Assessment of oil and gas fields in California as potential CO_2 storage sites

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Abstract

California's total annual greenhouse gas (GHG) emissions (425.3 $MtCO_2e$) in 2018 were about 6.4 % of the US total (6,677 $MtCO_2e$) and around 1 % of global emissions. About 39% of 2018 GHG emissions in California were from the industrial and electrical sectors. Many of these emissions were from large stationary point sources and were suitable for carbon capture retrofit with subsequent storage of the captured carbon dioxide (CO_2) in geological formations. Previous studies of California found suitable geology and CO_2 storage resource. This study refines and furthers prior work using a three-stage screening process of oil fields, gas fields, and underground natural gas storage (UGS) sites by combining criteria from previous studies while excluding sites that pose technical risk or are located in regions with surface restrictions including sensitive habitats and dense populations. In the first stage, 129 CO_2 storage sites in California were identified using qualification criteria based upon formation properties including geological conditions and pore pressure. The second stage identifies sensitive sites by applying conservative screens including seismic activity, faulting, population density, restricted lands, and

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sensitive habitats. During the third stage, 61 CO_2 potential storage sites were identified by subtraction of stage 2 areas from stage 1. The potential storage volume in the third stage ranged from 1.0 to 2.0 $GtCO_2$. Finally, we applied a scoring system with seven parameters to rank the 61 potential sites based on subsurface technical criteria. The scored sites are classified as high priority, medium priority, and sites for future study. Prospective CO_2 storage sites with high and moderate priority were selected and linked to CO_2 sources. There are 14 prospective sites (above 20 $MtCO_2$ storage resource per site) with a total storage resource of 1081 $MtCO_2$ distributed in Northern and Southern California. Of these sites, there are 9 potential CO_2-EOR sites and 1 depleted oil field with a total estimated CO_2 storage volume of ~800 $MtCO_2$ in the Southern San Joaquin and Ventura Basin. These 10 prospective sites with a storage resource greater than 20 $MtCO_2$ could potentially deliver more than 20 years of storage with an average injection rate of 40 $MtCO_2$/year. The remaining 4 highly prospective sites are in Northern California. Study results also suggest that saline formations should be re-evaluated in concert with storage in oil, gas, and natural gas storage reservoirs.

Keywords: Carbon storage, geological formations, screening parameters, scoring system, CO_2-EOR

Introduction

The California Air Resources Board (CARB) reports annual emissions from greenhouse gas (GHG) generating activities statewide in 2018 of 425.3 million metric tonnes (Mt) of carbon dioxide (CO_2) equivalent ($MtCO_2e$) (CARB, 2020). This amount is similar to 2017 levels and is 6 $MtCO_2e$ below the 2020 GHG target limit of 431 $MtCO_2e$ for California (CARB, 2019, 2020a). Among GHG emissions, CO_2 makes up about 81 % of the total in the US (U.S. EPA, 2020a). California GHG emissions were around 6.4 % of the US total of 6,677 $MtCO_2e$ in 2018 (U.S. EPA, 2020a). California contributes to about 1 % of global emissions. Figure 1 shows the distribution of all GHG emissions in California by economic sector-including transportation, industrial, electricity, commercial, and so on in 2018 expressed as CO_2 equivalent to account for the differing global warming potentials among GHG (CARB, 2020).

Industrial and electricity sector GHG emissions tend to occur from relatively large point sources. Hence, we focus on these two sectors that account for 39% or 166 $MtCO_2e$/year of emissions. Solutions to reduce emissions or capture emissions from these sources are important to meeting California's climate goals in a timely and cost-effective manner (EFI and Stanford, 2020). Emissions reduction technology scenarios, include efficiency, deployment of renewables, and carbon capture utilization and storage (CCUS) (IEA, 2019). The categories are not mutually exclusive and approaches may work in concert.

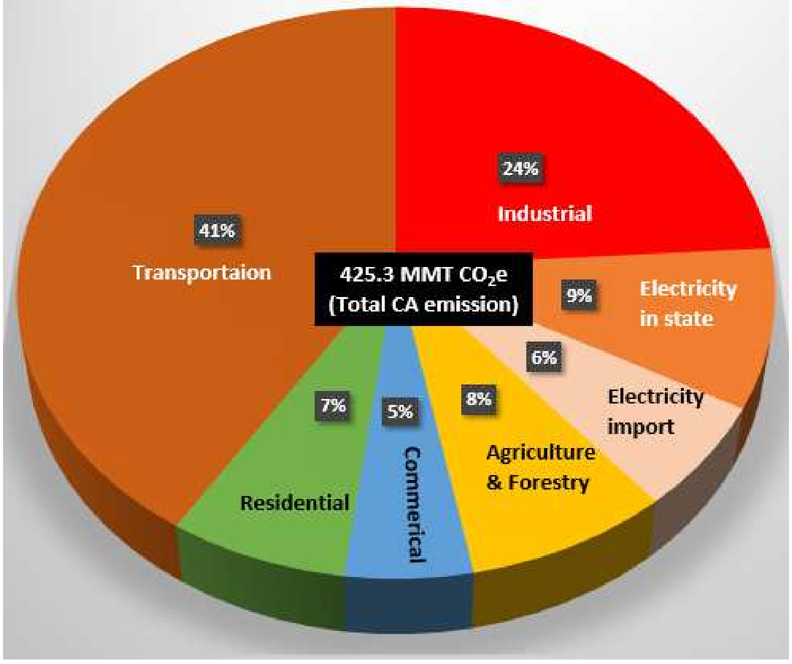


Fig. 1. California greenhouse gas (GHG) emission in 2018 by economic sector expressed as CO_2 equivalent (CARB, 2020).

Accordingly, carbon storage is an important option to reduce CO_2 emissions. State-specific estimates and site identification are critically important for further assessment of available carbon mitigation options. Our objective is to add certainty to estimates of the CO_2 storage potential of hydrocarbon-bearing formations and underground gas storage (UGS) sites in California. We note that saline formations were found to have much greater CO_2 storage potential. A previous study (NETL, 2015a) assessed the storage resource in California as 147.6 $GtCO_2$ (mean) in saline formation whereas hydrocarbon fields and UGS were assessed as 4.85 $GtCO_2$ (mean). While smaller in magnitude, this study places its focus on oil, gas, and UGS sites because these geological settings possess multiple $GtCO_2$ of potential storage and in many cases existing infrastructure and detailed geological data. Likewise, CO_2 injection wells are classified based on injector type by the EPA underground injection control (UIC) program. Class II wells apply to active hydrocarbon fields and Class VI wells to saline reservoirs or depleted oil and gas fields. Class II wells are regulated by the California Geologic Energy Management Division and typically take around 3 months to obtain a permit, whereas Class VI wells are regulated by the EPA. To date, only 2 Class VI permits have been issued in the U.S. and the wait time was over 3 years (Greenberg et al., 2017). Unlike North Dakota and Wyoming, California has not applied for primacy of Class VI well permitting.

Previous studies of CO_2 storage resource in California examined oil and gas fields as well as saline formations (Downey and Clinkenbeard, 2011; USGS, 2013; NETL, 2015a, b; Teletzke et al., 2018; Baker et al., 2020). Additional attention was paid to underground natural gas storage facilities (UGS) (NETL, 2015a; Long et al., 2018; Baker et al., 2020). Figure 2 shows the geographic distribution of identified CO_2 storage sites. The NETL (2015a) studies estimated storage resource to be 3.6 – 6.6 $GtCO_2$ for oil, gas, and UGS sites combined. The method of estimating storage resource was addressed thoroughly in Goodman et al., (2011), as summarized next. The production approach was utilized for oil and gas storage where production data was available. The volumetric approach used for storage formations when production data was not available. Another analysis (Baker et al., 2020) studied selected saline formations and oil/gas/UGS fields in the Sacramento and southern San Joaquin basins using publicly accessible data. Their conservative estimates for hydrocarbon and saline reservoir capacity within the Sacramento and Southern San Joaquin basin are 3 $GtCO_2$ and 14 $GtCO_2$, respectively. This is equivalent to 170 years of storage assuming an injection rate of 100 $MtCO_2$ per year. Therefore, carbon storage with captured CO_2 from large emitters may be a significant contributor to accomplish California decarbonization (IEA, 2019).

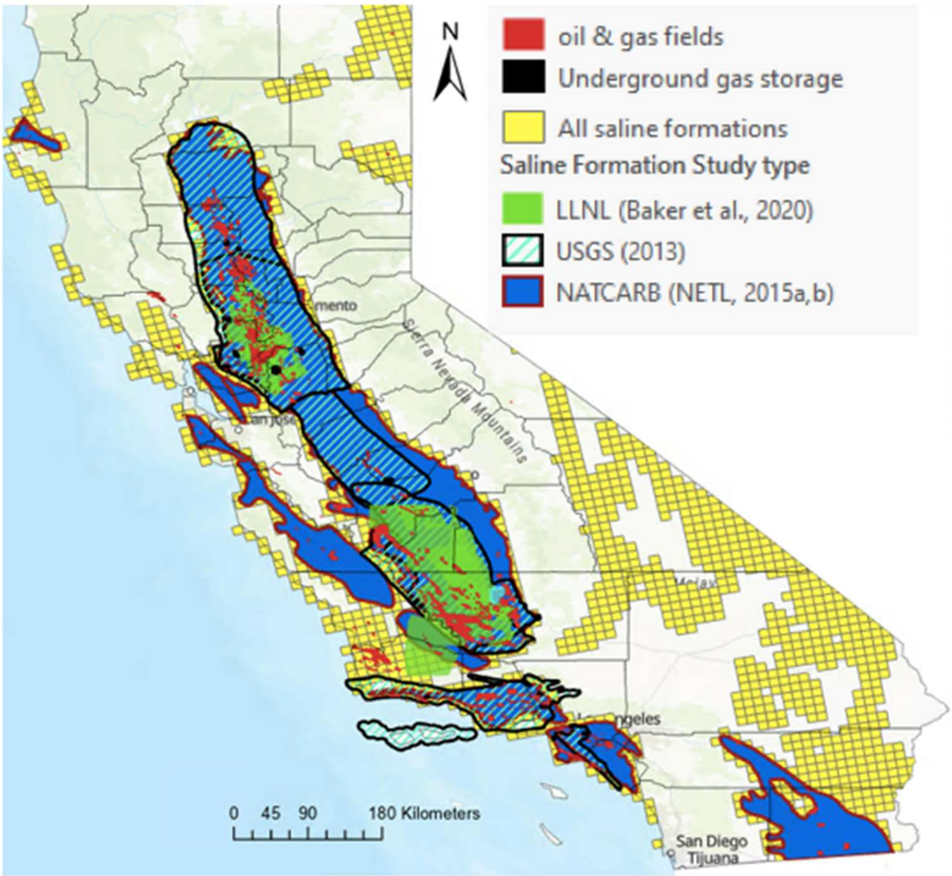


Fig. 2. CO_2 storage sites in California identified during previous studies including hydrocarbon and saline reservoirs (USGS (2013); NETL (2015a, b); Baker et al., (2020)). The colors indicate areas studied by different organizations. NATCARB (NETL, 2015a, b) defined all saline formations with 10 km by 10 km grids (yellow color) and estimated CO_2 storage resource of specific areas shown in blue color among these yellow areas.

