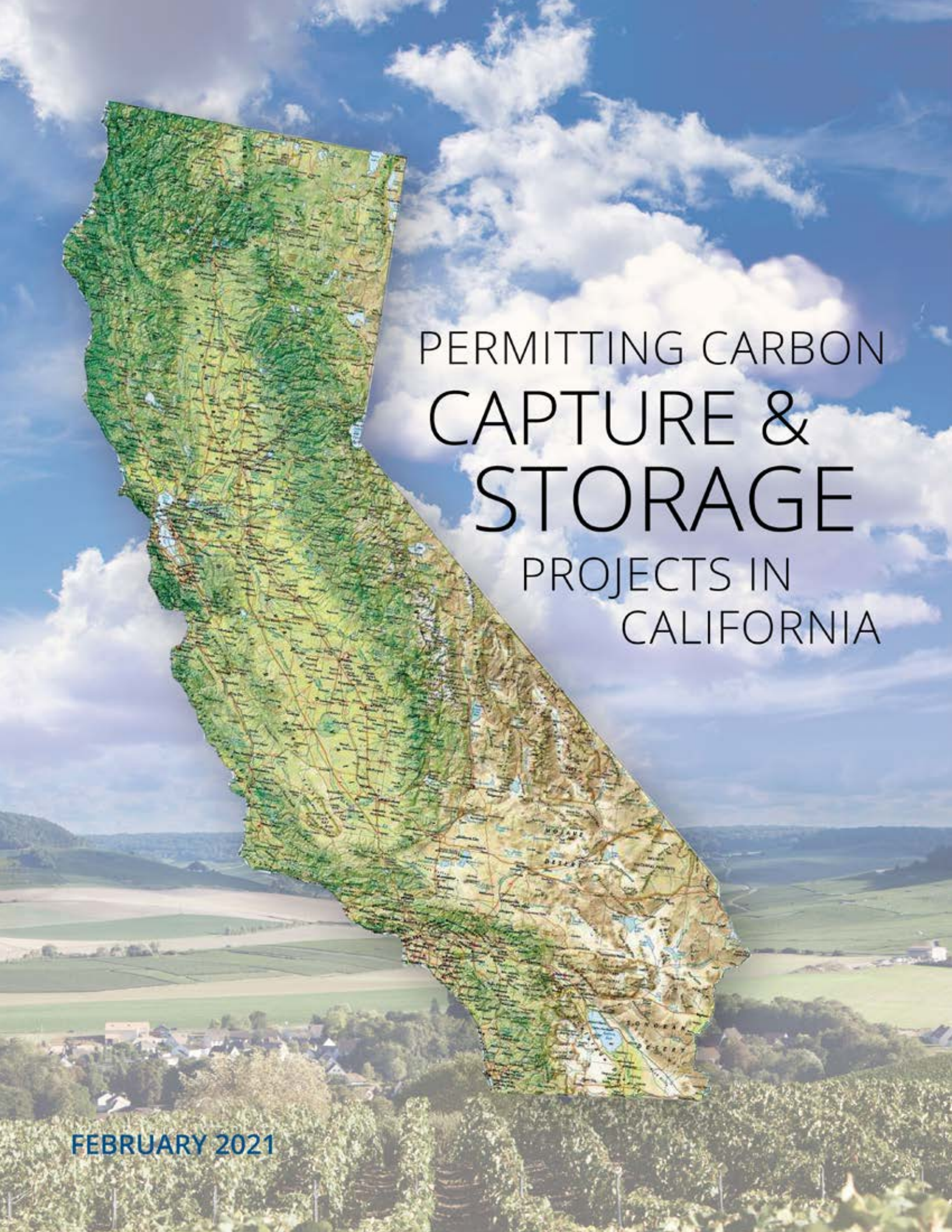

PERMITTING CARBON CAPTURE & STORAGE PROJECTS IN CALIFORNIA

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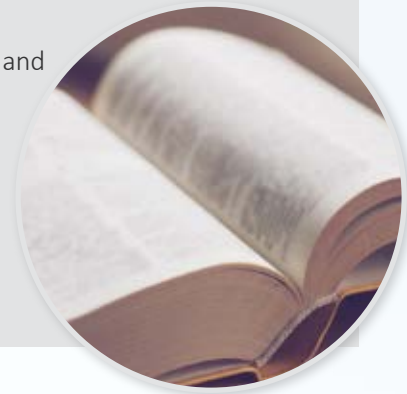
EXECUTIVE SUMMARY

To reach its ambitious goal of economy-wide carbon neutrality by 2045, California will have to capture, transport, and geologically store tens of millions of tons of carbon dioxide (CO_2) per year. This will come from the atmosphere and from large sources that have no other options for eliminating emissions. The needed technologies are available today and have been demonstrated at multiple U.S and international sites; California will need to host ten or more of these carbon capture and storage (CCS) projects to achieve its climate goals.

We studied the extensive regulatory framework – regulations and institutions – that applies to these CCS projects in California, and found it to be rigorous, robust, and capable of handling the permitting and review tasks while protecting Californians and their landscapes, ecosystems, and resources. However, this encompassing set of requirements, interactions, and the currently available resources and division of responsibilities may not allow sufficiently expeditious deployment of these projects to protect the rapidly worsening climate as quickly as needed. California can readily address the issues we have identified without any major overhaul. Specifically, the State could increase internal efficiency and coordination, secure adequate staffing and resources for the task, assign experienced process leads, expand its collaboration with relevant federal agencies, and adopt a small number of technical regulatory and legislative changes. Project developers should also recognize permitting complexity early, devote serious time and talent to obtaining necessary authorizations, and act in a transparent, timely, and competent manner to ensure that regulators have the information they need for efficient action.

BOX ES-1 Key Findings

- California has a robust and extensive array of regulations and institutions that are collectively sufficient to protect public health, safety, and the environment while CCS is being deployed.
- Permitting a sufficient number of sound CCS projects to achieve California's climate goals is unlikely due to scattered and/or poorly defined agency jurisdiction boundaries and responsibilities, inefficient and/or time-consuming processes, and inadequate staff resources.
- Environmental review, primarily under the California Environmental Quality Act and related litigation but also under the National Environmental Policy Act, will be a key determinant of project authorization timelines, which will likely span multiple years.
- The authorization process can be made more efficient while retaining its integrity and credibility with relatively few and straightforward operational and organizational fixes, and without major reforms.
- A small number of technical regulatory and statutory fixes would enable deployment of CCS technologies at the scale needed in the longer term.
- Project developers should anticipate and be equipped to handle a complex and technically involved authorization process.



Background

California has set itself ambitious mid-century climate goals. No state or nation can solve a large-scale global problem like climate change by itself, but California's goals aim to keep pace with the needed reduction of global greenhouse gas emissions. Specifically, Executive Order B-55-18 established a goal of achieving carbon neutrality no later than 2045 and ideally as soon as possible, and of achieving and maintaining net negative emissions thereafter. Multiple in-depth analyses have shown that, to achieve this goal, California must not only intensify efforts in emission reduction measures and technologies that are already under way but must also deploy technologies that dramatically reduce existing emissions from large sources such as industry, and also remove carbon from the atmosphere directly. Accordingly, the California Air Resources Board (CARB) has adopted a stance in line with these analyses.

Carbon Capture and Storage (CCS) refers to a family of technologies that remove CO_2 directly from large point sources or the atmosphere, transport it (commonly by pipeline, truck, rail, or barge), and then store it permanently and securely thousands of feet underground. This storage occurs in the same types of rock formations that held the carbon for millions of years in the form of fossil fuels, which have now been released to the atmosphere and are responsible for climate change. The technologies involved in CCS are not new, and a sizeable array of demonstration and early commercial-scale projects has emerged around the world over the past two or more decades. However, CCS projects are inherently complex and cross-cutting due to integrating three kinds of activity: CO_2 capture, transport, and storage. Any one of these phases is complex in itself and has significant regulatory and permitting needs that are managed by a large number of state and federal agencies. In addition, these projects will likely necessitate negotiations with private parties to ensure respect of existing surface and mineral ownership while obtaining authorization to site CO_2 pipelines and to inject CO_2 deep in the subsurface.

CCS projects can be permitted safely in California, but not at the pace dictated by climate goals

No CCS projects exist in California today. The state has a thorough and robust regulatory framework for screening and authorizing projects that may have environmental or public health impacts in general. In addition, extensive state and federal regulations have very recently been adopted specifically for geologic CO_2 storage, which take into account previous regulatory failings from the oil and gas sector and other gaps, and prescribe a preventative approach that screens out all but the best-designed and -executed projects. This report examines this regulatory framework in depth and outlines the majority of likely authorizations—regulatory or otherwise—that will be required for a CCS project in California. We conclude that, collectively, these authorization processes amount to a sufficiently high level of diligence to minimize risks to public health, safety, and the environment. However, this regulatory and permitting framework is also extensive and convoluted and was, for the most part, not devised with the complexity and cross-cutting nature of CCS in mind. Figure ES-1 below summarizes the likely permitting interactions for a typical CCS project.

In summary, a large number of private, local, state, tribal, and federal agencies be involved in processing authorization requests for CCS projects. Figure ES-2 below summarizes the nominal turnaround time, technical complexity, and political exposure involved in securing each of these permits or authorizations.

In addition, CCS projects will need to undergo environmental review under the California Environmental Quality Act (CEQA) and possibly the National Environmental Policy Act (NEPA). These review processes aim to evaluate whether a project may have significant effects on the environment and whether these effects can be avoided. CEQA review in particular is a significant undertaking and, unlike NEPA, can require mitigation measures. In practice, CEQA review, the completion of which must precede the issuance of most permits, is likely to be the primary determinant of projects' authorization timelines, along with possible related litigation.

Authorization related to:	Entity				
	Local Government	State Agency	Federal Agency	Tribal Government	Private Party
Local land use	✓				
Siting CO_2 pipelines	✓	✓	✓	✓	✓
Pore-space ownership & mineral rights	✓	✓	✓	✓	✓
Air permits		✓	✓		
CO_2 pipeline safety		✓	✓		
CO_2 injection permitting		✓	✓		
Discharges to water (including those of the State)		✓			
Discharge of dredge or fill materials into waters of U.S.			✓		
Endangered species		✓	✓		
Stream/river/lake alterations		✓			
Greenhouse gas reporting		✓	✓		
CO_2 crediting: the revenue stream		✓	✓		

Capture Transportation Storage

Figure ES-1. *Summary of main authorizations needed for a typical CCS project.*

Thus, we conclude that, given the complexity of this regulatory regime, the state cannot rely on the existing framework to process a significant enough number of CCS project applications to achieve its climate goals. In particular, factors that could compromise this endeavor include the following:

- Lengthy environmental review and permit application evaluation processes
- Lack of experience or established track record for state agencies leading the state environmental review process under CEQA for CCS projects specifically
- Poorly delineated regulatory authorities between agencies
- Need for cross-agency collaboration at local, state, and federal levels (sometimes several agencies need to review a permit application submitted to only one of them)
- Absence of an established and tested joint-review process for permit applications that involve multiple agencies

Figure ES-2. *Ranking of authorizations according to likely turnaround time, technical complexity, and political exposure.*

- Inadequate resources and staffing at regulatory agencies may not allow efficient handling of the anticipated high volume of applications spurred by recent CCS incentives
- Absence of statutory determinations and/or adjudication on the ownership of rock pore space where the CO_2 will be stored and its relation to mineral rights ownership

Fortunately, through some simple interventions to existing processes and structures, California can obtain faster and larger carbon emission reductions and removals while still maintaining robustness and rigor in its environmental review and permitting regime. Large reforms in the short- or medium-term are not necessary or even conducive to achieving these climate benefits, given the low level of public awareness

of CCS technologies. Rather, consideration of long-term measures to facilitate CCS deployment scale-up would be timelier after construction of the first wave of commercial-scale projects, which would inform a much more concrete discussion.

Options for state government

Options the State could utilize to ensure timely and efficient authorization of CCS projects to contribute to its climate goals while still safeguarding public health, safety, and the environment include the following:

Immediate (0-6 months)

- Assemble an interagency working group of state agencies likely to be involved in CCS project permitting
- Designate a staff contact for CCS permitting from each of these agencies to facilitate and expedite relevant conversations
- Through the working group, create an internally vetted list—to serve as a reference—of CCS permitting authorities and of the responsibilities of each agency
- Invite representatives from key federal and local agencies (such as key counties and air districts) to join the working group

Near-term (<2 years)

- Create a clear directive from the administration and/or legislature that unambiguously signals to state agencies the high-priority nature of CCS projects for the state and its climate goals and that calls for thoroughly and efficiently handling permit applications and environmental review
- Among the working group of relevant agencies, assign one agency to act as the central point of contact for CCS project permit applicants; this agency will function as coordinator, timekeeper, and manager for efficient permit processing, and will interact with developers and stakeholders
- Examine the desirability and legal feasibility of assigning a specific CEQA lead agency—from among those likely to have jurisdiction over most CCS projects—to assume this role and specialize in the CEQA process
- Assemble a flow chart with steps for state agencies to follow upon receiving a project application, including intended turnaround timelines for each step
- The U.S. Environmental Protection Agency, California Geologic Energy Management Division, California Air Resources Board, State Water Resources Control Board and regional water boards could perform a joint or coordinated review of the substantial and highly overlapping geologic information required for different regulatory or certification purposes.
- For all state agencies involved in CCS permitting, secure adequate staff and resources to ensure sufficient expertise, knowledge, and personnel availability to process what could be numerous and/or complex permit applications, and to navigate the CEQA process for multi-faceted projects
- Through California's administration and congressional delegation, convey the need for similar staffing and resources in Washington DC for federal agencies involved in permitting CCS projects in California
- To ensure timely processing of applications by federal agencies, pursue memoranda of understanding (MOUs) or informal agreements between state agencies and those federal agencies relevant to permitting CCS projects in California; also examine the potential for state and federal agencies to collaborate toward a common goal of CCS project deployment
- Make available the State's own land/mineral holdings for CO_2 pipelines or injection, where appropriate
- Through the Natural Resources Agency, review the relevance of certified programs under 14 CCR §§ 15250-15253 to CCS project permitting

- Weigh the desirability of California applying for primacy to administer EPA's Class VI injection well–permitting program
- Through the legislature, enact a minor technical amendment to the Elder Act, clarifying that the Act intends for the Office of the State Fire Marshal to also regulate intrastate CO_2 pipeline safety
- Through the legislature, clarify pore-space ownership, clearly vesting it with the surface owner, and possibly also clarify the relation of the surface estate with the mineral estate
- Through CARB, consider if (and which) changes to existing CCS Protocol provisions could meaningfully increase the array of projects in active development without materially compromising the Protocol's integrity or level of protection/precaution

Medium- and long-term (>2 years)

- Through state agencies and the legislature, consider more broadly the desirability of a parallel, certified process under CEQA with a specific agency as the lead
- Through the legislature, investigate the desirability of options for more efficient acquisition of rights-of-way for pipelines, and of pore space and mineral rights for injection, and then pursue the optimal option
- Construct a backbone of CO_2 trunklines with State involvement, such as a public-private partnership, that will link a large collection of CO_2 point sources to suitable storage
- Assemble a State-operated CO_2 transportation/storage utility to handle permanent subsurface storage

Considerations for project developers

In addition, project developers can follow a series of steps to stack the odds in favor of obtaining necessary authorizations efficiently.

CEQA considerations

- Developers should consider all aspects of a project, including location and stakeholders' disposition before choosing to proceed and should proactively engage in open conversations with stakeholders early; eliminating of disagreements at their root is easier said than done, of course, but an honest attempt to do so from the outset and shortlisting projects not on economic and technical merits alone ensures a smoother start
- From the outset, project developers need to thoroughly identify and mitigate impacts to the greatest extent feasible, and should also consider preparing a draft **initial study** preemptively to submit for the lead agency's consideration
- Project developers should identify and describe the preferred course of action, as well as the alternatives for both the project as a whole and its components
- Project developers can maximize the chances of a smooth CEQA process by seeking large and diverse coalitions of actors to coalesce towards a common objective

Permit application considerations

- As is customary and recommended, permit applicants should consider requesting **pre-application meetings** ("pre-app") with regulators to discuss the project and to learn which parameters the regulators consider critical
- Applicants should assemble and dedicate appropriate staff and/or consultant resources to permit applications, with as much skill and prior experience as possible
- Permit applicants should prioritize transparency, responsiveness and cooperation, and avoid a need-to-know policy with the regulators in permitting interactions

Chapter 1: Introduction

What is CCS and why is it needed?

Carbon Capture & Storage (CCS) refers to a family of technologies that remove carbon dioxide (CO_2) from the atmosphere or industrial point sources, transport it (commonly by pipeline, truck, rail, or barge), and then inject it thousands of feet underground in rock formations selected for their proven ability to hold fluids for millions of years. This geologic storage is key to CCS being able to permanently return millions of tons of CO_2 safely underground from whence it came. The technologies involved in CCS are not new, and a sizeable array of demonstration and early commercial-scale projects have emerged around the world over the past two or more decades.[01] CCS is an emission-reduction strategy in itself when applied to existing emission sources but is also a key component and enabler of CO_2 removal (CDR) from the atmosphere.

In no small part because CCS was originally seen as a solution only to coal-fired power emissions, the technology has not yet achieved broad deployment.[02] However, as the effects of climate change escalate and the need to contain them becomes even more pronounced and urgent, so is the case for broadly pursuing CCS alongside other strategies. To limit global warming to 1.5 or even 2 °C, the world will need not only to switch from fossil fuels to clean energy sources but also to aggressively capture CO_2 from existing large point sources and find ways to remove CO_2 from the atmosphere at a multi-gigaton scale by mid-century.[03,04,05] This need is due to the fact that some of these facilities cannot or will not be shut down, replaced, or switched to carbon-free fuels quickly enough for the planet to remain within the carbon budget needed to contain climate change at manageable levels. Further, we will also need mechanisms to correct what seems to be an unavoidable overshoot in atmospheric CO_2 concentrations.

Jurisdictions pursuing aggressive mid-century carbon-neutrality climate goals are rapidly reaching this conclusion. California is one such jurisdiction, having set a goal to achieve economy-wide carbon neutrality no later than 2045 and ideally as soon as possible,[06] with several interim milestones and sectoral targets. Even with redoubled efforts and policies in sectors where the state has already championed decarbonization, several analyses have shown that achieving the 2045 goal will also require mitigation of any remaining emissions from large sources, as well as removal of carbon from the atmosphere.[07,08] Naturally, for the state to become carbon neutral even sooner, pursuing carbon removal from the air is even more critical. Accordingly, the California Air Resources Board (CARB) has adopted a stance in line with these analyses, indicating that the state will need to deploy CCS to fully decarbonize industrial emissions and to remove CO_2 from the atmosphere to counterbalance remaining emissions.[09] This effort will require expeditiously deploying a large number of projects.

