II.3.1 Assessing Seal Capacity of Exploited Oil and Gas Reservoirs, Aquifers, and Coal Beds for Potential Use in CO_2 Sequestration

Investigators
M. D. Zoback, Professor of Geophysics; Amie Lucier, Lourdes Colmenares, Graduate Research Assistants

Background

In order for geologic CO_2 sequestration to be an effective tool in the stabilization of atmospheric CO_2 concentrations, a goal of sequestering about 3 Gt of carbon per year (~10 Gt CO_2/y) must be met by mid-century (based on current emissions predictions). Currently, pilot CO_2 sequestration projects such as Weyburn in Canada and Sleipner in the North Sea 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.

Three options for geologic storage 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 possible options in order to make a significant impact on global atmospheric CO_2 concentrations. Coal seams offer the unique and attractive ability to store CO_2 by adsorbing it onto the coal surface. CO_2 injected for sequestration purposes can also be used to enhance the production of coal bed methane (CBM). Deep saline aquifers may provide the most capacity of the three storage options, but most are often poorly characterized as to their structure and physical properties. They are important sites because deep saline aquifers can be found in most areas with large numbers of CO_2 point sources, such as coal-burning power plants. Depleted oil and gas fields offer attractive benefits such as partially in-place infrastructures, extensive databases, and the possibilities for value-added benefits from enhanced oil recovery (EOR) and possibly enhanced gas recovery (EGR). 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 indicates that injection of CO_2 into the reservoir would be possible.

We are engaged in three parallel studies investigating geomechanics applied to seal integrity and CO_2 sequestration in geologic formations. These projects cover all three options for geologic CO_2 sequestration:

- Unmineable Coal Seams:
  - Powder River Basin (PRB)
  - Collaboration with Western Resources Project Foundation and Dr. Jonny Rutqvist at Lawrence Berkeley National Laboratory
- Deep Saline Aquifers:
  - Ohio River Valley CO_2 Storage Project

  - Collaboration with Battelle, DOE, NETL, American Electic Power, BP, Schlumberger, Ohio Coal Development Office
- Depleted Oil & Gas Reservoirs:
  - Gulf of Mexico, South Eugene Island 330
  - Collaboration with ExxonMobil

CO_2 Sequestration and ECBM in Unmineable Coal Seams

Coal seams are both a source of methane and a carbon-dioxide sink. For sub bituminous coal like the ones in the Powder River Basin (Figure 3), the CO_2/CH_4 ratio is approximately 10:1 (Figure 4), which indicates the great potential of the Powder River Basin to sequester this greenhouse gas. In addition, CO_2 can also be used to enhance the production of CH_4 from the coal seam since CO_2 has higher adsorption capacity than CH_4 in coal (see Figure 3). This means that the injection of CO_2 in coal beds works for sequestering CO_2 and also enhanced coal bed methane production (ECBM).

From our previous work in the Powder River Basin, we have found that it is typical during drilling and completion operations for the "water-enhancement" activities in the coal seams to result in hydraulic fracturing of the coal and possibly the adjacent strata thereby resulting in both excess CBM water production and inefficient depressurization of coals. We have been able to collect water-enhancement test data in coals to obtain the magnitude of the least principal stress in the coal seam. The preliminary data we have analyzed indicates that the hydrofracs are horizontal in some areas, such that vertical fracture growth is not a problem. However, vertical fracture growth does appear to occur in some places in the Powder River Basin. We are investigating the idea of using the hydrofracs that have been produced in the coals as a more effective path to inject CO_2 for sequestration and ECBM.

CO_2 Sequestration in Deep Saline Aquifers

Several sequestration projects are looking at the deep saline aquifers in the Ohio River Valley as potential sites for CO_2 sequestration because of the large number of CO_2 point sources located in the Midwest. The Ohio River Valley CO_2 Storage Project is unique because it is a field investigation located on the site of the coal-burning Mountaineer Power Plant (Figure 5). Much of the field data needed to characterize the site has already been collected. A 2-D seismic survey through the site was collected in July of 2003. A 9190 ft well was drilled from May through July of 2003. The well was logged with a full suite of geophysical tools, including a Formation MicroImager (FMI) tool. Extensive core and brine sampling was also done. Pressure tests to determine the magnitude of the least principal stress are currently being performed in the well. All of this data is being analyzed to characterize the aquifer and the caprock for their CO_2 sequestration potential.

