Energy Research and Development Division

FINAL PROJECT REPORT

ASSESSMENT OF THE BARRIERS AND VALUE OF APPLYING CO_2 SEQUESTRATION IN CALIFORNIA

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PREFACE

The California Energy Commission Energy Research and Development Division supports public interest energy research and development that will help improve the quality of life in California by bringing environmentally safe, affordable, and reliable energy services and products to the marketplace.

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Assessment of the Barriers and Value of Applying CO2 Sequestration in California is the final report for the Assessment of the barriers and value of applying geologic CO2 sequestration in California project (contract number 500-09-005) conducted by the Lawrence Berkeley National Laboratory and the California Institute for Energy and Environment, University of California. The information from this project contributes to Energy Research and Development Division's Energy-Related Environmental Research program area.

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ABSTRACT

Carbon capture, utilization, and storage (CCUS) is an important technology for greenhouse gas reduction worldwide, and it may be a critical component to enable California to meet its greenhouse gas emissions reduction goals. CCUS is a suite of different types of technologies used to capture carbon dioxide emissions from power plants or large industrial point sources and use this captured carbon dioxide for various purposes including storage, and injecting in rock formations deep underground. Technologies for measuring and monitoring carbon dioxide in the subsurface or in surface facilities also are part of this suite.

Because of the complexity and diversity of CCUS technologies, there are numerous challenges to its deployment. The elements to undertaking a CCUS project include both technical and non-technical—reducing the risks associated with these elements are essential to assuring CCUS is an effective and economic mitigation technology. The greatest risks are associated with the subsurface; thus, proper site characterization and monitoring are important to project success.

This report reviews the findings from projects and activities in California, North America and worldwide and addresses the key questions California policy makers must answer to facilitate CCUS deployment effectively.

Keywords: carbon dioxide, carbon capture and storage, greenhouse gas emissions reduction, power plants, carbon utilization, technology

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Introduction

Carbon capture, utilization, and storage (CCUS) technology is recognized globally and by California's climate change policy as a greenhouse gas reduction strategy. California laws require greenhouse gas (GHG) emissions reductions to be in line with those recommended by the Intergovernmental Panel on Climate Change. In 2005, an executive order by Governor Schwarzenegger required California to reduce its GHG emissions to 2000 levels by 2010, to 1990 levels by 2020, and to 80 percent below 1990 by 2050 (Executive Order S-3-05). Assembly Bill 32 (AB 32) set the state on the path to meet the 2020 goal (Statutes of 2006, Nunez).

CCUS provides an option for reducing CO_2 emitted by large point sources such as power, fuel processing and industrial plants to meet 2050 GHG reduction goals. CCUS is a suite of technologies applying to a variety of emissions point sources and include those necessary for:

- Capture or removal of CO_2 from point source emissions.
- Economic use of the separated CO_2 products storing the CO_2 or produce a revenue stream.
- Compression and transport.
- Injection into a below ground storage formation.
- Monitoring, verification and reporting of permanent storage.
- Long-term stewardship, including remediation or mitigation of any leakage.

California is at the forefront of addressing the challenges involved in redesigning its energy infrastructure to meet 2050 goals; however, CCUS commercialization lags as a possible mitigation to reducing GHGs. This report examines why CCUS has not advanced as rapidly as other GHG emissions mitigation technologies and identifies ways CCUS commercialization may be advanced to support California's future energy infrastructure.

Study Purpose and Process

Efficiencies in energy use may result in declining per capita energy use in developed countries; however, the overall trend in world energy use is upward. The International Energy Agency estimates 2009 global CO_2 emissions to be approximately 31 Gigatonnes (Gt) and projects by 2050 emissions will reach 58 Gt in a business-as-usual scenario. According to climate change forecasts, these emissions result in a 6°C increase in the global mean temperature, alarmingly high compared to the goal of limiting the rise to a 2°C increase. To limit average global warming to 2°C will require global CO_2 emissions are no higher than 16 Gt by 2050. To achieve this level requires no further increases in fossil fuel CO_2 emissions and reducing emissions by 15 Gt, or 52 percent, during the next 37 years. This is equivalent to permanently removing almost all of California's current CO_2 emissions inventory from the global emissions footprint every year.

Energy use can be divided into five main sectors: electricity, transportation, industrial, residential, and commercial. In developed countries, the electricity, transportation, and industrial sectors are dominant; combined they typically account for about two-thirds to three-quarters of total energy use and GHG emissions for developed countries.

Worldwide trends in energy use demonstrate both OECD (Organization for Economic Co-operation and Development) and non-OECD countries are diversifying their energy portfolios to decrease their reliance on fossil fuels and reduce the carbon intensity of their energy use. However, the electrification of the developing world is being accomplished mostly by using fossil fuels, most notably, coal. Likewise, the growth in transportation is fueled by petroleum. Using efficiency, or non-carbon renewable energy to replace fossil fuels, using lower or no-net-carbon feed stocks (such as renewable biomass), and incorporating CCUS for fossil fuel generation all have potential to reduce the electricity sector carbon emissions.

California has fewer options for making the deep cuts in CO_2 emissions within the electricity sector to meet 2050 goals and is already the most efficient of all 50 states as measured by electric use per capita. While further efficiency measures continue to reduce per capita consumption, increasing population, is still driving electricity use upwards. A 1976 law prevents building any new nuclear plants until a federal high-level nuclear waste repository is approved. Most all of California's in-state electricity generation already comes from natural gas; and California will eliminate electricity imports from out-of-state coal-fired generation. The two options with best potential to reduce in-state power sector CO_2 emissions are replacing natural gas with renewable generation or employing CCUS on natural gas power plants.

The amount of CO_2 emitted per KWh has been declining in many countries. In the United States, increasing renewable energy use and replacing coal by natural gas have contributed. Even before the event at Fukishima, Japan in 2011, nuclear was being phased out in many countries, such as Germany and the United States. No new nuclear plants have been built in the United States since 1974; however construction was started in 2011 and 2012 on new units at existing plants.

Several countries have explored the potential for or adopted policies to completely replace fossil fuel and/or nuclear electricity generation with renewables. However, generating large amounts of power using renewables, even the 33 percent goal California currently has, challenges the stability and reliability of the electrical grid.

Vehicles, one of the largest emitters of GHGs, must be electrified or moved to biofuels or zero-carbon fuels to decarbonize the transportation sector. These options; however, transfer part of the energy and carbon footprint of transportation to other sectors, the power sector for electric vehicles; the industrial and agricultural sectors for biofuels or zero-carbon fuels. The underlying presumption to achieve overall carbon reductions is the electricity used by vehicles does not raise the carbon emissions of the power sector: biofuel feedstock growth, harvest, and processing uses low carbon energy or production of fuels from fossil feedstocks and employs CCUS. This results in future a transportation sector energy derived solely from renewables, biomass, or fossil fuel point sources using CCUS.

In the industrial sector, the largest contributors to GHG emissions are transportation fuel refineries and cement plants. Emissions from refineries come from on-site power generation and hydrogen plants; while fuel mixes can be changed to reduce the GHG emissions from processing and renewable sources can be used to generate power, larger decarbonization efforts requires CCUS. Similarly, for cement plants, power generation may use carbon-free feedstocks instead of fossil fuels,

but CO_2 emissions associated with the manufacture of cement products must be dealt with through CCUS.

Incorporating CCUS technology into California's energy future has significant challenges. From a technical standpoint, the component technologies are mature and can be readily deployed at commercial-scale. However, a diverse set of questions must be addressed before state planners, policymakers, and regulators should include CCUS as a part of the solution to meet 2050 goals:

- In what sectors does CCUS have the most potential to assist the state in reducing its CO_2 emissions?
- Do policies to facilitate CCUS enable continued use of fossil fuels even where there may be other viable options for energy generation?
- Are CCUS technologies, specifically subsurface storage elements, safe and effective over the long term?
- How can California agencies and lawmakers assure that CCUS projects are appropriately permitted, regulated, monitored, and verified?
- Can the state's industrial and energy infrastructure accommodate the changes necessary to integrate CCUS?
- In state planning for future energy infrastructure, should CCUS be included as a component? What is the risk in not doing so?
- If CCUS is to be relied on to reduce significant fractions of California's future emissions, at what rate should CCUS projects be coming on line, and what pathways to commercialization can accommodate this rate?

While the answers to some of these questions are unknown, insights can be gained from studying the experiences of other countries or states where CCUS has been analyzed or implemented to a larger extent than in California, by examining the technical data available from CCUS projects around the world, and by analyzing the results of many California-specific studies of CCUS and future energy infrastructure.

Study Results

CCUS has potential to be used for California's power, transportation and industrial sectors. Studies show increasing electricity demand will continue and aggressive energy efficiency measures are expected to contribute only about half of the 80 percent GHG reductions necessary by 2050. Within the power sector, CCUS may be recognized as an option for carbon neutral fuels, such as biomass, to generate net-negative CO_2 emissions that can generate "offsets or credits" that may be sold to other emitters.

CCUS may assist in decarbonizing the transportation sector by applying this technology to fossil fuel used in other sectors which will provide carbon-free energy to the transportation sector. For the industrial sector, while power demands may be filled by renewable generation, there are few to no options for reducing CO_2 emissions from refining or cement manufacturing processes other than CCUS.

Given the substantive efforts underway to diversify California's energy portfolio away from carbon-intensive fossil fuels, it appears likely that CCUS may only be included by policy when studies have demonstrated that no other options are available to decarbonize the electricity, transportation or industrial sectors. Given that both transportation and industrial sectors are likely to decarbonize by using carbon-free electricity, these sectors become dependent on the power sector for their energy supplies. It will become even more vital to California's economy to assure the reliability and sustainability of low cost electricity supplies.

CCUS projects worldwide provide data supporting that CO_2 can be stored safely in the subsurface for sufficiently long periods of time. Furthermore, these projects have tested a number of tools, including monitoring technologies, simulations, well completion methods, and well and cap rock integrity testing to give regulators confidence risks are measureable and monitor-able. For California, areas of particular concern are assuring the safety of groundwater resources from contamination and seismic hazards, including whether pressure buildup can induced felt-earthquakes and if the presence of stored CO_2 is likely to exacerbate risks of natural seismic hazards.

In general, CCUS requires less change in existing energy infrastructure than most other options for decarbonizing the power, transportation, and industrial sectors. Infrastructure requirements include capture facilities at CO_2 emission sources, pipelines, and injection and monitoring wells at storage sites. In addition, a labor force with expertise in power plant, pipeline, and well drilling engineering is necessary. Capture facilities must be paid by power producers. It is a policy decision as to whether these costs should be passed on to consumers by investor owned utilities. California will require substantial investment in pipeline infrastructure for CCUS to become widespread. Because a readily available supply of low cost CO_2 would benefit California's oil industry, that industry and federal subsidies for oil production may be sources of capital for pipeline development. California's CCUS project developers may be able to repurpose or co-utilize some existing infrastructure at California's numerous oil and natural gas fields if storage is done in conjunction with CO_2-Enhanced Oil Recovery (EOR) or by converting depleted reservoirs to storage sites. Storage in saline formations will require new infrastructure and development to assure safe and effective long term storage. California has plentiful geologic storage resource to accommodate captured emissions, according to studies by the California Geological Survey.

California's labor force includes people with the right expertise to support a CCUS industry. The state is home to many small start-up companies, universities and other research organizations developing utilization technologies, and there is sufficient venture capital to fund the most promising ones. The Energy Commission has already made some public fund investments to support growth of this sector. More public funding, possibly through cap-and-trade or EPIC programs, would accelerate developing better more cost-effective capture and innovative utilization technologies. California currently lacks experience in construction of high capacity CO_2 pipelines, and it may be bring in experts from other states—more than 6,400 km of pipeline carry gas from natural CO_2 domes to major oilfields throughout the Rocky Mountain, central and southern states.

Regulations and statutes require some changes to accommodate permitting and regulatory oversight of CCUS projects. There is a robust and growing body of knowledge worldwide to help formulate permitting and regulatory requirements assuring the safe and effective operation of CCUS projects. With the enactment of policies requiring attention to climate change impacts,

agencies are now tasked with safety and effectiveness responsibilities encompassing both traditional local environmental and, now, global climate change mitigation responsibilities.

Regulations and statutes require some changes to accommodate permitting and regulatory oversight of CCUS projects. Most important is including CCUS as an option for meeting obligations set by compliance or standard requirements. Beyond mentioning CCUS as an option, methodologies must be developed describing how storage or utilization technologies must account for CO_2 so project developers can incorporate them into business cases for project financing. Policies supporting a sustainable and predictable value for CO_2 are critical to enabling CCUS technologies.

If CCUS is to be a viable option for California to use to meet its 2050 GHG emission reduction goal, a large number of projects must be initiated within the next ten years. CCUS projects are large, industrial projects that require decades to plan, finance, permit and construct. To be conservative, more projects should be in development than might actually be required to reach the 2050 goal. Capture, injection, utilization, and storage operations must then continue for at least several more decades to have a measureable cumulative impact on GHG emissions reductions. The size of each project is limited by the size and number of the point sources that supply CO_2 to one or more storage sites. The number of injection wells and additional pipelines to connect a well array will depend on the injection capability and storage capacity of the formation(s) - storage site development may continue for many years after injection operations begin.

Economically, the largest potential uses for CO_2 are for enhance oil recovery (EOR), followed by embedding in building materials. At current oil prices, CO_2 commands about $40/ton for EOR. The state could benefit from substantive royalty revenues and job creation with more EOR production by injecting the captured CO_2 in the oil wells. Oilfield infrastructure might shorten the lead time for CCUS projects to become operational. While enabling fossil fuel production via CO_2 storage seems ironically counterproductive, there is actually significant CO_2 storage accomplished during EOR operations, and locally produced oil is preferable for several reasons over importing oil into the state. Estimates of CO_2-EOR potential in California's oilfields suggest there should be adequate demand for CO_2, provided oil prices remain high in the coming decades, to accelerate CCUS commercialization. Capture retrofits of power plants in close proximity to oil fields in the southern San Joaquin Valley could provide CO_2 for use in EOR. Other utilization technologies, such as building materials, are less geographically constrained and may be able to co-locate at emissions sources. The market for CO_2–based building materials is sufficiently large with a potential to use six tonnes of CO_2. Furthermore, building material CO_2 utilization technologies under development may prove to be some of the most cost effective ways to separate CO_2 from power plant flue gas, even though end products may not support paying high prices for CO_2—it may be a more cost-effective option for emitters than capture and sales for other utilization purposes.