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CCS requires a robust yet efficient permitting process

The technological components of CCS are generally mature and tested. Several capture technologies, many of which have been deployed for decades, are now available with commercial guarantees from major vendors. In the U.S. alone, over 4,500 miles of dedicated pipelines transport CO_2, while refrigerated and pressurized CO_2 tanks ride on trucks and other transportation means for use in carbonated beverages. Since the early 1970s, hundreds of millions of tons of CO_2 have been injected in oil production operations and dedicated storage projects. However, a CCS project brings together an unprecedented number of regulatory components, resulting in a complex mosaic: CCS links (1) an industrial facility of varying complexity at the capture site, (2) a mode of transport for the CO_2, and (3) underground injection and monitoring components. This three-step process necessitates interaction with an unusually large number of local, state, and federal regulatory agencies. While our assessment is that the California and federal authorities have established a robust and appropriate set of regulations applying to CCS, we have concerns about whether the permitting process can be navigated in a manner and timeline that allows for project financing and development to meet mid-century carbon-neutrality climate goals.

At the same time, the ability of CCS projects to live up to the highest environmental, public health, and safety standards is paramount, and the integrity and transparency of the permitting process must in no way be compromised. These permitting processes have been established for a reason, and they must remain true to their original objective.

This report

Given the climate time crunch in which we find our world, with drastic emission reductions already overdue, the most pressing task in implementing CCS as a solution becomes one of ensuring an efficient permitting process that does not waste precious time or resources, while leveraging agencies' expertise and existing structure and maintaining the environmental and social integrity of the permitting process.

This report outlines in detail the complex permitting framework for typical CCS projects to examine how these processes may hinder development of projects urgently needed to achieve California's climate goals. Further, this report presents actions that could make the permitting process more efficient without compromising its purpose or integrity or damaging public confidence in CCS.

Chapter 2:

What does a CCS project involve?

A CCS project typically comprises three distinct stages: capture, transport, and injection.

The *capture* stage takes place at the point of CO_2 generation. Whether the source is a direct air capture facility, an ethanol fermentation facility, a cement production plant, a power plant, a refinery, or another industrial source, the capture equipment is co-located with gas streams, slipstreams, or process streams containing CO_2 in high quantities and concentrations. CO_2 capture is almost always the most capital- and equipment-intensive of the three stages, requiring engineering components such as absorption and regeneration towers, heat exchangers, compressors, and piping.

The simplest form of CO_2 capture involves dehydration and compression of a pre-existing, concentrated CO_2 stream (for example an ethanol fermentation facility). For applications in which the CO_2 stream is more dilute and needs to be separated using physical or chemical processes, towers and other more complex equipment are required. These installations are usually smaller and less expansive than any infrastructure already in place for the core process of an industrial facility, but they do require space and have a surface footprint of their own within an existing plant.

The *transport* stage brings the now-purified CO_2 from its source to the injection site. Some facilities may be able to inject the CO_2 in geologic formations on site, but typically the exacting geologic requirements for injecting—and then storing CO_2 permanently—require the CO_2 be transported to a site selected specifically for its confluence of geologic, ownership, and infrastructure attributes. Pipelines are by far the most common means of transporting large quantities of CO_2, and today over 4,500 miles of pipeline transport CO_2 in the U.S.[10]; these pipelines are standard and mature technology. Other means of transporting CO_2 include truck, rail, or barge, which although not as economically efficient for larger volumes, may be suited to smaller projects or projects in which the siting of a pipeline may be too complicated or time consuming.

The third and final stage involves the *underground injection* of CO_2 for permanent storage. This task involves one or more injection wells and one or more monitoring wells used to inject the CO_2 in rock formations

10 "21st Century energy Infrastructure: Policy Recommendations for Development of American CO_2 Pipeline Networks." Better Energy, February 2017. https://www.betterenergy.org/wp-content/uploads/2018/02/GPI_Whitepaper_21st_Century_Infrastructure_CO_2_Pipelines.pdf

thousands of feet underground and monitor its location, movement, and storage integrity. These formations are thoroughly screened and selected for their ability to accommodate the injected volumes of CO_2 in permeable and porous formations (e.g., sandstones) and to trap them permanently by virtue of being confined by laterally extensive, impermeable layers (e.g., shales). For example, sedimentary rocks that have successfully trapped hydrocarbons and other fluids for millions of years are candidates. The federal and state regulatory requirements for this screening and selection process are substantial and have been written in the past ten years or so for the express purpose of storage security, environmental integrity, accountability, public health, and safety.

An injection site is often the most underwhelming part of a site visit to a CCS project, as the surface footprint is small and simply consists of a small number of wells and some fencing. The site environment is mostly static, without large equipment, and lacks the scale or commotion of the capture facility. Pre-existing land uses can usually continue undisturbed. Despite this low-key nature, however, selection of the right injection site with suitable geology through a rigorous characterization process is perhaps the most important step for a CCS project and carries one of the highest levels of regulatory oversight in the CCS chain.

Chapter 3:

Regulatory Interactions for CCS Projects in California

In this chapter we examine the multitude of local, state, and federal agencies with whom a CCS project operator needs to interact to obtain the authorizations necessary to operate a project. We use the term regulatory in a general sense, which includes not only mandatory permits under defined regulations but also the following: (1) certifications needed to generate carbon-related credits, (2) agreements with private third parties for CCS project needs, such as for siting pipelines to transport captured CO_2 from its source to the injection site, and for securing necessary mineral and surface rights to inject and store CO_2 underground at a particular site. Throughout the chapter, we label these components of the authorization process according to the agency or counterparty involved and the name of the permit, certification, or agreement discussed.

The list below is not meant to be exhaustive or all-inclusive. A number of local factors or project characteristics may invoke additional regulatory interactions. We have tried to cover most cases that would apply commonly across all project types, and we also mention some special cases that may be encountered frequently, such requirements specific to power plants. Figures 1 and 2 summarize the main authorizations needed for a CCS project in California, as well as the likely turnaround time, technical complexity, and political exposure.

An important note on permitting timelines

In what follows, we quote nominal permit turnaround timelines that are intended to provide an indication of the relative time it takes for the different agencies to process applications and issue permits under their jurisdiction. In practice, a project's approval timeline will primarily be primarily determined by the environmental review process (CEQA and NEPA – see following chapter). Commonly, takes place concurrently with the environmental review process, and the issuance of permits follows shortly after environmental review is completed.

In addition, the possibility of litigation—which some consider unavoidable—may also materially add to the approval timeline for projects and must also be considered. A court case and subsequent appeal(s) can add months to years to a project's timeline.

Authorization related to:	Entity				
	Local	State	Federal	Tribal	Private
Local land use	City/County Governments				
Siting CO_2 pipelines	City/County Governments	State Lands Commission Other agencies with surface/mineral ownership	Bureau of Land Management, Forest Service, Other agencies with surface/ mineral ownership	Bureau of Indian Affairs, Individual Tribes	Land Owners
Pore-space ownership & mineral rights	City/County Agencies man-aging surface/ mineral rights	State Lands Commission Other agencies with surface/mineral ownership	Bureau of Land Management, Forest Service, Other agencies with surface/ mineral ownership	Bureau of Indian Affairs, Individual Tribes	Land Owners, Mineral Rights Owners
Air permits		Local Air Districts	Environmental Protection Agency		
CO_2 pipeline safety		Office of State Fire Marshal	Pipeline & Hazardous Materials, Safety Administration		
CO_2 injection permitting		Geologic Energy Management Division, State Water Resources Control Board, Regional Water Quality Control Boards	Environmental Protection Agency		
Discharges to water (including those of the State)		State Water Resources Control Board, Regional Water Quality Control Boards			
Discharge of dredge or fill materials into waters of U.S.			Army Corps of Engineers		
Endangered species		Department of Fish & Wildlife	Fish & Wildlife Service		
Stream/river/lake alterations		Department of Fish & Wildlife			
Greenhouse gas reporting		Air Resources Board	Environmental Protection Agency		
CO_2 crediting: the revenue stream		Air Resources Board	Internal Revenue Service		

Capture Transportation Storage

Figure 1. *Summary of main authorizations needed for a typical CCS project.*

Figure 2. *Ranking of authorizations according to likely turnaround time, technical complexity, and political exposure.*

Local land use

Applicability: CO_2 capture, CO_2 transport, or CO_2 storage *that takes place within incorporated city boundaries or within certain parts of a host county*

Agencies: *Local government*

Nominal turnaround timeline: *>18 months*

In a nutshell: *Navigating land use—and related plans, plan amendments, or permits—with local government can be a time consuming and politically sensitive undertaking because of the complexity involved and because the fate of the permits is ultimately appealable to and decided by elected officials in what can be a highly visible process. These authorizations or amendments relate not only broadly to the types of activities that are allowed in certain areas but also to very detailed aspects of facilities and installations, such as building height, traffic, noise, and other environmental aspects.*

Cities and counties in California are required to adopt a comprehensive, long-term general plan for their physical development.[11] To further pursue the goals of their general plan, these local governments adopt zoning and land-use ordinances[12] and regulations that specify what types of activities are allowed within different parts of city or county boundaries.[13] These ordinances and regulations specify, for example, the allowed locations for housing, business, and industry and employ measures to maintain valued aspects of the community, including ensuring adequate open space, preserving aesthetics, protecting the public from noise and environmental hazards, and conserving natural resources. Some of these regulations can be very detailed and specific in nature, dictating for example the maximum height allowed for buildings, the nature of allowed lighting and landscaping, and layout requirements for parking lots and more.[14]

CCS retrofit projects on sites previously developed for similar purposes are likely to face fewer hurdles at the local government level since some uses may already be allowed for existing facilities—but not always. For example, the installation of tall columns for the carbon-capture solvent may trigger a reduced level of review at an existing refinery with much taller distillation columns but may be subject to greater scrutiny when exceeding specified height limits at a power plant site. Transporting CO_2 via pipeline, whether in an existing right-of-way (ROW) or otherwise, will likely face a high level of scrutiny and review, regardless of the assessed risk. Storing CO_2 underground is likely not to have been a previously planned for and allowed land use given that it is has never been undertaken in California, although general underground fluid injection or storage provisions may apply.

The siting, construction, and operation of CO_2 capture, transport, and storage facilities must either comply with these local requirements outright or seek other ways to comply. One way to reach compliance is to seek amendment of a city's or county's zoning map to allow certain uses or activities in the project's general area. Changing a general plan can be a comprehensive, strategic exercise that can take several years. Any amendments would also apply more broadly to other facilities and activities in the area and thus are likely to face a high level of scrutiny. By state law, general plans cannot be amended more than four times each year. Thus, such changes may be more appropriate when a local government is considering activities related to CCS as a long-term direction, as opposed to authorizing a single project.

Another possible mechanism for local governments to authorize activities of CCS projects within city or county boundaries is through the adoption or amendment of specific plans. These plans are supplementary to city and county general plans and delve into greater detail than that provided by the general plan. Specific plans, among other topics, describe allowable land uses. Specific plans must be consistent with the local general plan. A specific plan implements, but is not technically a part of, the general plan. In some jurisdictions, specific plans act in the same way as zoning.[15]

Finally, conditional use permits are a tool that cities and counties are authorized to employ to allow special land uses that may be essential or desirable to a particular community but that are not specifically listed by zoning regulations or in ordinances.[16] As with special plans, conditional use permits must be consistent with the general plan. Conditional use permits can also be used to control or restrict certain uses and simultaneously minimize detrimental effects on the community. Thus, a local government may also impose the requirement for a conditional use permit if it wishes to have finer control over capture, transport, or storage activities than is laid out in existing plans, ordinances, and regulations.

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11 T. Roberts, "Citizens Guide to Land Use Planning in California" Governor's Office of Planning and Research, January 2001. https://www.acgov.org/sustain/documents/CitizensGuidetoLandUsePlanninginCalifornia.pdf

12 An ordinance is a piece of legislation adopted by municipal government, typically pertaining matters not already covered by state or federal laws. It must be consistent with general state or sederal laws.

13 California Government Code, §§ 65000 et seq.

14 "Kern County Planning Department Comments and Request for Conditions; Review of Preliminary Staff Assessment-Hydrogen Energy International (HEI) Application for Certification (08-AFC-8)." Kern County Planning Department, January 10, 2011. https://efiling.energy.ca.gov/GetDocument.aspx?tn=59460&DocumentContentId=41307

15 Id., 3.

16 R. Cervantes and K. Lee, "The Planner's Training Series: The Conditional Use Permit." Governor's Office of Planning and Research, July 1997. https://opr.ca.gov/docs/theconditionalusepermit_071997.pdf

Plan amendments, new plans, and conditional use permits are subject to public notice and hearing requirements. They may first be considered by city or county staff or zoning/planning commissions but can usually be appealed, and it is safe to assume they are ultimately subject to approval by or appealable to city councils and county boards of supervisors. This nature adds a marked public-facing and political element to these approvals, distinct from the more technical evaluations that determine the issuance of other CCS-related permits by agency staff (e.g., for the permitting of CO_2 injection well or pipeline construction and safety standards).

Of note, several jurisdictions may be involved in land-use authorizations for a project, particularly for a pipeline or storage facility that transects or intersects several counties, for example. The amount of time necessary to secure one or more conditional use permits for a project located across multiple jurisdictions may prove longer than when just one jurisdiction is involved.

Siting CO_2 pipelines

Applicability: *CO_2 transport*

Agencies: *Potentially several, including private parties*

Nominal turnaround timeline: *>18 months*

In a nutshell: *Siting a CO_2 pipeline may be straightforward if the capture and storage locations coincide and a single owner holds all required land, but many cases will entail potentially lengthy negotiations with a large number of property owners. This step can require a great deal of time and a single holdout can cause serious delays or project derailment. Thus, areas with large land holdings in the hands of few owners will be attractive. A possible alternative to negotiations with private property owners in some cases may be negotiation of franchise agreements with local governments for siting pipelines along public roadways.*

Pipelines are often the most cost-effective way to transport CO_2 from the capture facility to the injection site. They are a widely deployed, mature technology; avoid the use of vehicles, vessels, and trains; and make sense from an economy-of-scale perspective when handling larger CO_2 volumes.

However, pipelines are also notoriously difficult and/or time consuming to site, simply because they may cross many different ownerships—tens or hundreds in some cases. Nonetheless, our public and private lands are rife with pipelines transporting drinking water, sewage, natural gas, and other materials for the common good. This infrastructure was established due to the importance of the underlying goal and the inherent value of the service offered and was practically aided by supporting regulations and legislation.

The most common types of surface ownership a pipeline may need to cross are private, local government (city or county), state, federal, and tribal, as well as existing third-party easements.

In the case of private lands, the mechanism most commonly used to allow siting of pipelines is the easement—a legal agreement conferring to the pipeline owner the right to site, construct, and operate the pipeline on a landowner's property. The term right-of-way (ROW) is often used interchangeably with the term easement, although an easement is the right to use another's property for a specific purpose and an ROW is an easement that specifically grants the holder the right to travel over another's property.[17] Easements can be of finite or, more typically, permanent duration and remain attached to the host property if the land is sold to a new owner.

The terms of an easement can cover a wide array of parameters, including (but not limited to) the easement's location and dimensions, the location and depth of the pipeline, terms that apply to the construction of the pipeline (methods, timeline, access, etc.) and restoration of the land owner's property post-construction, the allowed number of pipelines and carried substances, the operating conditions for the pipeline, liability, access for inspection and maintenance, signage, compensation, and easement modification/termination.

Easements are negotiated one-on-one with landowners and, unless powers of eminent domain apply (see below), these negotiations have no set timeline or certainty of outcome. Not uncommonly, pipelines may be rerouted due to a small number of holdout owners who do not consent to easements: landowners sometimes hold out as a negotiating tactic. Therefore,

17 P. Hall et al., "Negotiating Pipeline Easements." Ohio State University Extension. https://guernsey.osu.edu/sites/guernsey/files/imce/Program_Pages/ANR/Understanding%20and%20Negotiating%20Pipeline%20Easements%20Final.pdf

when siting a pipeline in areas where no other pipelines run, no shortcuts exist for the numerous and possibly prolonged negotiations.

Areas where existing pipelines run may offer a potentially easier pathway to siting. The notion of "reusing an existing right-of-way" is a simplification, but having current pipeline easements already in place may facilitate the siting of a new pipeline. The success of this approach hinges on exactly how the existing easements are written and if, for example, they provide for addition of a new pipeline or for repurposing or modification of an existing one. Many existing pipeline easements, based on their own terms and provisions, may not serve, or they can be outdated with regard to contemporary regulatory, insurance, and indemnity provisions. In such instances, the existing easement terms would need to be renegotiated, or, alternatively, a new easement would need to be obtained from the current property owner(s) that would parallel—or "twin"—the existing pipeline but not interfere with it. At the very least, the mere existence of an easement and pipeline is a possible indication of a willingness (past or present) to allow for that land use, and looking at existing pipeline routes can facilitate siting a CO_2 pipeline.

In certain circumstances, the backdrop of eminent domain may affect landowners' desire to negotiate a pipeline easement. Eminent domain refers to the authority to acquire, or to authorize the taking of private property for public use or public purpose.[18] More often than not, eminent domain is not actually exercised but acts rather as an incentive to negotiate easements. In California, the Public Utilities Commission (CPUC) may consider a CO_2 pipeline corporation that is also a public utility to be a "common carrier" if it is "providing transportation for compensation to or for the public or any portion thereof."[19] Common carrier regulation under the CPUC would enable the pipeline company to exercise eminent domain, but such regulation would be reserved for pipelines that source and carry CO_2 from a number of sources to a storage site and would also be subject to regulator-controlled fees, rates, and operating terms and conditions. For a pipeline that carries CO_2 from a single plant to a storage site, common carrier regulation would likely not apply, and operators of individual plant pipelines should plan for multiple negotiations with land owners, or, alternatively, for locating the pipeline in public roadways that rely on franchise agreements with the pertinent public agencies (see below).

A CO_2 pipeline route may also cross tribal, state, or federal land. In the case of tribal land, the negotiation would take place with the tribe(s) involved. In certain instances, the Bureau of Indian Affairs (U.S. Department of the Interior) could potentially maintain limited rights in certain tribal lands. In the case of state land, the State Lands Commission (SLC) would be the likely counterparty to the siting negotiations, although other departments may possibly own the land directly, such as the California Department of Parks and Recreation (DPR) or the Department of Water Resources (DWR)—all three are departments of the California Natural Resources Agency. The SLC utilizes a formal, multi-tiered, and time-consuming public process to permit ROWs and will often issue only a lease for easement purposes, for a term not to exceed 49 years. The term can be extended upon application.

In the case of federal property, the Bureau of Land Management (BLM), can authorize the crossing of federal land.[20] This authorization requires an application form with supporting information and a fee, and BLM states that it "places a high priority on working with applicants on a proposed ROW to provide for the protection of resource values and to process the application expeditiously." The quoted processing time is a 60-day window for applications. The ROW is granted for a term that is appropriate for the life of the project.

