Abstract

The Carbon Storage Assurance Facility Enterprise (CarbonSAFE) is a USDOE-NETL funded effort to certify and develop large-scale commercial CO₂ storage sites. Project ECO₂S is a CarbonSAFE venture with the main objective of demonstrating the suitability in an area near Mississippi Power’s (MPC) Kemper County Energy Facility (north of Meridian, Mississippi) for the commercial-scale injection and storage of CO₂. Project ECO₂S was designed as an accelerated project aimed at establishing an early CO₂ storage (ECO₂S) location capable of providing at least 50 million tonnes of storage capacity. This project is funded principally by the USDOE-NETL with support from Mississippi Power Company and is managed by the Southern States Energy Board.

A critical component to the development and execution of a commercial scale CO₂ injection and storage project is to comprehensively identify risk factors. Several key areas of risks to project success for commercial scale CO₂ storage include: geologic uncertainties; project management and planning; outreach; permitting and site access agreements; infrastructure development; the contractual and regulatory pathways; and a commercial development plan. Identifying and evaluating every important source of risk is of key interest to future owners/operators of such a project. Project success – the central entity that is “at risk” – consists both of project goals and objectives (e.g. contractual pathways) and of preclusions and avoidances (e.g. injury, damage to environment or reputation, etc.).

GHG Underground LLC designed and conducted a workshop-focused process to identify and evaluate risks. Within this process, project team members and stakeholders provided specific information about the project, to share this information among those involved with the risk process, and to provide semi-quantitative risk-evaluation data (e.g. Likelihood and Severity values) for analysis and reporting. The results of the ECO₂S risk workshop will be presented.
**Project Background and Status**

The Kemper County Project Project ECO2S is part of the CarbonSAFE Program and is financially supported by the USDOE-NETL and Mississippi Power Company. The project is managed by the Southern States Energy Board. Technical support is provided by Southern Company Research and Development. A major setback to the project was the loss of the designated CO₂ Source from the energy facility due to Mississippi Public Service Commission decision to cease coal fueled power generation. A main focus of current work is to secure a source of CO₂ and design a gathering network toward developing a regional storage hub at the original injection site.

**Project Details & Geologic Constraints**

Three characterization wells were drilled during the summer of 2017 in the study area, and a suite of geophysical, geochemical data were collected to characterize the geology and petrophysical parameters controlling CO₂ storage potential. To establish the geologic framework, core analyses were conducted on caprock and reservoir rock in conjunction with structural and stratigraphic interpretations. These data are applied to geologic modeling, injection simulations, flow modeling, reactive transport modeling and thermo-hydro mechanical modeling.

**Three Prominent Seals**
- Selma Chalk
- Tuscaloosa Marine Shale
- Upper Washita-Fredericksburg Shale

**Cretaceous Sandstone Storage Zones**
- Lower Tuscaloosa Group
- Washita-Fredericksburg interval
- Paluxy Formation
- Predictable Cretaceous-Tertiary structure
- Formations dip (deepen) to the southwest
- Marine Tuscaloosa dips 50 feet/mile
- Sub-Mesozoic unconformity dips 80 ft/mile
- High porosity in the potential sandstone storage horizons

**Acknowledgments**

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Risk Management for a Commercial-Scale CO₂ Storage Project

1. What is at risk?  

**PROJECT VALUES**

<table>
<thead>
<tr>
<th>Overarching Objective</th>
<th>Store commercial volumes of CO₂ safely, permanently, and economically within a regionally significant saline reservoir system</th>
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<tbody>
<tr>
<td>Specific Goals &amp; Objectives</td>
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<tr>
<td>- Brit, core, and log 3 new wells</td>
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<tr>
<td>- Refine knowledge of reservoir properties</td>
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<tr>
<td>- Build geological numerical model</td>
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<tr>
<td>- Model CO₂ injection to identify physical risks</td>
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<tr>
<td>- Develop site-specific monitoring plans</td>
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<tr>
<td>- Identify contractual and regulatory pathways toward development</td>
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<tr>
<td>- Comprehensively identify and manage risks to project success</td>
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<tr>
<td>Preclusions &amp; Avoidances</td>
<td></td>
</tr>
<tr>
<td>- Injuries to staff or public</td>
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<tr>
<td>- Environmental damage</td>
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<tr>
<td>- Reputation damage</td>
<td></td>
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<tr>
<td>- Noncompliance and illegality</td>
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<tr>
<td>- Public anger, rejection, negative opinion about CCS</td>
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</tbody>
</table>