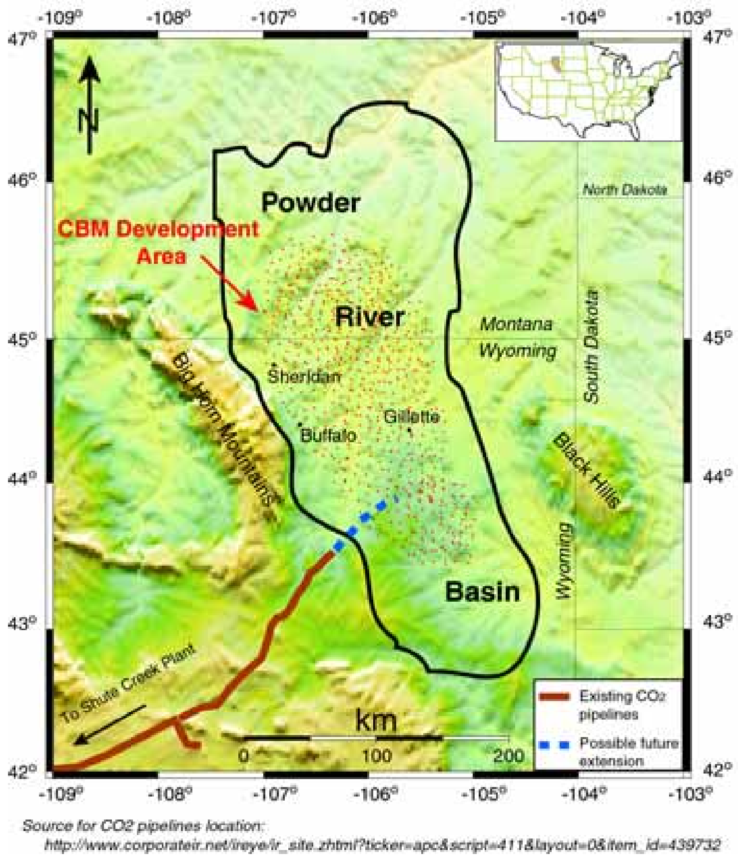

Figure 3: Topographic relief map of the Powder River Basin in Montana and Wyoming. The red dots cover the CBM development area. An existing CO_2 pipeline runs towards the southwest boundary of the basin, and there is a possibility that this could be extended into the PRB in the future.

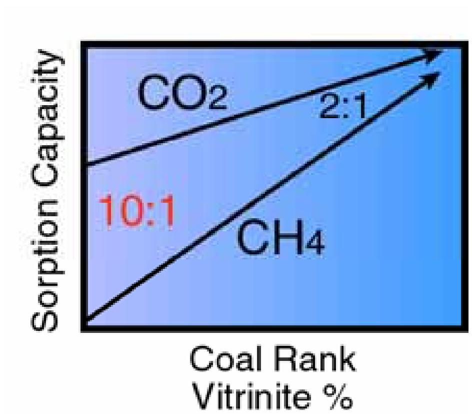

Figure 4: Sorption capacity with respect to Coal Rank. The replacement ratio of CO_2-to-CH_4 is highest for low rank coals, e.g. sub bituminous coals (Bustin *in* Reeves[18], 2003). The coal found in the Powder River

Basin is sub bituminous, making it a great candidate for CO_2 sequestration.

