Case studies of the application of the Certification Framework to two geologic carbon sequestration sites

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Abstract
We have developed a certification framework (CF) for certifying that the risks of geologic carbon sequestration (GCS) sites are below agreed-upon thresholds. The CF is based on effective trapping of CO2, the proposed concept that takes into account both the probability and impact of CO2 leakage. The CF uses probability estimates of the intersection of conductive faults and wells with the CO2 plume along with modeled fluxes or concentrations of CO2 as proxies for impacts to compartments (such as potable groundwater) to calculate CO2 leakage risk. In order to test and refine the approach, we applied the CF to (1) a hypothetical large-scale GCS project in the Texas Gulf Coast, and (2) WESTCARB's Phase III GCS pilot in the southern San Joaquin Valley, California.

Keywords: geologic carbon sequestration; risk assessment; leakage risk; well leakage; case studies

1. Introduction
We describe a novel and practical risk-based framework for certifying that the leakage risk of a potential geologic carbon sequestration (GCS) site is below agreed-upon thresholds [1]. Our approach addresses a wider set of risks than current federal deep underground injection regulations that protect underground sources of drinking water (USDW). The approach we developed, known as the Certification Framework (CF), proposes a standardized way for project proponents, regulators, and the public to analyze and understand risks and uncertainties of GCS in a simple and transparent way. Here we outline the CF methods and present the results from two case studies.

2. CF Methods
Objectives of the CF
The CF focuses on evaluation of the safety and effectiveness of a single GCS site as opposed to screening and ranking which examines multiple sites (e.g., [2,3]). We consider the surface operations associated with GCS (capture, compression, transportation) to be sufficiently well known that existing risk frameworks can be applied to

those operations. By this assumption, we focus the CF solely on geologic storage and specifically exclude consideration of surface operations.

The purpose of the CF is to evaluate the degree to which a GCS site is expected to be safe and effective. In this context, the word "safe" means that impacts to humans and other living things, the environment, and other resources are acceptably low over both short and long time periods. The word "effective" means that the site will contain indefinitely the vast majority of injected CO_2 [4]. In the CF we simplify the system into a tractable and logical form amenable to modeling and analysis. We assume that GCS projects in sedimentary basins share common concerns such as the presence of wells and faults as potential leakage pathways. We use the concept of "effective trapping" in the CF to acknowledge that GCS at a scale large enough to mitigate anthropogenic emissions involves the injection of enormous volumes of CO_2 into the Earth's crust, which is not a leak-proof container. The purpose of building the CF upon the effective trapping concept is to distinguish harmful from beneficial (or at least benign) migration. The risk assessment can thereby focus on the likelihood of the former. The CF is intended to be simple, but not too simple, and transparent in terms of what methods are being applied. Through its simplicity and transparency, we aim to encourage the CF be accepted by a wide variety of users, and we aim to make the CF useful around the world under various regulatory systems.

Terminology

The CF hinges upon precise definitions of several terms including "leakage":

- *Effective Trapping* is the proposed overarching requirement for safety and effectiveness.
- *Storage Region* is the three-dimensional volume of the subsurface intended to contain injected CO_2.
- *Leakage* is migration across the boundary of the Storage Region.
- *Compartment* is a region containing vulnerable entities (e.g., potable groundwater).
- *Impact* is a consequence to a compartment, with severity evaluated by proxy concentrations or fluxes.
- *Risk* is the product of the probability of an impact occurring and the severity of that impact.
- *CO_2 Leakage Risk* (CLR) is the risk to compartments arising from CO_2 migration.
- *Effective Trapping* is achieved if CO_2 Leakage Risk is below agreed-upon thresholds.

Making use of this terminology, the purpose of the CF is to evaluate the CO_2 Leakage Risk (CLR) for each compartment to determine whether the Effective Trapping threshold will be met for a given GCS site. Given that injected CO_2 will displace large amounts of brine (volumes similar to the volume of CO_2 at reservoir conditions), we further define the brine leakage risk (BLR) in a manner analogous to CLR.