For crossing land owned by local governments, such as cities or counties, the previous section on land-use planning considerations also applies to pipeline siting. Local governments approach requests for easement in a variety of ways, depending on their charter and current manner of administration. In certain cases, something other than easement will be offered instead, such as an agreement containing additional terms and responsibilities, a permit, or a franchise.

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18 Chester County Planning Commission, "Landowners Resource Guide for Pipeline Easements." Chester County Planning Commission, December 2015. https://www.chescoplanning.org/pic/pdf/LandownersResourceGuide.pdf

19 California Public Utilities Code § 211 et seq.

20 Bureau of Land Management Lands and Realty, "Obtaining a Right-Of-Way on Public Lands." U.S. Department of the Interior Bureau of Land Management, March 10, 2018. https://www.blm.gov/sites/blm.gov/files/Lands_ROW_ObtainingaROWPamphlet.pdf

Local governments, public agencies, and utility companies, including railroads, grant a license or permit for pipelines that perpendicularly (or very close thereto) cross their facilities or strips of land they own and/or operate. Such a license is not an interest in the underlying real property but is instead a personal and temporary right to cross the property. A license is unilaterally revocable by the licensor.

Further, local governments typically utilize franchise agreements to provide the rights necessary to construct and operate pipelines longitudinally in a public roadway. Such a public agency franchise represents a potentially easier option for acquiring a pipeline corridor. Simply put, a franchise is a contract between a city, county, or the State and a public or private utility provider who may need public roadway corridors to transport substances by pipeline. Franchise agreements are procedurally governed and will be of limited term but can be renewed. An annual fee for the use of the land as part of the franchise agreement is required and provisions may apply for future payment by operators for line relocations in case of street or highway construction or rerouting projects. Additional provisions will include, but not necessarily be limited to, maintenance of the ROW, pipeline abandonment, insurance, and indemnification. Governments can require bonding to ensure the work is done according to their requirements. Performance bond requirements are also often included and are intended to ensure the operator's obligations under the agreement. Utilizing a public roadway alignment for a pipeline serves to greatly reduce the uncertainty of a successful acquisition program from private parties in the absence of eminent domain authority.

The right to inject CO_2: pore-space ownership and mineral rights

Applicability: *CO_2 storage*

Agencies: *Potentially several, including private parties*

Nominal turnaround timeline: *>18 months*

In a nutshell: *The question of pore-space ownership remains unsettled in California and has not been determined by specific legislative action or adjudication. In addition, where oil, gas, or geothermal production occurs, a property right may be severed into one or more estates held by different parties, such as a surface estate and a mineral estate—such split ownership is typical in California. Depending on the nature of the project and the property, a project developer following the prevailing view may need to negotiate with both the surface estate owners and the mineral estate owners to secure a right to use a property's subsurface pore space. This step provides an immediate path forward for projects absent new legislation or adjudication but can require a great deal of time and a single holdout can cause serious delays or project derailment. Thus, areas with large holdings held by few property owners will likely be more attractive.*

The rights to inject and sequester CO_2 for CCS frequently center on the question of pore space. CCS projects inject CO_2 through wells into pore space deep below the surface, typically at depths of 3,000 ft or more. Pore space consists of voids in permeable and porous sedimentary rock layers overlain with impermeable rock, such as shales, mudstones, clay, and anhydrite sequences. The right to use these voids for CO_2 storage deep below the surface necessitates consideration of a jurisdiction's property law. The predominant view in the U.S. is that the subsurface rock pore space is a property right held by the surface owner. Consequently, using the subsurface to inject and store CO_2 will require an agreement with the owner of the property right.

In California, "[t]he owner of land in fee has the right to the surface and to everything permanently situated beneath or above it."[21] Land is defined as "[…] the material of the earth, whatever may be the ingredients of which it is composed, whether soil, rock, or other substance, and includes free or occupied space for an indefinite distance upwards as well as downwards, subject to limitations upon the use of airspace imposed, and rights in the use of airspace granted, by law."[22] While this definition implies that the surface owner also owns the pore space, a good deal of uncertainty remains because the issue of ownership of pore space for CCS purposes has not been determined by legislative action or express judicial decisions.

In other circumstances, a surface owner's estate may be subject to another party's right to underlying minerals, such as oil or gas. In such cases, one or more distinct and separately owned mineral estates may exist, severed

21 California Civil Code § 829.

22 California Civil Code § 659.

from the surface estate. In Graciosa Oil Co. v. County of Santa Barbara, 155 Cal. 140 (1909)—a dispute over property taxes—the California Supreme Court ruled (over a century ago) that "Such an absolute estate in an underlying stratum may be created and the estate of the owner of the overlying land and of the owner of the subterranean stratum will be as distinct and separate as is the ownership of respective owners of two adjoining tracts of land. For purposes of separate ownership land may be divided horizontally as well as superficially and vertically."

In addition, where a subsurface mineral estate has been carved out of the surface estate, the mineral estate is considered dominant. In Cassinos v. Union Oil Co. of California (1993) 14 Cal.App.4th 1770, the court ruled that "[s]urface owners typically own nearly all rights in the land except for the exclusive right to drill for and produce oil, gas and other hydrocarbons. The owners of the mineral estate, and their lessees, typically hold only the very limited right, analogous to an easement, to drill and capture subsurface oil and gas, and the incidental rights necessary to accomplish this. Thus, under a typical oil and gas lease, the lessee generally obtains only a non-possessory interest in real property to capture such substances, which is in the nature of an easement." The court also notes that "the right of the surface owner is subordinate to an oil and gas lessee, and he may not affect the mineral estate owner's rights so as to prevent his enjoyment thereof or unreasonably interfere therewith." Consequently, where there are separate surface and mineral estates, the mineral owner, as the dominant estate, may also have an interest in a property's pore space.

One reason a CCS project may look for greater certainty in its relationship with owners of a surface estate and, where present, an underlying mineral estate is the concern for liabilities due to trespass. The law remains unclear on this issue. As explained above, Cassinos v. Union Oil Co. holds that a lessee generally obtains only a non-possessory interest in real property. Generally, a non-possessory interest will not give rise to a claim for trespass. However, courts have gone to lengths to find damages for trespass, in part, because "[t]he rules of law should be sufficiently adaptable to reach a desirable result in this developing field of the law." (Callahan v. Martin (1935) 3 Cal.2d 110, 126, 43 P.2d 788.) In Cassinos, an action for trespass to a mineral estate resulting from wastewater injection, the court appears to have gone to great lengths to avoid answering the question of who owns the pore space. But the court did hold that, regardless of pore-space ownership, injection and migration of wastewater damaged the mineral estate's right to drill and extract minerals. This point is equally important in a case where CO_2 is injected in a saline formation because the elevated pressure created by CO_2 injection could cause other fluids (such as *in situ* brines) to migrate to other properties that did not previously contain these fluids.[23]

The question of pore-space ownership is therefore currently unsettled, pending future case law or legislation. A CCS project can closely examine the language of any property conveyance connected to a CO_2 storage site and any recent judicial and legislative developments relevant to the jurisdiction in which the project is sited and can then formulate a plan on how to best proceed. Depending on the conveyance language, it may be best to reach an agreement with the owners of both the surface estate and any mineral estate. Such agreements may take any number of forms, such as easement, servitude, lease, or license.

Therefore, similar to pipeline siting, CCS operators must negotiate with any number of land and mineral owners necessary to cover the surface footprint of the CO_2 plume and possibly beyond. These owners, once again, can be private, municipal, tribal, state, or federal. For certain prospective sequestration sites, numerous property owners may ultimately be involved. Thus, areas that combine suitable geology with the smallest number of land and mineral owners will be prime candidates for CO_2 storage sites.

Air permits

Applicability: *CO_2 capture*

Agencies: *Local air districts, possibly U.S. Environmental Protection Agency*

Nominal turnaround timeline: *~1 year*

In a nutshell: *Air permitting can be a complex undertaking with many moving parts and the potential*

23 Technical Advisory Team in support of The California Carbon Capture and Storage Review Panel, "Background Reports for the California Carbon Capture and Storage Review Panel." California Institute for Energy and Environment, Berkeley, California, December 2010. https://uc-ciee.org/ciee-old/downloads/Background_Reports_for_CCS.pdf

BOX 3-1 Air Permit Applications: How complex are they, and how long will they take?

How does the air permitting process unfold in practice, and how long can it be expected to take? Several "soft" factors affect the process and provide clues for both regulators and developers that could help expedite it.

Some air districts quote ranges for turning around an air permit application. For example, the Bay Area Air Quality Management District (BAAQMD) spells out 160-250 days for approval of NSR permits in its regulations explicitly. In some cases, turnaround can be quicker, depending on complexity and workload. Usually a queue of applications is already in place and, while normally the processing follows a first-in, first-out scheme, priority applications can be moved to the top of the queue. South Coast Air Quality Management District (SCAQMD) provides the ability to pay for expedited processing.

Some regulators advise applicants to submit applications earlier rather than delaying until the equipment design is finalized. Prior to an application being deemed complete, the process typically involves some form of back-and-forth exchange between applicant and regulator. While the formal back-and-forth may be limited to an incompleteness letter and an applicant response, in practice an informal dialogue often occurs that facilitates drafting of the incompleteness letter. The length of the back-and-forth process depends on the applicant's transparency and willingness to respond to the regulator's queries in a timely fashion and provide all of the requested information, as well as on whether the applicant's responses invoke a need for additional details. Such back-and-forth inquiries are common if the applicant is trying to protect business-sensitive information from being included in the permitting file, which is publicly available. An outstanding application processing fee may also delay an application from being deemed complete. Once the application is deemed complete, the permit evaluation is drafted, reviewed, and approved, and the permit, which will contain limits and conditions, is granted (e.g., in the form of authority to construct for new sources).

Some developers feel that the air permitting process is notably more protracted than the turnaround timelines quoted by regulators—more likely to be in the multi-year range—and is one of the most complex links in the CCS permitting chain. This belief may reflect a preference to submit an application before system design is complete or is still in a more conceptual phase (especially for complex systems), whereby developers design as they go based on the interaction with the regulator. Also worth keeping in mind is that the times quoted by regulators are often superseded by the timeline dictated by the CEQA review for a project. Past applicants also report that regulators can be understaffed for the volume of permits they need to process and that they have experienced variability in the efficiency of the process depending on the experience level the permitting engineers have with the type of facility being permitted.

From their end, permitting staff from regulatory agencies report that the permitting process is standardized and that whether or not it proceeds in a timely and efficient fashion depends heavily on the applicant. In particular, several situations can delay or complicate application processing: inexperienced staff assigned from the applicant's side, missing data and (sometimes basic) technical information, a lack of ability or desire to be transparent and responsive to queries or data requests by the regulator, failure to answer how the operation of a new or modified source will impact emissions from the other sources that are part of a complex facility, rejecting regulatory applicability determinations or claiming no emission impacts for equipment additions and engaging in "creative permitting," and failing to accept room for disagreement in the permitting process.

Regardless of one's perspective, air permit applications are clearly undertakings that require proper attention, skill, and prioritization to proceed smoothly.

for substantial back-and-forth with regulators if permit applications are deemed incomplete. For applications that are carefully put together and reflect an advanced stage of facility and equipment design, rules and practice dictate that one year is the minimum time needed. In practice, some applications are submitted at an earlier stage in order to begin the process, and design is refined along the way. Permitting equipment without final design information is often not straightforward, resulting in a process that can take a lot longer and can potentially make air permitting one of the most formidable steps for some applicants.

A CCS project will likely entail equipment that has the potential to emit air pollutants. In California, air districts are the local regulators that implement federal Clean Air Act requirements as well as state rules and regulations that apply to air emissions.[24] The state has 35 local air districts, which are responsible for regional air quality planning, monitoring, and stationary source and facility permitting.[25] A CCS project developer would engage these air districts to receive air permits.[26]

Although precise local rule language may vary, generally all of California's local air districts require any person constructing, altering, replacing, or operating any source that emits, may emit, or may reduce emissions to obtain permit authorization to construct before commencing construction and a permit to operate, unless expressly exempt. Exemptions tend to be limited to very low-emitting equipment, such as such as engines on compressors or emergency generators. In addition, we anticipate that an assessment of air permitting will be particularly applicable to the CO_2 capture stage, which would likely include the majority of the potential air pollution sources. For example, the construction and operation of a capture facility may emit NOx or particulate emissions, and fugitive emissions of an amine-based CO_2 scrubber would be a volatile organic compound (VOC) emission. These potential emissions would need to be accounted for and counterbalanced with the emissions reductions expected to occur due to any upgrades in plant design and the need to remove impurities from the CO_2 to a high standard for the carbon capture unit to operate properly.[27]

The federal Clean Air Act (1970 and subsequent amendments) is one of the Nation's landmark environmental statutes. After a 50 year lifetime, the Act can be credited with several success stories that have made the Nation's air cleaner, resulted in distinct public health benefits, and addressed pressing environmental problems: removing lead from gasoline, phasing out substances that deplete the stratospheric ozone layer, reducing sulfur emissions from power plants and transportation fuels, and reducing emissions of air toxics.[28] At the same time, the Act and/or its implementation have failed to reduce local and regional pollution levels in some areas that continue to have marked health impacts on local populations.[29,30]

At its heart, the Act requires the U.S. Environmental Protection Agency (EPA) to set National Ambient Air Quality Standards (NAAQS) to address the public health and welfare risks posed by certain widespread air pollutants. States are required to develop state implementation plans (SIPs), applicable to appropriate industrial sources in the state, in order to achieve NAAQS for six criteria pollutants: ground-level ozone, particulates, carbon monoxide, lead, sulfur dioxide, and

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24 Except CO_2 emissions – California air districts do not regulate these, and as such any CO_2 benefits will not be taken into account in an air permit application to an aid district. The CEQA review will almost certainly weigh this benefit, however.

25 "California Air Districts." California Air Resources Board. Accessed November, 2020. https://ww2.arb.ca.gov/california-air-districts

26 With one exception: facilities in the San Diego County Air Pollution Control District would have to interact with the regional EPA office (Region 9) for some Clean Air Act permits – all other California air districts can issue EPA-approved permits directly, some of which are appealable locally and some with federally.

27 The extent to which pre-existing emission of criteria pollutants and other pollutants would be affected by the installation of carbon capture is currently being studied in more detail. It is generally anticipated that the opportunity to direct capital and/or revise plant design when installing carbon capture equipment, along with the need for the CO_2 stream to be pure in order for the carbon capture unit to operate properly, will result in net pollution reductions compared to the base plant without capture. This is a topic of high significance to California's non-attainment areas and environmental justice hotspots, and needs to be studied further.

28 J. Aldy et al., "Looking Back at Fifty Years of the Clean Air Acts." Resources for the Future, January 2020. https://media.rff.org/documents/WP_20-01_Looking_Back_at_Fifty_Years_of_the_Clean_Air_Act_v8.pdf

29 M. Fowlie et al. "Climate Policy, environmental justice, and local air pollution" Brookings Institution, October 2020. https://www.brookings.edu/wp-content/uploads/2020/10/ES-10.14.20-Fowlie-Walker-Wooley.pdf

30 D. Pettit, "Don't Trade What You Don't Have." Natural Resources Defense Council, July 20, 2009. Accessed November, 2020. https://www.nrdc.org/experts/david-pettit/dont-trade-what-you-dont-have

nitrogen dioxide.[31] The Act also requires the EPA to set emissions standards based on technology performance for major sources of hazardous air pollutants (air toxics), which are pollutants that are linked to serious health effects.[32]

Whether or not a region has achieved its NAAQS goals determines what kind of permit process a facility will need to go through. In areas that have attained these standards (attainment areas), Prevention of Significant Deterioration (PSD) permits are required for new major sources or for a major source making a major modification. In non-attainment areas, Non-Attainment New Source Review (NNSR) permits are required for new major sources or for major sources making a major modification.[33] Of note, this consideration is made in a pollutant-by-pollutant manner: for example, large areas of California are in non-attainment status for ground level ozone and particulates, whereas virtually the entire state is in attainment for sulfur dioxide and nitrogen dioxide.

The required mitigation action is stricter in non-attainment areas and requires achieving the Lowest Achievable Emissions Rate (LAER), as well as the use of offsets to the extent allowed or available. Offsets are specific to each pollutant, but cross-pollutant trading has been allowed in some cases. In attainment areas, the corresponding requirement is installation of Best Available Control Technology (BACT). In addition, installation of CO_2 capture and associated equipment may trigger the federal major-modification threshold, depending on several factors, including the nature of the equipment, emission levels, parasitic loads,[34] and local precedent. For some applications (the extent of which is not yet fully studied and is dependent on equipment design), non-CO_2 pollutant emissions from an existing facility may be reduced, making air permitting easier. For example, these reductions might be due to an inherent need to clean up the flue gas to make it suitable for the carbon capture process or to the opportunity that fitting carbon capture equipment presents to make other plant modifications that are more efficient and/or reduce pollution.

Regardless of the specific emission triggers of a CCS project, as mentioned above, the need for air district permits is likely: the districts will require project proponents to obtain an Authority to Construct (ATC) and may require them to obtain or modify a Permit to Operate (PTO), in accordance with local air rules.

In addition to PSD and NNSR permitting, installation of CO_2 capture and associated equipment will likely trigger additional Clean Air Act Title V permitting with air districts. The Title requires major sources of air pollutants and certain other sources to obtain an operating permit, operate in compliance with it, and certify compliance at least annually.[35] Revision of a facility's Title V will be required as a major or minor revision and thresholds may vary among California's air districts.

CO_2 pipeline safety

Applicability: *CO_2 transport*

Agencies: *California State Fire Marshal, possibly U.S. Pipeline and Hazardous Materials Safety Administration*

Nominal turnaround timeline: *Several months*

In a nutshell: *Designing a CO_2 pipeline to safe and approved standards and obtaining necessary regulatory approvals should be a straightforward task. The primary responsible agency for this task remains unclear; the State Fire Marshal is very likely to, or has already asserted authority over this task, although its federal counterpart (the Pipeline and Hazardous Materials Safety Administration) may be the relevant body under some interpretations. A simple fix by the California legislature would readily clarify this point.*

In addition to obtaining the necessary siting permissions, a CO_2 pipeline must also be regulated for safety to

31 "Summary of the Clean Air Act." United States Environmental Protection Agency. Accessed November, 2020. https://www.epa.gov/laws-regulations/summary-clean-air-act

32 "Setting Emissions Standards for Major Sources of Toxic Air Pollutants." United States Environmental Protection Agency. Accessed November, 2020. https://www.epa.gov/clean-air-act-overview/setting-emissions-standards-major-sources-toxic-air-pollutants

33 "Learn About New Source Review." United States Environmental Protection Agency. Accessed November, 2020. https://www.epa.gov/nsr/learn-about-new-source-review

34 Parasitic load will only be an issue to the extent that market factors lead the project to maintain the same output as prior to the installation of carbon capture.