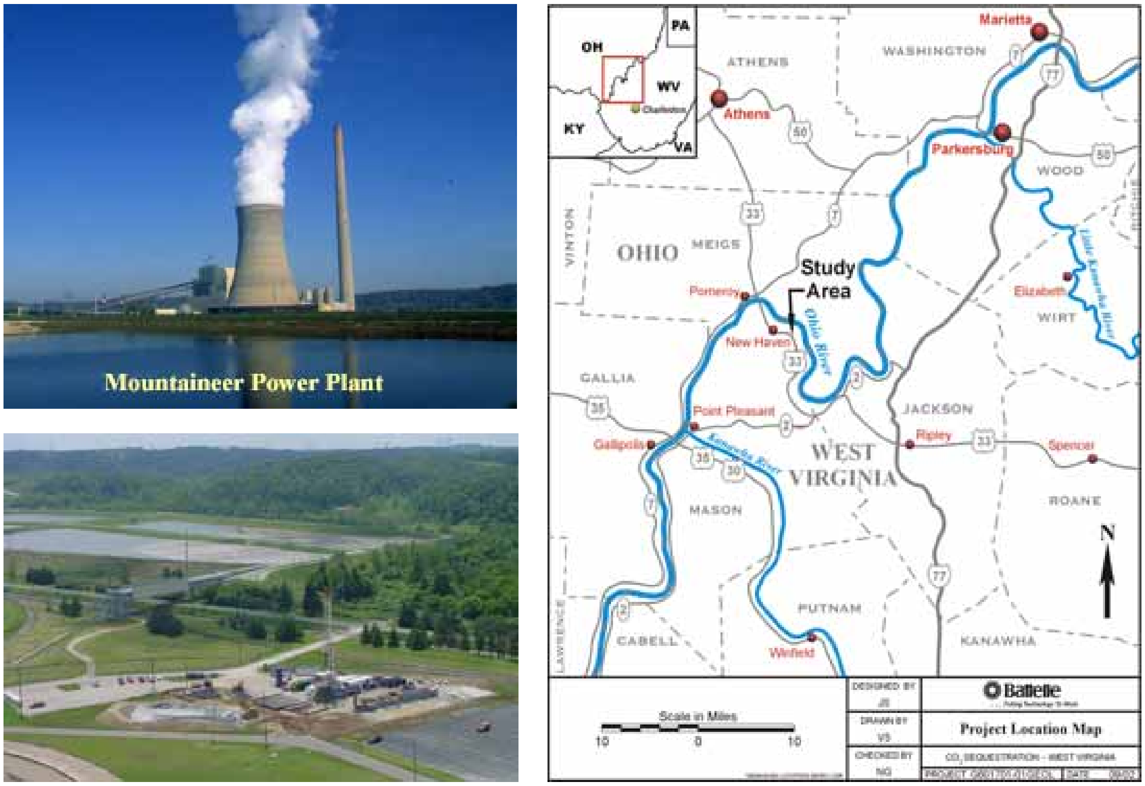

Figure 5: Location of the Mountaineer Power Plant, New Haven, WV. The pilot well (bottom left) for the Ohio River Valley CO_2 Storage Project was drilled on site at the power plant during the summer of 2003 (figures from Gupta[19]).

CO_2 Sequestration in Depleted Oil and Gas Fields

Depleted oil and gas fields seem to be the natural choice for the first large-scale CO_2 sequestration operations. Currently, one of the largest CO_2 sequestration projects in an oil and gas field is taking place in the Weyburn field in the Williston Basin of Saskatchewan, Canada. The project combines CO_2 sequestration with EOR operations to store about one million tons of CO_2 per year. This is an extremely small fraction of the amount of CO_2 that must be sequestered to make a significant impact on stabilizing atmospheric CO_2 concentrations.

We are beginning to examine the sequestration potential of fields in the Gulf of Mexico by developing a workflow for assessing reservoir suitability for sequestration. There are a number of factors that make the Gulf of Mexico an appropriate site for developing a regional workflow. Extensive datasets are available that are crucial in building a comprehensive picture of the 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 (Figure 6).

There is also significant capacity for storage in the region as well as potential for value-added benefits from CO_2 EOR.