Benefits to California

California regulatory agencies and policymakers have acknowledged the potential importance of CCUS technology to assist the state in meeting its GHG emission reduction goals. The most expedient way to enable CCUS from an economic and infrastructure perspective is to enable utilization of captured CO2. The largest potential uses for CO2 are for EOR, followed by building materials as a distant second. At current oil prices, CO_2 commands about $40/tonne for EOR. The

state could benefit from substantive royalty revenues and job creation through the enhanced production that might be realized by using captured CO2 in this way.

CHAPTER 1:
An Overview of Carbon Capture, Utilization, and Storage for California

1.1 Introduction

Carbon capture, utilization, and storage (CCUS) technology is recognized globally and in California's climate change policy as a greenhouse gas reduction strategy. To meet greenhouse gas (GHG) reductions in time to meet climate change mitigation goals, CCUS is one of the few options for reducing CO_2 emitted by large point sources such as power, fuel processing and industrial plants. The increasing rates of energy use suggest that meeting the 2050 GHG reduction goals recommended by the Intergovernmental Panel on Climate Change (Intergovernmental Panel on Climate Change 2005) will require accelerating the rates of CCUS adoption. Analysis also shows that if CCUS is omitted from overall emission reduction strategies, the costs of achieving the reduction goals by other means will be that much more expensive.

Carbon dioxide is a major contributor to a significant and accelerating rise in the average global temperature and the consequent effects of climate change (Consensus for Action 2013). For the purposes of this report, CO_2 reduction and GHG reduction are often used synonymously. CCUS technologies specifically target CO_2 emissions reductions from point sources such as power plants or industrial plants, and they may simultaneously reduce or increase emissions of other greenhouse gases. Consequently, it is important to consider the full life cycle effects on total GHG emissions when evaluating the benefits of CCUS implementation. CCUS is not one technology; instead it refers to a suite of technologies that together make up a system. CCUS technologies include those necessary for:

- Capture or removal of CO_2 from point source emissions
- Economic utilization of the separated CO_2 into products that store the CO_2 or produce a revenue stream; without this aspect, the technology is referred to as CCS
- Compression and transport
- Injection into a subsurface storage formation
- Monitoring, verification, and reporting of permanent storage
- Long-term stewardship, including remediation or mitigation of any leakage

Research, development, and commercialization of CCUS technologies have been underway for several decades with major conferences held since the early 1990s. Many component technologies were developed for other applications and have been commercially available for many years. For example, CO_2 has been utilized for enhanced oil recovery since the early 1970s. Knowledge and practical project experience in CCUS applications have grown only over the last 20 years. Thus, while many of the technological components of CCUS may be mature, it is critical to develop a history of successful deployment on a variety of commercial-scale CCUS projects. The greatest needs

for further technologic development are in the areas of utilization, monitoring, and capture (Burton, et al. 2011).

In 2005, the Intergovernmental Panel on Climate Change (IPCC) issued a Special Report on CCS which reviews a substantial body of evidence, knowledge, and peer-reviewed literature. In that report, the IPCC affirmed the effectiveness of CCS as a method for addressing GHG buildup in the atmosphere (Intergovernmental Panel on Climate Change 2005). The report concluded, based on observations from existing projects, engineered and natural analogs, and analytical models, that "the fraction [of CO_2] retained in appropriately selected and managed geological reservoirs is very likely to exceed 99 percent over 100 years and is likely to exceed 99 percent over 1,000 years. For well-selected, designed and managed geological storage sites, the vast majority of the CO_2 will gradually be immobilized by various trapping mechanisms and, in that case, could be retained for up to millions of years." (Intergovernmental Panel on Climate Change 2005).

Climate changes are anticipated to cost more than previously estimated as economists modeling the social cost of carbon are revising their figures upwards. With CO_2 levels now very close to 400 ppm ((National Oceanic and Atmospheric Administration 2014), the economic case for taking substantive action has never been stronger (Hope 2011)

California is at the forefront of states in transforming its energy sector and addressing its carbon emissions. Nevertheless, the challenge of implementing the necessary changes to meet its 2020 and 2050 GHG emissions reduction goals remains daunting. The state currently has no operational CCUS projects, although significant research and development efforts have been undertaken at many California institutions, funded by both federal and state agencies.

1.2 Forecasts of Energy Use and Carbon Emissions

The majority of California's energy use is in the electricity and transportation sectors, and these sectors also account for the majority of California's carbon emissions. As the transportation sector shifts to low-carbon fuels and electrification, the electricity sector may account for a relatively larger fraction.

The Energy Information Administration (Energy Information Agency 2010) shows California as the second largest consumer of electricity in the United States, ranking below Texas. In 2010, California used about 273,000 GWh (Kavalec, et al. 2012), near 7 percent of the national total of about 3,750,000 GWh; however, on a per capita basis, California ranks as the most energy-efficient of all 50 states, consuming 6,721kWh/person compared to a high in Wyoming of 27,457 kWh/person (Energy Information Agency 2010). Since the early 1970s, aggressive energy efficiency measures in California have maintained per capita electricity consumption at nearly constant levels, but population growth has resulted in overall increased electricity demand at a rate on the order of about a percent per year since 1990 (Kavalec, et al. 2012).

Forecasts of electricity demand predict growth rates will be of the same order through 2022, resulting in electricity demand ranging from 309,000-334,000 GWh in 2022 (Kavalec, et al. 2012). If these values are projected out for another 28 years, electricity demand estimates range from about 406,000 to 532,000 GWh in 2050. These estimates are consistent with the lowest projection of about 500,000 GWh, assuming increased energy efficiency and conservation measures, given in the report,

California's Energy Future: The View to 2050; however, they are less than half of the report's "business-as-usual" scenario estimate of 1,200,000 GWh for 2050, which is based on moderate economic growth and no additional energy efficiency measures (Greenblatt and Long 2012).

The rate of growth in electricity demand depends predominantly on rates of population growth and economic growth, but is also affected by other factors, such as electrification of the transportation sector and climate change impacts on temperatures and precipitation. For example, the Energy Commission's Integrated Energy Policy Report for 2013 forecasts that electricity demand will increase to less than 285,000 GWh by 2035 because of lower population growth forecasts and higher projected energy efficiency gains than used above (California Energy Commission 2013).

However, the Integrated Energy Policy Report also notes the detrimental effects that forecasted climate change impacts will have for energy. A study conducted by the Lawrence Berkeley National Laboratory (LBNL) for the 2012 California Climate Change Vulnerability and Adaptation Study (Sathaye 2012) found that higher temperatures would decrease the capacity of thermal power plants (for example, natural gas, solar thermal, nuclear, and geothermal) to generate electricity during particularly hot periods. At higher temperatures, power plant cooling is less efficient, reducing the plant's efficiency and how much energy it can generate. California's gas-fired generating plants have a nameplate capacity of about 44,000 megawatts (MW). By the end of the century, this capacity could be reduced by as much as 10,000 MW on hot days, compared to historical maximums averaging 7,600 MW over the 1961–1990 period. The LBNL study indicates that, by the end of the century, under certain climate scenario assumptions, energy supplies would need to increase by nearly 40 percent to meet increased demand from climate change and offset the lower capacity of thermal generating plants and substations, assuming no technology advancements or population changes (California Energy Commission 2013).

(Sanstad, et al. 2009) project the state's population for 2050 at approximately 60 million, a 30-35 percent increase over the 2012 population of about 40 million. Their projections for the state's economic growth, measured as gross state product, range from $3.87 to $4.48 trillion in 2050, compared to around $2 trillion today, or an approximate doubling of economic output.

Energy use will likely increase substantially due to climate change (California Natural Resources Agency 2009). Higher air temperatures are expected to increase the demand for electricity in the Central Valley and southern California, especially during hotter summer months, while reducing energy production and transmission efficiency and increasing the risk of outages. Population increases also are predicted to occur disproportionally in the Central Valley where the need for air conditioning is much greater than along coastal areas where population increases have been concentrated historically. Higher temperatures also decrease the efficiency of fossil fuel-burning power plants and energy transmission lines, requiring either increased production or improvements in the efficiency of power generation and transmission.

Extreme heat events also could cause significant impacts to the energy sector. California has a 17 percent probability of facing electricity deficits during high temperature (top 10 percent of historic temperatures) summer electricity demand periods, assuming constant technology and population growth (California Natural Resources Agency 2009). Addition of more generating units would be needed to accommodate this peak demand (California Energy Commission 2012).

Potential long term shifts in precipitation patterns would significantly affect hydropower which accounts for 12 to 20 percent of the state's current electricity supply (California Natural Resources Agency 2009). Climate projections used in the 2008 California Climate Impacts Assessment resulted in only one simulation producing slightly wetter conditions by 2050, and none did so for the end of the century. A warmer and drier future climate would reduce hydroelectric generation by about 20 percent, whereas a wetter future climate would increase hydroelectric generation by 5 percent. Pacific Gas and Electric Company (PG&E) and the Sacramento Municipal Utility District (SMUD) among many smaller utilities, receive significant portions of their annual generation from hydropower; SMUD is particularly vulnerable with hydropower accounting for up to 50 percent.

Current energy infrastructure must be adapted to address the effects of climate change, changes in electricity generation source mix and other legislative mandates, such as portfolio standards and prohibitions on once-through cooling, and growth in energy demand. This infrastructure includes natural gas pipelines, natural gas storage reservoirs, power plants, transmission lines, distribution wires and control systems. Transportation fuel infrastructure includes pipelines, refineries, and distribution systems. Infrastructure planning likely also will have to accommodate the effects of sea level rise, which is projected to be over one meter within the next century, and extreme weather events.

Most of California's electricity generation in 2010 was provided by a combination of in-state natural gas power plants and imported power, predominantly from large coal-fired plants. However, legislative mandates will significantly change the generation source mix for much of California's power over the next few decades (California Energy Commission 2011).

The Renewable Portfolio Standard (RPS) program requires investor-owned utilities, electric service providers, and community choice aggregators to increase procurement from eligible renewable energy resources to 33 percent of total procurement by 2020 (California Public Utilities Commission 2012). In 2010, renewable generation represented about 16 percent (10,000 MW installed capacity) of retail sales of electricity in the state ((California Energy Commission 2011). If existing facilities remain operational and new facilities projects in the pipeline are completed, the Commission predicts the 33 percent target could be met by 2020; however, if historical contract failure rates of about 30-40 percent pertain, the target would be missed (California Energy Commission 2011).

The Clean Energy Jobs Plan (California Governor's Office 2010) supports the RPS by requiring 20,000 MW of new renewable capacity by 2020, of which 8,000 MW may be large geothermal, solar or wind projects and 12,000 MW of distributed generation, local to consumer loads. Of the current renewable portfolio, about 30 percent (3,000 MW) is distributed generation, with about 6,000 MW additional under development or authorized.

Water use reduction policy, emissions performance standards, and tightening of air quality standards are putting pressure on California's power from fossil fuel generation. By 2020, California could see retirement, replacement, or divestiture of more than 15,000 MW of fossil generation, including 13,000 MW of gas-fired generation and 2,000 MW of coal-fired generation (California Energy Commission 2011). More than 13,000 MW of existing gas-fired generation will be out of compliance in 2020 with a policy to reduce once-through cooling for power generation. Plant owners indicate that long term power purchase agreements are necessary for them to repower or

retrofit existing plants with alternative cooling technologies. More than 2,000 MW of coal-fired generating capacity will be divested between now and 2019 as a result of Senate Bill 1368 (Perata, Chapter 598, Statutes of 2006) which requires setting a GHG emission performance standard for baseload generation. These standards apply to new or renewed long-term contracts to purchase electricity from baseload facilities owned by, or under long-term contract to, publicly or investor-owned utilities. Currently, the standard is 1,100 lbs (500 metric tons) of CO_2 per megawatt-hour (MWh), set by the California Public Utilities Commission (CPUC) and the California Energy Commission. The divestiture is predicted to reduce the share of California's electricity coming from coal-fired generation to less than 4 percent. All remaining coal contracts are expected to expire between 2027 and 2030. In addition, federal air quality constraints are resulting in closure of coal-generating plants throughout the country, including some that export power to California. Stricter regional air quality standards also are inhibiting development of new fossil fuel power plants within the state, particularly in southern California.

Nuclear power generation is constrained by a law that prohibits building of new plants until there is a federal nuclear fuel waste repository. In mid-2012 California had just one operational nuclear power plant, the Diablo Canyon facility near San Luis Opisbo. This 2.1 GW plant has an operational license until 2024. The 2 GW San Onofre facility situated between Los Angeles and San Diego, went offline in January 2012 for repairs, and in June 2013, as announced by Southern California Edison, that it would not be re-opened. Where the replacement will come from is unclear, but natural gas generation is likely for the immediate future.

Limited availability of emissions offsets also may constrain development of new fossil fuel generation capacity. Assembly Bill 1318 (Pérez, Chapter 285, Statutes of 2009), requires California agencies to assess the need for emission offsets and new power plant capacity in the South Coast Air Basin and to examine whether rule changes and other permitting mechanisms would allow power plants to be developed while safeguarding air quality.

