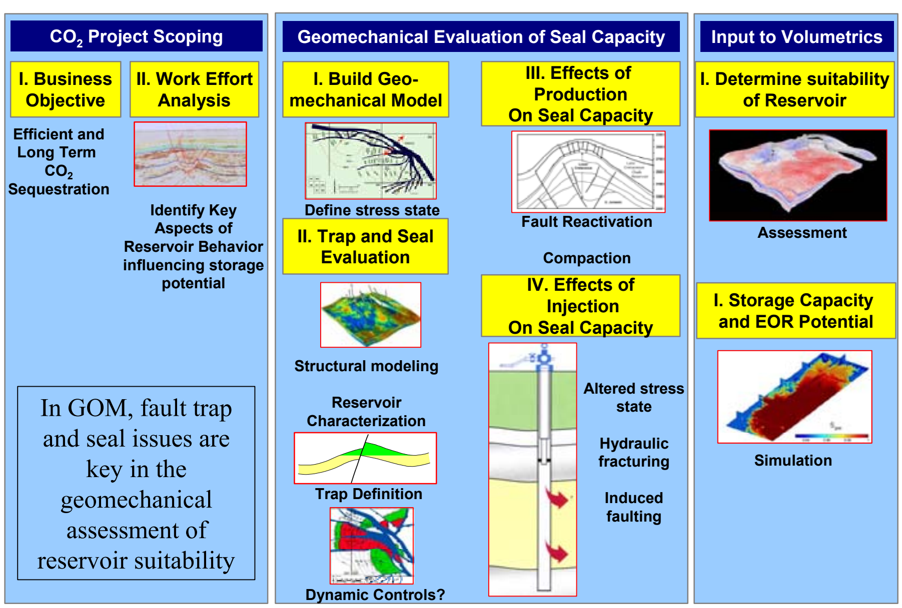


Figure 11: Initial draft of the Workflow for Assessing Reservoir Suitability for CO_2 Sequestration in the Gulf of Mexico.

FUTUREWORK: SEI 330

The next step in this project is to use SEI 330 as a hypothetical candidate for CO_2 sequestration in order to make the workflow more explicit and complete. In the process of doing this, we plan to accomplish the following:

- Create geomechanical and structural models of the field
- Re-examine hydrocarbon fill controls based on the new structural interpretations
- Quantify production effects
- Evaluate possible consequences for various injection scenarios
- Run CO_2 injection simulations for these scenarios

The main goal of this work will be the development of a complete and widely applicable workflow for integrating geomechanics, the evolution of reservoir and seal conditions, and CO_2 sequestration so that we can evaluate the potential of large capacity fields in the Gulf of Mexico and similar regions for sequestration.

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