There are two significant financial incentives for CO_2 storage in geological formations in California: federal section 45Q tax credits and California low carbon fuel standard (LCFS) credits (CARB, 2018; EFI and Stanford University, 2020; US EPA, 2016). These credits may mobilize carbon storage projects due to their economic benefits. The 45Q tax credit encourages storage of CO_2 from any anthropogenic source in saline formations, depleted oil and gas fields, and CO_2-EOR sites. The captured CO_2 from certain industrial facilities, power plants or direct air capture projects that meet certain criteria are eligible for the credit. The current credit for saline reservoirs and CO_2-EOR are \$34 and \$22 per tonne CO_2, respectively. The maximum credit will be increased to \$50 and \$35 per tonne for saline reservoirs and CO_2-EOR, respectively, in 2026. Thereafter, the credit will be inflation adjusted. There are limitations, however. The capture amount must meet or exceed 0.1 $MtCO_2$/year for industrial facilities and 0.5 $MtCO_2$/year for powerplants. Projects are only eligible for 12 years for the 45Q credit and construction needs to start prior to Jan. 1, 2026.

The LCFS establishes a credit market for transportation fuels in which regulated parties—importers or refiners of gasoline, diesel, and substitutes for those fuels—earn credits for producing cleaner fuels that are below the annual carbon intensity threshold. Parties can claim credits for 1) decarbonizing the upstream supply chain, 2) using renewable energy or renewable hydrocarbons for energy, 3) reducing the complexity or energy use of a refinery, 4) production of renewable hydrogen, and 5) direct air capture with CCS. The credit applies to fuel of any origin that is ultimately sold in California. LCFS and 45Q Credits can be combined as long as the requirements for each are fulfilled. For example, an ethanol plant can qualify for both credits when CO_2 is captured and sent to underground storage. The common requirement of 45Q and LCFS is that both credits require secure permanent storage and detailed and extensive monitoring plans.

This paper proceeds with a very brief basin-to-basin overview of the geology of CO_2 storage sites in California. Then, both a three-stage screening procedure and a scoring system are illustrated in detail, and results are discussed. The scoring system is shown to be relatively simple to implement, but powerful and easy to refine so that it can be replicated elsewhere. We clarify prospective CO_2 storage amounts in hydrocarbon and UGS sites in both Northern and Southern California. The importance of further work on saline formations in California is emphasized. In this way, we advance toward our goal of adding certainty to estimates of CO_2 storage potential in California and identification of potentially acceptable sites.

Method

The method consisted of identifying suitable geological repositories and identifying potential hazards or surface access limitations. Then, the screening procedure was applied. To the greatest extent, existing data were compiled and used. Additionally, a summary of large CO_2 emitters was obtained from a previous study by EFI and Stanford (2020).

Geological overview

Previous studies of California's geology are extensive (Meyer et al., 2007). The subsurface in California has thick sedimentary fill with multiple, and sometimes stacked, porous and permeable aquifers/hydrocarbon reservoirs and laterally thick persistent marine shale seals. From an operational point of view, California has abundant geological, petrophysical, and fluid data from over a century of oil and gas operations as well as numerous depleted or mature oil and gas fields that may be reactivated for CO_2 storage and operated for CO_2 enhanced oil recovery

(EOR). In particular, previous studies found 53 potential candidate sites for CO_2-EOR (ARI, 2005).

Geology varies from basin to basin. Figure 3 shows schematic cross sections across the important basins including southern Sacramento, San Joaquin, and Ventura. The shale layers (gray shading) function as seals and are well developed with thick and substantial areal extent over potential CO_2 storage sandstone formations (yellow shading). Generally, oil and gas reservoirs have low-permeability layers (seals) below which buoyant fluids are retained over geological time scales if there was no damage by oil field operations or seismic activity (Orr, 2018). Clearly, some oil and gas fields in California are suitable to store CO_2.

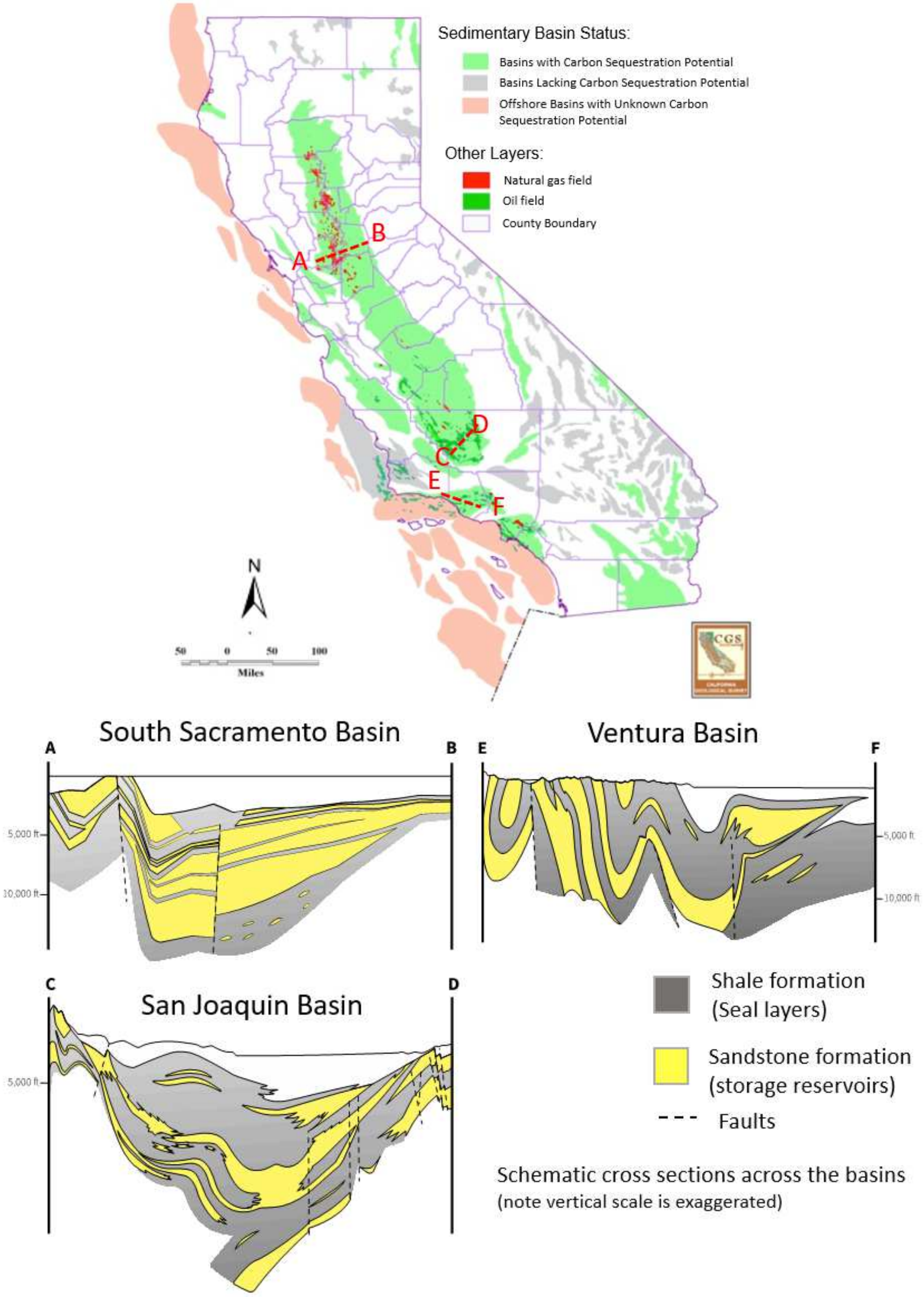


Fig. 3. Geological cross sections for specific areas (modified from WESTCARB, 2013; EFI and Stanford University, 2020). Reservoir seals are indicated in grey and storage formations in yellow. Offshore basins are shown but not analyzed here.

Screening

The three-stage process to evaluate CO_2 storage sites used input from the NETL (2015a, b) study of oil and gas fields in California as a baseline. The screening procedure to select potential CO_2 storage sites is summarized in Figure 4. Stage 1 produces a list of qualified sites from among candidate reservoirs. Stage 2 develops exclusion zones resulting from surface activities. Stage 3 applies exclusion zones and selects sites with a ratio of excluded to surface area less than 0.75.

In stage 1, all active and depleted oil and gas fields and underground storage sites in California (total 516 fields) were screened using existing public data. The qualifying conditions were established with specific thresholds and were based on LCFS and EPA class VI minimum siting criteria requirements. Table 1 shows the qualifying conditions applied in this study for qualified CO_2 storage sites. Seven screening parameters were selected: storage resource, depth of top formation, porosity, permeability, reservoir thickness, brine salinity, and pore pressure. The qualifying thresholds were applied site by site.

The minimum siting criteria for EPA VI wells and LCFS CCS projects (see Table 1, U.S. EPA, 2016; CARB, 2018) include broad criteria and use the term ‘sufficient’ when describing reservoir characteristics, except brine salinity that must be greater than 10,000 ppm (see Table 1). Brine with a concentration less than 10,000 ppm of total dissolved solids (TDS) may become usable for drinking or agriculture purposes with proper treatment. Therefore, in this study, this salinity criterion was applied selectively to dry gas fields and UGS sites. It was not applied to active oil fields because the water from crude oil fields may contain dissolved hydrocarbons and chemicals. Oil field water is typically not suitable to use for drinking or for agricultural purposes without significant treatment. In this way, the brine salinity criterion was relaxed for oil fields.