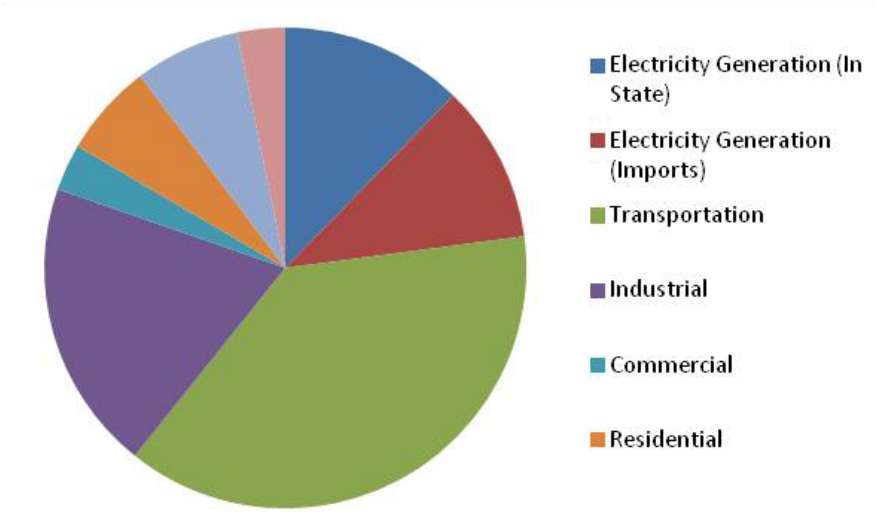
Unlike the United States as a whole and many nations, California has laws requiring GHG emissions reductions in line with those recommended by the IPCC. In 2005, an executive order by Governor Schwarzenegger required California to reduce its GHG emissions to 2000 levels by 2010, to 1990 levels by 2020, and to 80 percent below 1990 by 2050 (Executive Order S-3-05). The passage of Assembly Bill 32 (AB 32) set the state on the path to meet the 2020 goal (Nuñez, Chapter 488, Statutes of 2006). AB 32 requires a scoping plan that describes the approach California will take to reduce GHG to achieve the goal of reducing emissions to 1990 levels by 2020. The first Scoping Plan was approved by the California Air Resources Board (ARB) in 2008 and must be updated every five years to evaluate the mix of AB 32 policies to ensure that California is on track to achieve the 2020 GHG reduction goal. Preparation for the 2013 Update is underway and will be released in November 2013.

The total GHG emissions in California are currently about 500 Mt CO_2e/year. By 2050, GHG emission must be reduced to 77 Mt CO_2/year, or from the current 13 tons/person down to 2 tons/person, accounting for population growth (California Air Resources Board 2011).

From 2000-2009, California's transportation sector has contributed nearly 40 percent of greenhouse gas emissions (California Air Resources Board 2011). The second largest sector is electricity

generation, at slightly over 20 percent, with approximately equal portions of emissions from in-state and imported power generation (Figure 1). Within the industrial sector, cement plants and refineries are the largest emitters.

Figure 1: Greenhouse Gas Emissions for California by Sector (2009)

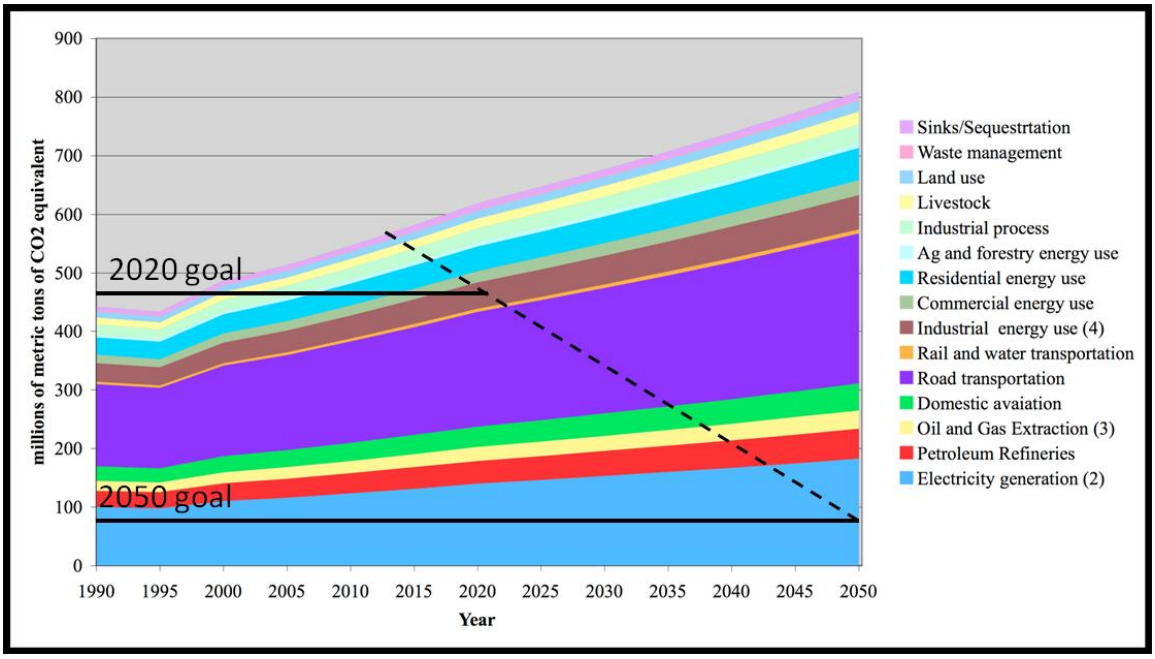


Source: (California Air Resources Board 2011)

Overall, California's GHG emissions differ from other U.S. states and most countries in that it relies less on coal than on natural gas to meet its electricity needs and the transportation sector accounts for a much higher portion of its total emissions. Forecasts of future emissions have been done. For a business-as-usual case, assuming moderate (1 percent) economic growth, projected total GHG emissions could exceed 800 Mt (Figure 2) (Schiller 2007). For the electricity sector, demand in 2050 could result in emissions of 120 Mt CO_2 per year, based on a business-as-usual scenario (Table 1).

To address emissions in the transportation sector, Executive Order S-01-07 directed ARB to create a low-carbon fuel standard (LCFS). The Order calls for a reduction of at least 10 percent in the carbon intensity of California's transportation fuels by 2020. The LCFS is separate from the mandatory reporting regulation and the cap-and-trade program and has its own reporting tools and credit-trading requirements. The LCFS framework is based on the premise that each fuel has a "life-cycle" GHG emission value that is then compared to a standard. The life-cycle analysis includes the direct emissions associated with producing, transporting, and using the fuels in motor vehicles, as well as additional emissions, direct and indirect, derived from effects of using that fuel—for example, emissions that result from changes in land use for crop-based fuels.

Figure 2: Forecast California GHG Emissions by Sector



Source: Modified from (Schiller 2010)

Table 1: Electricity Demand and CO2 Emissions in 2010 and Forecasts for 2050

	Demand (TWh/year)	Emissions (Mt CO_2)
2010	300	100
2050 Goals	-	77
2050 BAS	1200	140
2050 Scenario*	500-600	60

Source: (Greenblatt and Long 2012)

The standards are expressed as the carbon intensity of gasoline and diesel fuel and their alternatives in terms of grams of CO_2 equivalent per megajoule (g CO_2E/MJ). Providers of transportation fuels must demonstrate that the mix of fuels they supply meet the LCFS intensity standards for each annual compliance period by reporting all fuels and tracking the fuels' carbon intensity through a system of credits and deficits. Credits are generated from fuels with lower carbon intensity than the standard. Deficits result from the use of fuels with higher carbon intensity than the standard. A regulated party meets its compliance obligation by ensuring that the amount of credits it earns (or acquires) is equal to or greater than the deficits it has incurred. Credits may be banked and traded within the LCFS market to meet obligations.

1.3 Role of CCUS in Achieving CO_2 Reduction Goals

The path to achieving the 2020 goal and especially the 2050 goal presents significant challenges that include massive changes in energy infrastructure and consumer behavior. In order to meet targeted

reductions, state agencies are pursuing five broad approaches (California Air Resources Board 2008):

- Conservation: Reduction of energy through changes in consumer lifestyles and workplace environments to reduce transportation fuel use, home use of natural gas, and other measures.
- Energy efficiency: Efficiency must improve by about 1.2 percent per year for the next four decades in all sectors of the economy to keep costs manageable and reduce overall infrastructure requirements for new generation.
- Renewables for electricity generation: Commercialization of solar or wind generation with energy storage. A transition to low- or zero-carbon sources of electricity generation will be required in all sectors of the economy, including the transportation, residential, commercial, industrial and agricultural sectors.
- Low-carbon biofuels: Low-carbon biofuels could contribute approximately 6 percent of 2050 goals, but the use in the transportation sector may be limited by supply of biomass.
- Electrification of transportation: Increased electrification of private cars, fleets, trains and other vehicles will cause electricity to grow from 30 percent of total state energy consumption to 70 percent by 2050. Over 95 percent of electricity used for transportation must come from zero-carbon or very-low carbon sources.
- Low-, zero- or net negative electricity generation: The need to maintain grid reliability will create a high demand for low-carbon dispatchable and baseload generation. This generation might come from renewable energy with storage, nuclear energy, or fossil fuel or biomass generation with CCUS. It will be exceptionally difficult to balance the grid with only renewable or only nuclear energy. A mix of low-carbon baseload, dispatchable and peaking resources will be required.
- Terrestrial sequestration: Changes in forestry and land use practices could contribute approximately 15 percent of California's total GHG emissions savings in 2050.

In addition to these measures, California has implemented a cap-and-trade market for carbon allowances. The AB 32 Scoping Plan identifies a cap-and-trade program as one of the strategies to reduce GHG emissions. In October 2010, ARB released draft cap-and-trade regulations and designated the standardized methods established by the Mandatory Reporting Regulation of 2007 (effective January 2009) to provide source emissions data. Under cap-and-trade, an overall limit on GHG emissions from capped sectors is established by the cap-and-trade program and facilities subject to the cap must hold permits (allowances) equivalent to their GHG emissions. For example, if an oil refinery that emits 100,000 tons of carbon has credits for 90,000 tons, it either has to go on the market and buy credits for the extra 10,000 tons or lower its emissions. If it reduces its emissions, say to 80,000, then it could sell the unused permits to someone else. Trading allows facilities to purchase or sell allowances, thereby creating a market-based value for CO2. The cap-and-trade program held its first auction in November 2012 and its second auction in February of 2013. The settlement prices for CO2 for 2013 bids at the first and second auctions were $10.09 and $13.62 per allowance (per metric ton), respectively (California Air Resources Board 2013).

Within capped sectors, while some emissions reductions will be attained through direct regulations (e.g., LCFS, vehicle efficiency measures, and renewable portfolio and electricity standards), additional reductions are incentivized by the cap-and-trade market price placed on GHG emissions. Together, direct regulations and price incentives should lead to reduced emissions in the most cost-effective manner. If the system works as designed, the most efficient companies will be financially rewarded, polluters will pay, and greenhouse gases will be dramatically reduced.

California's cap-and-trade system is designed to work beyond its borders, including other states, Canadian provinces and even other nations. ARB is working closely with British Columbia, Ontario, Quebec and Manitoba through the Western Climate Initiative (WCI) to develop harmonized cap and trade programs that will deliver cost-effective emission reductions. The WCI jurisdictions have formed a non-profit corporation, WCI, Inc. to provide coordinated and cost-effective administrative and technical support for its participating jurisdictions' emissions trading programs.

Income from the cap and trade program should be expended in accordance with the 2012 implementing legislation that established the Greenhouse Gas Reduction Fund. The state Department of Finance is required to submit a three-year investment plan to the legislature that reflects a balanced effort to address major sources of climate change in California. Targeted expenditures to meet the state's 2020 emission reduction goals will be in transportation, energy generation and efficiency, and community development. A draft investment plan for 2013-2015 was issued (California Air Resources Board 2013) following public consultation and agency collaboration, which also notes that in order to meet post-2020 emission reduction targets, far-reaching new approaches will be required. Strategies for post-2020 energy planning were first outlined in the Climate Change Scoping Plan for 2008 (California Air Resources Board 2008), wherein it is noted that "…while the likely rate of deployment of CCS may not yield substantial reductions before 2020, CCS within California and the Western Electricity Coordinating Council…region has the potential to play a significant role in helping to achieve the GHG goals for 2050." Our analysis of data since 2008 indicates that CCS will be an essential technology to meet the 2050 goal.

CCUS is relevant to California's 2020 and 2050 GHG emissions reduction goals through application to the electricity, industrial, and transportation sectors. In California, refineries and cement plants are the largest emitters in the industrial sector. While the traditional focus of CCUS applications has been for power plants or industrial facilities, CCUS can provide a pathway to de-carbonize the transportation sector through the use of electric vehicles that utilize low-carbon power produced by CCUS-equipped power plants or use in conjunction with biofuels (Greenblatt and Long 2012).

A principal finding from the California Council on Science and Technology (CCST) reports is that California needs CCUS to meet its GHG emissions target. The Clean Energy Future 2010 report identifies several strategies to meet the state's 2020 emission reduction goal, which includes "…developing at least one utility-scale carbon capture and storage facility in California by 2020 (Greenblatt and Long 2012)." However, there is only one CCUS project at this scale that is under consideration in California, the Hydrogen Energy California (HECA) project. Although HECA has experienced several delays as will be discussed in later chapters, the project is expected to be operational before 2020.

California agencies recognize the importance of CCUS in the portfolio of technologies required to meet the state's GHG emissions reduction goals. The California Air Resources Board (CARB) names CCUS in its *Climate Change Scoping Plan,* recommending that "California should both support near-term advancement of the technology and ensure that an adequate framework is in place to provide credit for CCS projects when appropriate." (California Air Resources Board 2008). Further, CARB, at its meeting on December 16, 2010, when adopting California's cap-and-trade program, also adopted a resolution "to initiate a public process to establish a protocol for accounting for sequestration of CO_2 through geologic means and recommendations for how such sequestration should be addressed in the cap and trade program".

Regulatory agencies and policy makers have taken several actions over the last decade to investigate CCUS technology:

- In 2003, California became a founding member of the West Coast Regional Carbon Sequestration Partnership (WESTCARB), which is led by the California Energy Commission in partnership with two of California's national laboratories and over 100 other organizations. WESTCARB is one of seven regional carbon sequestration partnerships funded by DOE. WESTCARB's region includes Alaska, Arizona, California, Hawaii, Nevada, Oregon, Washington and the Canadian province of British Columbia. WESTCARB's work includes conducting technology validation and demonstration field tests, identifying major sources of CO_2 in its region, performing engineering and economic studies of capture technologies, and determining the potential in its region for storing captured CO_2 in secure geologic formations.
- The California legislature requested a report in 2006 (Blakeslee, Chapter 471, Statutes of 2006) from the Energy Commission and the Department of Conservation that contained recommendations for facilitating adoption of CCS for industrial sources in the state.
- In 2010, CARB, the CPUC and the Energy Commission convened the California CCS Review Panel to make recommendations for removing the policy and regulatory barriers to CCUS commercialization.