35 "Operating Permits Issued under Title V of the Clean Air Act." United States Environmental Protection Agency. Accessed November, 2020. https://www.epa.gov/title-v-operating-permits

ensure it is constructed and maintained properly and poses no environmental or public health and safety risk.

The federal Hazardous Liquid Pipeline Safety Act of 1979 (HLPSA)[36] and subsequent amendments authorize the Secretary of Transportation to establish regulations for gas and hazardous liquid pipelines to ensure "protection against risks to life and property."[37] CO_2 pipelines are mentioned separately, and standards apply for both liquid and gaseous state transportation of CO_2.[38] The Pipeline and Hazardous Materials Safety Administration (PHMSA) thus regulates interstate CO_2 pipelines, but states are allowed to regulate intrastate CO_2 pipelines.[39] The applicable federal regulations administered by PHMSA also distinguish between hazardous liquid and CO_2 pipelines.[40] Some pipelines that transport CO_2 through certain types of facilities or downstream of certain nodes in a CO_2 injection and recycling operation (most likely an oil field) are exempt from regulation.[41]

In California, the Office of the State Fire Marshal (OSFM) implements federal regulations as authorized by the Elder California Pipeline Safety Act of 1981.[42] However, unlike HLPSA, the Elder Act does not mention CO_2 pipelines specifically and instead only refers to hazardous liquid pipelines; HLPSA was amended by Congress in 1988 to require regulation of CO_2 pipelines, but no Elder Act amendments since then have tracked this development.[43] This formulation is also reflected in the relevant California regulations for hazardous liquid pipeline safety, which adopt the relevant part[44] from federal regulations "by reference as it relates to hazardous liquid pipelines."[45]

This asymmetry could be interpreted to mean that California law does not authorize the State Fire Marshal to regulate intrastate CO_2 pipelines and that the relevant authority lies with PHMSA. However, HLPSA authorizes the regulation of "carbon dioxide transported by a hazardous liquid pipeline facility,"[46] thus indicating that Congress considers the pipeline transport of CO_2 as taking place in a hazardous liquid pipeline. In addition, the Elder Act authorized OSFM to "act as agent for the United States Secretary of Transportation to implement the federal Hazardous Liquid Pipeline Safety Act (49 U.S.C. Sec. 2001 *et seq*.) and federal pipeline safety regulations as to those portions of interstate pipelines located within [California]."

Therefore, OSFM may have legitimate jurisdiction over intrastate CO_2 pipelines in California, despite the bifurcation in federal regulations between CO_2 and hazardous liquid pipelines. Indeed, at the time of this writing, OSFM staff has confirmed this understanding—and their intent to exercise jurisdiction over intrastate CO_2 pipelines that cross "open domain"[47]—and that OSFM acts as the state arm of PHMSA.

OSFM estimates that 6-7 months at most would be required to permit a CO_2 pipeline for compliance with safety standards.

Note that the State Fire Marshal recently issued new regulations for requirements for new or replacement pipeline near Environmentally and Ecologically Sensitive Areas in, or near, the Coastal Zone.[48] These regulations require use of Best Available Technology in order to protect these areas. An operator has the responsibility to

36 49 USC § 60101 et seq.

37 49 USC § 60102 (a) (1).

38 49 USC § 60102 (i).

39 49 CFR Part 195 Appendix A: "The HLPSA leaves to exclusive Federal regulation and enforcement the 'interstate pipeline facilities,' those used for the pipeline transportation of hazardous liquids in interstate or foreign commerce. For the remainder of the pipeline facilities, denominated 'intrastate pipeline facilities,' the HLPSA provides that the same Federal regulation and enforcement will apply unless a State certifies that it will assume those responsibilities. A certified State must adopt the same minimal standards but may adopt additional more stringent standards so long as they are compatible."

40 49 CFR Part 195.

41 49 CFR § 195.1(b).

42 California Government Code § 51010.

43 See Technical Advisory Team in support of The California Carbon Capture and Storage Review Panel (2010), footnote #94.

44 49 CFR Part 195.

45 19 CCR § 2000.

46 49 USC § 60102 (i) (1).

47 I.e. are not entirely within a single owner's property.

48 19 CCR § 2100 et seq. Also available at: https://osfm.fire.ca.gov/media/11548/_01_text2ndwdatescertain-final-clean.pdf

identify pipelines that are subject to or may be exempt from these new requirements.[49]

CO_2 injection permitting

Applicability: *CO_2 storage*

Agencies: *U.S. Environmental Protection Agency, California Geologic Energy Management Division, California State Water Resources Control Board, and regional water quality control boards*

Nominal turnaround timeline: *>18 months*

In a nutshell: *Permitting CO_2 injection wells is likely one of the most complex and technically intensive tasks CCS projects will encounter. For all projects, except those that inject CO_2 for the primary purpose of oil or gas production, a Class VI injection-well permit application to the U.S. Environmental Protection Agency regional office (Region 9) will be required. The application will also likely be shared for review with the State Water Resources Control Board (SWRCB), one or more of California's Regional Water Boards, and the California Geologic Energy Management Division (CalGEM). Nationwide, very few Class VI well permits have been issued since the class came into existence a decade ago. Some of those permits took over three years to issue. There is reason to believe that applications today may proceed faster, but this has not been proven in practice yet. California is currently contemplating a primacy application to administer the Class VI program through the Geologic Energy Management Division. Projects that inject CO_2 for the primary purpose of oil or gas production (without posing an increased risk to underground sources of drinking water) require only the simpler and more routine Class II well permit, issued by CalGEM.*

In 1974, Congress enacted the Safe Drinking Water Act (SDWA) to protect public health by regulating the nation's public drinking water supply and activities that can threaten it. The Safe Drinking Water Act seeks to protect drinking water and its sources: rivers, lakes, reservoirs, springs, and groundwater wells. Under SDWA authority, the U.S. Environmental Protection Agency (EPA) established the Underground Injection Control (UIC) Program in 1980 to prevent contamination of Underground Sources of Drinking Water (USDWs) caused by subsurface injection of fluids.[50] According to the EPA, the UIC program is responsible for regulating construction, operation, permitting, and closure of injection wells that place fluids underground for storage or disposal.[51]

The program initially comprised 5 well classes (designated Class I through to V), depending on their purpose and injected fluid, with unique regulations for each class. Class VI was added in 2010 specifically to regulate the underground injection of CO_2 for geologic sequestration.[52] Class VI well permits are issued directly by the EPA, unlike permits for Class II wells (used to inject brines, CO_2, steam, and other fluids associated with oil and gas production, as well as liquid hydrocarbons for storage), which are commonly issued by state oil and gas regulators under a primacy arrangement with EPA. The exceptions are North Dakota and Wyoming, which have applied for and received primacy for Class VI wells in 2018 and 2020, respectively.

For the immediate future, projects wishing to inject CO_2 for sequestration in California will need to apply to EPA Region 9 for Class VI permits or to CalGEM for Class II permits if the project's primary purpose is oil

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49 For the definition of California's Coastal Zone, see California Public Resources Code, Division 20, § 30000 et seq. Maps of the Coastal Zone boundary are also available by the California Coastal Commission: Accessed November, 2020. https://www.coastal.ca.gov/maps/czb/

50 Under 40 CFR part 136, a USDW is defined as "[…] an aquifer or its portion:

(a) (1) Which supplies any public water system; or

(2) Which contains a sufficient quantity of ground water to supply a public water system; and

(i) Currently supplies drinking water for human consumption; or

(ii) Contains fewer than 10,000 mg/l total dissolved solids; and

(b) Which is not an exempted aquifer."

51 B. Mordick and G. Peridas, "Strengthening the Regulation of Enhanced Oil Recovery to Align it with the Objectives of Geologic Carbon Dioxide Sequestration." Natural Resources Defense Council, November 2017. https://www.nrdc.org/sites/default/files/regulation-eor-carbon-dioxide-sequestration-report.pdf

52 Federal Requirements Under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO_2) Geologic Sequestration (GS) Wells (75 FR 77230, December 10, 2010), codified at 40 CFR 146.81 et seq.

or gas production.[53] UIC regulations also call for Class II wells to transition into Class VI if they are "injecting carbon dioxide for the primary purpose of long-term storage into an oil and gas reservoir […] when there is an increased risk to USDWs compared to Class II operations."[54] The determination of increased risk to USDWs is made by the UIC Program Director—in this case, U.S. EPA Region 9—according to factors listed in the regulations. This area is grey and untested, not least because the regulatory language relies on the simplistic and contrived notion that enhanced hydrocarbon recovery takes place first at a lower risk to USDWs, while sequestration becomes dominant as hydrocarbon production decreases and reservoir pressure increases again. In reality, many factors determine the actual risk level to USDWs in real time during any phase of operation. The determination of whether a Class II or Class VI permit is needed in California will, in practice, likely be determined by a combination of U.S. EPA Region 9 and CalGEM.

Class II well permits are issued by state regulators in most cases, according to state-specific Class II regulations approved by the EPA. Class II permits are commonplace and have been used for decades for disposal of fluids associated with oil and gas production and for the water flooding of oil and gas fields to aid production. The EPA listed just over 180,000 Class II wells in its 2018 nationwide state and tribal inventory.[55] Regulators are thoroughly accustomed to dealing with Class II injection-well applications, and the anticipated turnaround time and administrative effort is low, partially due to the sparser nature of federal UIC Class II regulations and of states' Class II regulations, on the whole (although some states have much more thorough requirements that others).[56] In fact, this nature of Class II regulations and the desire to address gaps in CCS regulation imposed by the limited mandate to protect USDWs under SDWA is one of the key factors that drove the California Air Resources Board (CARB) to develop its own CCS protocol (see below).

In contrast, Class VI rules are extensive and heavy on the science background work that must precede a successful application. The same EPA inventory only listed two Class VI well permits at the time of this writing. One of those permits—the injection well for the Archer Daniels Midland ethanol CO_2 capture facility in Illinois—took over three years for the EPA to process and approve (mid 2011–Sep. 23, 2014).[57] This exceptionally long timeline reflects both the more comprehensive nature of Class VI requirements and the relative inexperience of both applicants and regulators in respectively compiling and processing such applications. The EPA has stated its aspirations to turn Class VI permit applications around faster, now that its staff has gained some limited experience with application submission since the first permits were issued. However, the process is still likely to require longer than 18 months.

As described below, review of Class VI permit application material in California by agencies other than the EPA is also likely: CalGEM, the SWRCB, regional water boards, and CARB may also review application materials. Even though none of these agencies has a substantive, official role in the review and approval of a Class VI UIC permit per se, they do have significant relevant experience, and the EPA's current and expected future approach is to solicit their comments and input with a goal of permitting projects that garner their support. Local land-use agencies could potentially also insist on a role, perhaps beyond their CEQA responsibilities.

In California, Class II wells permits had been issued by the Division of Oil, Gas, and Geothermal Resources (DOGGR) for decades, under relatively light requirements. These regulations were revised in April 2019, following substantial concerns about their effectiveness and DOGGR's practices.[58,59] Today, CalGEM

53 There is also a theoretical possibility that a Class II well may need to transition to a Class VI well but, for reasons described in Mordick & Peridas (2017), we do not consider this.

54 40 CFR § 144.19.

55 "UIC Injection Well Inventory." United States Environmental Protection Agency. Accessed November, 2020. https://www.epa.gov/uic/uic-injection-well-inventory

56 Mordick & Peridas (2017).

57 "EPA Approves Permit for ADM's Second CCS Well." Ethanol Producer Magazine, November 20, 2020. Accessed November, 2020. http://ethanolproducer.com/articles/11495/epa-approves-permit-for-adms-second-ccs-well

58 14 CCR § 1720.1 et seq.

59 "Underground Injection Control", California Department of Conservation. Accessed January, 2021. https://www.conservation.ca.gov/calgem/general_information/Pages/UndergroundinjectionControl(UIC).aspx

(née DOGGR) is still the issuing agency, but SWRCB and the regional water boards play an active review role, and the pace of Class II permit issuance has reduced considerably.[60] Whether any additional agencies would request a review remains uncertain, and meeting Class II requirements is more straightforward than the more specific and comprehensive Class VI requirements.

Discharges to water (including those of the State)

Applicability: *CO_2 capture, transport, and storage*

Agencies: *California State Water Resources Control Board and regional water quality control boards*

Nominal turnaround timeline: *Several months*

In a nutshell: *The definitions of discharge and water are broader than the words imply. With proper project design and construction, discharges to water may be eliminated. However, that does not necessarily obviate the need for the State Water Resources Control Board (SWRCB) and one or more of California's regional water boards to review certain aspects of a CCS project. In particular, these agencies will also need to satisfy themselves that any Underground Injection Control (UIC)permits issued by the U.S. Environmental Protection Agency (EPA) or the California Geologic Energy Management Division (CalGEM) cover the bases of any waste discharge requirements that the water boards would have otherwise issued. This cross-agency issue adds a layer of review to injection well permit applications. Mitigation measures may overlap with federal requirements for discharges of dredged or fill material into waters of the U.S. (see below).*

The federal Clean Water Act (CWA) of 1972[61] aims to control discharges of pollutants into the waters of the U.S. and regulates quality standards for surface waters.[62] The Act authorizes the EPA's National Pollutant Discharge Elimination System (NPDES) permit program, which controls discharges. In California, implementation of the NPDES program lies with the SWRCB and 9 regional water quality control boards (Water Boards). NPDES permits are also referred to as waste discharge requirements (WDRs) that regulate discharges to waters of the U.S.

The California Water Code also authorizes SWRCB and the Water Boards to issue WDRs for discharges into waters of the State, and the person discharging or proposing to discharge must file a report and pay a fee.[63] The boards may also waive the requirements for certain categories.

SWRCB and the Water Boards regulate discharges of pollutants that are not limited to large outlet streams of chemical pollution, but may include rock, sand, and dirt, as well as agricultural, industrial, and municipal waste.[64] Therefore, some aspect of the construction or operation of a CCS project will likely necessitate obtaining a WDR from a regional Water Board. This process should require no more than a few months, provided the application is complete and substantiated.[65]

Specifically in relation to underground injection of CO_2, SWRCB and local Water Boards may also require WDRs. However, in some cases these boards waive the WDRs if they are satisfied that the conditions of the UIC permit also cover their own waste discharge requirements. CalGEM has a memorandum of agreement (MOA) in place with SWRCB that leaves permitting responsibility for Class II wells with CalGEM but affords SWRCB and local water boards an opportunity to review the application and permit.[66]

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60 For details on turnaround times for Class II permits by CalGEM, see California Department of Conservation, Legislative Reports, "Underground Injection Control Reports (SB 855, SB 83, SB 1493)". Accessed January, 2021. https://www.conservation.ca.gov/calgem/pubs_stats/Pages/legislative_reports.aspx. Also note the distinction between project approvals and individual well permits. A project may involve hundreds, or thousands, of wells, and undergoes a more rigorous evaluation to pave the way for more rapid, individual well permit issuance.

61 33 USC §1251 et seq.

62 "Summary of the Clean Water Act." United States Environmental Protection Agency. Accessed November, 2020. https://www.epa.gov/laws-regulations/summary-clean-water-act

63 California Water Code § 13260 et seq.

64 "National Pollutant Discharge Elimination System (NPDES)-Wastewater." California State Water Boards. Accessed November, 2020. \https://www.waterboards.ca.gov/water_issues/programs/npdes/

65 Personal communication with SWRCB.

66 "Revised Memorandum of Agreement Between The State Water Resources Control Board And The Department of Conservation Division Of Oil, Gas, And Geothermal Resources Regarding Underground Injection Control, Discharges To Land, And Other Program Issues." California Department of Conservation, The MOA was first issued in 1988 and revised in 2018: https://www.conservation.ca.gov/calgem/for_operators/Documents/MOU-MOA/2018.07.31_Revised_MOA_with_the_State_Water_Board.pdf

No such agreement is in place between the U.S. EPA and California's water boards; however, to ensure both sound review and a smoother regulatory pathway (that may avoid the imposition of WDRs), the bodies (U.S. EPA Region 9, SWRCB, the Water Boards, and CalGEM) have agreed that Class VI permit applications will be shared among them for review, with each agency conducting its own review but sharing information during the process and with U.S. EPA coordinating the effort.[67] CARB may potentially also be inserted into this process, since significant overlap is expected between supporting materials for a Class VI injection well application and certification under CARB's CCS Protocol (see below).

Discharge of dredge or fill material into waters of the United States

Applicability: *CO_2 transport and storage*

Agencies: *U.S. Army Corps of Engineers*

Nominal turnaround timeline: *A few weeks or >18 months*

In a nutshell: *Discharge of dredge or fill material into U.S. waters may be avoidable by CCS projects depending on design, local topography, and construction details. For the cases where it is not avoidable, a general permit allows for activities to proceed more expeditiously, provided any impacts are routine and small. If the potential impacts are larger and an individual permit review is triggered—something frequently encountered when pipelines cross jurisdictional waters, such as rivers, streams, creeks, and wetlands—a slow and protracted process involving the U.S. Army Corps of Engineers may ensue. Mitigation measures may overlap with those for state requirements for discharges to water (see above).*

The federal Clean Water Act (CWA) (Section 404) also requires a permit from the U.S. Army Corps of Engineers (USACE) in order to discharge dredged or fill material into U.S. waters.[68] The definition of material covered under the regulations has been the subject of court cases and regulatory revisions over the years[69,70] and is specific enough to merit a case-by-case determination by USACE. Depending on how a CCS project is constructed and possibly operated, these definitions and regulatory requirements could be triggered: for example, if a dock is to be constructed on a river or channel to enable barges to load and unload CO_2 or if a pipeline is laid on a riverbed or slough.

Several classes of activity are permitted under their own regulatory requirements. These classes fall under the general permit or the individual permit designation.[71] General permits authorize categories of activities in specific geographical regions or nationwide. For most discharges that will have only minimal adverse effects—for example, minor road activities, utility line backfill, and bedding—a general permit may be suitable. The general permit process eliminates individual review and allows certain activities to proceed with little or no delay.[72]

Individual permits are issued following a review of individual applications. An individual permit is required for activities with potentially significant impacts. USACE reviews applications under a public interest review, as well as under the environmental criteria set forth in the CWA Section 404(b)(1) Guidelines[73] by EPA.[74] The process for an individual permit entails public input and is more involved than a general permit. Past applicants fairly uniformly report a slow and protracted interaction with USACE.

In select cases, more agencies might be involved for the purposes of coordination. For example, the Dredged

67 Personal communication with relevant staff.

68 33 USC § 1344.

69 73 FR 79645. Also see: Further Revisions to the CWA Regulatory Definition of "Discharge of Dredged Material." United States Environmental Protection Agency. Accessed November, 2020. https://www.epa.gov/cwa-404/further-revisions-cwa-regulatory-definition-discharge-dredged-material

70 67 FR 31129.

71 33 CFR § 320.1.