Once leakage is defined as above, we assume in the CF that wells and faults are the only potential leakage conduits. This assumption is made to simplify the analysis and is based on the idea that GCS sites will be chosen so as to avoid sites with potentially discontinuous cap-rock seals.

Impacts Occur to Compartments

The upward leakage of CO_2 or brine may have negative consequences in the form of impacts to compartments, i.e., to collections of related vulnerable entities. For example, underground sources of drinking water (USDW), taken collectively at a site, form a single USDW compartment. We define five compartments in which impacts are evaluated.

- ECA = Emission Credits and Atmosphere
- HS = Health and Safety
- NSE = Near-Surface Environment
- USDW = Underground Source of Drinking Water
- HMR = Hydrocarbon and Mineral Resources

The compartments have general locations within the system but are abstract in the sense that they may include disconnected pieces. For example, there may be multiple zones of USDW separated by HMR-bearing layers, and yet the CF would utilize only one USDW compartment. The ECA compartment is even more abstract in that emission credits are not physical entities.

We present in Figure 1a a cross section of a generic GCS site showing a deep structure potentially suitable for use in sequestering CO_2, sealing formations, an oil-bearing formation, faults, wells, USDW, vegetation, and a residence with water well. This conceptualization of common elements of a GCS system is further abstracted to consist of the source, conduits, and compartments in Figure 1b. In summary, the CF simplifies the GCS system so that the CO_2 (and brine) form a potential source of hazard, wells and faults comprise the potential leakage pathways, and impacts occur to compartments. The overall work flow of the CF is summarized in Figure 2.

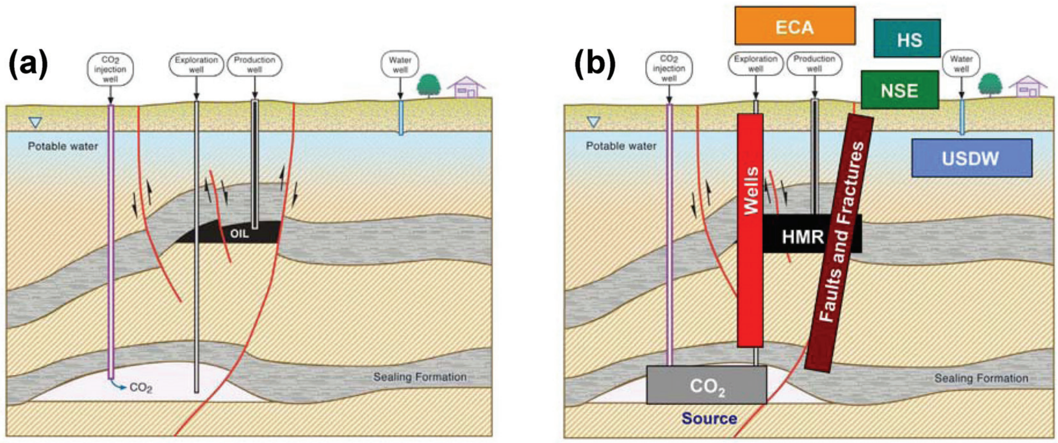


Figure 1. (a) Generic geologic cross section of potential GCS site showing reservoir and sealing formations, faults, wells, USDW, and near-surface and surface environments. (b) Generic cross section with CF source and compartments overlaid.