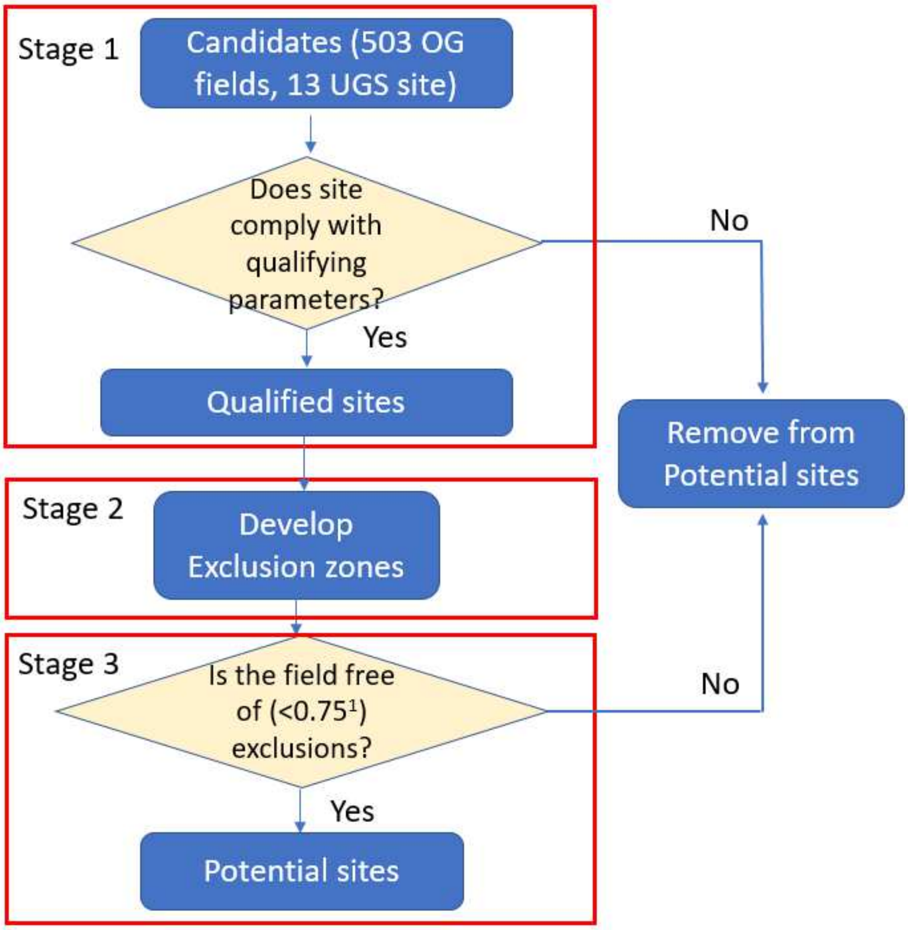


Fig. 4. The three-stage screening procedure to select potential CO_2 storage formations from oil, gas, and UGS sites.[1]

A potential storage site was selected in Stage 3 if the ratio of all exclusion zones upon the field area was less than 0.75.

Initially, the NATCARB (2015a) high-side estimate of CO_2 storage resource in an individual oil, gas, or UGS field was applied for screening. A value of storage resource greater than 3 $MtCO_2$ (high resource estimate) per field was chosen to exclude smaller volume sites that might have limited project life. For instance, long-term projects might last 30 years, have an injection rate of at least 0.1 $MtCO_2$/year, and thereby store 3 $MtCO_2$ over the project life. Hence, the threshold of 3 $MtCO_2$ was developed. Additionally, offshore sites were eliminated because they are not eligible for the LCFS credit.

To apply other criteria, field properties were compiled from the National Carbon Sequestration Database (NATCARB) (NETL 2015b), California Council on Science and Technology report (Long et al., 2019), and California Division of Oil, Gas and California Geothermal Resources (CA DOGGR, 1982, 1992, 1998). The criteria for the depth of the top of the formation was taken to be a depth where CO_2 is likely to exist in a dense supercritical state (temperature > 31 °C and pressure > 7.4 MPa (1015 psi)). We consider the depth of the top of the formation as the minimum injection depth in each field. Therefore, the threshold condition for the depth of the top formation was 800 m (Bachu et al., 2007; CARB, 2018).

The combination of porosity, permeability, reservoir thickness, and pore pressure are related to injectivity from an operational point of view. The qualifying thresholds of porosity and permeability are mean values greater than 10 % and 10 mD, respectively. The threshold of porosity is identical to other studies (Bachu et al., 2007; Ramirez et al., 2010). Previous studies provided differing thresholds of permeability, from 5 to 20 mD, depending on whether the reservoir is a CO_2-EOR candidate (Sun et al., 2018) or saline formation (IEA GHG, 2009). Additionally, the CO_2 injection project at In Salah (Ringrose et al., 2009) stored 2.5 $MtCO_2$ for 5 years into a saline formation that has 15 % porosity and 10 mD permeability. This project was challenged because CO_2 injection stimulated natural fractures and may have introduced new hydraulic fractures; this experience informs the suitable lower limit on permeability and the allowable pressure buildup of the injection zone (Ringrose 2009). Therefore, a 10 mD threshold in permeability is applicable depending on desired injection rate. Reservoir zones greater than 3 m thick when composed of a single layer are allowed or stacked layers with a total sum of at least 10 m of reservoir thickness are allowed. The threshold of reservoir thickness, 10 m, is identical to Ramirez et al. (2010). In particular, pore pressure and the rate of injectivity are related to pressure buildup that is a critical factor for implementation (Anderson and Jahediesfanjani, 2019).

Regarding sufficient injection pressure (pore pressure), reservoirs with initial pressures above 5000 psi (34.47 MPa) or with current pressure above 4000 psi (27.58 MPa) were disqualified in stage 1. Based on a hydrostatic gradient of 9.79 kPa/m for freshwater (Schlumberger, 2021), 34.47 MPa is equal to 3.5 km depth. Ramirez et al. (2010) also discussed the initial pressure in relation to preventing overpressure as one of their prescreening parameters. They stated that drilling cost increased exponentially greater than 3 km depth (Ramirez, et al., 2010). With large formation pressure, it is also difficult to develop sufficient injection pressure for meaningful injection rates. Injection and pore pressure screening criteria presented in Table 1 need to be extended to injectivity in subsequent site-specific studies. Importantly, the injection pressure cannot be exceeded 90 % of the fracture pressure of a storage formation as per EPA Class VI well regulations (U.S. EPA, 2016).

Stage 2 developed exclusion zones to account for risks such as seismicity and faults, relatively dense urban areas, restricted land ownership, and sensitive wildlife habitats. Here, restricted land refers to a geographical area where it might be difficult to store CO_2 due to social and environmental concerns. For instance, national and state parks were considered to be restricted land. The exclusion zone concept thereby identifies areas where development of CO_2 storage sites may be possible as well as areas that are currently deemed not acceptable for a variety of reasons. These ideas of site identification and establishment of excluded areas were implemented in ArcGIS Pro Version 2.6.

Table 1 Qualifying criteria for storage sites.

Category	**Criteria**	**Qualifying Threshold in this study**	**EPA Class VI well Minimum site Criteria**	**LCFS-CCS siting Minimum Criteria**	**Disqualified sites in this study**
Screening parameters	Storage resource (high estimate)	> 3 $MtCO_2$	Sufficient areal extent	Sufficient volume	306 fields
	Depth (to top of formation)	> 800 m		> 800 m	12 sites
	Salinity	> 10,000 TDS (applied to dry gas fields and UGS)	> 10,000 TDS (all well)		10 sites
	Permeability	> 10 mD (mean)	Sufficient permeability	Sufficient permeability	2 sites
	Porosity	> 10 % (mean)	Sufficient porosity	Sufficient porosity	-
	Reservoir Thickness	> 3 m (one layer) or sum of layers > 10 m	Sufficient thickness	Sufficient thickness	2 sites
	Pore Pressure (Injection pressure)	Any data suggests that the reservoir pressure meets the following conditions (initial reservoir pressure < 34.47 MPa (5000 PSI) or current reservoir pressure < 27.58 MPa (4000 PSI))	Injection pressure does not exceed 90 % fracture pressure of the injection zone	Sufficient injectivity	1 site

*additional 54 eliminated sites: 50 sites (insufficient data) and 4 sites (offshore sites)

In stage 3, potential CO_2 storage sites were identified through overlaying exclusion zone and storage site data in ArcGIS. Potential storage sites were identified by subtraction of excluded areas from storage sites identified in stage 1 that met the qualifying criteria. Finally, the potential storage site was selected if the ratio of all exclusion zones upon field area was less than 0.75. These potential storage sites were evaluated using a scoring system to classify and prioritize optimal storage sites.

Scoring system for potential sites

Storage site selection is important to optimize technoeconomics and mitigate unintended CO_2 migration. We propose a scoring system for oil, gas, and UGS sites as an initial step in high grading optimal storage sites from potential sites. Table 2 displays 7 parameters to be scored from 1 to 5 with a total possible score of 35 per site. The best score is 5 and the worst-case score is 1 for each parameter. We adopted this scoring system from the earlier work of Callas (2020). The threshold of five parameters (storage resource, porosity, permeability, reservoir thickness, and depth to the top of the formation) is directly applied from the qualifying criteria (see Table 1). We binned storage reservoirs based on total score as high priority (high score) for consideration (≥28), moderate priority (medium score, 23- 27), and future sites (low score) to consider (≤22). Fields receiving a score greater than '23' score were defined as 'prospective sites'. In fact, all of these sites passed extensive screening and have desirable qualities for storage.

Storage resource size is the key quality for each site. For example, a storage resource greater than 50 $MtCO_2$ scores a '5' and a storage resource of 3 to 5 $MtCO_2$ scores a '1'. Additionally, greater porosity and reservoir thickness receive higher scores because the product of porosity and thickness is proportional to storage resource. The threshold of porosity and reservoir thickness are 10 % and 3 m, respectively as discussed above. Porosity above 30 % receives the maximum score, '5'.

Table 2 Scoring criteria based on subsurface properties.