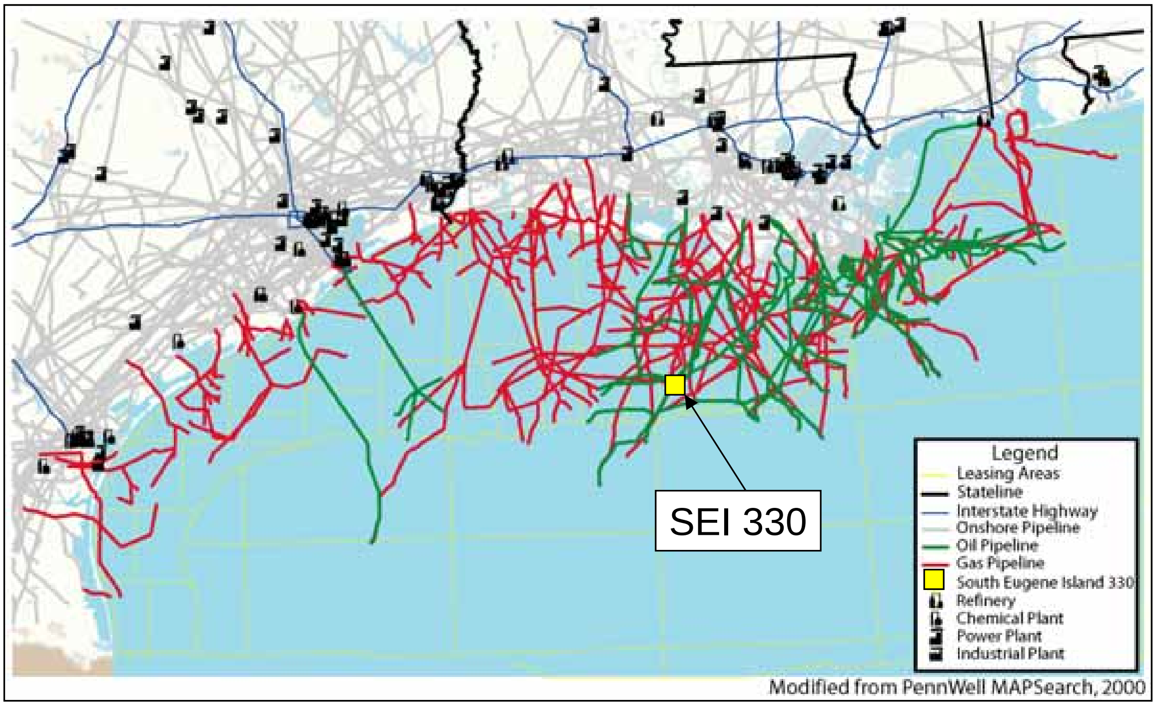

Figure 6: Map of the U.S. Gulf Coast and Gulf of Mexico and some of the existing infrastructure in the region[20]. Oil pipelines are in green, gas pipelines in red, and onshore pipelines in gray. The black figures are possible sources where anthropogenic CO_2 that could be captured and separated for sequestered in the Gulf of Mexico. In yellow is the location of our case study site, South Eugene Island Block 330.

Results

Powder River Basin

The first step in studying CO_2 sequestration coupled with ECBM in the unmineable coal seams of the Powder River Basin is mapping out areas where horizontal hydrofractures occur rather than vertical ones. Hydrofracs open horizontally when the least principal stress is the vertical stress (S_v). The magnitude of the least principal stress is determined by pressure tests like the water-enhancement tests. We can calculate S_v by integrating over the density log. If these two values are the same, horizontal hydrofracs can occur when the fluid pressures exceed the magnitude of the least principal stress.

Our next step is to run simulations of various injection scenarios. As shown in Figure 7, we intend to use stacked hydrofracs in the coal to inject CO_2 and produce CH_4. Specifically, we will investigate the efficiency of producing a hydrofrac towards the bottom of a coal seam where CO_2 would be injected, and a hydrofrac in the upper part of the coal seam from which CH_4 and water would be produced. The simulations have the following objectives:

- Examine multiphase flow characteristics of CO_2-H_2O-CH_4 system
- Test for hydrofrac spacing, thickness of coal seam, spacing of wells
- Investigate rates and volumes of sequestered CO_2 and produced CH_4

We also expect to find alternative ways of sequestering CO_2 in a specific setting like the PRB, which could take advantage of existing wells and hydrofracs during the injection of CO_2 into the coal.

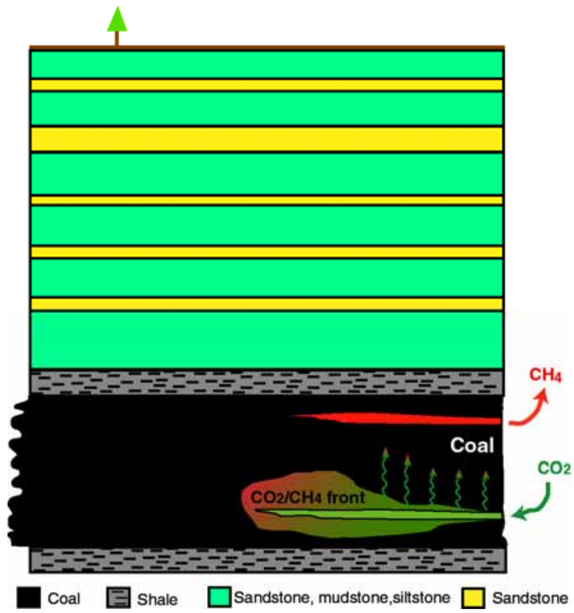

Figure 7: Schematic of suggested ECBM configuration. CO_2 is injected into the deeper horizontal hydrofrac. As the CO_2 front moves through the coal and is preferentially adsorbed, it displaces the methane. The free methane is then produced from a shallower horizontal hydrofrac.

To do these simulations, we have been collaborating with Dr. Jonny Rutqvist from the Lawrence Berkeley National Lab. The computer code we are using is TOUGH2 with the CBM module added to it. TOUGH2 is a numerical simulator for nonisothermal flows of multicomponent, multiphase fluids in one-, two-, and three-dimensional porous and fractured media (Pruess *et al.*[21]). Modifications were made to one of the original modules of TOUGH2 to be able to apply it to ECBM simulations (Webb[22]). The extended Langmuir isotherm for sorbing gases, including the change in porosity associated with the sorbed gas mass, has been included in the new ECBM module. We have started to build our code by creating meshes that would represent the structure that we want to study (described above, Figure 7) and during the test simulations, we are feeding the code real data.