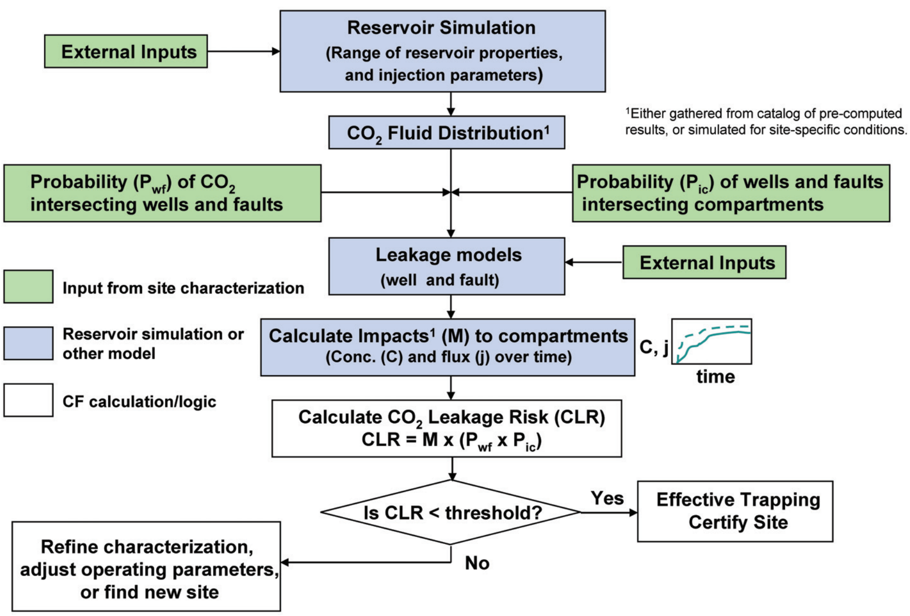


Figure 2. Flow chart of CF-CLR process showing logic and inputs and outputs.

Impacts of CO_2 to compartments are evaluated in the CF by modeling and simulation of proxy concentrations or fluxes. The CF assumes that there are agreed-upon limits on CO_2 or brine concentrations within the compartment as a whole, or on fluxes into the compartment, that can be established to ensure acceptably small impact to the compartment. Whether a concentration- or flux-based limit is appropriate depends on the context and compartment.

The CF is a risk-based approach that uses two likelihoods to estimate probability of leakage. The first is the likelihood of intersection of the CO_2 (or brine) source with a conduit. The second is the likelihood of intersection of the conduit and a compartment. The product of these likelihoods is the probability of the given source-to-compartment leakage scenario. The risk associated with that leakage is the product of the likelihood of leakage and the impact (severity) of that leakage event. Acceptable risks from CO_2 or brine leakage will be those below a threshold provided by external sources such as regulators or carbon-credit insurers. The source location for the leakage scenarios is determined by the movement of the CO_2 plume during and after injection which is modeled using reservoir simulation.

Discussion of CF Methods

The CF approach is intended to be simple, transparent, and accepted. We achieve simplicity by stripping the system down into its fundamental components, namely the CO_2 (or brine) source, conduits for leakage, and compartments where impacts may occur. We achieve further simplicity by using fluxes or concentrations as proxies for impacts, and by handling uncertainty through simple intersection probabilities of conduits and source, and conduits and compartments. Transparency is achieved through the use of formal terminology and a consistent framework for calculating leakage risk.

3. Case Studies

3.1. The Texas Gulf Coast

Introduction

The CF was applied to a purely hypothetical GCS project in the Texas Gulf Coast targeting the down-dip water leg of the Fulshear natural gas storage reservoir southeast of Katy, Texas (USA) (Figure 3). This choice of site is representative of a situation in which a reasonably good description of the geology is available. The gas reservoir is located in a roll-over anticline bounded to the NW by a SE-dipping fault (Figure 3 inset). The scenario we consider involves injecting CO_2 at a depth of 2,134 m (7,000 ft) into the Hillebrenner Sand approximately 3.5 km (2.1 mi) from the gas-water contact. The scenario considers a single well injection with screen across the entire 15 m (50 ft) thickness of the formation. The injection rate is set constant at 0.8 Mt/yr for 30 years, for a total of 24 Mt CO_2 injected. Table 1 lists the essential elements of the proposed injection. In terms of the CF, the storage region is defined as the Hillebrenner Sand with lateral boundaries located at a radius of 4 km (2.5 mi) from the injection well.

Table 1. Summary of properties and injection plan for the case studies.

Parameter	Fulshear	Kimberlina Phase III
Injection rate, period	0.8 Mt/yr, 30 yrs	0.25 Mt/yr, 4 yrs
Reservoir name	Hillebrenner Sand	Vedder Formation
Sealing Formation	Jackson Group	Freeman-Jewett
Structure	Monocline	Monocline
Reservoir depth	2,134 m (7,000 ft)	2,300 m (7,500 ft)
Thickness, dip	15 m (50 ft), 1^{o} SE	160 m (520 ft), 6^{o} SW
Temperature	88 ^{o}C (190 ^{o}F)	80^{o}C (176 ^{o}F)
Pressure	21 MPa (3100 psi)	22 MPa (3200 psi)

Surface and Subsurface Description

The Fulshear site is located on a flat coastal plain with land use predominantly small farming and ranching or suburban residential. The reservoir is capped by 470 m (1,550 ft) of Jackson Group shales and sands. Confining units totaling nearly 600 m (2,000 ft) separate the seal from potential USDW in the Jasper, Evangeline, and Chicot aquifers.