Parameter	**J =1 (least)**	**J =2**	**J =3**	**J =4**	**J =5 (best)**
Storage Resource (high estimate)	3-5 $MtCO_2$	5-10 $MtCO_2$	10-30 $MtCO_2$	30-50 $MtCO_2$	>50 $MtCO_2$
Bottom Seal	No seal				Yes-Seal
Depth of Top of Formation	800-1000 m	Deep (>3,000 m)	1,000-1,500 m	2,000-3,000 m	1,500-2,000 m
Permeability (mean)	10-20 mD	20-50 mD	>500 mD	50-100 mD	100-500 mD
Porosity (mean)	10-15 %	15-20 %	20-25 %	25-30 %	>30 %
Reservoir Thickness	3-20 m	20-50 m	50-100 m	100-300 m	>300 m
Geothermal Gradient (Geothermal favorability)	Warm Basin (>40 °C/km) Class1		Moderate (20-40 °C /km) (Class 2, 3, 4)		Cold Basin (<20 °C /km) (Class 5)

For depth to the top of the formation and permeability, we chose the optimal case based on the best score shown in Table 2. For example, we chose the permeability range of '100 – 500 mD' for the best store instead of 'above 500 mD'. Greater permeability provides for greater injectivity and faster plume transport, but relatively high permeability could be an issue in the event of unintended CO_2 migration. (Juanes et al., 2006; Doughty et al., 2010; Han et al., 2010). Some studies suggest the optimal depth to the top of the CO_2 storage formation should be greater than 1.2-1.3 km in the case of structural trapping because parameters including density of CO_2, the density difference between CO_2 and brine, and wettability with these depths shows optimal and secure storage of CO_2 (Miocic et al., 2016; Iglauer, 2018). Another study suggested an optimal depth to the top of formation to range from 1 km to 2.5 km (Smith et al., 2012) for CO_2 storage. Therefore, we assign a score of 5 to depths of '1.5 – 2 km'. As we discussed above, drilling costs increase exponentially for depths greater than 3 km (Ramirez, et al., 2010).

The geothermal gradient was obtained using two methods. In one case, the gradient was directly calculated using the average depth and temperature of each formation (CA DOGGR, 1982, 1992, 1998). In the second case, the gradient was obtained using geothermal-energy-favorability data (i.e., the Geothermal Prospector) from NREL (2011). The geothermal gradients calculated using both methods were essentially the same. A smaller geothermal gradient is preferred as the density of CO_2 increases with decreased temperature and solubility of CO_2 in brine is increased. Colder basins with a thermal gradient less than 20 °C/km received the best score.

Selection of CO_2 emitters

Large emitters of CO_2, including industrial facilities and natural gas fired powerplants were identified in an earlier study (EFI and Stanford, 2020). Among industrial sources, they classified five types of emitters including~~,~~ cement, combined heat and power (CHP), ethanol, hydrogen, and petroleum refinery (FCCU). In this study, industrial sources with emissions greater than 0.1 $MtCO_2e$/year were selected for CCS retrofit due to the threshold capture amount for 45Q credits.

Additional effort for ethanol plants may confirm the number of candidate ethanol plants (RFA, 2021; Edwards and Celia, 2018). The GHG emission data were averaged over 2018 and 2019 using the CARB Pollution Mapping Tool (CARB, 2021), EPA GHGRP Flight database (U.S. EPA, 2020b, 2021a), and RFA (2021). Emissions data from 2020 does not reflect historical trends due to the COVID-19 pandemic and resulting short-term changes in energy consumption. Hence, 2020 data was not used.

Electricity production from natural gas combined cycle powerplants is currently a significant source of CO_2 emissions in California. Natural gas (NG) powerplants that have a capacity 250 MW or greater and were constructed after 2000 were selected as potential sources. The average GHG emissions from 2018 to 2019 were used (U.S. EPA, 2020c, 2021b).

Results

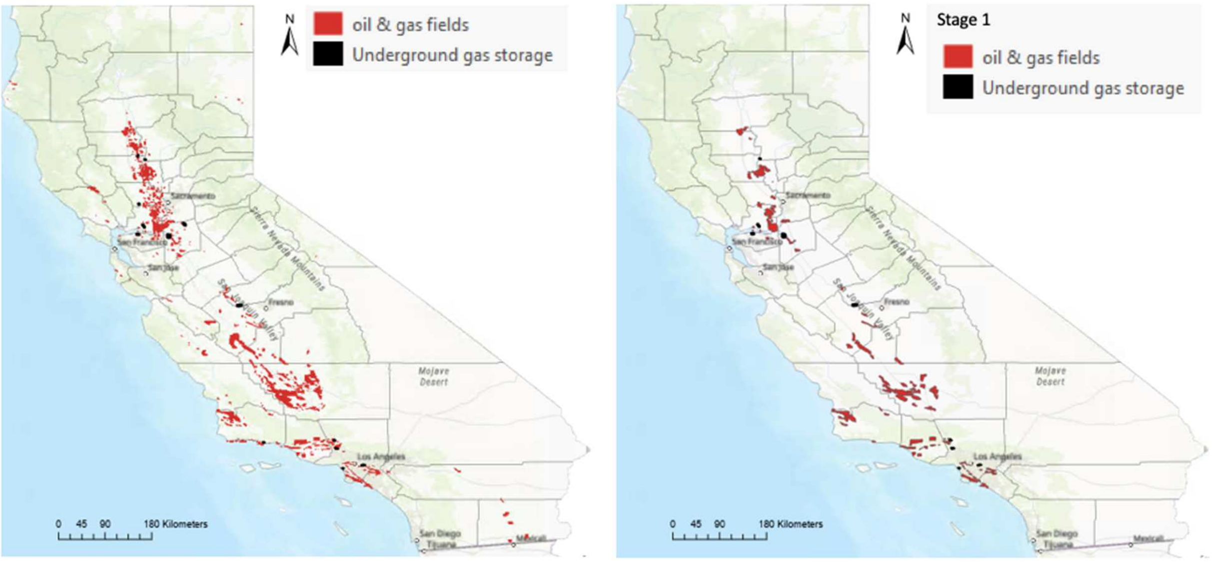
In this section, we show the result of each stage and discuss the number of sites passing through each stage. Geospatial analysis was used to select and visualize the various potential storage sites after the consideration of exclusion zones. The scoring system high graded these prospective storage sites based on specific technical aspects. The most prospective storage sites are discussed for Northern and Southern California due to their proximity to emission sources.

Stage 1: Qualification of CO_2 storage sites

California has 516 oil, gas, and UGS fields in 4 different geographical districts (Northern, Inland, Coastal, Southern district) (CA DOC, 2020). There are 13 UGS sites (Long et al., 2018) and the remaining 503 sites are active or depleted oil and gas fields. NATCARB estimated the cumulative CO_2 storage as 3.6 – 6.6 $GtCO_2$ for the 485 fields with available data among the 516 fields in California (NETL, 2015a).

The number of fields disqualified by applying each criterion are shown in Table 1. The ordering in Table 1 illustrates how the criteria were applied from top to bottom. As a first step, the storage resource of CO_2 (NETL, 2015b) was assessed and 306 sites were disqualified because their individual storage resource was less than 3 Mt. The criterion of sufficient storage resource is the main reason to qualify CO_2 storage sites in this study. Second, 12 sites were eliminated because they are too shallow. Third, the criterion for salinity eliminated an additional 9 dry gas fields and 1 UGS site. Other criteria (permeability, porosity, reservoir thickness, and pore pressure) eliminated very few fields because many fields were already disqualified by the storage resource criterion. Additionally, 54 sites were eliminated due to insufficient data (50 fields) and the 4 offshore locations (Molino offshore gas, Gaviota offshore gas, Elwood South offshore, Belmont offshore) were excluded even though these fields passed the qualifying conditions. Recall that offshore sites are not eligible for the LCFS credit.

After completion of stage 1, 120 oil/gas fields as well as 9 UGS sites were qualified out of the original 516 fields screened. Their spatial distribution was visualized using the ArcGIS platform as shown in Fig. 5. The total CO_2 storage resource of these 129 fields was estimated to range from 2.9 to 5.3 $GtCO_2$. The detailed list of the 129 qualified storage sites is shown in the Appendix Table S-1.



Total sites (516): O&G (503) and UGS (13) sites

Total resource (NATCARB) of OG/UGS: 3.6 - 6.6 GtCO$_2$

Total sites (129): O&G (120) and UGS (9) sites

Total resource of OG/UGS: 2.9 - 5.3 GtCO$_2$

(a) *(b)*

Fig. 5. Screened qualified CO$_2$ storage sites in California: (a) sites and their distribution prior to stage 1 screening and (b) after stage 1 screening. Oil & gas fields are shaded in red and underground gas storage is black.

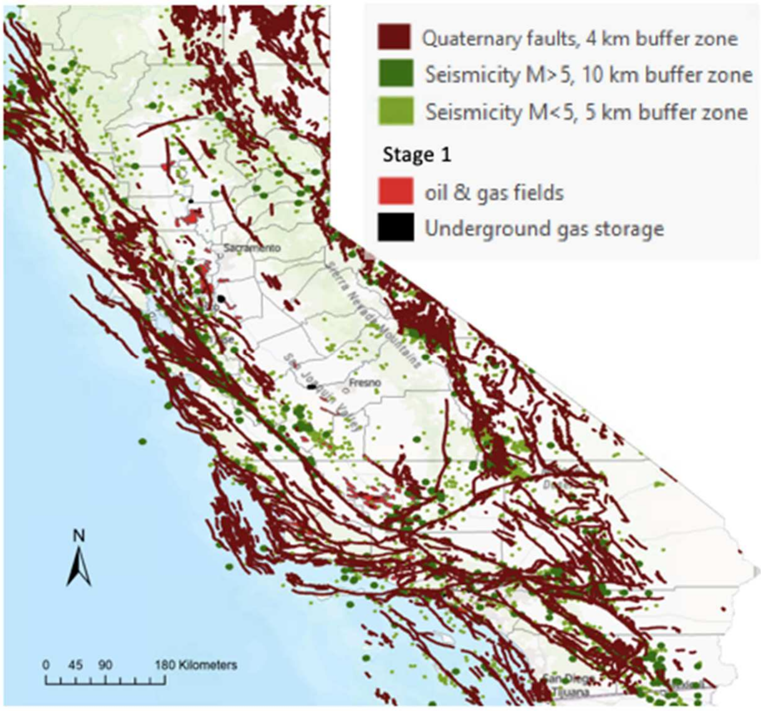
Stage 2: Excluded zones

The criteria for geographical areas to be excluded were developed based on several categories including proximity to risk zones (faults and seismic activity), population density, restricted lands, and sensitive habitats. Table 3 shows the categories of areas excluded and provides some details about rationale, methods, and data sources. All categories of exclusion were taken into account using GIS shapefiles. A shape file is a vector map that uses polygons to represent geographical areas. On the ArcGIS platform, individual layers are combined to prepare one master image delineating areas to consider for storage and areas to be excluded.