The current regulations implementing SB 1368 allow for the use of CCUS to meet the EPS, but the mechanisms for determining compliance are unclear. The Energy Commission regulation states that for covered procurements that employ geologic CO_2 storage, the successfully sequestered CO_2 emissions shall not be included in the annual average CO_2 emissions. The EPS for such power plants shall be determined based on projections of net emissions over the life of the power plant. CO_2 emissions shall be considered successfully sequestered if the sequestration project meets the following requirements:

- Includes the capture, transportation, and geologic formation injection of CO_2 emissions
- Complies with all applicable laws and regulations
- Has an economically and technically feasible plan that will result in the permanent sequestration of CO_2 once the sequestration project is operational.

Under the LCFS, CCUS is specified as an option for producers of high carbon intensity crude oil to reduce emissions for production and transport of crude oil to less than 15 g CO2e/MJ. CCUS could also be considered when used for the production of alternative transportation fuels such as hydrogen, compressed natural gas, and electricity. For CCUS to be formally incorporated into the LCFS, a quantification methodology would be necessary.

These requirements differ from AB 32 requirements in a few key ways. First, the EPS is based on emissions over the lifetime of the plant whereas AB 32 is based on annual emissions, and the LCFS) considers life-cycle emissions (including indirect emissions). Second, the EPS requires an economically and technically feasible plan for permanent storage, while AB 32 accounting would need a quantification methodology for any emissions and verification of permanent storage. The definition of permanent storage is not included and may have different criteria than those which will be defined under the AB 32 regulations.

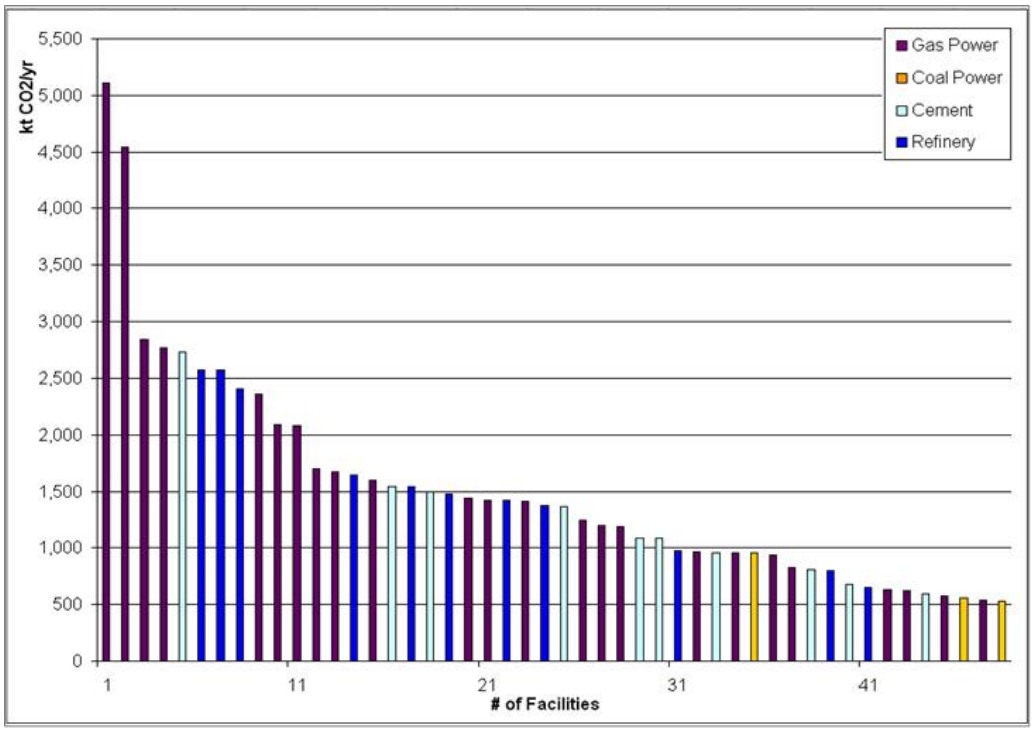
When CARB approved the cap-and-trade regulation and revisions to the Mandatory Reporting Regulation to support the cap-and-trade program at its December 16, 2010, Board meeting, it included the following directive pertaining to CCUS:

"BE IT FURTHER RESOLVED that the Board directs the Executive Officer to initiate a public process to establish a protocol for accounting for sequestration of CO2 through geologic means and recommendations for how such sequestration should be addressed in the cap and trade program, including separate requirements for carbon capture and geologic sequestration performed with CO2-enhanced oil recovery; carbon injected underground for the purposes of enhanced oil recovery will not be considered to be an emissions reduction without meeting ARB's monitoring, reporting, verification, and permanence requirements (California Air Resources Board 2010)."

Infrastructure investment decisions made in this decade may determine whether or not CCUS will be included in the portfolio of technologies used to achieve the state's 2050 GHG reduction goals. Projects can take over a decade to permit, construct and bring on-line, and many will have useful lifetimes of 40 years or more. Infrastructure choices made in the next ten years thus may strongly influence the GHG emissions reduction trajectory over the next 40 years.

Capture infrastructure is source-specific. Among the state's largest GHG point sources, there is none which produce highly concentrated CO_2 streams, such as ethanol plants or natural gas processing facilities. Among the state's largest point sources in the power sector are 50 relatively new natural gas combined cycle (NGCC) power plants. Cement plants and refineries are the other major types of sources (Figure 3).

Figure 3: Fifty Largest CO_2 Point Sources in California.



Source: (Katzer and Herzog 2008)

Some studies have suggested that application of CCUS to biomass or biofuel plants may be a valuable option for the state to achieve its 2050 emissions reduction goal (Greenblatt and Long 2012). Only about 2 percent of the state's electricity (600 MW) is generated from 33 small biomass power plants. Approximately 196 million gallons of biofuels are produced in-state by ethanol and biodiesel facilities; the demand estimated by the California Energy Commission is approximately 1.6 billion gallons per year. California's Low Carbon Fuel Standard includes eligibility of CCS as a measure to lower the carbon intensity of fuel stocks. Emissions from these sources are considerably less individually and in aggregate than from coal and NGCC power plants or petroleum refineries, but these sources are free from cap-and-trade emission constraints and would produce net-negative emissions if outfitted with CCUS. These negative emissions could be used as offsets for fossil generation or fuels if allowed by policy. The California 2012 Bioenergy Action Plan recognizes the need to analyze and mitigate potential problems with particle air emissions that have created challenges for biomass plants, such as the Klamath Biomass Plant in southern Oregon. These and other challenges facing biofuel development, such as assumptions about the accounting benefits, have been raised (e.g., (Bundy 2013)).

WESTCARB has performed preliminary studies of the engineering and economics for capture retrofits and new builds of typical NGCC plants in the state. Details of the study's results are included in Chapter 3. Capture or separation of CO_2 from flue gas may be applied as pre-combustion, post-combustion or via oxy-combustion where an air separation plant is used to create an oxygen stream for combustion and the exhaust gas is predominantly CO_2 and H_2O. A special

case of oxy-combustion, wherein a high-temperature "rocket-engine" design is used for the turbine, is also in development in California.

A recent research roadmap for the Energy Commission examined a range of CO_2 utilization technologies for their potential to assist California in meeting its greenhouse gas emissions reductions goals (Burton, et al. 2011). The results of this study are discussed in Chapter 3.

For out-of-state coal generation exported to California, CCUS applications are allowed for plants to meet the SB1368 emission performance standard. As noted above, however, the Energy Commission anticipates an essentially complete divesture of coal generation from California's electricity portfolio. Many of the coal plants that contract with California are in their final decade of service (California Energy Commission 2013). Furthermore, given other pressures on coal plants, such as increasingly stringent federal air quality regulations and current projections of low prices for natural gas compared to coal in the U.S. for the next few decades, it is unclear whether power providers will choose to retrofit their existing coal plants with CCUS. However, in some instances, where power generation is owned by entities, such as Native American tribes, that also are heavily invested in coal, the choice may be made to apply CCUS if capture can be done economically relative to other options.

At present there is no CO_2 pipeline infrastructure in California to carry the large volumes of CO_2 captured from point sources to storage sites. This situation contrasts significantly with other parts of the U.S. where CO_2 is carried by pipeline from natural CO_2 domes to oilfields in many regions throughout the mountain, central, and southern states. There are over 6,400 km of CO_2 pipeline in the U.S. transporting over 30 Mt of CO_2 per year to oilfields for CO_2-EOR. While California has significant numbers of oilfields that are candidates for CO_2-EOR floods, the lack of CO_2 availability at an economic price, relative to historic price trends for produced oil, has precluded the application of this EOR method in the state.

The California Geological Survey performed a study for WESTCARB (Downey and Clinkenbeard 2011) to establish the state's storage resource potential. They screened 27 basins throughout the state and focused on 10 sedimentary basins with the greatest potential. California has almost 240 Bt of CO_2 storage capacity offshore, 146-840 Bt on-shore, of which 75-300 Bt in deep saline formations with between 335-1,277 Mt in oil reservoirs and 3,035-5,179 Mt in gas fields (see (Hwang 2010). Further studies by the California Geological Survey have refined these estimates for some regions and for offshore. One of the challenges for making estimates is that while the formations may be quite laterally extensive, they are often truncated by faulting or other geological discontinuities that would prevent the CO_2 from accessing the full extent of the formation. These are beneficial in that they provide stratigraphic and structural traps for the CO_2, but also may be potential leakage risks if CO_2 can migrate up fault planes or other discontinuities to reach the surface or potable groundwater. However, these same types of structural and stratigraphic traps have contained oil or gas for millions of years, a testament to their long-term ability to store buoyant fluids. A 2005 study of the EOR potential in California's oilfields indicated that 6.5 bbl of miscible oil could be economically recovered (Advanced Resources International 2005).

1.4 Summary

In many respects, California is at the forefront of addressing the challenges involved in redesigning its energy infrastructure and addressing GHG emissions reductions to meet goals consistent with IPCC recommendations. CCUS has potential applications to electricity, transportation and industrial economic sectors in the state. Analyses demonstrate that CCUS deployed on a variety of emissions sources, including carbon-neutral fuels, is an important part of the portfolio of options the state needs to meet its goals. Many state agencies have recognized the potential role that CCUS can play. Yet, in California, as in the rest of the world, CCUS commercialization lags behind other technologies that address GHG emissions. This situation is somewhat puzzling given the state's forefront position in aggressive climate change policy.

There is no doubt that incorporating CCUS technology into California's energy future has significant challenges. From a technical standpoint, the component technologies are mature and can be readily deployed at commercial-scale; however, CCUS technology as an integrated system is still in the development stages. The public and private investment in CCUS infrastructure must be substantial to commercialize the technology; and its acceptance would substantially change future directions for energy infrastructure. Thus, policymakers must feel assured that choosing the CCUS path is both necessary to meet climate change goals and appropriate to the state's other needs, such as resource protection and economic equity and sustainability. This report seeks to answer a diverse set of questions to assist state planners, policymakers, and regulators in assessing why and how to include CCUS:

- In what sectors does CCUS have the most potential to assist the state in reducing its CO_2 emissions?
- Do policies to facilitate CCUS enable continued use of fossil fuels even where there may be other viable options for energy generation?
- Are CCUS technologies, specifically subsurface storage elements, safe and effective over the long term?
- How can California agencies and lawmakers assure that CCUS projects are appropriately permitted, regulated, monitored, and verified?
- Can the state's industrial and energy infrastructure accommodate the changes necessary to integrate CCUS?
- In state planning for future energy infrastructure, should CCUS be included as a component? What is the risk in not doing so?
- If CCUS is to be relied on to reduce significant fractions of California's future emissions, at what rate should CCUS projects be coming on line, and what pathways to commercialization can accommodate this rate?

While the answers to some of these questions are unknown, insights can be gained from studying the experiences of other countries or states where CCUS has been analyzed or implemented to a larger extent than in California to date, by examining the technical data available from CCUS

projects around the world, and by analyzing the results of many California-specific studies of CCUS and future energy infrastructure.