Ohio River Valley CO_2 Storage Project

We are developing a comprehensive geomechanical model of the Ohio River Valley CO_2 Storage Project site. This is an integral step in the complete characterization of a potential CO_2 storage site that provides a good indication as to the suitability of these aquifers for long-term storage of anthropogenic CO_2. In particular, we are examining the state of stress and fracture characteristics in the Rose Run aquifer as well as the layers adjacent to this formation. We have used the FMI log to pick the drilling-induced tensile fractures along the wellbore (Figure 8). These propagate in the direction of greatest horizontal stress, S_{Hmax}. The minimum horizontal stress, S_{hmin}, is oriented 90° from S_{Hmax}. From the drilling-induced tensile fractures, we have determined that S_{Hmax} is oriented N47°E, and S_{hmin} is oriented N43°W (Figure 8). This is consistent with the regional stress. The presence of en echelon tensile fractures in the near-vertical wellbore indicates localized stress perturbations exist (Figure 8). The next steps in this study are to compile a pore-pressure profile of the well, the results of ongoing mini-frac tests to determine the magnitude of S_{hmin}, and to integrate over the density log to get the vertical stress. Using this information, we can constrain the magnitude of S_{Hmax} to complete our geomechanical model of the site. We have also used the FMI data to pick natural fractures that cross the wellbore.

We plan to use our geomechanical model and fracture characterization to determine the distribution and orientation of hydraulically conductive fractures within the aquifer and the effectiveness of adjacent layers to act as seals against the vertical migration of the injected CO_2. By assessing the magnitude of the least principal stress in the Rose Run aquifer, we will determine the injection pressure at which hydraulic fracturing will occur as well as the direction of the hydraulic fracture propagation. This is fundamental in the development of a safe and effective injection plan. We will also determine the maximum fluid pressures that can be maintained in the formations (i.e., their dynamic capacity) without resulting in frictional failure and leakage through hydraulically active fractures.

Gulf of Mexico

It is imperative to approach any assessment of CO_2 storage potential in the Gulf of Mexico from a geomechanical perspective. Many of the trapping mechanisms in the region depend on fault seal. So it is necessary to determine the initial state of the trapping and sealing mechanisms, examine the effect of production on the seal, and predict changes associated with CO_2 injection and storage (Figure 9). A complete geomechanical model is important in assessing the reservoir and seal conditions throughout the lifetime of the reservoir. We are using South Eugene Island Block 330 (SEI 330) as a case study site to develop and test a geomechanical workflow for assessing CO_2 sequestration potential in the Gulf of Mexico.

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. Hydrocarbons are trapped by rollover anticlines created during salt-withdrawal related faulting. It is a mature field that was discovered in 1971 and began production in 1972. An extensive dataset exists for the field, including a recent 3D seismic survey, numerous well logs, bottom-hole pressure readings, and pressure tests (leak-off tests and formation integrity tests).