2. How to Quantify?  

**SEVERITY and LIKELIHOOD SCALES**

<table>
<thead>
<tr>
<th>LIKELIHOOD of Impact or Failure Occurring (L)</th>
<th>1</th>
<th>2</th>
<th>3</th>
<th>4</th>
<th>5</th>
</tr>
</thead>
<tbody>
<tr>
<td>Very Unlikely</td>
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<td></td>
<td></td>
</tr>
<tr>
<td>Unlikely</td>
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<td></td>
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<tr>
<td>50/50</td>
<td></td>
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<tr>
<td>Likely</td>
<td></td>
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<td></td>
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<tr>
<td>Very Likely</td>
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</tbody>
</table>

In 50 ECO2-like commercial projects, might happen once.

Nearby well test for EOR of CO₂ Project. Once per several years.

3. How to capture values from experts?  

**LIVE and WEB-BASED**

During a one-day workshop involving all ECO25 project staff, 12 of 102 risk scenarios were semi-quantitatively assessed as the impact of Project Severity (S) and Likelihood (L). S and L were each judged on a categorical 5-point scale (L, scale shown at left).

Followup via spreadsheet yielded S and L values for the remaining 90 scenarios.

S and L values and text (comments and new scenarios) were input “live” via personal web-connected devices, and all data were displayed on screen in real time.

Scenarios were presented in five topic groups. Staff identified their areas of expertise among the five groups, and from those more vs. less familiar with the subject matter were distinguished. This method preserves individual expertise, information sharing, and “the wisdom of crowds.”

Several of the highest risks fall into the Program and Project Management topic group, focusing on concerns about attaining technical objectives without the Kemper CO2 source. A contingency plan for loss of that source — using the project site as a regional CO2 storage hub — also bears risks such as the loss of surface and/or pore-space rights. Among geological issues, the main concern is caprock integrity rather than reservoir. Risk rankings by participants more vs. less familiar with the specific scenario topics are similar.

4. How to select risks to treat?  

**MULTIPLE SCREENS**

<table>
<thead>
<tr>
<th>Scenario Description</th>
<th></th>
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</thead>
<tbody>
<tr>
<td>insufficient CO₂ supply commitments to support regional storage hub</td>
<td></td>
</tr>
<tr>
<td>MPC/SCDO management do not continue to support project during next 2-5 years</td>
<td></td>
</tr>
<tr>
<td>MPC, DEP management not required in regulatory integration of storage hub</td>
<td></td>
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<tr>
<td>Few lease rights are insufficient for the project.</td>
<td></td>
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<tr>
<td>Kemper energy facility does not become a source of CO₂</td>
<td></td>
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<tr>
<td>Operational problems at CO₂ source plant prevent delivering CO₂ to Kemper energy within-scale geologic storage</td>
<td></td>
</tr>
<tr>
<td>Changes in U.S. government personnel or policies result in removal of government support of the Kemper/CO₂ project</td>
<td></td>
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<tr>
<td>Existing pipeline network not designed to be used as a regional hub</td>
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<tr>
<td>Changes in the operational status or conversion viability of CO₂ source plant prevent meeting project objectives</td>
<td></td>
</tr>
<tr>
<td>Uncertainties in CO₂ storage delay specific operating or regulatory requirements</td>
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</table>
## Risk Scenarios