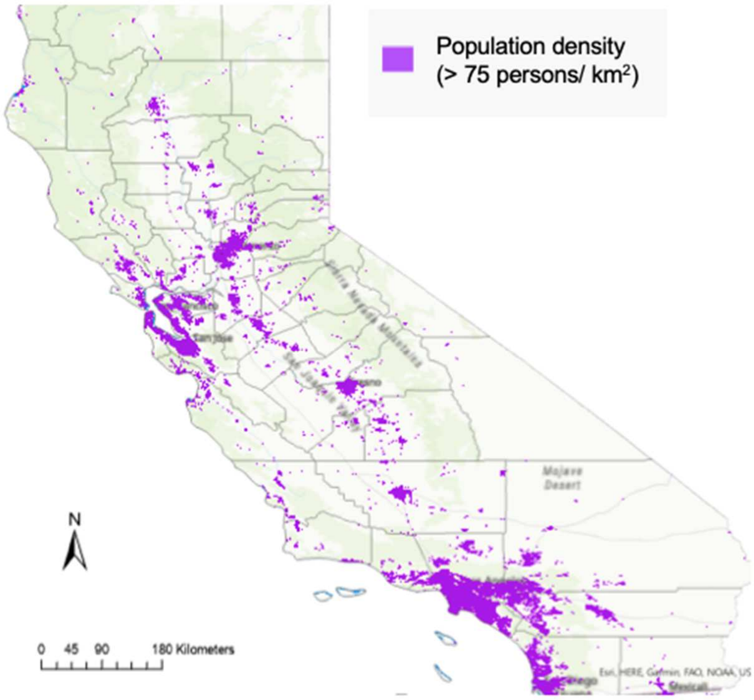
One of the major risks to consider is seismic activity including proximity to faults. Several researchers have identified the need to manage site selection to minimize risks from seismic activity (Bradshaw et al., 2007; Bachu, 2008). We prepared shape files of both fault and historical earthquake locations and established buffer zones around them. The geospatial risk zones were obtained from the California Department of Conservation geological hazard data map (CA DOC, 2010) and the USGS earthquake hazard program (USGS, 2020). A 2 km-wide buffer zone was applied on each side (4 km width) of each mapped quaternary fault following the definition of an active fault region by USGS. Areas with known seismicity were assigned a buffer zone based on the degree of magnitude (M) of the historical earthquake. A 10 km diameter was adopted for magnitude greater than 5 whereas a 5 km diameter buffer zone was used for magnitude less than 5 (Zoback, 2020).

Table 3 Data sources and establishment of buffer and exclusion zones.

Category zone		Exclusion area/conditions	Data sources
Risk	Recent Faulting	4 km wide "buffer zone" around all quaternary faults	California Geologic Hazard Data & Maps (CA DOC, 2010)
	Seismic activity	10 km diameter for M>5 (from 1769 – present), 5 km diameter for M<5 (from 2015 – present)	USGS Earthquake Hazards Program (USGS, 2020)
Population density		Above 75 persons/ km^2	LandScan (ORNL, 2018)
Restricted lands		National landmarks, conservation lands, all military installation zones, Federal lands, state lands, and Native American lands	Protected area (USGS, 2019)
Sensitive zones/habitats		Cultural sites (national park/monument, national register properties), Ecology habitats (e.g., sharp tailed grouse, desert tortoise connectivity, and so on), Wildlife habitat (wildlife allocation, wilderness study area, wildlife management area)	Wind Energy Development Exclusions and Resource Sensitivities zone (ANL, 2016)

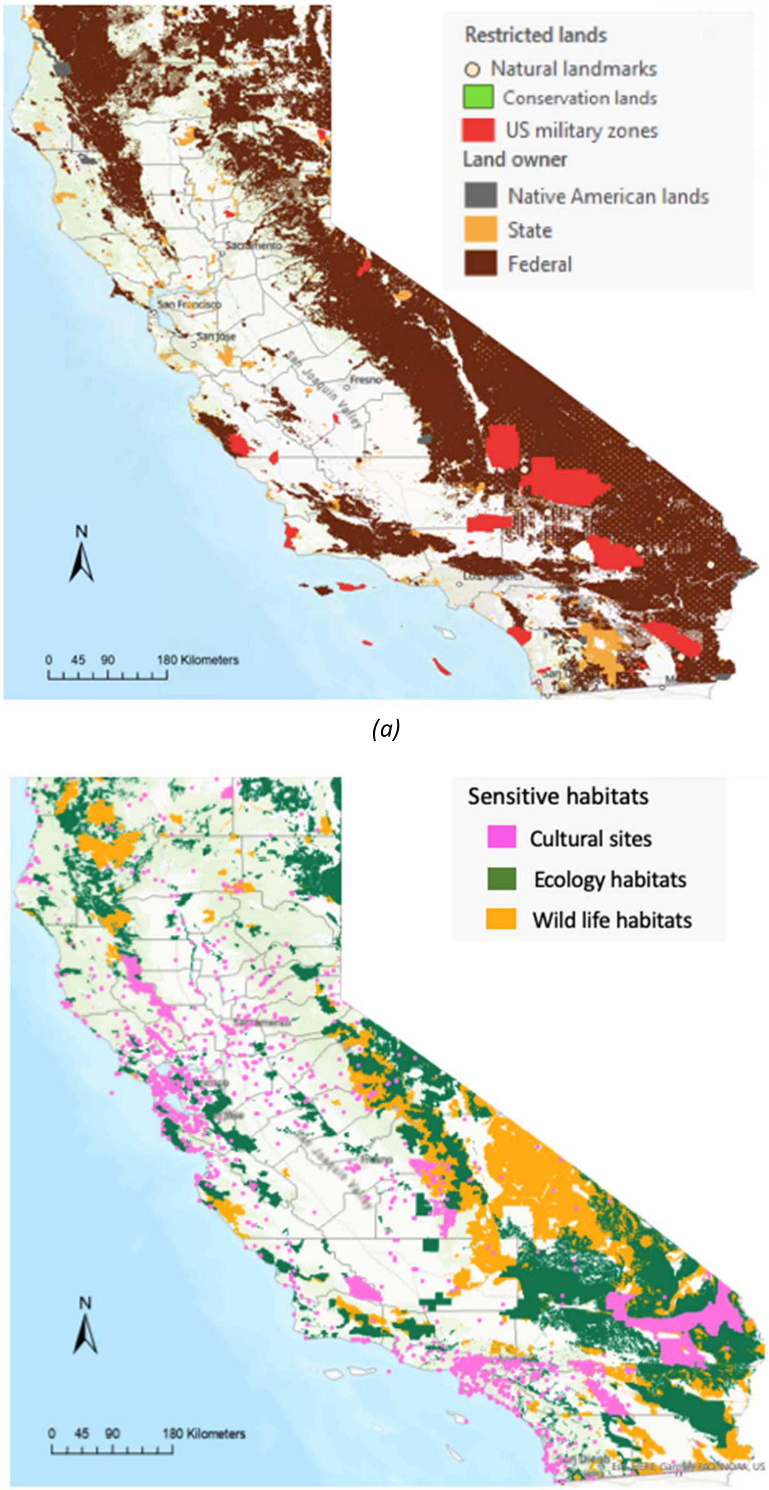


(a)



(b)

Fig. 6. Identification of (a) quaternary faults and seismicity and (b) population density (Above 75 persons/ km^2).



(a)

(b)

Fig. 7. Identification of (a) restricted lands and (b) sensitive habitats/zones.

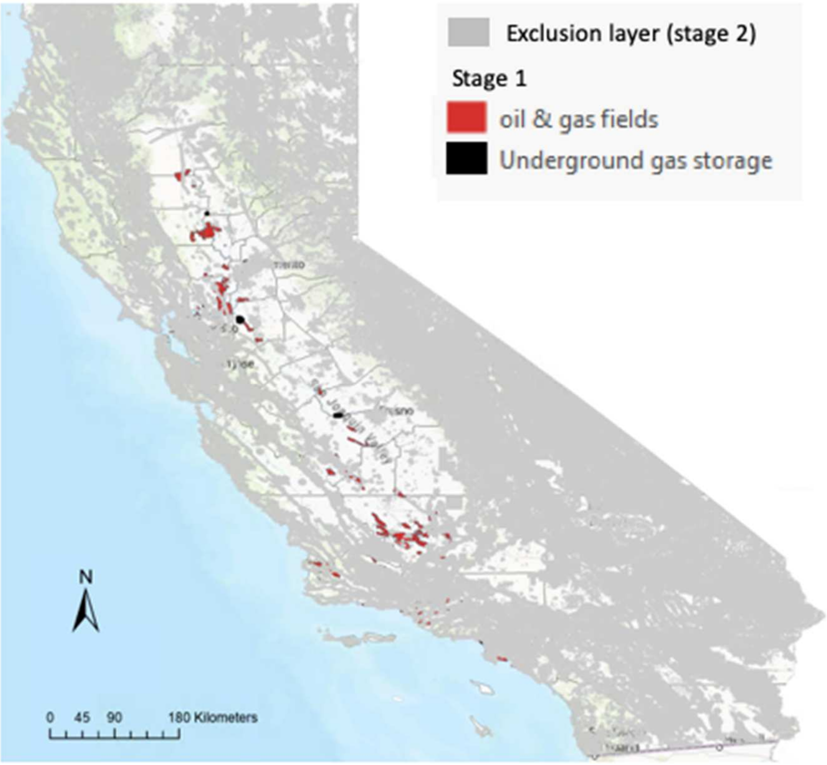


Fig. 8. The combined exclusion layer in California at the end of stage 2.

The population density data was imported from Oak Ridge National Laboratory's (ORNL) LandScan (ORNL, 2018) community population distribution database of approximately 1 km spatial resolution. The criterion for site inclusion was a population density of less than 75 people/km^2. Regarding lands with restricted uses, we began with the 'USGS Protected area' database that includes ownership status for federal, state, Native American, and military lands. Also, it includes national landmarks and conservation lands. In addition, we considered sensitive habitats including cultural sites, wildlife habitats, and so on. These geospatial data were obtained from the 'West-Wide Wind Mapping Project Mapping & Data' (ANL, 2016).