72 "Permit Program under CWA Section 404." United States Environmental Protection Agency. Accessed November, 2020. https://www.epa.gov/cwa-404/permit-program-under-cwa-section-404

73 40 CFR Part 230.

74 "Permit Program under CWA Section 404." (Accessed November, 2020)

Material Management Office (DMMO) might be involved for instances involving the San Francisco Bay.[75]

Endangered species

Applicability: *CO_2 capture, transport, and storage*

Agencies: *California Department of Fish and Wildlife, U.S. Fish and Wildlife Service*

Nominal turnaround timeline: *Several months*

In a nutshell: *Depending on location and project specifics, CCS projects may have potential impacts to species and their habitats that are protected under federal and/or California law. Eliminating or mitigating these impacts to the greatest extent possible is good practice and will make for a smoother and more expeditious regulatory interaction. Industrial operators in certain parts of California are accustomed to dealing with species that are listed as threatened or endangered.*

The federal Endangered Species Act (ESA) of 1973[76] recognized the U.S.' natural heritage as being of "esthetic, ecological, educational, recreational, and scientific value to our Nation and its people." Thus, the ESA seeks to protect and recover imperiled species and the ecosystems upon which they depend. The ESA may list any species as either endangered or threatened. Endangered applies to a species in danger of extinction throughout all or a significant portion of its range. Threatened applies when a species is likely to become endangered within the foreseeable future.[77]

The ESA prohibits the "take" of listed species through direct harm or habitat destruction. According to the Act's 1982 amendments, however, the U.S Fish and Wildlife Service (USFWS) may issue permits—an "enhancement of survival" permit or an "incidental take" permit—that authorize a predetermined level of take associated with otherwise lawful activities. Depending on the permit, applicants must design, implement, and secure funding for either a candidate conservation agreement with assurances or a Habitat Conservation Plan, both of which minimize and mitigate harm to listed species from the proposed project or activity.[78]

The state equivalent of the ESA—the California Endangered Species Act (CESA)[79]—seeks to protect any native species or subspecies of bird, mammal, fish, amphibian, reptile, or plant that is in serious danger of becoming extinct throughout all or a significant portion of its range.[80, 81] The CESA is implemented by the California Department of Fish and Wildlife (CDFW), which may also issue incidental take permits. These permits contain measures that a permittee must implement in order to be exempt from the take prohibition, with the measures being roughly proportional to the impact of take. Specifically, an applicant must ensure adequate funding to implement the measures, and the take must be minimized and fully mitigated and must not jeopardize continued existence of the species.[82]

Generally, the ESA and CESA overlap in their listed species, but the two lists need not be identical, and the designation in each may be different. For example, the San Joaquin kit fox and the blunt-nosed leopard lizard are two species commonly encountered near oil and gas operations in California's Central Valley. The former is listed as federally endangered but is only threatened

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75 The DMMO was set up as a joint program of the San Francisco Bay Conservation and Development Commission, San Francisco Bay Regional Water Quality Control Board, State Lands Commission, the San Francisco District U.S. Army Corps of Engineers, the U.S. Environmental Protection Agency, the California Department of Fish and Wildlife, the National Marine Fisheries Service, and the Fish and Wildlife Service. The stated purpose of the DMMO is to cooperatively review sediment quality sampling plans, analyze the results of sediment quality sampling and make suitability determinations for material proposed for disposal in San Francisco Bay. See "Dredged Material Management Office (DMMO)", U.S. Army Corps of Engineers - San Francisco District Website. Accessed January 2021. https://www.spn.usace.army.mil/Missions/Dredging-Work-Permits/Dredged-Material-Management-Office-DMMO/

76 16 USC § 1531 et seq.

77 "Endangered Special Act Overview." The United States Fish and Wildlife Service. Accessed November, 2020. https://www.fws.gov/endangered/laws-policies/

78 "Habitat Conservation Plans Under the Endangered Species Act." The United States Fish and Wildlife Service. https://www.fws.gov/sites/default/files/documents/habitat-conservation-plan-fact-sheet.pdf

79 California Fish & Game Code § 2050 et seq.

80 "Threatened and Endangered Species Protected Under the California Endangered Species Act." California Department of Fish and Wildlife. Accessed November, 2020. https://wildlife.ca.gov/Conservation/CESA

81 For a comparison between ESA and CESA, "CESA to the Federal Endangered Species Act." California Department of Fish and Wildlife. Accessed November, 2020. https://wildlife.ca.gov/Conservation/CESA/FESA

82 California Fish & Game Code § 2081 (b); C.C.R. §§ 783.2-783.8

under CESA in California, whereas the latter is listed as endangered both federally and in the state.[83]

Plans and measures under ESA and CESA are subject to public comment, and the process of issuing permits can be expected to span a few months (but likely less than a year). New seasonal flora and fauna surveys may be required, depending on whether previous surveys are available.

Due to requirements in the California Air Resources Board's CCS Protocol (see below) to perform regular ecostress monitoring, synergies may arise between a certification under that protocol and ESA or CESA conservation agreements that benefit habitat.

Notably, for the U.S. Environmental Protection Agency (EPA) to issue a final Underground Injection Control (UIC) permit, it must find that the project will be in compliance with section 7 of the ESA. If that analysis has already been done in support of or under the obligation of another agency or a state process (such as CEQA), then it can be used by the EPA as long as it sufficiently demonstrates federal ESA compliance.

Stream, river, or lake alterations

Applicability: *CO_2 transport and storage*

Agencies: *California Department of Fish and Wildlife*

Nominal turnaround timeline: *Weeks to a few months*

In a nutshell: *Certain locations or construction requirements may trigger the need to notify and obtain agreement from the California Department of Fish and Wildlife for stream, river, or lake alterations. Again, the range of what could be considered a stream, river and lake is wider than the words imply. Mitigation or avoidance of impacts should further simplify what is already a straightforward regulatory interaction that has short and well-defined timelines.*

The California Fish and Game Code finds that "protection and conservation of the fish and wildlife resources of this state are of utmost public interest. Fish and wildlife are the property of the people and provide a major contribution to the economy of the state, as well as providing a significant part of the people's food supply; therefore their conservation is a proper responsibility of the state."[84]

To that effect, the Code prohibits any entity from substantially altering any stream, river, or lake without beforehand, inter alia, notifying the California Department of Fish and Wildlife (CDFW) in writing describing the alteration, and without either receiving written notification from CDFW "that the activity will not substantially adversely affect an existing fish or wildlife resource" or a final agreement from CDFW that includes reasonable measures necessary to protect the resource, with which the entity must comply.[85] The Code allows CDFW 60 days to respond to the entity, after which time the entity may proceed with the alteration if CDFW has not issued a draft agreement, provided the entity conducts the activity as described in its notification to CDFW, including any measures intended to protect fish and wildlife resources. However, once CDFW does send a draft agreement, the entity then has 30 days to accept or dispute the draft agreement. If the entity disputes it, CDFW must meet with the entity within 14 days thereafter to seek a resolution. If a resolution is not found, a three-member arbitration panel is set up, which must rule within 14 days of its establishment.

Notably "river, stream, or lake" includes those that are dry for periods of time, as well as those that flow year-round,[86] increasing the likelihood that construction of CO_2 pipelines, injection wells, or other CCS project facilities could plausibly trigger the need for an alteration agreement with CDFW. Despite the formality, California law sets specific, short timelines for this process as described above, and we do not anticipate that it will pose a substantial issue for well-designed projects.

Greenhouse gas reporting

Applicability: *CO_2 capture, transport, and storage*

Agencies: *U.S. Environmental Protection Agency, California Air Resources Board*

Nominal turnaround timeline: *Weeks to a few months*

83 "State and Federally Listed Endangered and Threatened Animals of California." California Department of Fish and Wildlife. Accessed November, 2020. https://nrm.dfg.ca.gov/FileHandler.ashx?DocumentID=109405&inline

84 California Fish & Game Code § 1600.

85 California Fish & Game Code § 1602.

86 "Lake and Streambed Alteration Program." California Department of Fish and Wildlife. Accessed November, 2020. https://wildlife.ca.gov/conservation/lsa

In a nutshell: *Entities that capture, inject, or store CO_2 in the subsurface must report certain data to the U.S. Environmental Protection Agency (EPA) and to the California Air Resources Board (CARB). If CO_2 is being stored but not in conjunction with hydrocarbon production, federal reporting must include a monitoring, reporting, and verification (MRV) plan to detect and quantify leaks from the subsurface to the atmosphere. Creating and implementing this MRV plan is an additional undertaking to the basic meter-based requirements that otherwise apply, but any entity with the competence and wherewithal to pursue a CCS project successfully should be readily capable of handling this requirement.*

The federal Clean Air Act also provides the U.S. EPA with the authority to require reporting of data relevant to the EPA's implementation of a wide variety of the Act's provisions.[87] The EPA has thus established the Greenhouse Gas Reporting Program (GHGRP),[88] which requires reporting of greenhouse gas (GHG) data and other relevant information from large GHG emission sources, fuel and industrial gas suppliers, and CO_2 injection sites. The data are intended to be used by businesses, stakeholders, government, and the public to track and compare facilities' GHG emissions, identify opportunities to cut pollution and save energy, and develop climate policies.[89]

Different requirements apply to projects for which storage is the only objective—and thus involve no hydrocarbon production—than apply to projects that store CO_2 in producing oil or gas fields. Specifically, subpart RR of the GHGRP applies to "wells that inject a CO_2 stream for long-term containment in subsurface geologic formations,"[90] while subpart UU applies to wells that inject a CO_2 stream into the subsurface (without the objective of long-term containment).[91]

All wells with a Class VI Underground Injection Control (UIC) permit must report under subpart RR. Operators of Class II CO_2 injection wells must report under subpart UU but may choose to "opt in" and report under subpart RR.

The two reporting regimes have fundamental differences. Subpart RR requires reporting the quantities of CO_2 received, injected, and produced, as well as equipment leaks and vents. In addition, operators must develop and submit a monitoring, reporting, and verification (MRV) plan for EPA approval within 180 days of receiving their Class VI permit. The purpose of the MRV plan is to calculate any surface leaks of CO_2 by identifying potential surface leakage pathways and to establish a strategy for detecting and quantifying any surface leakage. The plan must define monitoring areas, establish baselines, and be revised within 180 days of any material changes to the injection or its permit.[92] The MRV plan that operators first submit to EPA does not need to be made public. The Administrator may request changes and then issues a final MRV plan, which is then published and may be challenged by interested parties via the EPA's Environmental Appeals Board (EAB).

Subpart UU, on the other hand, contains comparatively sparse reporting requirements, that are primarily based on simple surface meter readings and equations. Notably, neither subpart RR nor subpart UU mandate any leakage prevention measures as such nor do they prohibit surface or subsurface leakage. Their purpose, dictated by the underlying Clean Air Act authority, is to ensure that any surface leakage is reported. Subpart RR's requirements under the MRV plan do represent common-sense steps that an operator would routinely undertake to select the best possible site and minimize the risk of leakage.

As such, the GHGRP does not impose any major additional regulatory burdens on CCS projects, and the substantive steps needed to comply with subpart RR can be viewed as subsets of the steps needed to obtain a Class VI injection permit or certification under CARB's CCS Protocol (see below). The GHGRP does mandate an additional interaction with EPA, although timelines appear to have become expeditious. At

87 42 USC § 7414.

88 40 CFR Part 98.

89 "Learn about the Greenhouse Gas Reporting Program (GHGRP)." United States Environmental Protection Agency. Accessed November, 2020. https://www.epa.gov/ghgreporting/learn-about-greenhouse-gas-reporting-program-ghgrp

90 40 CFR §§ 98.440 - 98.449.

91 40 CFR §§ 98.470 - 98.478.

92 40 CFR § 98.448.

the time of this writing, EPA listed 11 approved MRV plans on its website.[93] The first of these reportedly took approximately 2.5 years from the time scoping conversations began between the proponent and EPA. Subsequent applications required around 1.5 years, whereas the most recently approved MRV plans have an estimated turnaround time of approximately 4 months between submission and approval.

Additional federal reporting requirements related to CO_2 injection—subpart PP of the GHGRP[94]—applies to "suppliers of CO_2" and mandates that facilities with production process units that capture a CO_2 stream—for purposes of either supplying it for commercial applications or of injecting it—report certain quantities to EPA.

California has its own GHG reporting requirements, codified in the Mandatory GHG Reporting Regulation (MRR).[95] The MRR echoes the EPA's requirement for "suppliers of CO_2," and CCS projects in California would have to report to CARB under this category. Notably, no category similar to the EPA's GHGRP subparts RR or UU exists under the MRR.[96]

CO_2 crediting: the revenue stream

Applicability: *CO_2 capture, transport, and storage*

Agencies: *California Air Resources Board, Internal Revenue Service*

Nominal turnaround timeline: *~1 year*

In a nutshell: *Two main incentives apply to certain types of CCS project in California today: credits under the state's Low Carbon Fuel Standard (LCFS) and the federal 45Q tax credit. The processes for securing these two incentives stand in strong contrast to each other. The process for project certification and crediting under the LCFS with the California Air Resources Board is almost certainly the scientific and technical crux for a project and will require competence and diligence. Despite this complexity, and aware of the importance of the incentive to projects, the agency aspires to short application turnaround times. In contrast, claiming the 45Q federal tax credit only requires completing a simple form when the credit is claimed in a tax return. Claiming it legitimately and in accordance with Internal Revenue Service (IRS) requirements does require a level of document retention, certification, and/or participation in regulatory programs administered by other bodies—however these burdens are minor compared to a Class VI injection-well application or a LCFS and related California CCS Protocol application.*

Two main incentives apply to certain types of CCS project in California today: the state's LCFS and the federal 45Q tax credit. Obtaining these credits is not mandatory for projects to move forward, nor are any permits issued by these programs. But the revenue stream from certification under these programs is almost certainly instrumental to the vast majority of CCS projects under development in California today and in the near future, so here we summarize the requirements for crediting under both. We expect eligibility under one or both to be an integral part of the project development calculus in the state.

California Low Carbon Fuel Standard and CCS Protocol

California's Low Carbon Fuel Standard (LCFS) was instituted in response to the state's first overarching climate statute: the Global Warming Solutions Act of 2006, also known as Assembly Bill 32 (AB32).[97] The LCFS is part of the portfolio of tools under AB32, and it aims to reduce the carbon intensity (CI – measured in gCO_2e/MJ) of California's transportation fuels. The California Air Resources Board (CARB) first approved the LCFS regulation in 2009, with a target of decreasing transportation fuel CI by at least 10% by 2020 compared to a 2010 baseline. The regulation was amended in 2018 (effective Jan. 1, 2019) with an updated target of a 20% CI reduction by 2030.

In the 2018 LCFS regulation amendments, CARB also adopted a CCS Protocol and opened eligibility for credit generation under the program to certain types of CCS projects—those that affect the lifecycle CI of transportation fuels used in California—and to direct air

93 "Subpart RR-Geologic Sequestration of Carbon Dioxide." United States Environmental Protection Agency. Accessed November, 2020. https://www.epa.gov/ghgreporting/subpart-rr-geologic-sequestration-carbon-dioxide

94 40 CFR §§ 98.420 – 98.428.

95 17 CCR § 95100 et seq.

96 17 CCR § 95123.

97 "Global Warming Solutions Act of 2006." California Air Resources Board. Accessed November, 2020. https://ww2.arb.ca.gov/resources/fact-sheets/ab-32-global-warming-solutions-act-2006

capture projects around the world. LCFS credits have generally been trading near the $200/ton CO_2 mark since that time, generating a good deal of interest in CCS projects that qualify under the program.

Choosing to pursue certification under the LCFS for CCS projects is voluntary. However, certification requirements are substantial, and CARB's CCS Protocol has been characterized as the most comprehensive CCS regulation in any jurisdiction. Two basic steps are required for CCS projects to generate credits under the LCFS: (1) certification of a fuel pathway under the program for the project type in question if none already exists or if the project does not fall under one of the types explicitly listed in the program, and (2) certification under the CCS Protocol.

The LCFS allows for credit generation in three main ways:[98] fuel pathway–based crediting, project-based crediting, and capacity-based crediting. Under *fuel pathway crediting*, applicants obtain a certified CI score for their fuel, which is based on a lifecycle analysis of the process for producing and supplying the fuel to the California market. Fuel pathways fall under two tiers: Tier 1 comprises the most commonly encountered applications and fuel types and includes a look-up table for these pathways, whereas Tier 2 comprises the less common or more complicated pathways that CARB evaluates and certifies individually. No CCS pathways are included in Tier 1 at this point, and the LCFS regulation requires CCS fuel pathways to be Tier 2. New Tier 2 fuel pathways are typically submitted to CARB for informal review while in the draft stage, until they eventually undergo formal review and are subjected to public comment when the details have been refined. The public comment window is usually 10 business days or 45 days for some pathway types. Verification occurs after credits have been issued, and credits are calculated relative to annual CI benchmarks. The 2018 LCFS amendments also introduced a design-based pathway as a special circumstance for fuel pathway applications.[99] Generally, LCFS fuel pathways are developed based on 24 months of operational data. To encourage development of innovative fuel and other technologies, CARB now allows a design-based pathway for a fully engineered and designed facility with no operational data. After a design-based pathway has been in production for at least three months, it is eligible to report and generate credits but first must complete a provisional pathway application. Approval of a provisional pathway application allows a transportation fuel or project to generate credits during its 24-month period of developing operational data.[100]

Under *project-based crediting*, CARB allows for certain types of explicitly listed projects to generate credits. These project types include emission-reduction actions at refineries and at crude oil production and transportation facilities, as well as direct air capture projects. Verification occurs before credits are issued, and the credits are equal to the lifecycle GHG emission reductions.

98 "Low Carbon Fuel Standard." California Air Resources Board. https://ww2.arb.ca.gov/sites/default/files/2020-09/basics-notes.pdf

99 17 CCR 95488.9(e).

100 17 CCR 95488.9(c).

Fuel Pathway Based Crediting	Tier 1: Most common fuels, not applicable to CCS; simplified carbon intensity calculation
	Tier 2: Innovative, next generation fuel pathways, including CCS; full lifecycle analysis for calculating carbon intensity
Project Based Crediting	Refinery investment credits (including CCS)
	Innovative crude credits (including CCS)
	CCS projects that use direct air capture

Figure 3. *LCFS crediting opportunities relevant to CCS.*

Currently, *capacity-based crediting* does not apply to CCS.

CARB's CCS Protocol is a self-standing document but has been incorporated by reference into the LCFS regulation (but not yet under any of California's other climate programs, such as the Cap-and-Trade program).[101] The Protocol applies to both new and existing CCS projects that capture CO_2 and sequester it onshore, in saline formations or in depleted or producing oil and gas reservoirs. Although the Protocol also deals with atmospheric CO_2 emission accounting aspects of CCS projects, it contains a large body of requirements to ensure minimized project risks to public health, safety and the environment, and either mirrors or exceeds federal requirements for wells injecting CO_2 for geologic sequestration. The Protocol contains extensive requirements, including but not limited to those for site characterization, risk assessment and mitigation, design and operation, monitoring, remedial and emergency response, reporting, verification, decommissioning, and financial assurance. The steps for certifying (1) the sequestration site and (2) the proposed project parameters are collectively labelled permanence certification, without which crediting cannot proceed.