CHAPTER 2:
Elements of a Carbon Capture, Utilization and Storage Project

2.1 Overview

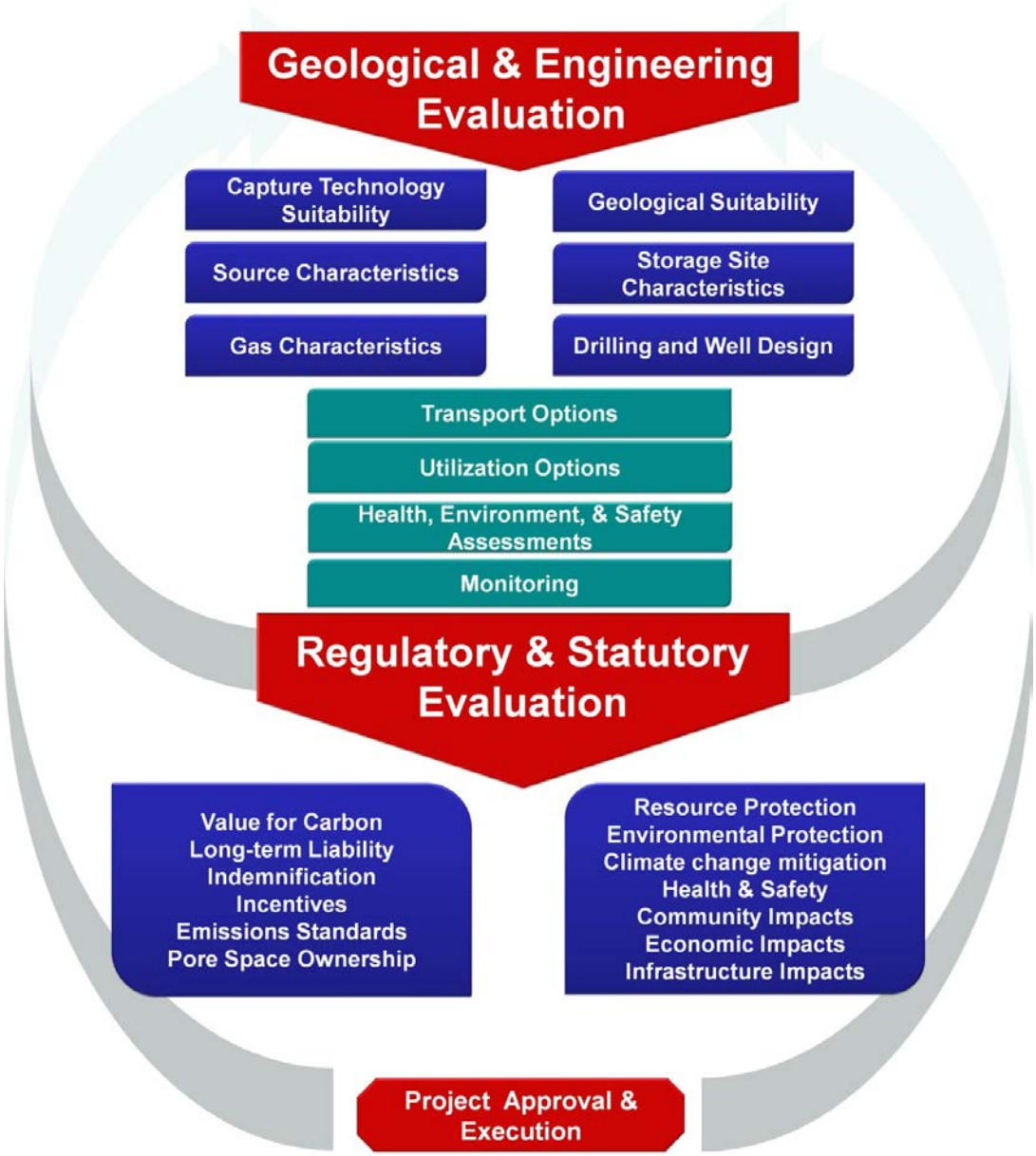
Since the IPCC report in 2005, the body of knowledge about the risks of undertaking, or not undertaking, CCUS projects has evolved significantly. Various different groups involved in a CCUS project have different stakes in the various components of project risk. At a macro-level, risks can be categorized as related to business or societal needs. From a societal standpoint, areas of risk include the effects of CCUS implementation on jobs, consumer costs, public health and safety, and environmental issues. From a business standpoint, the areas of project risk include not only technical risks, which are greatest in the subsurface, but also substantive financial and regulatory or statutory risks. All stakeholders must have information to evaluate the case for CCUS compared to other options and choose the option that presents the lowest cost and least risk for meeting future GHG reduction goals or compliance obligations. These risks may be evaluated by stakeholder groups at different levels: local community, region, state, national or global.

What is defined as a significant risk involves an assessment of both the likelihood and severity of an event, however these parameters are difficult to define from a strictly theoretical basis. Case history experience and data are extremely valuable in helping to identify the types of events that are most likely to occur, as well as the impacts of those events. Case history data provide a basis for developing mitigation approaches and technologies to further reduce risks in the future. For CCUS projects, experience from analogous industries, such as natural gas storage and oil and gas production operations, especially CO_2-EOR, can be particularly valuable in providing data for robust risk assessments.

Once a site is chosen by a project developer, engineering and geologic parameters are fixed constraints on project feasibility; however, a society recognizing it has a stake in CCUS development can use research and development investment to reduce the risks associated with these parameters. Regulatory and statutory parameters are not rigid, but the timeline for changing them may be viewed as so long by a business stakeholder that he considers them fixed for the purposes of evaluating a specific project. For a society with a long term macro-view, regulations can be changed to facilitate integrating CCUS into energy infrastructure and climate change mitigation strategies, and statutes may be put in place to enable projects. Statutory changes might include mandating development of new regulations, defining standards, clarifying lines of ownership or financial responsibility for damages, or creating sustainable values for carbon via a tax or carbon market.

In 2008, the California Energy Commission published a report to the California legislature (Burton, et al. 2008) in fulfillment of the requirements of Assembly Bill 1925 (Blakeslee, Chapter

Figure 4: Components of a CCUS Project



A CCUS project is modular and includes two main categories of evaluation: a technical evaluation with geologic and engineering components, and a regulatory and statutory evaluation. This flow chart shows the flow and iterative processes among the modules that are required to make a project successful.

Source: (Burton, et al. 2009)

471, Statutes of 2006) that summarized the state of development of CCS technology and relevant California statutes and regulations, including information current to about 2006. Since that time, there has been further progress in CCUS technology development, including studies of engineering, economics, policy and regulatory needs, and advances through field demonstrations. This chapter summarizes the current state of knowledge and experience while drawing on information previously published in the Assembly Bill 1925 report (Burton, et al. 2008). Areas where advancements have taken place of particular relevance to California include: engineering and

economic assessments of retrofits and new builds of capture and separation technologies on natural gas combined cycle plants; understanding of the relationship of CO_2 subsurface injection and seismic hazards; and technologies combining carbon capture and storage with utilization, especially enhanced oil recovery, but also including geothermal, enhanced gas recovery, water co-production, and manufacturing of products.

Figure 4 shows the modular nature of a CCUS project and the major elements that are sources of risk. Risk assessment and risk management are two key elements of risk mitigation and should be part of all projects. Fundamental to risk assessment is a process that identifies risks and rates each risk on the likelihood that an event will happen and the severity of that event should it occur. In the process of risk management, specific project-related actions are identified to mitigate the risks. The process is not static, but evolves over time as new information and confidence is gained.

Components of CCUS infrastructure include capture facilities on power plants and other point sources, networks of CO_2 pipelines connecting sources with suitable storage or utilization sites, and subsurface facilities suitable for safe, long-term geologic storage. Additional technical infrastructure-related needs are personnel with appropriate training in capture, transport, and storage operations, and supporting industries to construct capture plants, pipelines, and perform drilling operations. Policy and regulation are additional risk elements, as are public and stakeholder perception issues which can facilitate or impede project development. Summaries of these elements in actual CCUS projects at various development stages are reviewed in Chapter 7 for California projects and in Appendix A and B for projects in North America and worldwide.

CCUS projects entail the usual risks associated with the construction and operation of large industrial projects. Storage projects will involve laying pipelines and drilling deep wells. Employees and contractors will be working outside in remote locations with large, heavy, equipment. The process of digging trenches for pipelines entails worker safety risks as well as risks to the environment. Similarly, well drilling entails risks to workers from conditions encountered in the subsurface as well as to the environment, due to construction of the drill site. These risks need to be assessed, managed, and mitigated, but will not be discussed further under the assumption that they are well understood in the context of common industrial operations.

The primary concern regarding storage is leakage, which could result in groundwater and other resource contamination, localized damage in the soil layer, significant release to the atmosphere, or health and environmental hazards. The pathways for leakage potentially include the handling of CO_2 en route to the injection site, issues with well integrity, and migration through faults or fracturing of the seal. An additional concern is induced seismicity. Subsurface risks usually can be mitigated by careful site selection and characterization, proper injection practices and monitoring during injection operations and after injections stops. Confidence in the ability to mitigate storage risks and in the methods, tools, and approaches for doing so derive from many decades of experience in analogous industrial operations

The need for risk assessment and management is not unique to geologic storage. Over the past ten years, considerable effort has been devoted to tailoring and adapting risk assessment approaches to geologic storage. As a result, there are now commercially available “packages” specifically for geologic storage, although development of risk assessment tools remains an active area of research.

An understanding of the risks associated with CCUS is fundamental to the development of regulations that ensure protection of workers, the general population, the environment, and natural resources. Although the idea of intentionally storing large quantities of CO_2 in underground geologic formations for extended periods is relatively new, industrial operations, including petroleum exploration and production, enhanced oil recovery using CO_2, underground gas storage, and disposal of acid gas and hazardous wastes, provide many decades of relevant knowledge and experience for determining the risks of geologic storage, as well as the methods and technology to mitigate those risks. Using this knowledge as a basis, many studies have been undertaken over the last decade to determine the specific risks associated with geologic storage.

Two additional overarching factors, technology readiness and life-cycle analysis, also are critical to assessing the risks of whether CCUS technology will be available and appropriate to address the needs of California in reducing GHG emissions.

2.2 Technology Readiness

Technical barriers include subsets of regulatory and economic barriers that are specific to a technology. In order to successfully launch new products into the energy marketplace, a technology must meet technical performance, meet regulatory requirements (including health and safety requirements), and have acceptable process economics. Typical barriers to technology readiness might be:

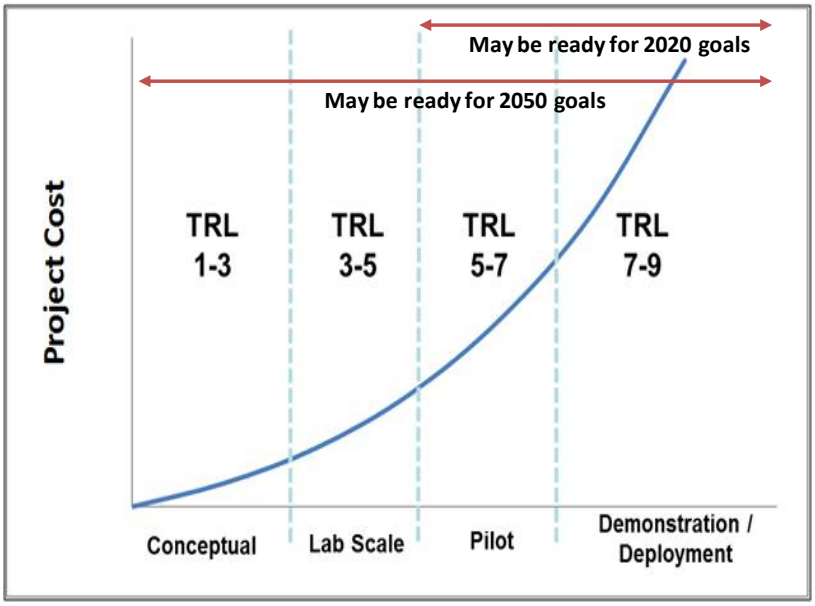
- Technology: unable to scale process to meet feed stream volumes or unable to achieve acceptable performance, e.g. product purities
- Regulatory: regulations that either impede the deployment of the technology or favor the deployment of competing technologies
- Economics: process economics are too expensive for the current market place

The Technology Readiness Level (TRL) scale developed by NASA, now widely used by the Department of Defense (DoD) and other agencies, provides a way to assess the relative maturity of a particular technology. It is viewed as one component of a risk-reduction process and creates a "common language" that facilitates the integration and comparison of technologies from various universities or research labs, such as National Renewable Laboratory and the Argonne National Laboratory (Graettinger, et al. 2002).

The TRL ranking is a means to determine the relative time scale to commercialize a technology (i.e., less than 3 years, 3-10 years, or greater than 10 years) (Figure 5). Technology risk and the time to commercialize (i.e., full deployment) are reduced as projects move from the left side of the horizontal axis to the right side. New energy technologies typically mature as they are transitioned from a conceptual, to lab scale, to pilot scale, and finally to demonstration and deployment. The transition from lab to pilot scale is particularly critical since this indicates evaluation in the field, e.g., at a power generation site. It is not uncommon for energy technologies to perform acceptably in a laboratory environment, yet only to fail when tested at a pilot scale level. Scalability is a common barrier that needs to be overcome.

Project costs and manpower requirements commonly increase significantly during this transition out of the controlled laboratory environment. Project costs are shown by the blue curve, increasing significantly as technologies move through TRL stages from conceptual to demonstration. Each TRL is associated with a range of three numbers within each stage, collectively ranging from 1 to 9. Considering the time scales of relevance to California's GHG reduction goals, this ranking could be simplified to two overlapping categories: less than 10 years (may be ready for 2020 goals) and more than 10 years (may be ready for 2050 goals).

Figure 5: Relationship Between TRL, Project Scale and Costs



Source Adapted from Energy Commercialization, LLC

2.3 Life Cycle Analysis

With regard to adopting any technology, but perhaps critically for carbon mitigation technologies, it is important to understand the full life-cycle effects of implementation. Life cycle assessment provides a framework for holistic analysis of a technology system and can provide crucial information regarding environmental, social, and economic tradeoffs to policy-makers and other stakeholders as they consider technology options. A group of researchers at Lawrence Berkeley National Laboratory has been studying life cycle assessment (LCA) of carbon mitigation technologies, including CCUS. Their findings are summarized below and their report included as Appendix C.

An LCA strives to characterize the environmental burdens posed by mass and energy flows across the entire life cycle of a product or process, including its raw material extraction, manufacture, use, and disposal phases. To conduct an LCA, the goal and scope must be defined describing the purpose of the study, the system boundaries of the analysis, and the functional unit used for assessment and comparison. Then, an inventory assessment quantifies the inputs and outputs of mass and energy attributable to processes occurring within the system boundaries. An impact assessment characterizes the effects of these inputs and outputs considering resource depletion,

human health, ecosystem quality, and climate change. Finally, the inventory and impact assessment results are interpreted to identify significant conclusions, recommendations, and implications for decision-making.

Accounting methodologies must have effective and workable system boundaries established broadly enough to capture the significant impacts of interest, but not so broadly as to make the analysis too unwieldy. In practice, this is rarely straightforward. Geographic specificity is important, especially for CCUS, and can be captured with spatially explicit modeling and databases. For example, variation in state regulations, infrastructure, demographics, and geology will likely affect the performance and potential of CCUS technologies. Incorporating time dynamics is challenging but important, and is relevant to power plant fleet turnover, technology advancement, resource depletion, behavior of CO_2 in geological storage, and urgency of GHG mitigation measures in the face of cumulative radiative forcing from greenhouse gas (GHG) emissions.