Figure 6a shows the results of the risk identification exercise including quaternary faults (brown color) and seismic zones (dark/light green color). Potential sites that passed the stage 1 screening are also shown. We observe that most fields near the Los Angeles metropolitan area were eliminated due to both faults and seismicity. Population density (purple color) is shown in Fig. 6b.

Figure 7 shows the restricted lands and sensitive habits. There are 6 different types of restricted lands and 3 of them have significant areal acreage as shown in Fig. 7a: 1) military zones are red, 2) state lands are orange, and 3) federal lands are brown. Figure 7b shows three different types of sensitive habitat zones including cultural sites in pink, ecology habitats in dark green, and wildlife habitats in orange. Figure 8 shows the combination of all four categories of exclusion and depicts all excluded areas with a gray color. In Appendix Table S-1, we show the detailed reasons for exclusion of each site based on each of these categories. We eliminated any site when the exclusion zone covered more than 75 % of the surface area of the potential storage site.

Given the location of the storage sites considered, quaternary faults and seismic activity are the main factors to exclude CO_2 storage sites in this analysis.

Stage 3: Potential CO_2 storage sites and CO_2 emitters

In the final stage, potential viable storage sites are obtained by subtracting excluded areas from sites passing the stage 1 screening. The stage 3 results in Fig. 9 show potential CO_2 storage sites including depleted oil/gas fields in red, and UGS sites in black, and CO_2-EOR fields in purple. These maps show the available area in each field after subtraction of relevant exclusion zones above each field. The total storage resource of these sites is estimated to range from 1.0 to 2.0 $GtCO_2$. The stage 3 result includes 3 UGS sites, 37 depleted oil and gas fields, and 21 CO_2-EOR candidate sites.

The 21 miscible CO_2-EOR candidates are in the Ventura and southern San Joaquin basins. Near Bakersfield in Kern County, there are 14 candidate CO_2-EOR sites (see the red circle in Fig. 9). The list of selected potential 61 CO_2 storage sites taking into account field availability and resource size is shown in Appendix Table S-2.

Large emitters of CO_2, including industrial facilities (50 sites) and natural gas fired powerplants (25 sites) are overlain on the potential CO_2 storage sites (Fig.8). Among 52 large sources that met this criterion in the previous study (EFI and Stanford, 2020), two facilities (Facility ID: 107390, Golden Eagle refinery and hydrogen system) have recently announced plans to shut down (KQED, 2020). As a result for this study, we consider industrial CO_2 emitters at 50 sites including cement (8 sources), CHP (15 sources), ethanol (4 sources), hydrogen (15 sources), and petroleum refineries (8 sources). The capturable emissions are assumed to be 90 % GHG except for ethanol plants where capture is 100 % (EFI and Stanford, 2020). The total GHG emissions of these 50 large industrial emitters were ~34.2 $MtCO_2e$ per year upon averaging of 2018 and 2019 data. The industrial facilities are mainly distributed near the metropolitan San Francisco Bay area and the Los Angeles/Orange County metroplex. The detailed list is presented in Appendix Table S-3.

Natural gas powerplants are distributed all over the state. The total GHG emissions (2018-2019 average) of these NG powerplants were about 22.8 $MtCO_2e$ per year. The total capturable CO_2 amount is roughly 27.5 $MtCO_2e$ per year when the NG powerplant is assumed to be retrofitted with a post-combustion system that captures 90 % of emissions and operates at a capacity factor of 60%, that may be larger than current (EFI and Stanford, 2020). The capacity and current emissions of each NG powerplant were found in the eGRID database for 2018 and 2019 (US EPA, 2020c, 2021b). Then, the emissions when operated at 60 % capacity factor were estimated. The detailed list is presented in Appendix Table S-4.

The stage 3 results indicate a potential CO_2 storage resource of 1.0 – 2.0 $GtCO_2$ in oil, gas, and UGS fields. California's GHG emissions in 2018 and 2019 were 425 $MtCO_2e$ and 418.2 $MtCO_2e$, respectively (CARB, 2021a). These sites represent from 26 to 50 years of resource for a storage rate of ~42.0 $MtCO_2$/year (10 % of annual California emissions). Therefore, depleted oil and gas fields and CO_2-EOR candidate sites have sufficient resource to be deployed for carbon storage. More details follow in the discussion.

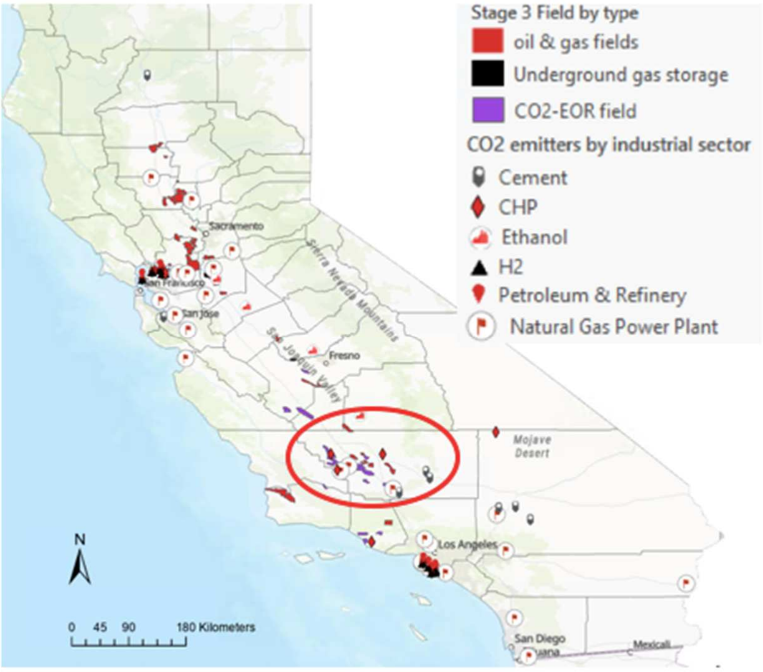


Fig. 9. Potential CO_2 storage sites at the end of stage 3.–Sites are overlain with large CO_2 emitters. Available area in each field is shown after subtraction of exclusion zones (if any) above each field.

Prospective storage sites in California

At the completion of the scoring of the potential 61 fields, there were 8 high priority sites, 37 moderate priority, and 16 fields indicated for future consideration. The specific parameters for the site receiving the lower scores are described in Appendix Table S-2. Table 4 summarizes the 8 highest-priority fields based on the scoring system. Among them, 4 fields (Santa Maria Valley, Sutter City Gas, Coles Levee North, and Greeley) have relatively small total storage resource.

Table 4 High-priority fields after assigning grades using the scoring system.

Type	Field name	Storage Resource (High estimate), $MtCO_2$	Storage Resource (Low estimate), $MtCO_2$
Oil/gas field	Santa Maria Valley	25.8	10.4
	Sutter City Gas	14.0	8.1
CO_2-EOR field	Coles Levee, North	21.8	15.0
	Elk Hills	453.9	135.2
	Greeley	14.2	11.4
	Kettleman North Dome	147.5	66.0
	McKittrick	30.5	13.3
	Paloma	40.5	24.7

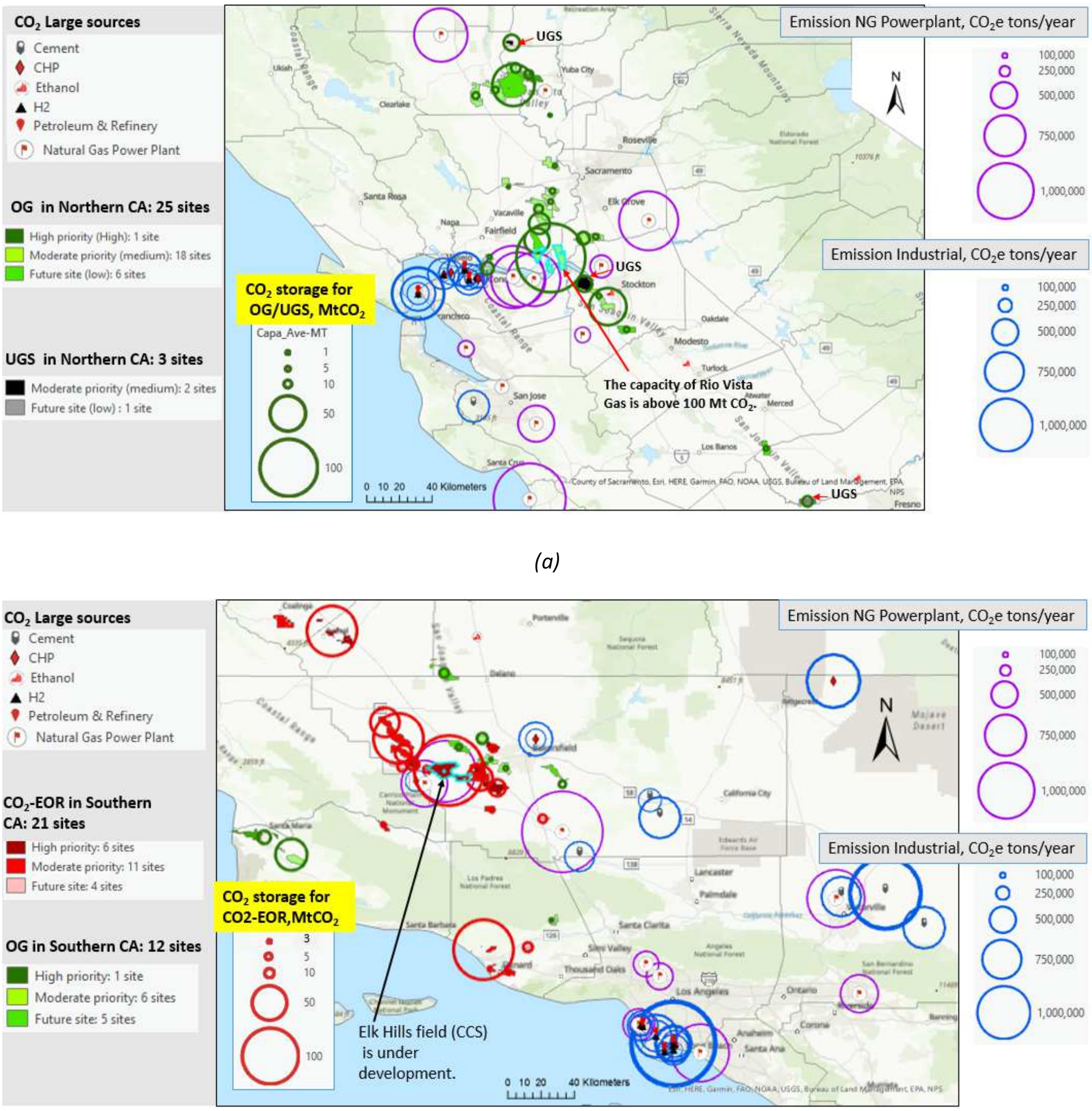
Focus areas are explored and priority suggestions for CO_2 storage sites are developed in this subsection. Figure 10 shows the prospective CO_2 storage sites and CO_2 emitters in the focus areas of California (Bay Area and LA region). The size of a circle represents the amount of emissions per year. The GHG emissions of natural gas powerplants are shown in purple circles and industrial sources are in blue circles. The size of an empty circle at a site represents the mean CO_2 storage resource ($MtCO_2$). Green and red colors are used to denote depleted oil/gas/UGS fields and CO_2 EOR fields, respectively.