We anticipate that the work leading to project approval under the CCS Protocol will be the most scientifically and technically intensive of the entire CCS project authorization chain. Where sequestration in saline formations takes place, the subsurface tends to be less known and will likely require substantial characterization. CCS in oil or gas fields with a production history will generally have the advantage of a high level of site characterization, previously performed as part of oil and gas exploration and extraction. For both project types, we expect site characterization work to be more extensive and time consuming and less linear than the engineering aspects of the capture plant, and it is paramount that this work be done with the necessary care and diligence. While we expect the work leading up to an application under the CCS Protocol to be some of the most time consuming, CARB realizes the importance of timely processing and has stated its aspirations of a 6-month turnaround time for each of the two certifications under the CCS Protocol: the permanence certification and the project certification. In practice, many factors could prolong this nominal 12-month combined estimate, but it still serves as an initial indicator.

Notably, the work leading up to an application under the CCS Protocol and the work required to apply for a Class VI injection-well permit from the U.S. EPA have significant overlap. In fact, an injection-well application (covered above) will parallel an application to CARB; in fact, staff from CARB, EPA, the State Water Resources Control Board (SWRCB) and local water boards, and the California Geologic Energy Management Division (CalGEM) will likely confer to process the geologic and project information in an application under the CCS Protocol and for a Class VI injection well.

Federal 45Q tax credit

In 2008, Congress enacted a tax credit for CO_2 sequestration under Section 45Q of the Internal Revenue Code.[102] The credit amounted to \$20/ton CO_2 for pure storage and \$10/ton CO_2 for settings in which CO_2 was being injected with enhanced hydrocarbon recovery. The credit soon proved too low to incentivize any CCS projects and primarily served as a windfall to certain operators who were capturing and selling CO_2 for injection into oil fields already but without complying with the requirements that the Internal Revenue Service (IRS) had set for the statutory requirement for secure storage. After this practice was exposed,[103] U.S. Senator Menendez, a senior member of the Senate Finance Committee initiated an investigation with the U.S. Treasury Inspector General for Tax Administration (TIGTA) in 2019. TIGTA found that several companies had improperly claimed nearly \$1 billion in 45Q tax credits without complying with EPA's requirements for certifying secure storage as the IRS had dictated, and stated that enforcement actions were under way.[104]

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101 "Carbon Capture and Sequestration Protocol under the Low Carbon Fuel Standard." California Air Resources Board. https://ww2.arb.ca.gov/sites/default/files/2020-03/CCS_Protocol_Under_LCFS_8-13-18_ada.pdf

102 26 USC § 45Q.

103 J. Noel, "Carbon Capture and Release Oversight Failures in the Section 45Q Tax Credit for Enhanced Oil Recovery." Clean Water Action, Spring 2018. https://www.cleanwateraction.org/sites/default/files/docs/publications/Carbon%20Capture%20and%20Release%20-%20Clean%20Water%20Action%20-%20May%202018%20-%20Web%20Resolution.pdf

104 J. George, "Letter to Honorable Robert Menendez." Department of the Treasury, April 15, 2020. https://www.menendez.senate.gov/imo/media/doc/TIGTA%20IRC%2045Q%20Response%20Letter%20FINAL%2004-15-2020.pdf

In the meantime, Congress amended the 45Q tax credit in the Bipartisan Budget Act of 2018, increasing its value up to $50/ton CO_2 for pure storage, up to $35/ton CO_2 for settings in which CO_2 was being injected with enhanced hydrocarbon recovery, and also allowed other types of CO_2 utilization. The credit pool is no longer finite. However, different types of eligible facilities have minimum capture amounts, the credit can be claimed for only up to a 12-year period, and project construction must begin by a certain date: the original deadline of January 1, 2024, set in 2018, was extended by two years to December 31, 2025 in the federal omnibus spending package of December, 2020.

At the time of this writing, the IRS had also just published final regulations for the 45Q tax credit that were about to be submitted to the Office of the Federal Register for publication.[105] The regulations require operators to report under theEPA's Greenhouse Gas (GHG) Reporting Program subpart RR or, if storing CO_2 as part of enhanced oil recovery operations, the IRS gives operators the option to follow the procedures in the International Standards Organization CSA/ANSI ISO 27916:19 standard. This standard is self-administered and does not entail any interactions with regulators, but the proposed IRS regulations require retention of some documentation and third-party verification. The IRS would evaluate this material in the case of an audit. In addition, the Treasury Department and the IRS have published Revenue Procedure 2020-12, 2020-11 I.R.B. 511 and Notice 2020-12, 2020-11 I.R.B. 495. The former provides a safe harbor under which the IRS will treat partnerships as properly allocating the section 45Q and the latter provides guidance on the determination of when construction has begun on qualified facility equipment.

Claiming the 45Q tax credit does not require submission of any extensive documentation to the IRS, nor is prior authorization needed. Applicants must submit a relevant IRS form[106] and further comply with the IRS' requirements laid out in the proposed regulations and IRS communications described above, such as for secure storage,[107] size eligibility, and commencement of construction.

Altogether, claiming the 45Q credit entails a straightforward direct permitting interaction with the IRS but doing so may be contingent upon compliance with other programs that impose a larger but still relatively small additional effort.

Special cases

The most commonly expected regulatory interactions and authorization needs for all types of CCS projects in California are described above, but the list is not exhaustive. Special circumstances or project types may necessitate additional interactions. These cases may be of importance to a single project, or even project classes, but do not apply uniformly to all projects. Here, we present some indicative examples that may prompt further investigation by interested parties.

- A project located in a coastal zone for which the development involves certain activities (such as demolition, construction, clearing of vegetation, impeding access to recreational areas, altering property lines, change of land use intensity, or repair and maintenance activities)[108] is required to obtain a coastal development permit (CDP) from the California Coastal Commission (CCC).[109]
- The California Energy Commission (CEC) has the statutory responsibility[110] for licensing thermal power plants 50 megawatts and larger, including the plants' related facilities, such as transmission lines, fuel supply lines, water pipelines, and carbon capture equipment.[111] The CEC runs an expedited one-stop permitting process that is a certified regulatory program under the California Environmental Quality Act (see below). Power plants above the threshold size wanting to install carbon capture would apply under this CEC process.

105 Department of the Treasury, Internal Revenue Service, "Credit for Carbon Oxide Sequestration". January 2021. https://www.irs.gov/pub/irs-drop/td-9944.pdf

106 IRS form 8933. "Carbon Oxide Sequestration Credit." Department of the Treasury. https://www.irs.gov/pub/irs-pdf/f8933.pdf

107 85 FR 34050.

108 "When Do You Need a Coastal Development Permit?" California Coastal Commission, https://www.coastal.ca.gov/enforcement/cdp_pamphlet.pdf

109 Energy Futures Initiatives and Stanford University "An Action Plan for Carbon Capture and Storage in California: Opportunities, Challenges, and Solutions." October 2020. https://static1.squarespace.com/static/58ec123cb3db2bd94e057628/t/5f96e219d9d9d55660fbdc43/1603723821961/EFI-Stanford-CA-CCS-FULL-rev1.vF-10.25.20.pdf p. A-2.

110 California Public Resources Code § 25000 et seq.

111 "Power Plants." California Energy Commission, Accessed November, 2020. https://ww2.energy.ca.gov/sitingcases/

- In 2006, California enacted an emissions performance standard (EPS) that applies to long-term investments in the state's utilities' baseload generation for power plants based on greenhouse gas (GHG) emissions: the GHG emission rate limit is set at 1,100 $lbCO_2$/MWh. The CEC enforces this standard for publicly owned utilities, and the California Public Utilities Commission (CPUC) enforces it for investor-owned utilities.

  CPUC rules require that load-serving entities provide "documentation demonstrating that the CO_2 capture, transportation and geological formation injection project has a reasonable and economically and technically feasible plan that will result in a permanent sequestration of CO_2 once the injection project is operational. *The plan must comply with Federal and/or State monitoring, verification and reporting requirements applicable to projects designed to permanently sequester CO_2 by preventing its release from the subsurface. If at the time the application is filed Federal and/or State requirements have not been finalized, the plan must include monitoring activities to detect releases of injected CO_2 from the subsurface, must provide for verification of any detected releases and must include a schedule for reporting any detected releases to the Commission or other Federal and/or State agencies requesting that information." (emphasis added)*

  The language "The plan must comply […] agencies requesting that information" was added to the original rule language in 2010.[112] Whether CPUC today would interpret this language to mean that compliance with CARB's CCS Protocol is necessary remains unclear. On one hand, the Protocol is a "State monitoring, verification and reporting requirement […] applicable to projects designed to permanently sequester CO_2 by preventing its release from the subsurface." On the other hand, the Protocol has only been incorporated by reference into the LCFS program and does not apply uniformly to all long-term investments in baseload generation—only to applicants wishing to generate LCFS credits. Either way, the language implies that reporting under EPA's Greenhouse Gas Reporting Program (GHGRP) subpart RR would be necessary.

112 CPUC Decision 10-07-046: "Decision Granting, in part, petition of Natural Resources Defense Council et al. to modify decision 07-01-039" Accessed November, 2020. https://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/121474.htm

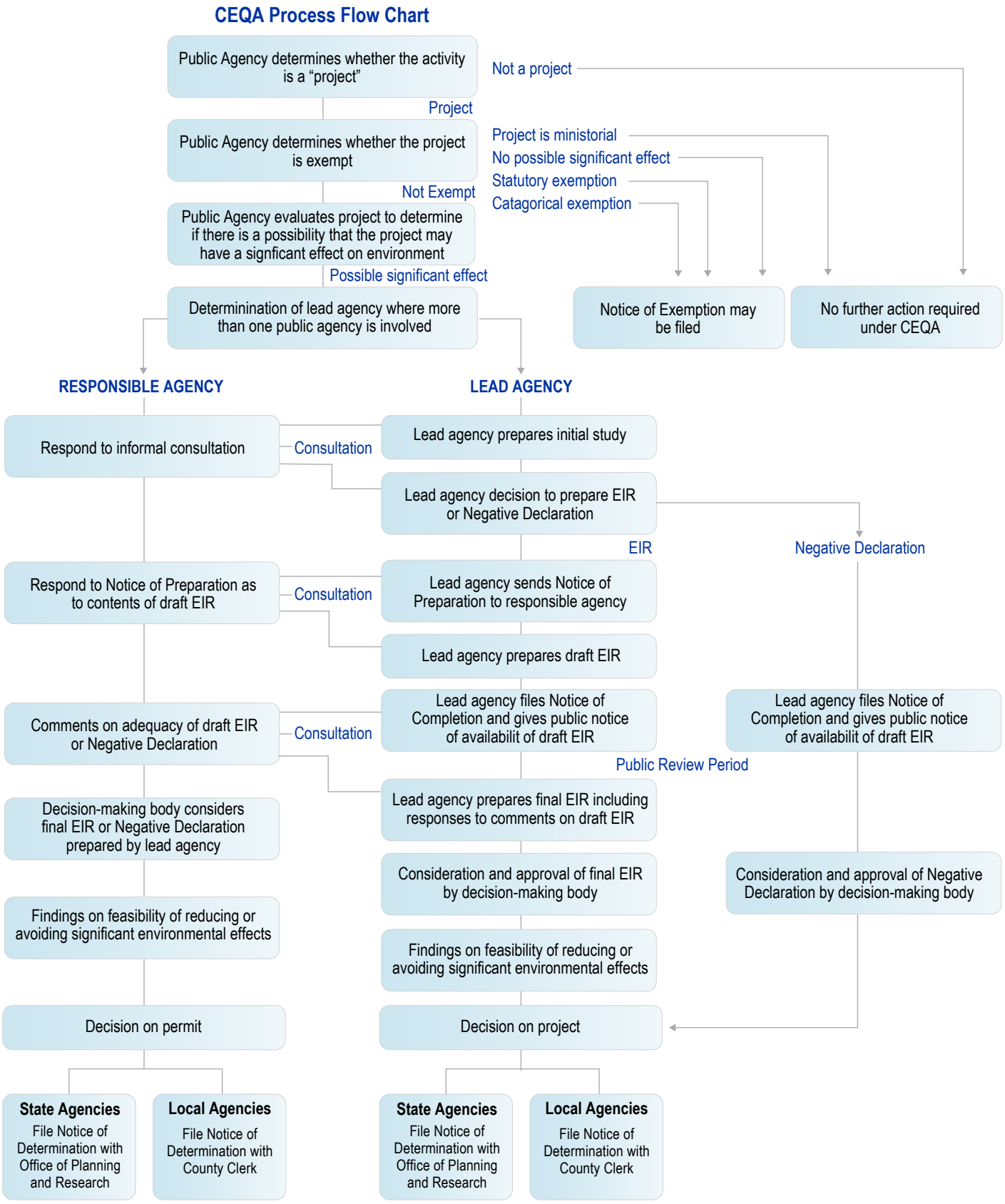

Figure 4. *CEQA process flow chart. Source: https://www.conservation.ca.gov/calgem/CEQA/Documents/CEQA_Process_Flowchart_OPR.pdf*

Chapter 4:

Environmental Review: CEQA and NEPA

In a nutshell: *The California Environmental Quality Act (CEQA) and its federal equivalent, the National Environmental Policy Act (NEPA) mandate environmental review processes, triggered when a state or federal agency, respectively, propose taking a discretionary action, such as issuing certain permits, which may result in significant environmental effects. The review process begins with an initial evaluation of the potential for such effects, and a thorough study ensues if some such effects are identified. The study, known as an EIR (Environmental Impact Report under CEQA) or EIS (Environmental Impact Study under NEPA), is often a lengthy document subject to review by multiple agencies and the public. In addition, CEQA calls for mitigation measures to be implemented (NEPA does not).*

The environmental review process can be convoluted and protracted and must precede the issuance of most of the permits described in the previous chapter. This process is often one of the most formidable authorization steps for any project and is perhaps even more so for CCS projects, which are cross-cutting and comprise several different types of activity over the CO_2 capture-transport-storage chain. Stakeholders and advocates view CEQA and NEPA as critical safeguards against ill effects from projects and development. In contrast, project developers view them as time- and resource-intensive processes that require careful navigation and can derail a project through delays or the addition of expensive or infeasible mitigation measures.

Environmental review is often the principal arena in which differences over a project are aired. The nature of the process unquestionably lends itself to (very) protracted, substantive, but also procedural, debate, and legal challenges are common. Seeking to minimize disagreement through careful project siting, selection and design, and early and honest interaction with stakeholders can result in a smoother and faster environmental review process, as well as better projects; some of the most successful environmental reviews of thorny projects involved the coalescence of a broad array of stakeholders toward a common goal. The skill and familiarity of agency staff with the process, as well as the political will of agency heads, are necessary—but not sufficient— elements for the completion of complicated and controversial environmental reviews.

Few issues divide project developers and stakeholders as much as environmental review. CEQA and its federal equivalent, NEPA, are seen by stakeholders and advocates as bedrock statutes that safeguard against egregious projects, agency actions, and environmental impacts, whereas developers often view them as minefields that take considerable time to navigate and that give a small but vocal minority an avenue to derail any project. This division is perhaps not surprising in a state as populous, diverse, and rich in contrasts as California. In practice, environmental review processes—CEQA in particular—often become the main arena where project proponents and opponents clash.

California Environmental Quality Act

Governor Ronald Reagan signed CEQA[113] in 1970. With the stated intent to "develop and maintain a high-quality environment now and in the future, and take all action necessary to protect, rehabilitate, and enhance the environmental quality of the state,"[114] CEQA requires that all discretionary projects proposed to be carried out or approved by public agencies (including the issuance of several of the permits and approvals listed in the previous chapter) undergo a review of potentially significant effects on the environment, and undertake actions to avoid or mitigate any such effects.[115]

CEQA states that "public agencies should not approve projects as proposed if there are feasible alternatives or feasible mitigation measures available which would substantially lessen the significant environmental effects of such projects," except "in the event [that] specific economic, social, or other conditions make infeasible such project alternatives or such mitigation measures, [when] *individual projects may be approved in spite of one or more significant effects thereof.*"[116]

113 California Public Resources Code §§ 21000 - 21189.

114 California Public Resources Code § 21001 (a).

115 California Public Resources Code § 21080.

116 California Public Resources Code § 21002.

BOX 4-1 Program Reviews under CEQA

The following case studies hold useful insights for CCS projects, both in terms of designing and siting in a responsible manner and also in terms of increasing the odds of successful implementation.

Case study #1:

March Air Force Base in Riverside County came into existence in 1918. After a long period of operation, it was chosen for base realignment and closure in the early 1990s—a post–Cold War federal process to increase the efficiency of the U.S. Department of Defense. The 6,500-acre Air Force base was to be converted to a smaller Air Reserve base. The March Joint Powers Authority (MJPA)—a public entity cooperatively formed by the cities of Perris, Moreno Valley, and Riverside and the County of Riverside—was created in September 1993 to handle the use, reuse, and joint use of the realigned base. MJPA comprised elected officials from the four respective local government entities. March Air Force Base became March Air Reserve Base (ARB) in 1996, creating a surplus of ~4,400 acres of land and a number of buildings and causing a distinct direct and indirect economic impact to the local economy due to the loss of military and civilian jobs and related economic activity.[01]

In 1996, MJPA adopted a redevelopment plan and accompanying Environmental Impact Report (EIR) for the now idle land and, in 1999, it adopted a general plan and master EIR for reuse of 4,400 acres. The plan allowed, inter alia, for up to 2 million square feet of industrial development on 433 acres. In 2003, MJPA also adopted a specific plan and accompanying EIR that included mitigation measures and established guidelines for commercial uses.[02]

In 2006, a corporation (Tesco) received approval from MJPA to build and operate goods-storage facilities totaling 1.925 million square feet on 88 acres, on the basis that the activity was consistent with the specific plan and its EIR, which were already in place/complete. A lawsuit was filed against MJPA's decision to approve the development, and the Riverside County Superior Court ruled against the decision in 2008, mandating an additional environmental review. However, in 2009, the Fourth District Court of Appeal overturned the lower court's decision and ruled that "[t]he Tesco facility is not a discrete CEQA project but one component of the specific plan for the larger March Business Center" and that "unless there are substantial changes or new information affecting the specific plan, there is no justification for additional environmental review of Tesco's design plan application."[03,04]

Case study #2:

The Desert Renewable Energy Conservation Plan (DRECP) was jointly developed through collaborative planning and analysis, and extensive public input by the California Energy Commission, California Department of Fish and Wildlife, U.S. Bureau of Land Management, and the U.S. Fish and Wildlife Service.[05] The aim of DRECP is to enable California to expand its renewable energy sources while protecting the sensitive habitat, species, cultural heritage, and present-day recreational uses of the Mojave, Colorado, and Sonoran deserts—an area of ~22.6 million acres.[06]

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01 "March Joint Powers Authority." Accessed November, 2020

02 "No EIR Needed for Warehouse Covered by Specific Plan, Court Rules." California Planning and Development Report. Accessed November, 2020. https://www.cp-dr.com/articles/node-2349

03 Ibid.

04 Health First v. March Joint Powers Authority, No. E045541, 2009 DJDAR 8441. Decided May 18, 2009.

05 "Desert Renewable Energy Conservation Plan." California Energy Commission, Accessed November, 2020. https://www.energy.ca.gov/programs-and-topics/programs/desert-renewable-energy-conservation-plan

06 "Desert Renewable Energy Conservation Plan Executive Summary for the Record of Decision." United States Department of Interior, Bureau of Land Management. https://eplanning.blm.gov/public_projects/lup/66459/133459/163123/DRECP_BLM_ROD_Executive_Summary.pdf

Marrying the streamlined development of solar, wind, and geothermal resources, as well as transmission lines, with the need to preserve and respect some of the most ecologically intact landscapes remaining in the U.S. is not an easy task.[07] To accomplish it, the DRECP identified areas in the desert appropriate for the utility-scale development of renewable energy resources and developed an Environmental Impact Review (EIR)/Statement (EIS) for the purposes of CEQA and NEPA respectively. The arrangement allows streamlined permitting of facilities in locations identified as suitable—provided operators adhere to certain mitigation measures—without necessitating new CEQA or NEPA reviews in each case.