The results of an LCA can be used to compare the environmental performance of different (and often competing) technology options for meeting a given societal service if they are expressed in terms of consistent functional units. A functional unit should be selected to facilitate and inform the decision-making process; different functional units may be appropriate for different uses. For example, most CCUS LCAs have analyzed electric power plants and have quantified results on a "per kWh of deliverable electricity" basis. While useful for understanding the differences in technologies at a power plant, this functional unit does not consider technologies that do not produce electricity (e.g. cement plants, oil refineries), and is not indicative of the valued output of those systems. In these situations, it may be appropriate for a CCUS LCA to express results in more than one functional unit. For example, using captured CO_2 for enhanced oil recovery (EOR) serves to both sequester CO_2 and allow the recovery of additional quantities of oil, so calculating CO_2 sequestered per barrel of oil produced might be an appropriate additional metric. However, the method used to allocate CO_2 storage benefits among multiple products (e.g. electricity generation and oil production) is not always straightforward and can significantly affect the calculated emissions of the products.

Although CCUS technologies are intended for carbon mitigation, accounting methodologies must evaluate performance metrics beyond carbon-capture compliance. To produce LCA results that contribute to robust policy decisions, LCA practitioners should endeavor to quantify all relevant environmental benefits and costs of CCUS systems, including non-climate aspects. The combined evaluation of GHG and non-GHG effects of CCUS encourages the development of strategies that lead to optimal reductions across multiple societal, resource, and environmental impacts. Several areas of evaluation are considered critical to the assessment and comparison of diverse technologies:

- Natural environment: The potential for CCUS to mitigate climate change should be determined by quantifying the resulting avoided cumulative radiative forcing. For example, the percentage of CO_2 removed from power plant flue gas is typically 90% or less, and the additional fuel extracted to meet the energy demand of current commercial CO_2-capture technologies also leads to increased upstream emissions, including releases of high global warming potential methane from coal mines or from natural gas production and pipeline networks. Including emissions system-wide, the net GHG reductions may only 60% to 85%. Ecological damage may occur from system-wide and CCUS operations. Aside from GHG

emissions, conventional LCA impact categories include fresh- and saltwater acidification, eutrophication, ozone depletion, and terrestrial and aquatic ecotoxicity.

- Human health: Particulate matter, ozone, radiation, and toxic emissions associated with construction and operation of energy infrastructure, including CCUS projects, can lead to human health damage. The mass of harmful emissions to land, air, water and soil systems can be quantified using characterization factors that convert the LCA inventory to damage equivalents. The resulting human exposure from these system vectors translates to statistical measures such as disability-adjusted life years (DALY). The damage associated with the CCUS component of a project relative to the project without CCUS is relevant to compliance accounting, and estimates require extensive research, monitoring, and uncertainty management.
- Natural resources: CCUS technologies consume limited resources like land, minerals, fossil fuels, and water. LCA impact categories include cumulative energy demand, and cumulative consumption and degradation of materials (both renewable and non-renewable), land, and water and reveal the impact that a technology may have on local, regional, and national resource markets.
- Man-made environment: This area accounts for damage to buildings and other assets that hold cultural, historical, or economic value. Methods are being developed so that previously intangible impacts, such as noise pollution, monument deterioration, land use change, and traffic density, can be accounted for.
- The scope of LCA is expanding to address several additional areas of evaluation that are necessary for supporting sustainable decision-making:
- Life cycle costing: The total economic cost of a CCUS technology's life cycle stages is useful for calculating the cost effectiveness of different CCUS options, often measured using "cost per unit of avoided CO_2 emissions" as a functional unit. The results of CCUS LCA can also be monetized to arrive at estimates of indirect costs; for example, the health care costs associated with air pollution attributable to the life cycle energy use of the technology. This information can be included for estimation of full societal costs (i.e., direct plus indirect costs), which can aid in assessing the likely net economic impacts of technology deployment.
- Investment risks: The first large-scale CCUS projects may face unique legal and regulatory investment risks. Permit processes can delay or even freeze projects. Public knowledge and acceptance of CCUS projects by all stakeholders are also important considerations. The simultaneous development of competing technologies may serve to undermine (or enhance) the economic viability of CCUS technologies.
- Equity: Environmental justice implies equal protection from environmental and human health hazards for all individuals, regardless of their race, economic status, gender, or age. It also means that all individuals have a voice in the decision-making process. When used in conjunction with geospatial mapping tools, LCA can identify where environmental impacts are likely to occur. This information can provide decision-makers with the foresight to achieve equitable distribution of environmental, human health and economic cost burdens.

- National security: The United States' dependency on foreign fossil fuels is an issue of national security. LCA databases will allow LCA to quantify the source and quantity of fuels and energy consumed. A life cycle inventory and assessment can highlight stages in a technology's life cycle where cumulative energy demand is high. Once identified, these stages may be targeted for improvement. Carbon utilization technologies that are used for domestic EOR may reduce our dependency on foreign oil. The caveat to this is that available renewable energy sources may lose a financial competitive edge if domestic oil becomes cheaper.
- Risk of catastrophic failure: The risk of catastrophic failure should be a determinant of a technology's adoption. The modelling and interpretation of low-probability, high-impact events is challenging with conventional LCA methodologies. However, an LCA approach may be useful to identify sources of risk throughout the system.
- Uncertainty and variability: To effectively guide decision-making, LCAs must credibly model the potential system-wide effects of CCUS technologies implemented at large scale. Uncertainty and variability must be managed to reduce the risk of policy failure, or the implementation of policy that generates counterproductive results. When analyzing CCUS systems, uncertainty exists at many levels, including measurement uncertainty and variability, structural uncertainty due to the complexity of models and their validation, temporal uncertainty regarding past and future events, and translational uncertainty in interpreting results. A comprehensive uncertainty analysis should evaluate uncertainties derived from parameters, models, and scenarios.

Initial efforts have been made within the LCA research community to project and estimate the life cycle environmental, social, and economic performance of emerging CCUS technologies when deployed on a large scale. Such timely projections can provide critical feedback to the policy-making and R&D processes, and help steer material, design, and operational specifications towards the most environmentally-, socially-, and economically-robust development pathways. Accounting and regulatory structures should be based on a holistic evaluation of options, which requires a system-wide analysis in a life cycle perspective. Once embodied in policy and standards development, LCA can play an important role in determining appropriate roles for CCUS in future energy systems.

2.4 Technical Risks

Referring back to Figure 4, the site- or project-specific technical aspects can be divided into surface aspects, which are predominantly addressed by engineering studies, and subsurface aspects, which are predominantly addressed by geological studies. Surface aspects focus on the emissions point source location, capture or separation facilities; any associated utilization facilities; transport infrastructure; and the compression and injection equipment at the storage site. Utilization is an alternative to geologic storage of CO_2 that makes products or uses CO_2 as a working fluid for processes which store the CO_2. Examples include enhanced oil or gas recovery, geothermal energy systems, building materials, biochar or plastics.

Evaluations of technical elements in surface facilities may include:

- Engineering analyses of best fit between plant facilities and capture technologies

- Gas purity/quality variation and tolerances for utilization or transport
- Capture site baseline monitoring
- Safety, health, environmental impacts
- Impacts of plant upsets/ variations in gas quantities on transport, utilization, or injection operations

Surface health and safety risks are related to chemical usage and potential for CO_2 leakage from facilities and pipelines. In most cases, established procedures exist for handling and accidents with these chemicals and CO_2.

CO_2 is non-toxic and nonflammable; we exhale CO_2 and plants uptake CO_2 for photosynthesis. Though high concentrations of CO_2 in the atmosphere are easily dispersed by air currents, if a high concentration is allowed to persist, it can displace breathable air, posing a risk of asphyxiation in humans and animals. High concentrations in the soil will cause stress and can eventually kill vegetation. CO_2 is somewhat soluble in water, which produces the "fizz" in soft drinks and mineral water. The mild acid formed from this dissolution, however, can corrode steel and dissolve cement and rock. In the subsurface, reactions between the CO_2 in the pore water and the surrounding rock can result in the release of organic and inorganic compounds into the water. Since CO_2 will be transported and injected under elevated pressure, risks accompanying compressed gas transport and injection also must be considered.

If capture utilizes amine compounds, there are concerns about exposure. Amines are a family of chemicals that are used as solvents in post combustion capture. They are used in varied forms for this purpose and different amine compounds will be developed as post combustion carbon capture technology evolves. The airborne emissions of amines results in decomposition into other compounds, including nitrosamines which are carcinogenic. A report prepared by The Bellona Foundation acknowledges amines and amine degradation products as having the capability of adverse effects on human health and the environment, but notes that risks are manageable and should not be a major impediment to CCUS implementation (Shao and Stangeland 2009).

Ethanolamine, commonly called monoethanolamine (MEA), which is used as a proxy for the chemical properties of the solvents generally used in CO_2 capture technologies, is a toxic, flammable, corrosive, colorless, viscous liquid with an odor similar to ammonia. It is used in many industrial applications, including the power industry. It is also used in many consumer household soaps and detergents. MEA has been evaluated for RCRA characteristics and does not meet the criteria of a hazardous waste if discarded in its purchased form. It is exempt from the California Toxic Substance Control Act (TSCA) Chemical Substance Inventory. MEA has the same general safety and environmental awareness concerns as ammonia, which is a common product found at many power plants and in households.

From the point of capture, CO_2 will require transport, which at best will be a short distance from a power plant to an adjacent storage site or, in the case of utilization, a processing site. Depending upon the utilization process, a variety of health and safety risks from chemicals or processes may be present at facilities. The options for transport are train, truck, or pipeline. From the standpoint of net carbon reduction benefit and the massive volumes involved with commercial-scale storage, trains

and trucks are impractical. If trains or trucks were to be used, the risks due to traffic would have to be evaluated. Pipelines create little to no emissions and can be built to handle high volumes; but they do require permitting and regulation, and the construction costs are high. Risk elements include leakage, challenges in obtaining right-of-way, and security. Because the CO_2 in pipelines, surface injection facilities, and injection wells will be at high pressure, however, the risks associated with industrial compressed gas operations must be considered. CO_2 is not flammable, so fire in the event of a sudden release is not a risk; however, a high-velocity (explosive) release of CO_2 could cause damage, injury, or death.

Proper construction of transport and injection facilities will mitigate many surface risks. For pipeline transport, the development of a pipeline complex to deliver CO_2 to the Permian Basin, Texas, CO_2-EOR operations since the early 1970s has motivated the promulgation of best practices and regulations. The most significant risk associated with pipeline transport is leakage, and a variety of methods are in place to mitigate this risk. The Dakota Gasification Company pipeline has a capacity of 5 million tons a year and carries CO_2 that also contains 0.8 percent–2 percent H_2S. Any pressure drop resulting from a significant leak activates block valves, which are situated along the length of the pipeline and therefore limit the volume of the leak. The entire pipeline and compression operations are monitored by telemetry (Duncan et al., 2009). The pipeline has also been designed for internal inspection by devices to detect corrosion or other defects.

Subsurface aspects include evaluation of the geological suitability of a site, engineering design of injection and monitoring wells, and evaluation of monitoring needs. Evaluations could include:

- Estimation of storage capacity and seal effectiveness
- Computer simulations of the long-term behavior of the injected CO_2
- Assessment of leakage risk through faults or pre-existing wells
- Induced seismic risks
- Baseline or background monitoring by surface and subsurface techniques

Storage requires underground rock formations of specific types that will retain the CO_2 permanently underground. Suitable geological reservoirs include deep saline and oil or gas reservoirs. The Regional Carbon Sequestration Partnership (RCSP) program at the U.S. Department of Energy (DOE) has evaluated the CO_2 storage potential throughout the United States and Canada. The methodology and definitions of storage resource and capacity are defined and described in reports by the National Energy Technology Laboratory ((National Energy Technology Laboratory 2010). Storage resource is different from useable capacity given uncertainties such as subsurface permeability continuity, injectivity, as well as non-geological factors, such as terrain accessibility, proximity to sources, and competing subsurface and surface land-use issues.

Sequences of sedimentary rocks, such as sandstones and shales, accumulated to great thickness in ancient deltaic, coastal or marine settings provide the best sites for storage. California's Great Valley is a prime example of such a setting. Carbon dioxide can be stored in sandstones or other porous rocks. These rocks contain very saline formation water or in some instances, may contain oil or gas deposits. These sedimentary sequences may occur on land or offshore.

The risks of geologic storage can be mitigated by careful site selection and characterization, proper injection practices, and careful monitoring during injection operations and after injections stops. Confidence in the ability to mitigate storage risks, and the methods, tools, and approaches derives from many decades of experience in analogous industrial operations, including petroleum exploration and production, enhanced oil recovery using CO_2, underground gas storage, and disposal of acid gas and hazardous wastes in deep injection wells. Convincing the public that a sufficient level of subsurface risk mitigation can be achieved remains a challenge, however, because the public have little to no general knowledge of the subsurface, except in communities dominated by the oil industry.

Some uncertainty about subsurface conditions and properties will always remain at the end of the characterization phase. Likely sources of uncertainty relevant to storage risks are the potential presence of fractures in the seal, hydrologic properties of faults, in-situ stress state, and hydrologic boundary conditions. There will also be uncertainty in predictions of the area occupied by the CO_2 and the pressure increases caused by injection.

A monitoring program provides data that are important to risk mitigation. Measurements provide direct evidence when something goes wrong—a leak, for example. The primary paths for leakage from a deep reservoir would be improperly installed and/or abandoned wells and undiscovered geologic discontinuities such as faults. CO_2 tends to move outward from the injection well because the CO_2 is injected at a pressure greater than the pressure in the fluids already present in the rock; it moves upward due to buoyancy – in most cases CO_2 will be less dense than the fluids already present in the rock. Since leaks to the surface due to faults or fractures or other geologic pathways are not expected to happen suddenly, early detection by monitoring methods (see Chapter 5) mitigates the risk of serious impacts. Another use of monitoring data is to reduce uncertainty in the geologic model, which increases confidence in predictions of how the CO_2 will behave in the future. Monitoring may include stations at a significant distance from the injection well. When CO_2 is injected, it is trapped by various mechanisms within the storage reservoir, however, the injection also causes the pre-existing fluids to become compressed and displaced in order to make room for the CO_2. In saline formation storage, the movement of the displaced saline water can pose a contamination risk to groundwater and other resources.