### Geological

<table>
<thead>
<tr>
<th>Scenario ID</th>
<th>Scenario Group</th>
<th>Severity</th>
<th>Likelihood</th>
<th>Risk</th>
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</thead>
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<tr>
<td>G01</td>
<td>M06</td>
<td>3.66</td>
<td>1.95</td>
<td>7.33</td>
</tr>
<tr>
<td>G02</td>
<td>M03</td>
<td>2.31</td>
<td>2.77</td>
<td>6.62</td>
</tr>
<tr>
<td>G03</td>
<td>M32</td>
<td>3.32</td>
<td>1.91</td>
<td>6.52</td>
</tr>
<tr>
<td>G04</td>
<td>M32</td>
<td>1.40</td>
<td>2.00</td>
<td>6.49</td>
</tr>
<tr>
<td>G05</td>
<td>M32</td>
<td>1.40</td>
<td>1.71</td>
<td>6.38</td>
</tr>
<tr>
<td>G06</td>
<td>M32</td>
<td>3.42</td>
<td>1.84</td>
<td>6.65</td>
</tr>
<tr>
<td>G07</td>
<td>M32</td>
<td>1.52</td>
<td>1.24</td>
<td>4.33</td>
</tr>
<tr>
<td>G08</td>
<td>M32</td>
<td>1.52</td>
<td>1.69</td>
<td>4.31</td>
</tr>
<tr>
<td>G09</td>
<td>M32</td>
<td>3.96</td>
<td>1.28</td>
<td>3.85</td>
</tr>
</tbody>
</table>

A geological seal is compromised by discontinuity or high permeability.

Core samples from geological seals are inadequate (for various reasons) to demonstrate sealing capacity.

A known or unknown fault cuts a geological seal (crack).

Unforeseen spill points/leakage pathways exist in storage reservoir and/or confining units.

The primary CO2 injection stream is intercepted by a natural (e.g., water) stream result in subsurface contamination.

The primary CO2 injection stream is intercepted by a natural (e.g., water) stream result in equipment damage.

Premature deceasing of the reservoir’s effective capacity.

A lack of whole core from potential storage reservoir leads to uncertainty as to reservoir quality.

Fracturing of seal layers impairs CO2 containment.

Lack of process information on the CO2 reservoir and/or caprock formations are susceptible to mineral dissolution that may compromise reservoir or caprock formation integrity.

The limited data on local seismic events suggests unrealistically low seismicity; unexpected induced seismicity occurs.

Plume unexpectedly migrates to a fault, changes stresses there, and induces seismicity.

Rapid mineral precipitation occurs with CO2 injection, causing reduced reservoir permeability.

Pre-Pakay unconfined stress is regime and causes long distance gap/migration of CO2 beyond the Pakay plugouts.

Plume migration differs from baseline models.

Lifepan of monitoring tools and results interpretation are shorter than the 50-year monitoring period.

Numerical modeling predicts plume migration beyond secured land rights or monitored area.

Users of project data find the data archiving/access system to be awkward and inefficient.

During injection, pressure increase at a monitoring well exceeds the limit established by a Class VI permit condition.

At end of the planned and budgeted post-injection monitoring period, criteria for showing plume stability remains unclear, and regulator continues monitoring while reviews continue.

Modeling suggests that existing plumes/pressure front monitoring tools will be inadequate for the Kemper storage complex (ultra-high permeability with moderate anticipated pressure buildup).

At end of the planned and budgeted post-injection monitoring period, regulator deems that data showing plume stability are inadequate.

Monitoring wells are utilized or mis-compacted, and thus miss the developing plume.

Monitoring the plume with mis-constructed or monitoring data is not sufficient to quantify CO2.

Digital data is damaged, lost, or destroyed.

Insufficient baseline data (type, quality, or duration) are gathered prior to injection to establish a consistent CO2 tracer.

Pressure increase exceeds models, raising possibility that brine extraction will need to manage plume and/or maintain injection rate.

Prior to decision to start injection, data and models are insufficient to confirm integrity of geological seals.

Impairments in CO2 stream behavior differ from expected.

Overlying USDW is underpressured, causing a larger than expected AOR to be calculated.

Monitoring data system not appropriate for size/type of data.

After some CO2 injection, a new nearby project (e.g., oil or gas) injection influences or affects the CO2 plume.

Available stress data (largely from Messieurs) provides little guidance at stages of deeper levels, giving little assurance on project-induced seismicity.

Operational problems at CO2 source plant prevent delivering the CO2 needed to show commercial-scale geological storage.

Offsite boom drives up project costs and increases lease time out of service.

Loss of surface access rights in area of planned injection well.

Uncertainty in CO2 source(s) delay pipeline specification and design.

Process problems lead to varying injection rates and problems meeting UIC requirements.

Capture facility does not operate smoothly, causing interruptions in CO2 supply.

Wells within the expected Kemper plume/presure front have unknown capacity.

Numerical modeling indicates more injection wells than planned will be required to inject 3 MM tonnes per year.

CO2 leak cannot be stopped by existing technologies.