Based on the scoring discussed previously, we rank and display high priority, moderate priority, and future sites for CO_2-EOR in dark red (high, 6 sites), red (moderate, 11 sites), and salmon (future, 4 sites). Oil/gas sites are dark green (high, 2 sites), green (moderate, 24 sites), and light green (future, 11 sites) whereas UGS sites are black (moderate, 2 sites) and gray (future, 1 site). The purpose of ranking with three levels is to select higher priority CO_2 injection sites for additional study.

Figure 10a shows a map of CO_2 storage sites overlain with emitters in Northern California. The potential CO_2 storage volume at each site is the average of the low and high estimate resource (NETL, 2015a). The CO_2 storage sites in Northern California are shown in green (Fig. 10a). They are mainly comprised of gas fields based on the classification of California Geologic Energy Management Division (CalGEM). Emitters in the Bay Area are not located far from potential storage sites. Also, there are 3 UGS sites marked with red arrows at McDonald Island gas, Wild Goose gas, and Gill Ranch gas. In general, UGS sites are needed for storage of natural gas. The selected 3 UGS sites, however, may be converted to CO_2 storage if state policy changes. Storage sites with greater than 20 $MtCO_2$ resource in Northern California include Rio Vista gas (130.6 $MtCO_2$), Grimes gas (60.6 $MtCO_2$), and Lathrop gas (43.5 $MtCO_2$), McDonald Island Gas (22.2 $MtCO_2$) and Wild Goose Gas (22.1 $MtCO_2$).

Among these large CO_2 storage fields, the Rio Vista field has been considered previously due to its geological and significant health, safety, and environmental aspects (Trautz et al., 2006; Meyer et al., 2007). The total GHG emissions from large sources within 40 miles of Rio Vista are 14.3 $MtCO_2e$/year. Assuming 90 % CO_2 capture from these GHG sources, Rio Vista alone can store about 10 years of CO_2 emissions. The Grimes gas field was rated for future consideration even though it has a large CO_2 resource estimate. Grimes received a score of 22 due to a low rating for its bottom seal. We observed that there are some faults reported in this field (Weagant, 1972; CA DOGGR, 1982). The low rating resulted from proximity to complex cross-layer vertical and horizontal faults as well as unclear bottom sealing (Annunziatellis et al., 2008; Bradshaw et al., 2007; Pickup et al., 2011). Site specific work at Grimes could result in better understanding of its bottom seal as well as the role of faults resulting in an increase of our initial rating.

A remarkable aspect is that faults, associated fractures, and heterogeneity can be beneficial to CO_2 storage for certain spatial distributions (Miocic et al., 2016; Yang et al., 2018). For example, faults and fractures in the storage formation can promote the migration of CO_2 while reducing the accumulation of pressure (Yang et al., 2018). Therefore, fault structure and associated fractures should be studied using subsurface pressure analysis and fault seal analysis. In this study, we conservatively selected prospective storage sites to avoid these complex cross-layer fault structures. Among 129 qualified sites (stage 1), 68 sites were eliminated based on exclusion zones. Among these 68 sites, 51 sites were mainly excluded due to quaternary faults.



(a)

(b)

Fig. 10. Prospective CO_2 storage and emitter sites in (a) Northern California and (b) Southern California. Natural gas power plants are circled in purple-and other industrial emissions are circled in blue. The size of circles is proportional to the magnitude of emissions. High, medium, and low scores refer to high priority for consideration, moderate priority, and sites to consider in the future. Available area in each field is shown after subtraction of exclusion zones (if any) above each field.

Figure 10b shows storage sites and emitters in Southern California. Near Bakersfield in Kern county, CO_2-EOR candidate sites are abundant near NG powerplants. Previous studies found that these oil reservoirs are favorable for miscible CO_2-EOR (ARI, 2005). All CO_2-EOR sites in Kern County received scores of high or moderate priority. In fact, a CCS project at the Elk Hills field is under development. It is planned to store CO_2 from the Elk Hills natural gas powerplant (Haney, 2020). In Southern California, there are several CO_2-EOR storage sites with mean CO_2 resource above 20 $MtCO_2$ including Elk Hills (276.1 $MtCO_2$), Kettleman N. Dome (106.7 $MtCO_2$), South Belridge (106.2 $MtCO_2$), Ventura (89.7 $MtCO_2$), North Belridge (59.8 $MtCO_2$), Coles Levee south (51.9 $MtCO_2$), Paloma (32.6 $MtCO_2$), Cymric (32.1$MtCO_2$), and McKittrick (21.9 $MtCO_2$). There is also a depleted oil field at Cat Canyon (29.0 $MtCO_2$).

There are no prospective CO_2 storage sites near the Los Angeles metropolitan area due to dense population and seismic hazards, but there are industrial CO_2 emissions to capture. Pipelines could be built for delivery of CO_2 to the Ventura basin or Kern County in order to transport CO_2 emissions out of the Los Angeles basin. Table 5 summarizes the GHG emission data and the CO_2 capturable by type and location as well as prospective CO_2 storage resource with greater than 20$MtCO_2$ capacity in both Southern and Northern California.

Table 5 GHG emissions/capturable emissions and CO_2 storage amount for potential/prospective sites in Southern and Northern California.

	GHG Emission[1], $MtCO_2e$/year			Capturable, $MtCO_2e$/year			CO_2 storage resource[2], $MtCO_2$	
	Industrial	NG	Total	Industrial	NG	Total	Potential sites (stage 3)	Prospective sites with >20 $MtCO_2$ storage resource
South	22.29 (29 sites)	12.01 (13 sites)	34.29 (42 sites)	20.08	14.58	34.66	1030.2 (33 sites)	805.9 (10 sites)
North	11.89 (21 sites)	10.83 (12 sites)	22.72 (33 sites)	10.74	12.92	23.66	536.6 (28 sites)	218. 2 (4 sites)
Total	34.18 (50 sites)	22.84~~2~~ (25 sites)	57.01 (75 sites)	30.82	27.49	58.32	1566.8 (61 sites)	1024.2 (14 sites)

[1]: Average (2018-19) emission data; [2]: CO_2 resource is average of low and high estimate.

Figure 11 complements the visual information in Fig. 10 and Table 5 by showing the average estimated CO_2 storage resource for individual fields that are greater than 20 $MtCO_2$ as well as high to moderate priority for consideration. The Grimes gas field is not shown as discussed above. There are 14 sites in total with a combined mean CO_2 storage resource of 1.02 $GtCO_2$. These 14 sites represent 67 % of the total storage resource resulting from the 3-stage screening process (see Table 5). The Southern San Joaquin and Ventura Basin have a combined storage resource of 805.9 $MtCO_2$. It is sufficient for 20 years of storage with a 40 $MtCO_2$/year injection rate. We notice that the capturable CO_2 amount in Southern California was 34.7 $MtCO_2$ (see Table 5).

In Northern California, Rio Vista gas, Lathrop gas, Wild Goose gas, and McDonald Island gas are relatively close to each other (see Fig. 10b) with a combined mean CO_2 storage resource of 218.2 $MtCO_2$. These fields and three nearby saline formations (Mokelumne River, Starkey, and Winters) of the Sacramento Basin represent 3 $GtCO_2$ storage (Baker et al., 2020). The proximity of these gas fields and saline reservoirs suggests that carbon storage projects may begin in the gas fields and could transition gradually to saline reservoirs to accommodate greater storage rates or additional resource. Regarding the 14 most prospective sites (> 20 $MtCO_2$ storage resource), injectivity and dynamic storage capacity will be investigated in future work.

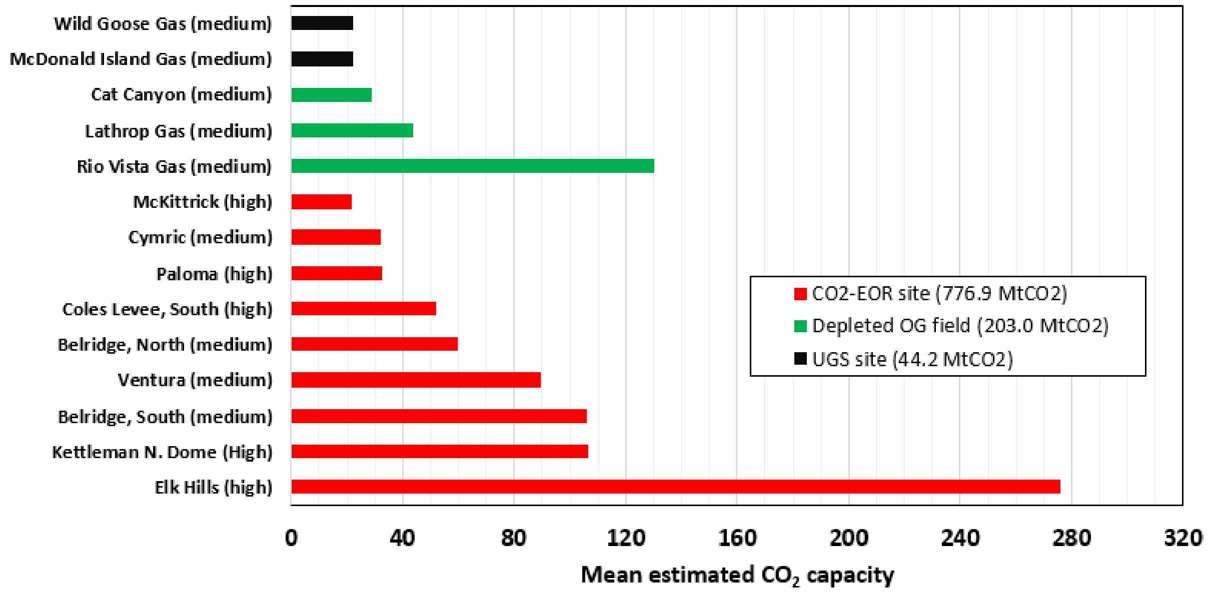


Fig. 11. Potential CO_2 storage sites in California with average estimated CO_2 storage above 20 $MtCO_2$ that received high or moderate priority grades.