A substantial amount of effort, analysis, consultation, and preparatory work made the plan possible, essentially front-loading any future environmental review efforts. Both the willingness of federal agencies to work toward the stated objective and the cooperation and constructive participation of conservation groups that valued development of renewable energy were crucial to the DRECP's perceived success.

However, fatigue among DRECP participants can be pronounced, and several report mixed feelings about what can be described as a diluted outcome—perhaps a trademark of compromise.

Case study #3:

Kern County Zoning Ordinance 2015(C) was approved by the County in 2015, targeting streamlined local oil and gas permitting.[08] Initiated in response to a request by three oil and gas industry associations, the objectives of the ordinance were to streamline the regulatory and permitting process and actions of the County, the California Geologic Energy Management Division (CalGEM), (née DOGGR), and other permitting agencies; expedite environmental review; develop industry-wide best practices to protect public health and safety; and facilitate oil and gas production in the County.[09]

Five years and tens of thousands of oil and gas wells later, the Fifth District Court of Appeal in Fresno ruled against the County in February 2020,[10] citing inadequacies and failings in the almost 2,000-page (excluding appendices) EIR upon which the ordinance was based and stating that the ordinance violates CEQA due to improperly deferred mitigation for water supply impacts, inadequate mitigation for farmland conversion, and inadequate analysis of noise impacts.[11]

At the time of this writing, Kern County was taking steps to revise the EIR and address the points raised by the court and had circulated a revised EIR for public comment. The revised EIR is expected to be in front of the County Board of Supervisors in 2021, which will likely vote to reinstitute the guidance. In the meantime, wells in Kern County have been permitted without the county ordinance or prescribed mitigations but through the usual CalGEM pathway and the accompanying CEQA process.

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07 "The Desert Renewable Energy Conservation Plan." Center for Biological Diversity. Accessed November, 2020. https://www.biologicaldiversity.org/campaigns/drecp/index.html

08 "Environmental Impact Report for Revisions to the Kern County Zoning Ordinance-2015 C, Focused on Oil and Gas Local Permitting." Kern County California Planning and Natural Resources Department. Accessed November, 2020. https://kernplanning.com/environmental-doc/environmental-impact-report-revisions-kern-county-zoning-ordinance-2015-c-focused-oil-gas-local-permitting/

09 M. Regalia, "Fifth District Holds EIR for Kern County's Ministerial Oil and Gas Well Permitting Ordinance Violates CEQA Due to improperly Deferred Mitigation For Waters Supply Impacts, Inadequate Mitigation For Farmland Conversion, and Inadequate Analysis of Noise Impacts." JD Supra, March 5, 2020. Accessed November, 2020. https://www.jdsupra.com/legalnews/fifth-district-holds-eir-for-kern-81421/

10 King and Gardiner Farms, LLC v. County of Kern, et al. (California Independent Petroleum Association, et al., Real Parties in Interest); Committee for a Better Arvin, et al. v. County of Kern, et al. (California Independent Petroleum Association, et al., Real Parties in Interest) (5th Dist. 2020) Cal.App.5th

11 Ibid.

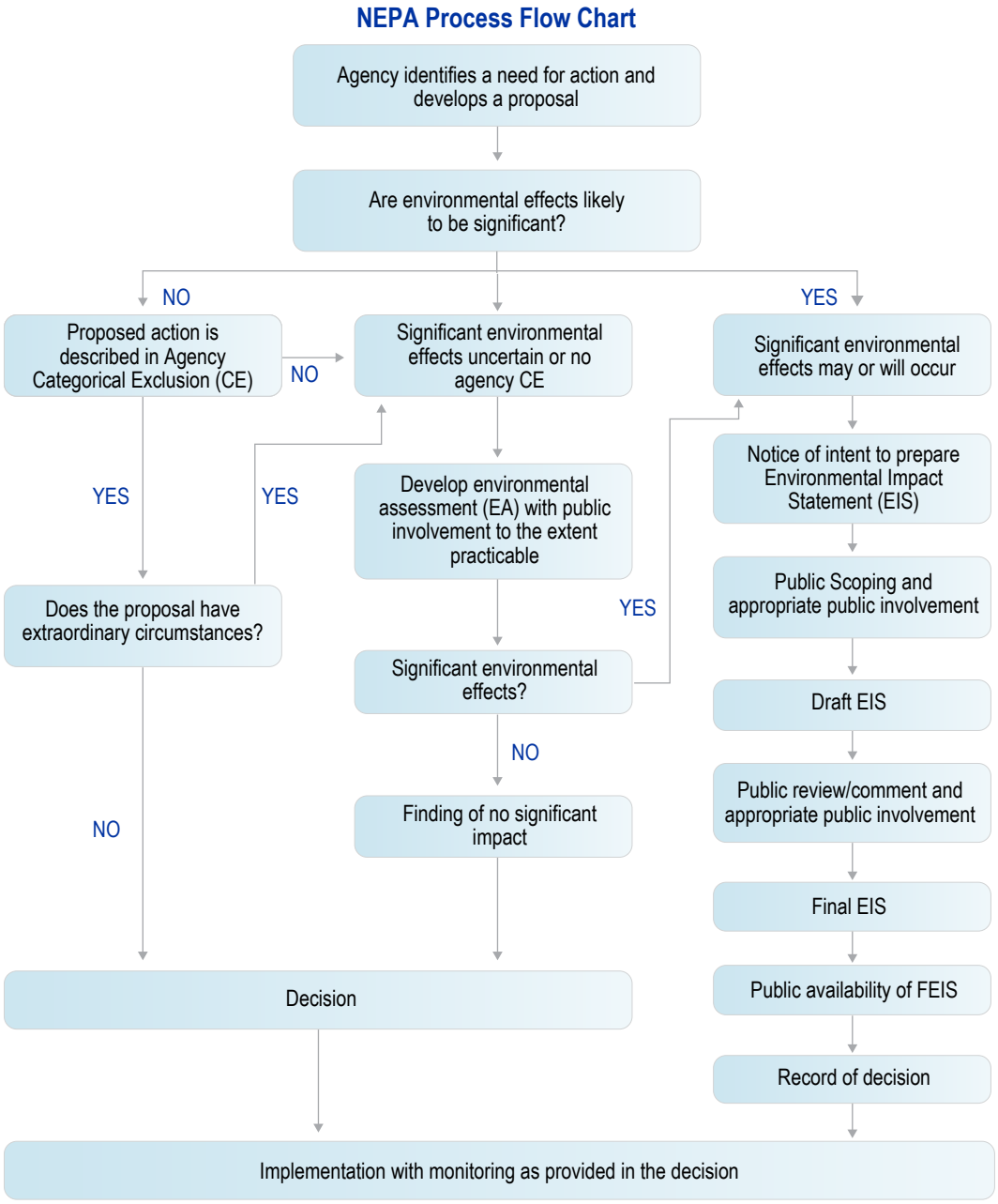

Figure 5. *NEPA process flow chart. Source:* ***https://ceq.doe.gov/docs/get-involved/Citizens_Guide_Dec07.pdf***

CEQA process flow

A substantial body of exemptions, guidelines, and case law exists for CEQA, which is certainly a continually evolving field requiring specialized attorneys, as courts continue to rule on cases even fifty years post-enactment. In very broad terms, the process flow for CEQA review is as follows[117,118]:

117 Ibid.

118 "The California Environmental Quality Act." California Department of Conservation. https://www.conservation.ca.gov/calgem/CEQA/Documents/CEQA_Process_Flowchart_OPR.pdf

- The agency concerned identifies whether an activity meets the definition of a project under CEQA and is not exempt; when more than one agency is involved, a lead agency is set, and all other agencies are termed responsible agencies
- The lead agency prepares an initial study to evaluate whether the project may have a significant effect on the environment; the lead agency consults with responsible agencies, who can rely on the findings of the lead agency
  - If no effect is identified, the lead agency issues a negative declaration
    - The negative declaration undergoes public review and, if approved, a decision is made on the project and a Notice of Determination is filed
  - If the whole record before the lead agency provides substantial evidence that the project may have a significant effect on the environment, the lead agency must prepare an environmental impact report (EIR)
  - The lead agency solicits content from responsible agencies and prepares a draft EIR, which is then made available for public review
  - The lead agency considers comments from the public and responsible agencies and prepares a final EIR, which is then considered for approval by the lead and responsible agencies
  - The lead agency makes a decision on the project, and responsible agencies make their decisions on individual permits, based on the EIR's findings regarding the feasibility of avoiding significant effects on the environment
    - The lead agency may reject a project if it has significant effects that cannot be avoided or substantially lessened
    - The lead agency may approve the project regardless of these effects if the project's economic, legal, social, technological, or other benefits (including regionwide benefits) outweigh its adverse effects; in this case, the lead agency issues a statement of overriding considerations
  - If finally approved, a Notice of Determination is filed

Lead agency choice and the importance of leadership in responsible agencies

For complex undertakings with many components, such as CCS projects, numerous state agencies will likely play a role in the CEQA process. Parties knowledgeable and experienced in CEQA uniformly state that the choice of lead agency is of primary importance to the outcome and timeline of the process. The lead agency's skill and experience are critical to ensuring both a thorough and defensible analysis, and that all the strict requirements—procedural and otherwise—are met in a manner that does not create legal-challenge vulnerabilities.

Typically, the CEQA lead agency is the agency that acts first or that has the most jurisdiction over the proposed project. Local governments, such as cities or counties, usually act as the lead agency when they are involved; however, the complexity of CCS projects may make local governments less likely or willing to assume the role. In general, given the responsibilities of being a lead agency, agencies do not actively compete against each other for the role, unless an agency is pursuing a project of prime importance to its own interests or concerns. In practice, some agencies are accustomed to acting in the role of lead, whereas others rarely adopt it.

State leaders and agency heads with fortitude and a desire to pursue projects for the common good are necessary—but not sufficient—for a timely and successful CEQA review. CEQA does not require absolute certainty in the outcome, but it does require a thorough evaluation of impacts and weighing of risks. Without determined leadership, an agency or group of agencies may enter an endless loop of evaluating impacts without ever reaching a conclusive decision. The Kern County local oil- and gas-permitting ordinance (see Box 4-1) demonstrates an incidence of a local government body determined to work toward an outcome in the face of ongoing challenges and unfavorable court decisions (and is also an example of the potential for protracted litigation and opposition when the root cause of the disagreement—in this case, whether or not oil and gas production in the area is desirable—remains unresolved).

Which permits require CEQA review for CCS projects in California?

Of the permits analyzed in the previous chapter, the following would automatically trigger a CEQA review: authority to construct and permit to operate for the capture facility (air districts), Class II UIC permits (by CalGEM), conditional-use permits (local governments), incidental-take permits (CDFW), lake/stream/river-alteration agreement (by CDFW), and coastal-development permit (by CCC). The CEQA process must

be complete before any of these agencies can issue the permits. Although a federal Class VI injection-well permit is not under California's purview, the CEQA lead agency could potentially find some nexus between the Class VI permitting exercise and its jurisdiction to ensure that the Class VI well is included in the CEQA process. [119]

As stated in the previous chapter, the CEQA process flow and interactions between these agencies inherently involves iteration and review. In addition, the public review windows and multiple opportunities for administrative and legal challenges can significantly add to a project's development timeline. In other words, CEQA review is often a major—if not the largest—determinant of a project's approval timeline. Practical experience shows that any outstanding permits are usually issued relatively quickly after successful completion of the CEQA review.

Parallel processes

Section 21080.5 of the California Public Resources Code provides that a regulatory program of a state agency shall be certified by the Secretary for Resources as being exempt from the requirements for preparing EIRs, negative declarations, and initial studies if the Secretary finds that the program meets the criteria contained in that code section. A certified program remains subject to other provisions in CEQA, such as the policy of avoiding significant adverse effects on the environment where feasible.[120] Among the regulatory programs listed as certified in this manner, some may apply to CCS projects, such as those for coastal-development permits issued by the CCC or power-plant permitting by the CEC. The list of certified programs appears to be relatively static, without frequent or recent updates.[121]

At first sight, not having to strictly follow CEQA requirements might imply a less rigorous and more expeditious process. In practice, however, the parallel certification process that follows in lieu of CEQA can be thorough, rigorous, and time consuming in itself. For example, the process followed by the CEC to permit power plants can take on a formal, judicial character with testimony, cross examination, and multiple data requests and responses. This parallel process may potentially be more expeditious than a normal CEQA review route, but this would more likely be due to the CEC staff's intimate familiarity with the process, and their skill and experience in the lead role than to the design of the process itself.

Program review in lieu of individual project reviews

CEQA offers the option to perform an EIR either (1) on a series of actions that can be characterized as one large project and that are related, inter alia, geographically, as logical parts in the chain of contemplated actions, in connection with issuance of rules or (2) as individual activities carried out under the same authority that have generally similar environmental effects with similar mitigation solutions.[122]

In theory, a program EIR has several advantages, enabling a more exhaustive consideration of effects—including cumulative ones—and alternatives than an individual review. Further, it allows the lead agency to consider broad policy alternatives and program-wide mitigation measures at an early stage, while at the same time avoiding duplicative treatment of considerations, added strain on staff and resources, and processing time. In practice, part of the value of a program review is that it provides an early venue for proponents and stakeholders to air mutual objectives and concerns, paving the way for projects that are more sound and interactions that are smoother. The cost, of course, is the added early effort and complexity.

National Environmental Policy Act

The National Environmental Policy Act (NEPA) was also signed into law in 1970.[123] The stated purposes of NEPA are to "declare a national policy which will encourage productive and enjoyable harmony between man and his environment; to promote efforts which will prevent or eliminate damage to the environment and biosphere and stimulate the health and welfare of man; to enrich

119 Somewhat paradoxically, even though Class VI permitting is significantly more involved than Class II permitting, CEQA is not strictly triggered because a federal agency – EPA Region 9 – is currently responsible for processing Class VI well permits in California. This would change if a state agency was granted primacy for the Class VI program by EPA.

120 14 CCR §§ 15250 - 15253.

121 14 CCR § 15251.

122 14 CCR § 15168.

123 42 USC Chapter 55.

the understanding of the ecological systems and natural resources important to the Nation; and to establish a Council on Environmental Quality."[124]

NEPA requires federal agencies to assess the environmental effects of their proposed actions prior to making decisions on permit applications, adopting land management actions, or constructing highways and other publicly-owned facilities. Under NEPA, agencies must evaluate the environmental and related social and economic effects of their proposed actions and provide opportunities for public review and comment on those evaluations.[125]

NEPA process flow

The NEPA process begins when a federal agency proposes a major action. If more than one agency is involved in the action, a lead agency and cooperating agencies are assigned. If the action does not fall under one of the existing categorical exclusion (CATEX) categories,[126] the lead agency may prepare an Environmental Assessment (EA), which determines, inter alia, whether or not the action may cause significant environmental effects, the purpose and need for the proposed action, and alternatives.[127] The EA is equivalent to the initial study under CEQA.

If the agency determines, based on the findings of the EA, that the action will not have significant environmental impacts, the agency will issue a Finding of No Significant Impact (FONSI) that outlines the rationale. If significant environmental impacts are expected, an Environmental Impact Statement (EIS) must be prepared. The EIS is equivalent to an EIR under CEQA. After public notice and review of the draft EIS, a final EIS is made publicly available and a record of decision issued.

Which permits require NEPA review for CCS projects in California?

Of the permits analyzed in the previous chapter, the incidental-take permit (by USFWS), the issuance of a federal right-of-way (by BLM), and a dredge/fill discharge-permit (by USACE) would likely trigger a NEPA review, as would the use of federal funds (such as those issued by the Department of Energy) in the project. Class VI injection-well permits are notably excluded from NEPA review.[128]

Differences between CEQA and NEPA

Apart from the obvious difference that CEQA applies to California state government actions and NEPA to federal government actions, the most substantive difference between the two is that NEPA is procedural and informational: it does not require any mitigation steps even if significant environmental impacts are identified, as long as they are identified and disclosed.[129] In practice, this difference means that a NEPA review is usually narrower and more procedural, whereas a CEQA review can result in real changes to project design.[130]

Coordinating reviews under CEQA and NEPA

CEQA and NEPA each mandate their own procedural steps, which have to be followed strictly in order to remain compliant and avoid challenges. However, if reviews under both CEQA and NEPA are required, CEQA allows for some alignment between the two.[131] For example, if the NEPA document will be ready before the CEQA document, CEQA allows for a FONSI and EIS to be used in lieu of a negative declaration and EIR, provided the analysis is adequately expanded to take into account mitigation measures or growth-inducing impacts—points that would normally be absent from a NEPA review.[132]

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124 42 USC § 4321.

125 "What is the National Environmental Policy Act?" United States Environmental Protection Agency. Accessed November, 2020. https://www.epa.gov/nepa/what-national-environmental-policy-act

126 40 CFR § 1508.1(d).

127 "What is the National Environmental Policy Act?" (Accessed November, 2020)

128 75 FR 77229: "The SDWA UIC program is exempt from performing an Environmental Impact Statement (EIS) under section 101(2)(C) and an alternatives analysis under section 101(2)(E) of NEPA under a functional equivalence analysis. See Western Nebraska Resources Council v. US EPA, 943 F.2d 867, 871-72 (8th Cir. 1991) and EPA Associate General Counsel Opinion (August 20, 1979)."