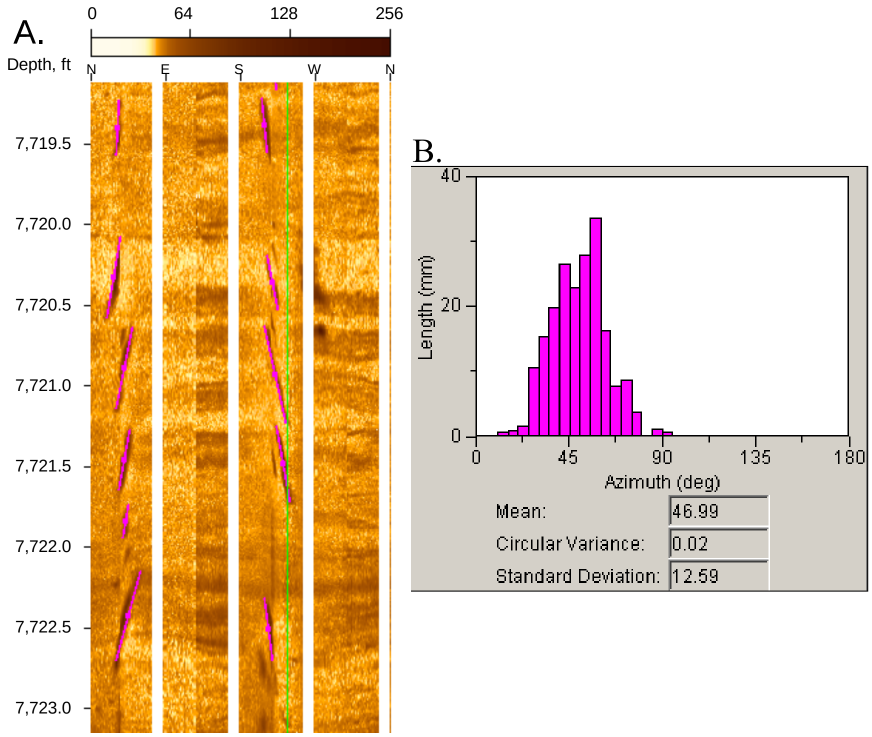

Figure 8: Drilling-induced tensile fractures from the AEP#1 well drilled on site at the Mountaineer Power Plant in New Haven, WV. A) FMI image showing en echelon drilling-induced tensile fractures. The color scale is conductivity. The green line shows the orientation of caliper 1; the pink lines are picks of the individual fractures. B) A plot of azimuth vs. length of the tensile fractures picked from 6400 ft to 9100 ft. The mean azimuth is 47°, so we estimate that the orientation of S_{Hmax} is N47°E.

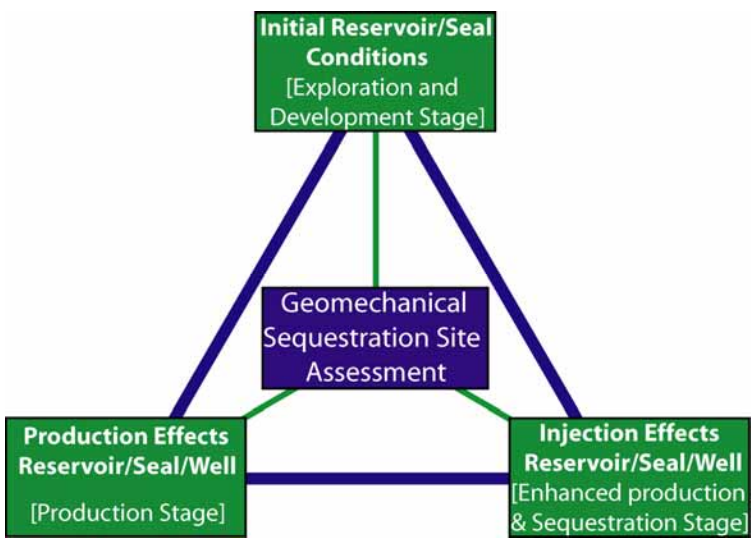

Figure 9: The strategy for building a geomechanical sequestration site assessment is to integrate data from the three stages in the lifetime of a field.

Dynamic constraints on hydrocarbon fill are of interest when looking at this field as a possible site for CO_2 sequestration. Dynamically controlled reservoirs are pressure-limited rather than volume-limited, making it more difficult to determine the capacity of the reservoir for CO_2 storage. Examples of dynamic controls on hydrocarbon fill are capillary entry pressure of the caprock, hydraulic fracture limit (equal to the magnitude of the least principal stress), and dynamic fault-slip limit (equal to a critical pore pressure based on the state of stress and Coulomb failure criterion). When any one of these pressure limits is reached at the top of a reservoir, the caprock cannot support any additional hydrocarbons. If additional hydrocarbons enter the system, the dynamic control acts to release the fluids, through capillary entry, hydraulic fracturing or dynamic fault slip, which decreases the buoyant pressure on the caprock (Figure 10). This presents a unique problem when injecting CO_2 into dynamically constrained reservoirs. Because the density of CO_2 at normal reservoir conditions is about 500-700 kg/m^3 depending on temperature-and-pressure conditions, an oil reservoir can hold a smaller volume of CO_2 than oil, but a gas reservoir can support a larger volume of CO_2 than gas (Figure 10). In reality, the fluids in a reservoir undergoing sequestration operations will be a complex, time-dependent mixture of oil, gas, and CO_2. Therefore, it is important to fully understand the initial controls limiting hydrocarbons in the reservoir prior to production and have production history data to be able to estimate the capacity of reservoir to store CO_2.