Well integrity cannot be established prior to primary cementing failure in one or more of the wells.

Loss of downhole monitoring component results in expensive workaround in order to comply with injection permit.

Limited data on model assumptions suggest unrealistically low leakage risk and potential for overlooking/underestimating CO2 leakage.

Trade restrictions disrupt delivery of tubulars required for project, e.g., chrome and other alloy materials.

Pipeline or other surface facility damaged by traffic, construction, excavation, etc.

Captured CO2 is out of spec with pipeline injection limits.

Screened (open hole) completions are necessary to maintain well/reservoir integity, making engineered well completions and injection monitoring challenging.

Weather damages control system during injection resulting in unplanned shutdown.

Injection causes near-wellbore formation damage in one or more injection wells.

Critical equipment is stolen from injection site.

Traveling to a nightime logging run, staff member falls asleep while driving.

Impairments remaining in the CO2 stream result in equipment damage.

Impairments remaining in the CO2 stream result in subsurface contamination.

Monitoring instruments placed in wellbore hinder injection.

Non-well (i.e., surface) monitoring equipment malfunctions or is damaged.

Changes in the operational status or commercial viability of CO2 source plant prevents meeting project objectives.

Kemper energy facility does not become a source of CO2.

Insufficient CO2 supply commitments to support regional storage hub.

MPC / SPOC management not interested in supporting a regional storage hub.

MPC / SPOC management do not continue to support project during 5-10 years.

Existing pipeline networks not designed to be used as a regional hub.

Pore space rights are insufficient for the project.

Potential CO2 sources believe that no mature capture technology is available, so will not commit to project.

Loss of pore space access (due to land sale or other cause) limits the overall storage capacity of the hub.

Infrastructure development costs are considerably higher than expected.

The single source/sink structure of EGSE’s project does not fully substantiate future designs of integrated multi-source/sink CCS infrastructure.

Infrastructure development costs are considerably higher than expected.

Competition with CO2 for EIR prevents delivering the CO2 needed to show commercial-scale geological storage.

Lack of process information on the CO2 source plant prevents developing an adequate design basis and cost for CO2 compression, dehydration, and purification.

Infrastructure damage from extreme weather.

Insufficient effectiveness does not cover costs of claimed project/costed project to a non-project resource (offsite, farm, residence, etc).

Power to injection facility is outside Southern Company network resulting in unstoppable delays.

CO2 transmitter requires more stringent CO2 containment.

Goals of the CarbonSAFE program and this project are not adequately understood by the project team, which results in failure to meet the project objectives.

Quadrifled drivers for CO2 transport are in short supply.

Changes in U.S. government personnel or policies result in removal of government support of the CarbonSAFE program.

Local animosity toward MVEF leads to opposition of EGSF project.

Permitting of a Class VI UIC permit for storage is delayed.

Regulatory uncertainty causes delay to project timeline.

Premature decommisioning of site results in a negative opinion from the public and potential users.

Insurer of major project partner (MPC, SPOC, UAB,...) threaten policy termination based on concerns about project.

Never coverage of CO2 leaks from Creekfield, MS site raises regulator and public concerns about permitting storage at Kemper site.

Public opposition or unacceptable environmental impact to new pipeline construction.

Opposition arises due to concerns about impact to USDW.

State environmental agency denies injection permit, citing risk to USDW.

Future legal challenge extinguishes project’s complete rights that were based on control of surface.

Cultural or archeological sites are found within area of study/interruption to the rail.

Pipeline permitting delays due to crossing state lines (multiple agencies).

Changes in CO2 stream composition may cause 50-year injection period (e.g., source) exceed existing UIC permit conditions, and require new permits or major modification.

In considering UIC permit application, regulator requests evidence that undocumented boreholes are unlikely to exist within the expected Kemper plume/presure footprint.

Land use changes impact injection activities (e.g., site access).

Landowner refuses access for seismic shot or other surface-based monitoring over critical area.

Environmental Impact Statement is rejected due to potential impacts to wetlands or other sensitive habitats/species.

NGO opposition to CCS threats project.

Regulatory authority denies use of existing Phase II wells for monitoring purposes.

The owner of land next to where property rights have been secured alleges trespass and sues.

Local landowner builds residence(s) over CO2 pipeline.

Vandalism at control room damages system controls.