Wells and Faults

Numerous abandoned oil and gas exploration and production wells that penetrate the Hillebrenner dot the Fulshear area as shown in Figure 3. The Fulshear fault that forms the gas-storage reservoir trap is attenuated in the clayey Jackson Group less than 600 m (2,000 ft) above the Hillebrenner Sand and is a sealing feature.

Potential Impacts to Compartments

The natural gas of the Fulshear gas storage facility will be directly impacted by CO_2 injection through brine displacement. Because the Fulshear gas storage reservoir is part of the proposed CO_2 storage region, the impact of CO_2 on the natural gas would not be due to leakage by definition and therefore such impact does not contribute to risk from the point of view of the CF. The Jasper Aquifer lies approximately 1,000 m (3,300 ft) above the Fulshear CO_2 sequestration target, with the Evangeline, and Chicot Aquifers at shallower depths. These three Gulf Coast aquifers in the vicinity of the Fulshear reservoir have a TDS <10,000 mg/L and as such are part of the USDW compartment.

Reservoir Simulation

For this case study, the model scenario includes 30 yrs of injection followed by plume migration for 1,000 yrs. Simulations of the injection scenario suggest the CO_2 plume will travel 2.6 km (1.6 mi) radially away from the well after 30 yrs of injection, and slowly up-dip under gravity after injection stops such that after a total time of 100 yrs, the up-dip plume extent is 2.8 km (1.7 mi) from the injection well (Figure 3).

Probability of Plume Intersection with Wells and Faults

Because of the numerous wells in the Fulshear area, there is a very high probability (~100%) that the CO_2 injection plume will encounter at least one well in 30 years of injection. The pressure at the well when the plume reaches it is predicted by the model to be 3.5 MPa (510 psi) above hydrostatic.

Well leakage model

For risk assessment purposes, we consider the possibility of well leakage by defining three non-zero effective permeabilities that likely span the range of possible conductivities for wells with highly degraded cement (e.g., 100 md (10^{-13} m^2) and 1000 μd (10^{-15} m^2)) to intact cement (10 μd (10^{-17} m^2)). The leakage model we use is a simple one-dimensional single-phase model that includes the possibility of flow into the surrounding formation. The highest leakage rate calculated is approximately 10^{-4}% of the injection rate, while the lowest is 10^{-8}%.

Modeled Impacts to Compartments

There are no identified vulnerable hydrocarbon resources, therefore the probability of impact to HMR is zero. If there is a clay or cement backfill blocking an open section of the well that reaches USDW, the well leakage flux would enter the aquifers. The well-flow model predicts a range of CO_2 fluxes into the aquifers at the site from 3.6×10^{-3} kg m^{-2} s^{-1} to 3.6×10^{-7} kg m^{-2} s^{-1}. If we multiply these fluxes by the area of the well of 10 cm (4 in) diameter, we obtain a range of flow rates from 2.8×10^{-5} kg s^{-1} (2.4 kg day^{-1}) to 2.8×10^{-9} kg s^{-1} (2.4×10^{-4} kg day^{-1}). At standard conditions of 1 bar and 20 °C, these flow rates are approximately 1.5 m^3 day^{-1} (53 ft^3 day^{-1}) and 0.00015 m^3 day^{-1} (0.0053 ft^3 day^{-1}). In the absence of a regulatory upper limit on CO_2 flux into an aquifer, we can compare these flow rates to the pumping rates of the municipal wells (~1,000 gpm or 5,000 m^3 day^{-1}) and speculate that the calculated flow rates are small enough as to be tolerable.