2.5 Non-technical Risks

Non-technical risks include financial, regulatory and statutory, and public /stakeholder perception issues. These risks are extremely difficult to quantify and can change dynamically during the project from circumstances inside and outside the project. Many non-technical risks are project-specific, but others may result from external factors. An example of a project-specific non-technical risk may be acquisition and permitting of pipeline right-of-ways. A non-project-specific risk that results in a project risk could occur, for example, if a natural gas pipeline accident occurs that is totally unrelated to and nowhere near the project site; then, a public resistance to permitting CO_2 pipeline right-of-ways for the project results. Another example would be risks from regulatory and statutory requirements which change during the project due to legislative or agency actions that literally change the rules. There are also significant risks to projects when statutes and regulations are ambiguous or non-existent, which is often the situation for early technology project developers.

While most technical elements involve project personnel or contractors, one significant challenge of non-technical elements is that they frequently involve not only the project developers, but also many other stakeholders, including government permitting agencies, local communities, environmental groups, and investors. Furthermore, the technical elements must be communicated to all stakeholders, and technical elements may have to be revisited to comply with permitting requirements or address stakeholder concerns. Thus, the technical and non-technical risks become intertwined. The success of the project may ultimately hinge, not on the risk inherent in the project technical elements, but instead on how well these risks are communicated to stakeholders.

In some cases, technical risk translates into non-technical risks. For example, the technical risk of a leak can be translated into a financial risk of having to pay damages and the costs of remediation. Trabuchi and others undertook an analysis using a standard financial instrument called a probablistic simulation to develop an understanding of the financial impacts of the risks of damages to health and the environment due to accidental CO_2 releases (Trabuchi, et al. 2012). They used the detailed plans for the Jewett, Texas, FutureGen 1.0 site as the basis for the financial analysis even though this site never developed into a real demonstration. The probablistic simulation modelling creates a large number of scenarios and their possible outcomes to determine the probability of various potential damage amounts incurred. The exercise was divided into five steps (selection of risk events; characterize magnitude and probability of risk events; evaluate potential costs of impacts; combine data into an integrated spreasheet model; identify possible costs using probablistic modelling). The final step involved 100,000 runs to assure statistical integrity. The model estimated the costs of potential adverse effects over a 100 year span to be between $0.15-$0.34 per tonne sequestered. Of these costs, 95 percent would be due to releases from existing oil and gas wells at the Jewett site, most of which could be mitigated through better well completion or moving sequestration to an area with fewer wells.

Agencies and entities required to meet GHG reduction compliance caps carry risks of implementing CCUS technology that ultimately fails to meet GHG reduction goals. On the macro-level, the impact of climate change creates risks for all regions of the world, including lost agricultural productivity, disease and other health effects, property damage, and ecosystem changes. These risks are not straightforward to document or to monetize and the LCA method discussed above is one promising approach. For agencies tasked with applying CCUS technology to meet climate change mitigation mandates, the risks of accepting a GHG reduction technology must be balanced against alternative technologies and against an analysis of the social cost of doing nothing—the business-as-usual case (e.g., (Greenspan and Callan 2011)). This social cost is a measure of the benefit of reducing carbon emissions now to avoid climate change damages in the future and has been estimated at about $35 per ton today, climbing to $71 per ton of CO_2 by 2050 (Congressional Budget Office 2013) (in 2007 dollars). To our knowledge, no California-specific analysis has been undertaken of the social cost of carbon emissions, but the potential impacts of climate change that are likely in California have been studied and partly quantified monetarily (e.g., (California Natural Resources Agency 2009).

CHAPTER 3:
Advances in Capture and Transport Technology

A wide range of CO_2 capture concepts and technology exists and includes the following categories: pre-combustion, post combustion, oxy fuel, and other methods or concepts. Given that California's fleet of power plants is dominantly NGCC, consideration of capture technologies is focused on those applicable to natural gas fired plants, but also considers new technologies for future power generation options. Most research nationally and internationally to date has been focused on capture for pulverized coal power plants. The main difference in emissions between coal and gas-fired applications is that flue gas from coal has about 5 percent oxygen and about 12 percent CO_2, whereas flue gas from NGCC has less than 5 percent CO_2 and greater than 12 percent oxygen. The lower CO_2 concentration makes capture more difficult and the higher oxygen concentration can cause solvent degradation.

For the scenario of a future new NGCC power plant (assumed designed compatible with CO_2 capture), all of the CO_2 capture technologies (pre-combustion, post combustion, oxy-fuel, and other CO_2 capture technology categories) have the potential to be developed. The pre-combustion and oxy-fuel categories are of particular interest in terms of possible applications to new power plant designs; however, retrofitting onto existing power plants favors post-combustion technologies. Technologies that also require significant changes in the design of the major equipment such as gas turbines, steam turbines and Heat Recovery Steam Generators (HRSGs) will not be as easy to commercialize.

The retrofit applications also must consider the effects of the capture technology on the operation of the existing NGCC power plant. WESTCARB performed a study to evaluate various types of capture technologies for application to the NGCC plants in California using the following screening criteria:

- What is the level of development and commercial maturity a CO_2 capture technology (e.g., conceptual concept, laboratory-scale experiments already conducted, pilot-scale experiments already conducted, field-demonstration already conducted, commercially installed on full scale application)
    - Does the CO_2 capture technology have reasonable prospects for being commercially available by 2020?
    - Does the technology have a minimum threshold of development of nominally one MW equivalent scale by March 2011?
    - Did the supplier provide an adequate description of the level of development or commercial maturity; for processes not yet commercially ready, does the documentation include a list of plans for scale-up and demonstration along with associated funding status and any scale-up limitations or concerns?
- Does the technology have fundamental operating principles, performance information, and cost characteristics for applications to an NGCC plant?

- Is there documentation of the technology's impact on, or interaction with, plant design and operations for utility-scale NGCC or cogeneration/combined heat and power units?
- Are there documented ratings of the technology (in lieu of quantified values) for the following characteristics:
    - Thermal and electrical loads
    - Minimum steam conditions for solvent regeneration
    - Capital cost
    - Operations and Maintenance (O and M) costs
    - Solvent make-up
    - Land requirements
    - Cooling and process water demand
    - Material handling and disposal requirements for the solvent
    - Health, safety, and environmental considerations

3.1 Pre-Combustion Capture

Pre-combustion capture is a technique where the CO_2 is captured before burning the fuel in a combustor. It is commercially available for several applications, including hydrogen, ammonia, and synthetic gas production. The technique consists of a natural gas reforming or coal gasification step followed by water gas shift reforming of the gas, with subsequent steps for separation of CO_2 and H_2 to produce a H_2 -rich gas, which is the fuel used for power generation, transportation, or as a feedstock for other processes. The main challenge for this technology is the development of economically feasible gas turbines for electricity generation that reliably can burn fuel with a high H_2 content. The Hydrogen Energy California (HEECA) project is an example of a pre-combustion capture technology power plant design. This project is discussed in more detail in Chapter 7.

3.2 Post-Combustion

In Post-Combustion Capture, the CO_2 is removed from the power plant flue gas. The state-of the-art technique for separating CO_2 from flue gases is via chemical solvent scrubbing (usually with an amine). The CO_2 reacts with the amine in the absorber, is separated from the amine solution in a stripper, and then water must be removed prior to compression and transport. The separation step, including regeneration of the solvent, becomes more energy intensive per unit of CO_2 as the concentration or partial pressure of CO_2 in the flue gas decreases. To reduce this energy penalty, improved solvents, more optimized processes and alternative separation methods are being studied. On a relative basis, when compared to the other CO_2 capture technology categories, however, post-combustion capture technologies ranked more highly in the WESTCARB study for adoption for NGCC retrofits and new builds already in the planning stages primarily because these technologies are already commercially mature and have data available for costing and documentation of performance, operations and other characteristics.

Table 2: Carbon Dioxide (CO_2) Capture System Inlet Flue Gas Flow Rates and Compositions

CASE (GE 7FA.04)	MAX Flow Rate	MIN Flow Rate	NORM Flow Rate	UNITS
Flue Gas Flow Rate				
Per Train	3,736,000	2,419,800	3,472,000	lb/hr
Per Two Trains	7,472,000	4,839,600	6,944,000	lb/hr
CO_2 Flow per Train	223,039	138,413	208,667	lb/hr
CO_2 Flow for Two Trains	446,078	276,826	417,334	lb/hr
Constituents				
CO_2 Fraction	5.97	5.72	6.01	Wt percent
Ar Fraction	1.26	1.25	1.26	Wt percent
N_2 Fraction	73.73	72.37	72.87	Wt percent
O_2 Fraction	14.14	14.08	13.82	Wt percent
H_2O Fraction	4.90	6.59	6.05	Wt percent
Stack Temperature	187	190	220	Deg F
Estimated Emissions				
NO_x			3.50	ppmvd@15 percent dry O_2
NH_3 (slip)			5.00	ppmvd@ 15 percent dry O_2
CO			3.00	ppmvd @ 15 percent O_2
VOC			2.00	ppmvd @ 15 percent O_2
UHC			7.00	Ppmvw
Particulates (front)			9.00	lb/hr (per train)
Condition	100 % /fired/30F	60 %/ unfired/97F	100 %/ unfired/70 F	

Flow Rate data for two trains of combined cycle combustion turbine (CCCT) systems, Model GE 7FA.04 Combustion Turbines with HRSG.Units are in parts per million by volume dry (vd) or wet (vw).

Source: unpublished WESTCARB report

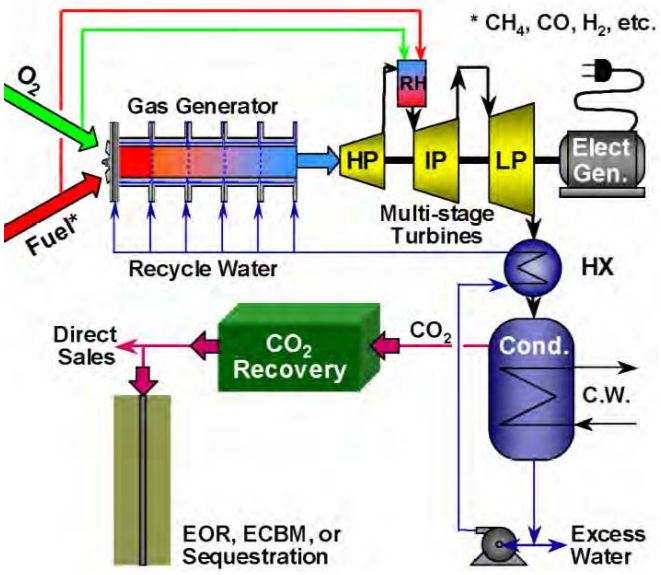
Post-combustion CO_2 capture technology is technically capable of treating the flue gas from existing NGCC power plant, although with challenges. A typical NGCC plant uses oxygen from air for combustion of the natural gas fuel. The flue gas is generally at atmospheric pressure and the CO_2 concentration is in the range of 3 to 5 percent by volume. Table 2 presents the flow rate and properties of the flue gas from an existing NGCC plant, employing two natural gas fired combustion turbines (Model 7A.04) with HRSG.

A unique challenging characteristic of an existing NGCC flue gas is the relatively higher flow rate, at a comparatively low CO_2 concentration but higher oxygen (O_2) and moisture (H_2O) content, when compared to flue gas from other fossil fired power plants such as coal-fired units. A positive attribute of NGCC flue gas is the relatively low concentration of particulate matter and acid gases such as sulfur dioxide and hydrochloric acid, when compared to a coal-fired power plant.

3.3 Oxy-Fuel Combustion

In oxy-fuel combustion, (also called denitrogenation), an air separation unit is used so that the fuel can be combusted using almost pure oxygen at near stoichiometric conditions. This creates a flue gas consisting of mainly CO_2 and H_2O (and possibly small amounts of SO_x and NO_x from the fuel). A portion of the CO_2 in the flue gas is recycled in order to control the combustion temperature. Oxy-fuel combustion has been used within the metal and glass manufacturing industries for some time, but has so far not been applied to full scale conventional steam boilers. The main challenges with this concept are the combustion environment in the burner, and the high energy demand of the air separation unit.

Figure 6: Schematic of Oxy-Fuel Combustion System



Source: Clean Energy Systems

An oxygen-fuel power cycle, shown in Figure 6, features an oxy-fuel gas generator and high, intermediate, and low-pressure turbines (HPT, IPT and LPT respectively) to generate electricity; The HPT and LPT can be implemented using existing steam turbine technology or can be further

developed using advanced turbine development methods. To produce high efficiencies, the IPT is critical, due to the need for sophisticated turbine materials and cooling technology.

Incidentally, oxygen-fuel turbine-based power plants create byproduct water, cool steam (~200ºC), and pure CO_2 that can be used as cooling fluids within the combustor and IPT systems. The performance of the cycle is greatly enhanced by increasing inlet temperatures of the IPT to 760-1250ºC (1400-2280ºF). Although gas turbines with these inlet temperatures are readily available, the resources required to adapt these machines to an oxygen fuel working fluid are relatively significant. A novel type of oxy-combustion has been under development in California that uses a very high temperature turbine.

3.4 Impact of CCS on Plant Operations

Infrastructure modifications or additions associated with retrofit of CO_2 capture and compression technologies for a particular power plant thus may include modifications to existing infrastructure related to environmental compliance with air and water use and discharge. Existing facility designs affect the efficacy of integrating the mass and energy balance requirements of selected CO_2 capture technologies into existing plant systems and whether new process equipment must be installed to eliminate or minimize any new air or water discharges due to the CO_2 capture technology. For example, existing NGCC facilities with wet cooling towers are likely to have more flexibility for integrating water and wastewater streams associated with the CO_2 capture technologies than a facility using an air cooled condenser for plant heat rejection.