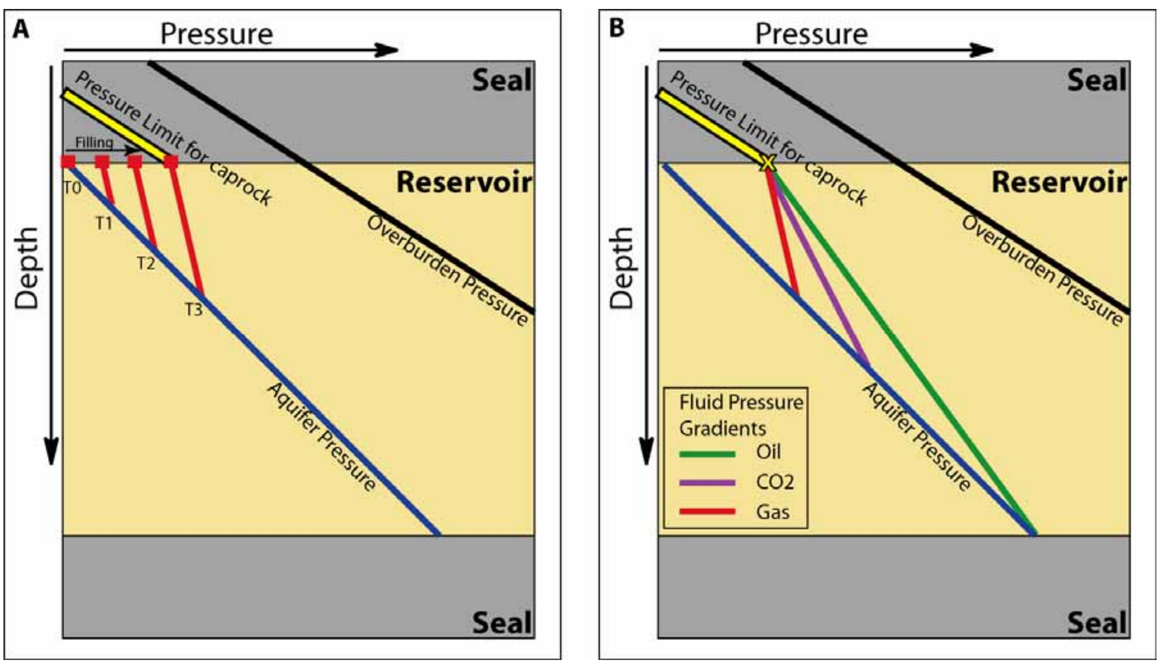

Figure 10: Effect of buoyant fluids on reservoir capacity in the presence of pressure-limited seals. A) Modified from Finkbeiner *et al.*[23], at T0 there are no hydrocarbons in the reservoir, and the pressure at the cap rock falls along the pressure gradient of water in the aquifer. As the reservoir fills through time from T0 to T3, the pressure at the top of the reservoir increases, falling along the hydrocarbon pressure gradient. When the buoyancy force on the cap rock equals the pressure limit, the seal cannot support any additional

hydrocarbons. B) The different buoyancies of oil, CO_2, and gas affect the volumes of these fluids that can be sustained by a pressure-limited seals.

A study by Finkbeiner *et al.*[23] shows that dynamic controls on hydrocarbon fill exist in some of the reservoirs in South Eugene Island 330. One example of a dynamically controlled reservoir is the OI-1 sand in Fault Block A. Figure 10, which is modified from Finkbeiner *et al.*[23], is a pressure vs. depth plot that illustrates the dynamic fault-slip limit is acting as a control on the seal capacity of the OI-1 sand in Fault Block A. The blue line is hydrostatic pressure, and the black line is the overburden pressure. The green dashed line is the hydraulic fracture limit or least horizontal stress, interpolated from leak-off tests and formation integrity tests. The yellow box is the dynamic slip limit calculated from the overburden stress and the least horizontal stress over a range of coefficients of friction between 0.3 and 0.6. The oil columns are shown in green, and the gas columns in red. The pressure at the top of the oil leg reaches the dynamic fault slip limit, suggesting that this reservoir is controlled by dynamic fault slip. However, other shallower sands in the same fault block are clearly not limited by the dynamic fault slip or hydraulic fracture limit.