129 42 USC § 4332.

130 L. Haglan, "What's the Difference between NEPA and CEQA?" Dewberry, March 12, 2020. Accessed November, 2020. https://www.dewberry.com/news/blog/post/blog/2020/03/12/whats-the-difference-between-nepa-and-ceqa

131 14 CCR § 15170, 14 CCR §§ 15220 - 15229.

132 14 CCR § 15221.

If NEPA documents will not be complete before CEQA documents, then CEQA directs the lead agency to try to prepare a combined EIR/EIS or a negative declaration/FONSI, involving the federal agency and entering into a memorandum of understanding if needed.[133] CEQA also allows for treating NEPA FONSI and EIS public notice and review actions as sufficient for having satisfied the equivalent CEQA requirements, provided the NEPA documents have been circulated "as broadly as state or local law may require" and the notice given satisfies CEQA's own standards. In such cases, the lead agency under CEQA may use the federal document in the place of an EIR or negative declaration without recirculating the federal document for public review.[134]

Whether or not the two processes can be successfully aligned depends both on the CEQA lead agency's skill and experience in navigating these arrangements and on whether the federal agency is willing to cooperate, since federal law generally prohibits a federal agency from using an EIR prepared by a state agency unless the federal agency was involved in preparing the document.[135]

133 14 CCR § 15222.

134 14 CCR § 15225.

135 14 CCR § 15222.

Chapter 5:

Conclusions, Options for the State of California, and Considerations for Project Developers

Findings

The previous chapters demonstrate that the regulatory framework that applies to CCS projects in California is rigorous, robust, and capable of handling the permitting and review tasks while protecting public health, safety and the environment. The framework is also extensive and convoluted and was, for the most part, not devised with the complexity and cross-cutting nature of CCS in mind. CCS projects by nature concatenate three complex undertakings: CO_2 capture, transport, and storage. Obtaining or modifying an air permit is often difficult on its own, let alone also siting a pipeline that potentially crosses multiple types of land holdings, obtaining permission from numerous and possibly distinct surface and mineral rights owners to inject CO_2 in/under their property, and finally completing a potentially multi-year process to obtain a Class VI injection-well permit.

Navigating this framework successfully, and in time to allow for project development and financing that are critical to California's climate goals, will require an unprecedented degree of coordination between local, state, and federal agencies, as well as skill and experience on behalf of developers and regulators alike. Successful deployment of the necessary clean energy and climate mitigation infrastructure in California, while meeting the state's climate goals, hinges on the ability to maintain the robustness of the permitting process in an appropriate time frame to meet the demands of a rapidly changing climate. Failure to do so would result in projects only succeeding when special and uncommon circumstances stack the odds in their favor: for example, when capture and storage are co-located, suitable geology is present on-site or nearby, land ownership comprises large parcels in the hands of single or few owners, and mineral ownership is not severed from surface ownership.

No CCS projects are operating in California at the moment. Early projects will test the existing regulatory framework, and centralized planning now is valuable since many more projects will be needed to make a meaningful contribution to the state's extremely ambitious climate goals—perhaps on the order of tens of projects. This ambitious infrastructure deployment cannot take place without both a supportive policy framework for CCS and changes to the current permitting process for projects.[136]

The path to broader CCS deployment in California

Policy backdrop

As outlined in the Introduction, California's attainment of its mid-century carbon neutrality goals depends on, among other things, the ability to remove CO_2 from the atmosphere and store it securely underground. Currently only two policy drivers exist for development of CCS: the LCFS and the federal 45Q tax credit. These two drivers are critical for near-term deployment of the first ever CCS projects in California, but because eligibility is limited to projects associated with transportation fuels (LCFS) and a December 2025 deadline to begin construction (45Q), they alone will not be sufficient to spur the degree of deployment needed to shore up the state's mid-century climate goals. Making the most of these driving policies in the near term requires a robust but workable authorization regime that allows for sound projects to move forward efficiently and transparently.[137,138]

A staged but deliberate path to making CCS a meaningful tool in California's climate portfolio

As explained in the first chapter, meeting California's mid-century climate goals, as well as global goals, cannot

136 Energy Futures Initiative and Stanford University (2020).

137 Baker et al. (2020).

138 E. Moniz et al., "Optionality, Flexibility and Innovation: Pathways for Deep Decarbonization in California." Energy Futures Initiatives, May 2019. https://static1.squarespace.com/static/58ec123cb3db2bd94e057628/t/5ced6fc515fcc0b190b60cd2/1559064542876/EFI_CA_Decarbonization_Full.pdf

be done without both intensified reduction of existing emissions and removal of CO_2 from the atmosphere. CCS is a key enabling technology for both applications. Yet the state is starting from zero in the field of CCS deployment, with the exception of some past geologic and regulatory studies and some project prospects that did not materialize.

CCS projects' complexity easily points to a 5-6 year timeline from initiating development to completion, and many tens of projects need to be operating by 2045 to shore up the carbon neutrality goal. How can the state achieve such a dramatic scale-up in such a short amount of time?

The challenge is amplified by the fact that the public and a majority of policy makers generally have very little, if any, awareness of CCS, with some notable exceptions. Much like the need for CCS to play a role in the climate portfolio, the manageable risks of CCS, its successful track record, and the fact that nature has been storing fluids in the subsurface in the same manner for hundreds of millions of years—long before humans existed—is not widely known or understood. This lack of awareness is neither surprising nor unreasonable: asking questions about the safety and efficacy of injecting CO_2 underground is perfectly logical and healthy. If deployment of the technology in the state is to take off, however, scientists' and experts' deep understanding of the technology will need to be shared more widely with an understandably skeptical public.

The optimal path, in our view, first builds familiarity and confidence through a small number of commercial-scale demonstration projects and without attempting regulatory reforms prematurely, while at the same time vetting and paving the way for the measures and structures that may be needed to achieve deployment at scale. The projects could either be privately developed or could involve some manner of State participation. This approach would steer clear of substantial regulatory or legislative reforms at first and focus instead on surgically addressing the most pressing needs of the first projects.

We believe that, once these first projects are operational, the knowledge they create about regulatory and technical issues will be extremely valuable. A common theme among those who have visited one of the many operating CCS projects around the world is just how unremarkable and commonplace injection sites are. A capture facility draws more interest, with its modern and impressive engineering components (that are nonetheless still usually dwarfed by the pre-existing industrial facility that produces the CO_2). With a handful or so of operating projects around the state that anyone could visit and come to better understand, the path toward broader deployment could be substantially smoother.

The options we lay out below thus follow this staged paradigm and are grouped into immediate and near-, medium-, and longer-term actions that the state could consider in an effort to help CCS become part of its climate portfolio. As will become evident below, steps to address the flow of the permitting process are most critical in the immediate and near terms, and in relation to the first wave of projects. Beyond that, and assuming the immediate- and near-term steps have been taken and the prospects of CCS in California have not floundered, the emphasis shifts to broader measures intended to ramp up deployment to a scale relevant to the state's climate goals: tens of projects statewide.

Below we present such possible steps and highlight how they would fit into a logical time progression that would take CCS from mere prospect to a viable tool in California's portfolio.

Options for California State government

IMMEDIATE (0-6 MONTHS)

The biggest immediate need is for the State to fully understand the permitting tasks that lie ahead and to understand more broadly the specifics of the technology and how it fits into California's statutory and regulatory framework. Since CCS projects will require an unusually large degree of interagency coordination, concrete beginnings to the environmental review and permitting processes are necessary and best established immediately.

Specifically, the state could employ the following:

- **Assemble an interagency working group of state agencies likely to be involved in CCS project permitting:** Air Resources Board, California Energy Commission, California Geologic Energy Management Division, California Geological Survey, Department of Fish and Wildlife, Natural Resources Agency, Office of the State Fire Marshall, Public Utilities Commission, State Lands Commission, and State Water Resources Control Board.
- **Designate a staff contact for CCS permitting from each of these agencies,** to facilitate and expedite relevant conversations.
- **Through the working group, create an internally vetted list—to serve as a reference— of CCS permitting authorities and of the responsibilities of each agency.** As aids or starting points, available reports that cover the topic include the present one, the recent Energy Futures Initiative/ Stanford report,[139] and the 2010 State-appointed CCS Review Panel report.[140]
- **Invite representatives from key federal and local agencies (such as key counties and air districts) to join the working group.**

NEAR-TERM (<2 YEARS)

The foremost objective in the near-term is to enable proper, yet efficient, permitting for the all-important first wave of projects that will serve as proof-of-concept for CCS technology for the state and its residents and that will enable a smoother and more informed conversation about how the state can scale up deployment.

Actions that would further this objective include the following:

- **Create a clear directive from the administration and/or legislature that unambiguously signals to state agencies the high-priority nature of CCS projects for the state and its climate goals, and that calls for thoroughly and efficiently handling permit applications and environmental review.** Such a directive is not tantamount to prejudging the outcome of environmental reviews or permit applications, looking the other way, saddling Californians with unacceptable environmental impacts, or cutting corners. Rather, it is a signal to agencies to assign sufficient and experienced staff to applications, act in a timely manner, coordinate across agencies as needed, and decisively weigh any impacts that the CEQA process determines cannot be mitigated against the value of the project to the state and its climate goals.
- **Among the working group of relevant agencies, assign one agency to act as the central point of contact for CCS project permit applicants; this agency will function as coordinator, timekeeper and manager for efficient permit processing and will interact with developers and stakeholders.** The optimal agency for this role would be one with cross-cutting jurisdiction, deep scientific expertise in the various aspects of CCS, and credibility with stakeholders.

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139 Energy Futures Initiatives and Stanford University (2020).

140 Technical Advisory Team in support of The California Carbon Capture and Storage Review Panel (2010).

- **Examine the desirability and legal feasibility of assigning a specific CEQA lead agency—from among those likely to have jurisdiction over most CCS projects—to assume this role and specialize in the CEQA process.**
- **Assemble a flow chart with steps for state agencies to follow upon receiving a project application, including intended turnaround timelines for each step.** The chart would serve both as an internal script for agencies and as a guide for project applicants.
- **U.S. EPA, CalGEM, CARB, CGS, SWRCB, and Water Boards could perform a joint or coordinated review of the substantial and highly overlapping geologic information required for different regulatory or certification purposes.**
- **For all state agencies involved in CCS permitting, secure adequate staff and resources to ensure sufficient expertise, knowledge, and personnel availability** to process what could be numerous and/or complex permit applications, and to navigate the CEQA process for multi-faceted projects. As simple as this action sounds, clear signs indicate that agency staff may already be stretched to their limit or overwhelmed by the current volume and complexity of the task of processing permits for CCS projects, primarily as a result of interest in projects spurred by the LCFS and 45Q tax credit.
- **Through California's administration and congressional delegation, convey the need for similar staffing and resources in Washington DC for federal agencies involved in processing permits for CCS projects in California.** Absent state primacy for Class VI injection wells, the largest need would be with EPA.
- **To ensure timely processing of applications by federal agencies, pursue memoranda of understanding (MOUs) or informal agreements between state agencies and those federal agencies relevant to permitting CCS projects in California; also examine the potential for state and federal agencies to collaborate toward a common goal of CCS project deployment.** Recent collaboration experiences around renewable energy projects funded by the American Recovery and Reinvestment Act (2009) and the Desert Renewable Energy Conservation Project are likely to hold insights and lessons and to serve as a valuable starting point.
- **Make available the State's own land/mineral holdings for CO_2 pipelines or injection, where appropriate.** This resource would ease the burden of negotiating with potentially numerous private owners.
- **Through the Natural Resources Agency, review the relevance of certified programs under 14 CCR §§ 15250-15253 to CCS project permitting.**
- **Weigh the desirability of California applying for primacy to administer EPA's Class VI injection well–permitting program.** This approach may be one means of hedging against unknown and potentially long permitting timelines with EPA (based on limited past experience), but CalGEM—the likely applicant for primacy—may face lingering mistrust from the legislature and public alike due to past conduct and track records that predate recent reforms within the agency and current management. Primacy may thus not pave the way to smoother permitting, regardless of whether or not the mistrust is justified. Notably, primacy would explicitly subject Class VI permits to CEQA review by making the issuance of Class VI permits a state action rather than federal action, whereas they are currently exempt from both CEQA and NEPA review. However, as noted previously, some local agencies may also insist on a role regardless of primacy status, perhaps beyond their CEQA responsibilities.
- **Through the Legislature, enact a minor technical amendment to the Elder Act, clarifying that the Act intends for the Office of the State Fire Marshal to also regulate intrastate CO_2 pipeline safety.** This action would completely rule out legal ambiguity for what is already the prevailing interpretation and the agency's intent.

- **Through the legislature, clarify pore-space ownership, clearly vesting it with the surface owner, and possibly also clarify the relation of the surface estate to the mineral estate.** The former action would codify the generally prevailing view under today's statutes and case law.
- **Through CARB, consider if (and which) changes to existing CCS Protocol provisions could meaningfully increase the array of projects in active development without materially compromising the Protocol's integrity or level of protection/precaution.** Given the brand new nature of the Protocol and the considerable project interest it has attracted, readily available feedback already exists on which provisions may prove challenging to implement in practice.

MEDIUM- AND LONG-TERM (>2 YEARS)

In the medium-term, the main tasks will likely be taking heed of lessons learned during the early days, standardizing procedures, and increasing the number of projects in development while retaining integrity in the permitting process, transparency, and public trust.

In the longer term, the options below are aimed at paving the way for broad-scale CCS deployment in California after the first wave of projects have validated the efficacy and safety of large projects with the public and provided a forum of exchange for discussing the role of CCS in the state's climate portfolio. Although some of these actions would certainly facilitate early projects, we do not consider them necessary or, in fact, advisable at present as they run the risk of premature and polarized debate and of needlessly derailing early projects.

- **Through state agencies and the legislature, consider more broadly the desirability of a parallel, certified process under CEQA with a specific agency as the lead.** The CEC would be a logical choice to run such a process, given its multi-decadal experience in power-plant permitting.
- **Through the legislature, investigate the desirability of options for more efficient acquisition of rights-of-way for pipelines and of pore space and mineral rights for injection, and then pursue the optimal option.** Options could include pooling, unitization, eminent domain, or incentives.
- **Construct a backbone of CO_2 trunklines with State involvement, such as a public-private partnership, that will link a large collection of CO_2 point sources to suitable storage.** Environmental review for such pipelines could potentially be done in one go and State lands could be made available for this purpose.
- **Assemble a State-operated CO_2 transportation/storage utility to handle permanent subsurface storage.** This operation could be complementary to private operations and would centralize the permitting process, taking advantage of economies of scale and aiming to deploy CCS hubs that link major CO_2 sources to areas with the most suitable geology for safe and permanent storage.

Considerations for project developers

In this section, we present some specific considerations for project developers wishing to stack the odds in favor of obtaining necessary authorizations efficiently. This list of considerations is not meant to be a comprehensive best-practice guide—we limit discussion to considerations directly related to the subject matter presented in this report.

CEQA considerations

The case studies in the previous chapter, along with a multi-decade record of experience with CEQA, suggest several courses of action that could lead to both better projects and smoother interaction with CEQA.

First, **developers should consider all aspects of a project, including location and stakeholders' disposition, before choosing to proceed and should proactively engage in open early conversations with stakeholders.** Acrimony surrounding a project often plays out as a prolonged and litigious CEQA process. While it is possible to persevere and prevail, CEQA offers ample opportunities for challenges, and a protracted process with multiple court and agency decisions may ensue if a project applicant does not address—early on—the underlying root points of disagreement. The cases of high-speed rail and Delta tunnels are examples of projects that, despite unquestionable and strong backing from state government and the Governor himself, have made tortured progress and scored only Pyrrhic victories. Of course, eliminating disagreements at their root is easier said than done, but an honest attempt to do so from the outset and shortlisting projects not on economic and technical merits alone ensures a smoother start. For example, studies point to shorter permitting timelines and substantially lower land acquisition requirements and mitigation costs when utility-scale solar power installations use low-impact sites in situations where biodiversity impacts are a key consideration.[141]

Second, **from the outset, project developers need to thoroughly identify and mitigate impacts to the greatest extent feasible.** Entering the CEQA process having thoroughly assessed potential impacts and mitigation measures is critical, as opposed to entering the process blindly and unprepared. Thorough preparation does not preclude the possibility of later opposition or disagreements with stakeholders, but it can save valuable back-and-forth time with the lead agency and responsible agencies once the process begins. Project developers should also consider preparing a draft initial study preemptively to submit for the lead agency's consideration: it is often easier to modify existing work than to start from scratch.

Third, **project proponents should identify and describe the preferred course of action, as well as the alternatives for both the project as a whole and its components.** Alternatives, or the failure to describe them, are commonly scrutinized in the public review process, and this action provides the applicant and stakeholders a platform to discuss what the alternatives are and provides the lead agency with a stronger basis on which to base its decision.

Fourth, **the CEQA process is smoothest when large and diverse coalitions of actors coalesce toward a common objective.** The Desert Renewable Energy Conservation Plan is a strong case in point, in which the ultimate prize of increasing California's share of renewable energy dictated a different tenor of conversation with stakeholders and advocacy groups than would have prevailed were another kind of development contemplated.

Permit application considerations

Regulators often cite a range of possible project design maturity levels when they first receive applications. The design stage plays a clear role in whether a permit application will be deemed complete and on how long it might take for the regulator to process the application and issue a permit.

On one hand, a complete and finalized design may allow for a greater level of detail and data to be shared with the regulator, which can reduce back-and-forth interactions and allow for smoother processing. On the other hand, a design that is fully crystallized may be harder to revise if the regulator requests changes necessary for compliance, and the applicant may have missed some design junctures, necessitating additional iteration.

141 S. Dashiell et al., "Green Light Study: Economic and Conservation Benefits of Low-Impact Solar Siting in California", 2019. https://www.nature.org/content/dam/tnc/nature/en/documents/FINAL_Green_Light_Report_LR.pdf

To strike the correct balance, **it is customary and recommended for permit applicants to request pre-application meetings ("pre-app") with the regulator(s) to discuss the project and to learn which parameters the regulators consider critical.** Often, a series of such meetings will precede a permit application and inform project design and subsequent permit application processing.

In addition, **applicants should assemble and dedicate the appropriate staff and/or consultant resources to permit applications**. Some of the application processes are highly specialized, and there is no shortcut to prior experience. The technical complexity of some applications will require the applicant to have a high level of skill, and approaching an application as a mere paper-pushing exercise without assigning due importance will likely result in complications and delays.

Finally, **the degree of transparency, responsiveness, and cooperation with the regulator—unsurprisingly—colors the nature of the permitting interaction.** Driven by a desire to safeguard business-sensitive information or avoid "pitfalls," some applicants adopt a need-to-know policy with regulators. While we cannot comment on the general need for or advisability of such a stance, this stance has repeatedly proven—particularly in the case of air permitting—to be inconducive to expeditious application processing.