Assuming the well extends to the ground surface, the fluxes predicted by the well-flow model are 1–10,000 times a typical ecological flux. Focusing only on the high end of the predicted CO_2 flux, and assuming this flux is averaged over one hectare by wind dispersion at the surface, we obtain a flux equal to a typical ecological flux which is small enough to be difficult to detect [5]. If such a leaking well discharged directly into a basement or building, CO_2 concentrations could become hazardous if not ventilated. The local building style and density, land-use history, and knowledge of abandoned wells in the area argue that such a scenario is highly unlikely. As for the environment (NSE compartment), potential impact could occur locally near the well as CO_2 migrates upward and is emitted near the ground surface. If the CO_2 were emitted just below the ground surface, concentrations could build up to high levels in the soil even if the flux is small [6].

If the CO_2 were emitted into a surface water body (e.g., creek or wetland) with depth less than 0.6 m (2 ft), the larger fluxes would be transported upward through the water column as bubbles and emanate from the surface [7]. Such shallow water bodies are well mixed by wind or currents and thus we expect rapid equilibration with the atmosphere and no possibility of buildup of dense CO_2-charged water at depth.

Finally, impact to the ECA compartment from the highest probable well leakage rate is negligible. First on the emission credits side, the largest leakage rate calculated here is 2.8×10^{-5} kg s^{-1} (2.4 kg day^{-1}) assuming leakage is over the entire diameter of the well. Compared to the CO_2 injection rate of 0.8 Mt yr^{-1} (25 kg s^{-1} or 2,200 t day^{-1}), the leakage rate is approximately 10^{-4}% (one part per million) of the injection rate.

CO_2 Leakage Risk--Effective Trapping

Effective trapping is calculated in the CF in terms of CO_2 leakage risk (CLR) which is the product of impact and probability of occurrence of the processes leading to that impact. As discussed above, the impact driver appears to be the NSE compartment, and the environment local to the well in the case that CO_2 leaks up the well into the shallow subsurface in particular. This finding suggests monitoring and/or remediation of abandoned wells should be undertaken to reduce the CLR and ensure effective trapping.

3.2. WESTCARB's Kimberlina Phase III Pilot

Introduction

The Kimberlina site is located in the southern San Joaquin Valley. The target storage reservoir is the Vedder Formation at a depth of 2,300 m (7,500 ft) with a thickness up to 160 m (520 ft), temperature of approximately 80°C (176 °F), and pressure of approximately 220 bars (Table 1). The Vedder sands and shales are overlain by a thick, low-permeability formation called the Freeman-Jewett Formation intended to serve as the caprock seal to prevent upward migration of buoyant CO_2. The pilot plan is to inject 250,000 metric tonnes (t) CO_2/yr, sourced from the planned 50 MW Kimberlina power plant, for four years into the Vedder Formation. The proposed storage region is the southwest-dipping (7°) Vedder Formation extending outward 10 km (6 mi) radially from the well with the Freeman-Jewett as the caprock (100 m (330 ft) thick).

Surface and Subsurface Description

The surface environment in the Kimberlina area consists of flat, sparsely populated agricultural land approximately 30 km (18 mi) northwest of Bakersfield, California (Figure 3b). Freshwater (total dissolved solids (TDS) <2,000 mg/L extends to a depth of approximately 750 m (2,450 ft), quite deep for groundwater production, but shallow relative to the Vedder at 2,300 m (7,500 ft). The depth of the 10,000 mg/L isohaline is estimated to be around 1,300 m (4,300 ft), 1 km (3,300 ft) shallower than the proposed pilot injection horizon.

Wells and Faults

The lithologic section at the Kimberlina site has been penetrated by wildcat oil and gas wells. The closest exploration wells to the power plant site do not penetrate to the depths of the Vedder. The nearest exploration well that penetrates to the Vedder is to the northeast of the power plant, approximately 2.5 km (1.5 mi) away, farther than the CO_2 plume is predicted to migrate.