Discussion

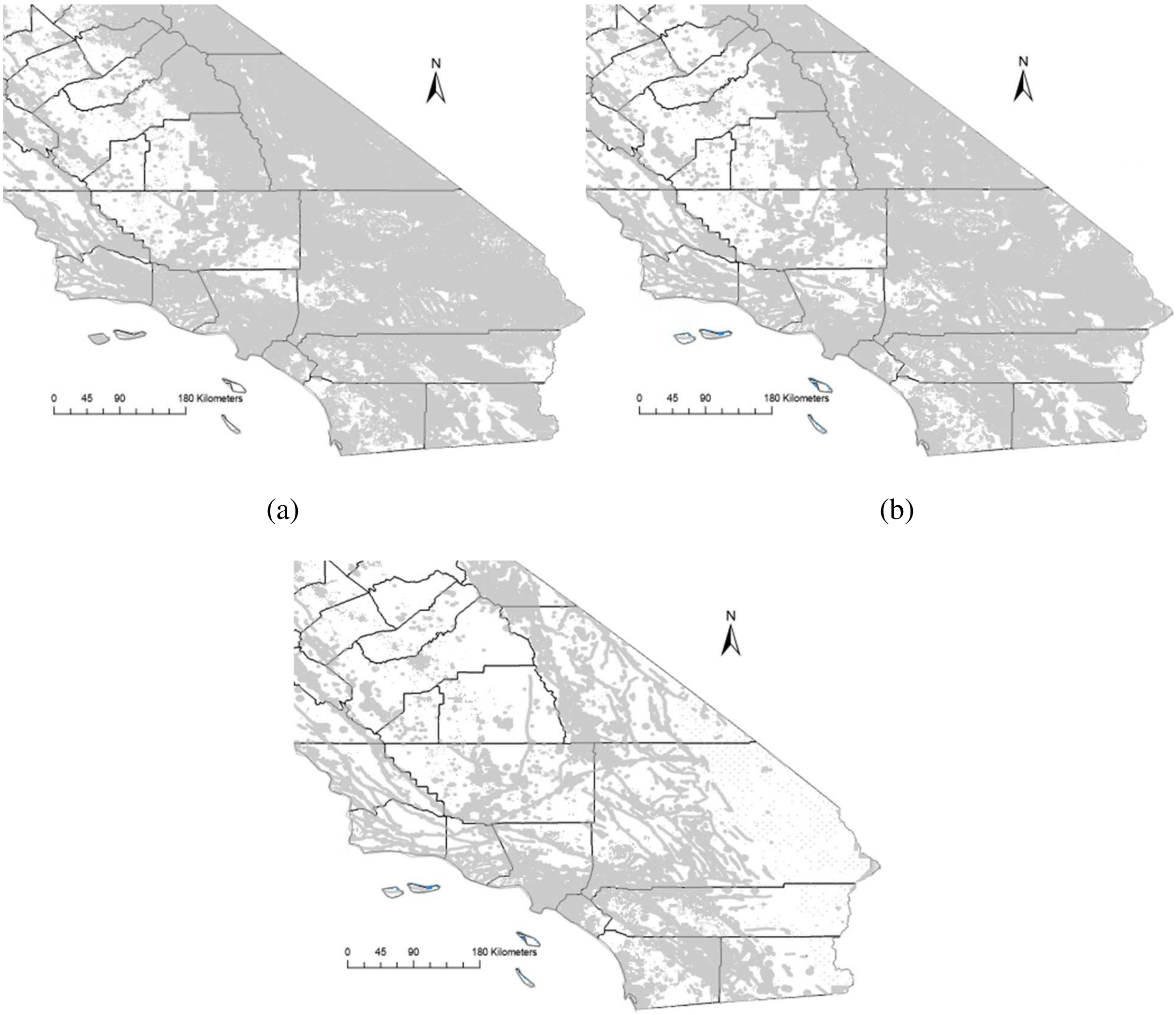
This study set the minimum threshold of storage resource for an entire field as 3 $MtCO_2$ because this mass is equivalent to an injection rate of 0.1 $MtCO_2$/y for a 30 year project. Downey and Clinkenbeard (2011), on the other hand, applied a cutoff of 0.5 $MtCO_2$ for individual pools within a field and they did not consider exclusion zones. Their cutoff was fashioned to incorporate the economics of constructing injection wells and associated costs. Specifically, Downey and Clinkenbeard (2011) identified seven pools in Millar and two pools in Conway

Ranch. After we apply exclusion zones to both Millar (50 % field availability) and Conway Ranch (50 % field availability) fields, our estimate of CO_2 storage resource is larger than that of Downey and Clinkenbeard (2011) because of their more conservative 0.5 $MtCO_2$ per pool cutoff. For Conway Ranch, we obtain an average of 3.5 $MtCO_2$ whereas Downey and Clinkenbeard (2011) find 2.1 $MtCO_2$. At Millar we estimate an average storage resource of 11.4 $MtCO_2$ and Downey and Clinkenbeard (2011) find 7.0 $MtCO_2$.

Accordingly, the minimum threshold for storage sites is a sensitive parameter. The injection rate of 0.1 $MtCO_2/y$ or greater baseline taken in this study qualifies for the U.S. 45Q credit for storage, and so is reasonable. Site selection and economics including analysis of production history and detailed field are future work.

Results are also sensitive to exclusion zone specifications. Excluded areas, Fig. 8, were selected conservatively to avoid potential technical (seismic) risk as well as social and environmental conflict. Additionally, this work sought primarily to locate prospective CO_2 storage sites among oil/gas/UGS fields for possible early adoption. Nevertheless, the exclusion exercise was also applied to saline formations, Fig. 8. For example, saline formations in eastern California near the borders with Arizona and Nevada were excluded in portions of Riverside, Imperial, and San Bernardino Counties. These saline formations have not been fully assessed.

Hence, we briefly consider the sensitivity of the exclusion exercise using this area of California as an example. Figure 7 shows that the excluded areas include federally controlled lands with protected or sensitive habitats. It is conceivable that storage operations can be conducted with a small surface footprint and in a manner that does not disrupt pre-existing surface conditions. Some surface exclusions might, thus, be relaxed. One possible benefit is to provide storage options that might be developed in concert with neighboring states, such as Arizona, that exports electricity to California. Figure 12 presents an example of how potential storage sites in the region of Riverside, Imperial, and San Bernardino Counties could change if storage is permitted under federal lands. Figure 12a shows the result with the original excluded zones. Figures 12b and 12c show the results with relaxation of the exclusion zone under two scenarios. In the first case in Fig. 12b development on federal lands is allowed except for those lands with sensitive habitats (cultural sites, wild-life, and ecological habitats). Figure 12b is not materially different from Fig. 12a. In the second case in Fig. 12c all federal land is considered for development, including the sensitive habitats. In summary, a cost-benefit-impact study with careful re-examination of the pore volume under these zones is an interesting area of future study.



(a) (b)

(c)

Fig. 12. Southeastern California exclusion zones with (a) the current result, (b) relaxation of the selected federal land restriction except sensitive habitats (cultural sites, wild-life, and ecological habitats), and (c) relaxation of restrictions on all federal lands. Gray color represents the excluded areas.

Summary

A three-stage process was used to evaluate CO_2 storage sites in California starting with the results of the NETL (2015a, b) study of oil and gas fields. Initially, 129 potential CO_2 storage sites out of 516 oil/gas/UGS fields in California were identified using rigorous screening criteria. Saline formations were not evaluated. The screening criteria identified those sites satisfying minimum criteria established for EPA class VI wells and the LCFS CCS protocol. Sites were assessed by considering proximity to seismically active areas, faults zones, large population density, restricted-access lands, and sensitive habitats. Proximity of storage sites to these areas led to site exclusion. As a result, 61 potential sites remained with an estimated storage resource of 1.0 to 2.0 $GtCO_2$. These sites include 21 CO_2-EOR sites, mainly located in the southern San Joaquin, southern Sacramento, and Ventura Basins. This storage resource of 61 potential sites is sufficient for 26 to 50 years of storage with an injection rate of 42.5 $MtCO_2$/year. This storage rate amounts to 10 % of California GHG emissions averaged over 2018 and 2019. Note that saline reservoir storage resource, not explicitly considered in this study, would greatly increase these numbers.

A scoring system with 7 parameters was adopted to select technically superior storage sites from those 61 potential sites meeting screening criteria. The sites are ranked as high priority, moderate priority, and future priority for study as CO_2 injection sites. All of these sites passed extensive screening and have desirable qualities for storage. High and moderate priority CO_2 storage sites were identified and linked with CO_2 emission sources. The annual GHG emission of large emitters (50 industrial sources and 25 NG powerplants) in Southern and Northern California are

34.3 and 22.7 $MtCO_2e$, respectively. Fourteen large prospective sites representing 20 $MtCO_2$/year storage rates were identified near the Sacramento Basin and in Kern County. The storage resource of these 14 sites represents 67 % of the total potential resource that emerged from the stage 3 screening process. Specifically, 10 storage sites in the southern San Joaquin and Ventura Basins have a combined average storage resource of 806 $MtCO_2$. In Northern California 4 sites (2 depleted gas fields and 2 UGS sites) have a combined average CO_2 storage resource of 218.2 $MtCO_2$.

Saline formations need to be reevaluated to complement and expand the assessed storage resource in this study. Previous studies of saline formations in California suggest resource of more than 50 times that of hydrocarbon and gas storage fields. Evaluation of these sites using the risk assessment methodology proposed here is important. Furthermore, techno-economic analysis with scenario and policy development will be key to deployment of CCS projects in California.

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