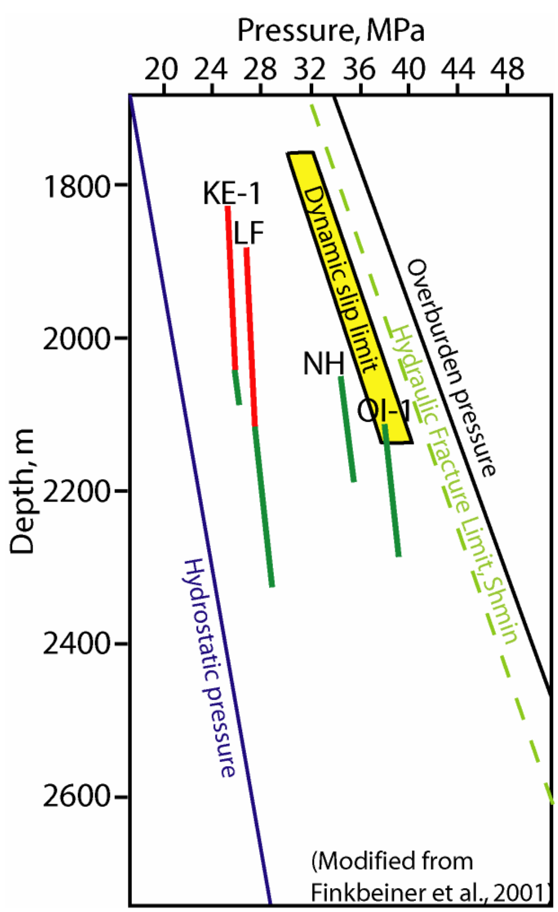

Figure 11: Pressure vs. depth plot of SEI 330 Fault Block A. The oil column in the OI-1 sand appears to be controlled by the dynamic slip limit, while the other shallower sands are not limited by that dynamic control. See text for more explanation.We are developing

a geomechanical workflow in the context of the SEI 330 field (Figure 12). We have chosen to study this field in more detail because 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 (Alexander and Flemings[24]; Alexander and Handschy[25]; Gordon and Flemings[26]; Losh *et al.*[27]; Stump and Flemings[28]; Finkbeiner *et al.*[23]; Losh *et al.*[29], and others). Many of these studies are based on the structure maps generated by Pennzoil over a decade ago. Currently, ExxonMobil is creating structure maps based on a newer 3D survey 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.

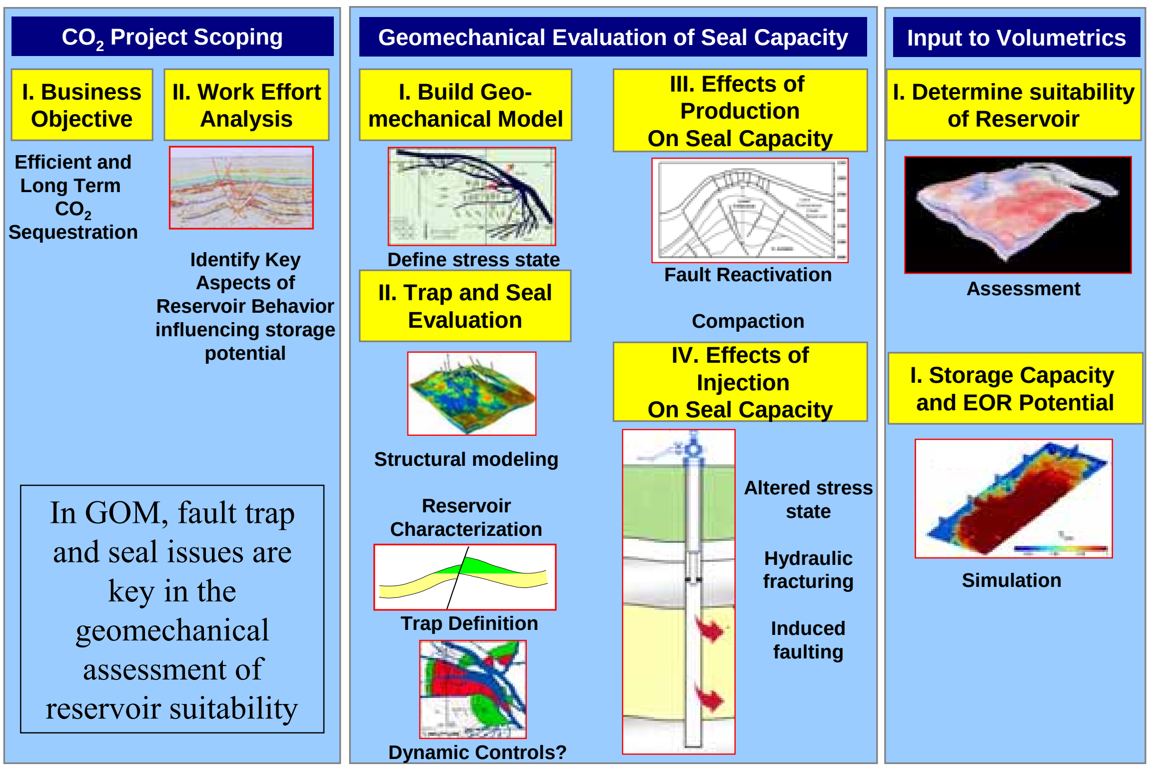

Figure 12: Initial draft of the Workflow for Assessing Reservoir Suitability for CO_2 Sequestration in the Gulf of Mexico.