Because of the lack of available geologic and geophysical data, details of faults are not available for Kimberlina. Fault orientations, lengths, and throws (vertical offsets) of 956 fault segments were measured from California Division of Oil, Gas, and Geothermal Resources structure maps of surrounding oil fields. The primary orientation of faults in the Kimberlina region is north to northwest. The density of faults large enough to offset the Freeman-Jewett caprock (100 m (330 ft)), is estimated to be 0.03 km/km^2 (0.05 mi/mi^2). This means that statistically we expect a 30 m length of fault of this size per square kilometer of area.

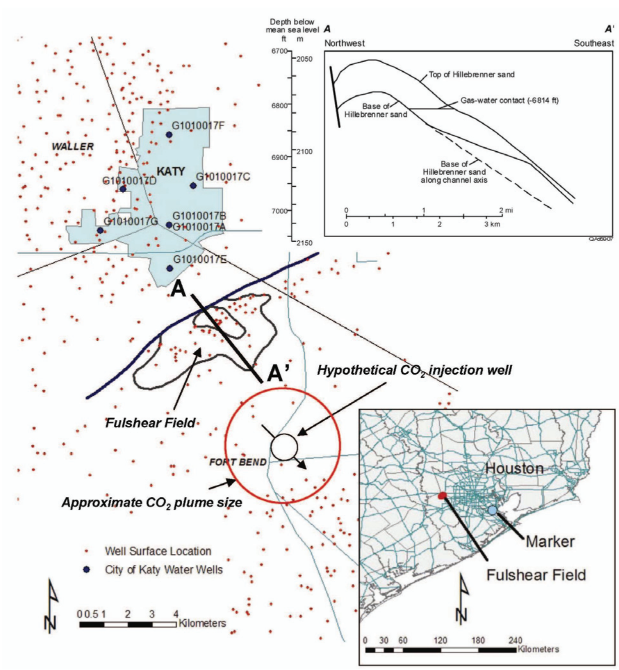
Reservoir Modeling

Reservoir modeling with TOUGH2 and CMG-GEM suggests the CO_2 plume will have a generally oval footprint, and migrate up dip to the northeast approximately 600 m (2,000 ft) after four years of injection and extend a total length of less than 1.5 km (5,000 ft) by a total width of 1 km (3,300 ft) after hundreds of years. Residual phase trapping is expected to be significant, leaving the plume essentially immobile after 20 years.

Application of the CF

Using site characterization results along with model predictions as inputs to the CF, we compute the expected behavior of the CO_2 and displaced brine and their potential for impacting the environment, resources, health, and safety. There are no known wells within the predicted CO_2 plume footprint that penetrate to the Vedder. There is a chance that the plume will intersect faults that could be large enough to be a concern. Due to the lithology, we expect that most such faults will have a relatively low permeability. Therefore, we consider it improbable (less than 1% chance) that CO_2 will leak up a fault out of the storage region. As for displaced brine migration, it is very likely that the pressure pulse from CO_2 injection will extend to nearby wells and faults that penetrate to the depth of the Vedder. However, we consider it unlikely that brine will migrate upward any significant distance to impact compartments along either wells or faults in the area. Overall, we conclude that the risks to HMR, USDW, NSE, HS, and ECA compartments due to CO_2 or brine leakage are de minimis. To reduce uncertainty in this preliminary assessment, future work could be directed toward additional data gathering, e.g., on faulting in the area of the injection well.

(a) Texas Gulf Coast Case Study



(b) California San Joaquin Valley Case Study

Figure 3. (a) Location map of a hypothetical GCS project in the Texas Gulf Coast showing oil and gas wells (small red dots), water wells, Fulshear gas reservoir, and injection well in the water leg of the Hillebrenner Sand. Upper inset shows cross section through the Fulshear gas reservoir showing growth fault, gas cap, and down-dip water leg. Note vertical exaggeration; dip of the Hillebrenner is approximately 1° to the southeast. (b) Location of the Kimberlina site with prediction of footprint of the CO_2 plume from TOUGH2 numerical model along with nearby wildcat wells.

4. Conclusions

We have developed the CF approach for risk assessment of GCS sites based on the concept of effective trapping, which allows for potential leakage of CO_2 or brine provided the associated risk is below agreed-upon thresholds. We have applied the CF to two case studies to demonstrate the approach and refine CF methods.

5. Acknowledgments

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