One important consideration for any type of capture technology is the effect on the plant's overall resource impacts: energy use, air pollution, water use and water discharge. Some capture technologies need thermal energy (e.g., amine regeneration), which can be provided at least in part by extracting steam from the existing NGCC power plant steam cycle. However, if new sources of steam supply are required (e.g., new auxiliary steam boilers), then the additional air emissions and water needs of this new source must be quantified and evaluated. The CO_2 capture technology process make-up water requirements may be sufficiently small to allow use of existing plant raw water supplies or recycling of plant water. Cooling requirements for capture technology also may be met by air cooling (e.g., no additional cooling towers), which greatly reduces the need for make-up water. NGCC plants that utilize ACC for heat rejection could produce a net surplus of water, resulting from condensing water vapor contained in the flue gas. Capture technologies also create a low volume of wastewater. These could be treated for use on site, processed using zero-liquid discharge approaches, or released for off-site use.

Retrofit CO_2 capture technologies will modify the flue gas characteristics of existing stacks at NGCC facilities. In addition to potential changes in criteria pollutants or hazardous air pollutants, flue gas dispersion characteristics affecting plume buoyancy will likely be modified by the addition of the CO_2 capture technology and will need to be considered in any air dispersion modeling that is required as part of the CO_2 capture technology retrofit. The primary factors affecting plant operating flexibility are startup time – HRSG drum heat up rate and steam turbine heat up rate; load ramp rate – steam turbine temperature differentials; and turndown – gas turbine minimum load.

It is assumed that, similar to current sulfur capture systems, the carbon capture system will be bypassed until the power island has reached stable operating conditions. Thus, startup time will not

be affected. Since the CCS system operates at significantly lower temperatures and pressures than the steam power cycle, the piping and pressure vessels have thinner walls than the heavy wall steam cycle components and experience smaller temperature swings; the CCS system is therefore less restrictive than the power plant components. Thus, ramp rates will not be affected.

The impact of a full scale Carbon Capture Unit on NGCC flue gas with respect to Criteria Pollutants and Hazardous Air Pollutant Emissions is not widely known (but see (Koornneef, et al. 2012)). However, impacts to Plant Criteria Pollutant and Hazardous Air Pollutant Emissions are not considered to be a fundamental limiting factor in the development or application of CCS technology to NGCC power plants. It would not be unreasonable for a CCS system to result in some carryover of process compounds much in the same way that there is ammonia carryover from a selective catalytic reduction process.

Carbon dioxide capture solvents do not have material safety data sheets available for review, because of the proprietary information in their formulation. However, the chemical compound that is generally referred to in their formulation, monethanolamine (MEA), is a common industrial product. Therefore, the material safety data sheet and the common industrial uses of MEA were reviewed to determine the operational, safety, environmental control, and material handling factors for the application of CO_2 capture solvents at NGCC sites. MEA is a product that is currently used within the power generation industry for a variety applications including corrosion control, cleaning agents, lubrication, metal machining, adhesives, and cooling water additives. It has operation, safety, environmental control, and material handling factors similar to ammonia, which is used at most NCCG sites. Based on safety and environmental data contained on the MEA material safety data sheets, the CO_2 capture solvents would not appear to be considered a hazardous waste or subject to California Toxic Substances Control Act chemical substances inventory. Therefore, due to characteristics common among CO_2 capture solvents and products typically used at NGCC sites, there should not be any major changes in the operations, safety preparedness measures, environmental control/assurance, or material handling and disposal procedures.

Review of the design characteristics of the CCS processes indicated that they would not be the limiting factor on power plant startup, ramp rate or turndown. Thus, the addition of a CCS system would not be likely to significantly affect the operational flexibility of the power plant. Evaluation of the available information regarding the process solvents indicated that they are no more of an impact on health, safety and the environment than other chemicals currently in use at typical NGCC plants. Similarly, the addition of a CCS system would not be expected to cause significant to hazardous air pollutant emissions.

3.5 Advances in Compression and Transport

CO_2 compression systems pressurize and dehydrate CO_2 for pipeline transport to storage sites or to other sites for utilization, such as enhanced oil recovery. In pipeline systems, specifications for trace contaminants, including water vapor, and temperature and pressure operational ranges, are set by state or federal regulations to assure safe transport. In pipelines from which CO_2 is sold for utilization, more stringent specifications may be set for levels of contaminants, etc. based on the needs of the CO_2 purchaser. Additional compression is likely to be needed at the storage site, depending on the depth of the storage formation and injection pressures needed. Compression and

transport systems also must be designed to accommodate plant or well site upsets which may cause disruptions in the supply or off-take of CO_2. Compressors prepare CO_2 for transport and provide additional pressurization at the wellhead, if necessary, depending on the depth of injection.

The technologies required for compression and pipeline transport are mature, however, systems for monitoring and safety of pipeline systems have advanced significantly because of national security concerns. Incidents with natural gas pipelines, such as the explosion of the San Bruno pipeline, have increased public awareness of health and safety issues surrounding underground pipelines in urban areas and have increased regulatory requirements.

CHAPTER 4:
Utilization Technologies

The AB 1925 report did not include an assessment of CO2 utilization technologies, apart from consideration of oil fields as sites for storage. Beneficial use or CO_2 utilization is defined to include technologies that produce a useful product directly from captured anthropogenic CO_2 or in connection with the processes of capture or sequestration of CO_2. In 2011, a qualitative evaluation was performed of utilization technologies to determine which ones were or would be expected to reach commercialization commensurate with the time frames set for California's emissions goals in 2020 and 2050 and to have the potential to make significant contributions to greenhouse gas reductions (Burton, et al. 2011). This evaluation was prepared to give guidance to the California Energy Commission to define future funding priorities in the area of CO_2 utilization or CO_2 beneficial use technology research and development.

4.1 Overview

To evaluate utilization technologies, a set of parameters was established to define the current status for each technology (Table 3). For each technology, inputs to the process (CO_2 and other components including water), process attributes and outputs from the process (product and other components, including waste products) were identified. These factors were then supplemented with additional parameters specific to each technology and used to rate technology readiness, barriers to deployment, knowledge gaps, maturity, availability of lifecycle analyses, environmental impact, water use, and economic benefits.

No systematic set of data and existing methodology was found to enable comparison of the various technologies. Each technology has key advantages and disadvantages, but their relative importance can only be qualitatively inferred. This is particularly problematic when comparing direct uses, such as working fluids, with indirect uses such as fresh water production from saline aquifer fluids. A lifecycle analysis is needed for each technology that lays out the relative merits in a quantified way. The evaluation then used ranking categories A to D to bin utilization technologies according to their maturity and relevance to California's GHG reduction goals (Table 4).

Table 3: Categories of Utilization Technologies

CATEGORIES	TECHNOLOGY DESCRIPTION
CO_2 as a working fluid	• Enhanced oil recovery (EOR) • Enhanced gas recovery (EGR) • Enhanced coal bed methane recovery (ECBM) • Enhanced geothermal systems (EGS)
CO_2 for Building Materials Manufacture	• Carbonates and other construction materials
Biochar	• Pyrolysis of biomass
Fuel and Chemical Production	• Chemical Conversion • Biological Conversion
Power Generation Applications	• Super critical CO_2 for Brayton Cycle Turbines • Working fluid / cushion gas for energy storage
CO_2 as a Solvent	• Supercritical fluid extraction and other food processing applications • Dry cleaning
CO_2 in Agriculture and Biomedical Applications	• Greenhouse atmosphere additive • Grain silo fumigant • Sterilization for biomedical applications
Miscellaneous Industrial Applications	• Fire extinguishers • Shielding gas for welding • Refrigeration and heat pump working fluid • Propellant • Rubber and plastics processing - blowing agent • Cleaning during semiconductor fabrication
Water from displaced aquifer fluids	• Water purification • Extraction of Value Added Solids from Water

Source: (Burton, et al. 2011)

Table 4: Evaluation Categories Used for Ranking Utilization Technologies

A	High potential for application in California (either by volume of CO2 used or based on other factors that might make the technology important for the state); expected to be a commercially deployable technology in California to meet 2020 goals
B	Moderate potential for California (based on volume or other factors that would make it important to the state); expected to be commercially deployable to meet 2020 or 2050 goals
C	Low potential for California or commercialization unlikely to meet 2020 or 2050 goals
D	Not significant to the state (remove from further consideration).

Source: (Burton, et al. 2011)

Importantly, rankings include other factors in addition to the total potential volume that implementation of the utilization technology might accomplish for 2020 or 2050. In fact, very few utilization technologies apart from CO_2-EOR, EGR, and possibly building materials, are likely to

have enough market demand to contribute significantly to GHG reductions. Instead, some utilization technologies may be important because they can enhance acceptance of an integrated CCUS project. For urban industrialized areas, in particular, utilization technologies may temper local community opposition to geologic sequestration. Utilization processes require manufacturing facilities which may create local jobs and taxes, unlike a CCS project. Other utilization technologies may be important because they create replacements for products that would otherwise create more GHG emissions. They may also be applicable to smaller sources for which construction of capture facilities would not be economic. Thus, utilization technologies could provide important contributions to the state's overall strategy in ways beyond sequestration of large volumes from single point sources, the traditional target for geologic sequestration.

The study resulted in the following categories of technologies ranking most highly:

- Biological Conversion
- Treatment of displaced aquifer fluids
- EOR and EGR
- Building materials
- Working fluids for energy storage
- Geothermal working fluid
- Chemical conversions
- Working fluids for energy generation

Utilization technologies present some additional challenges for the purposes of including them in compliance and accounting schemes for cap-and-trade or other policies. Issues which must be addressed include:

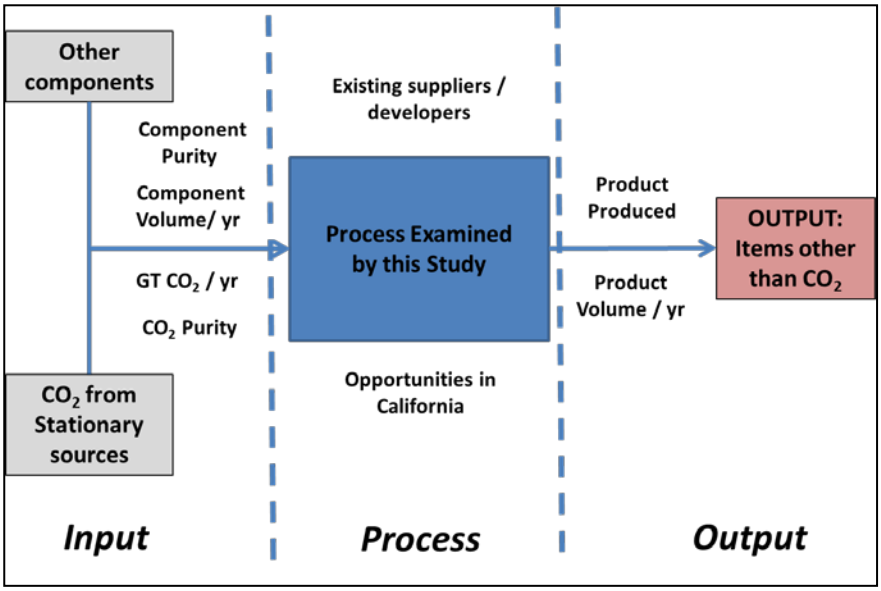
- Verification of sequestration for the products created, including a life cycle analysis of carbon and energy, which will require development of acceptable methodologies to meet AB32 or other policy requirements
- Studies to establish the best sites in the state for investment in integrated infrastructure that could combine multiple sources and geologic and utilization sequestration options to realize economies of scale, local benefits and climate change goals most effectively.

For evaluating each technology, inputs to the process (CO_2 and other components), process attributes, and outputs from the process (product and other components, including waste products) were identified (Figure 7).

Attributes of the process that were considered include whether there are existing suppliers/developers and if there are opportunities to deploy the process within California. These factors are especially important in considering the potential impact of the technology in California. It was also important to examine the outputs from the process, including saleable products and waste product streams. These factors provide additional insights into how these technologies might impact California's resources, economy, and environment. These factors were then supplemented

with additional parameters to be able to rate technology readiness, time to commercialize, barriers to deployment, knowledge gaps, maturity, availability of lifecycle analyses, environmental impact, water use, and economic benefits. The full set of parameters used to define state-of-the-art of CO_2 utilization technologies is shown in Table 5.

Figure 7: Inputs, Process Attributes and Outputs for Evaluating Utilization Technologies



Source: (Burton, et al. 2011)

Table 5: Parameters for Defining Beneficial Use Technologies

Parameter	Factors
Technology Maturity	Technology Readiness Level (TRL)
Input to Process	Attributes of CO_2 required, especially amount of CO_2 utilized by process
	Attributes of additional components, especially indicating any water usage
Output from Process	Attributes of Product Produced
Time Frame for Commercial Viability	Less than 10 years
	Greater than 10 years
Environmental impacts	Potential impact on air emissions, disposal of used components, etc.
Economic Benefit	Job creation / growth of new or existing industries in California
Federal Investment	Status of previous and existing federal investment in R, D and D of technology
Barriers to deployment	Example: Technology / Regulatory / Economic based factors that limit deployment of technology
Knowledge gaps	Knowledge or know-how hindering the removal of barriers
Suppliers	Existing developers / suppliers for the technology

Source: (Burton, et al. 2011)

Despite the wide range of categories and technologies examined there are some commonalities. These provide the basis for some key research, development and demonstration efforts that would impact a range of beneficial use technologies. Research needs include:

- CO_2 Life Cycle Analysis. This is a critical factor that forms the basis for a more quantitative comparison of the technologies. As a part of this analysis, the amount of energy required also needs to be quantified. It is recommended that a standard be developed and be utilized for all technologies. This is a critical common metric.

- Monitoring CO_2 Levels. In subsurface storage applications, it is critical that monitoring methods be standardized, adopted and utilized to enable acceptance of these technologies in cap-and-trade or other accounting schemes for CO_2 emissions reduction. Where technologies create products, the CO_2 life-cycle analysis should be sufficiently robust to allow assignment of a carbon mitigation value that is acceptable in meeting California's GHG emissions reductions requirements.

- Addressing Permitting, Regulatory, and Legal Hurdles. These are common themes that include permits and regulations related to (1) CO_2 capture retrofits on existing CO_2 sources or for new builds, (2) pipeline infrastructure, and, in some cases, (3) the subsurface. Given that networks of CO_2 suppliers and users will be necessary to support deployment of many of these technologies, the legal liability/chain of custody for the CO_2 should be clearly

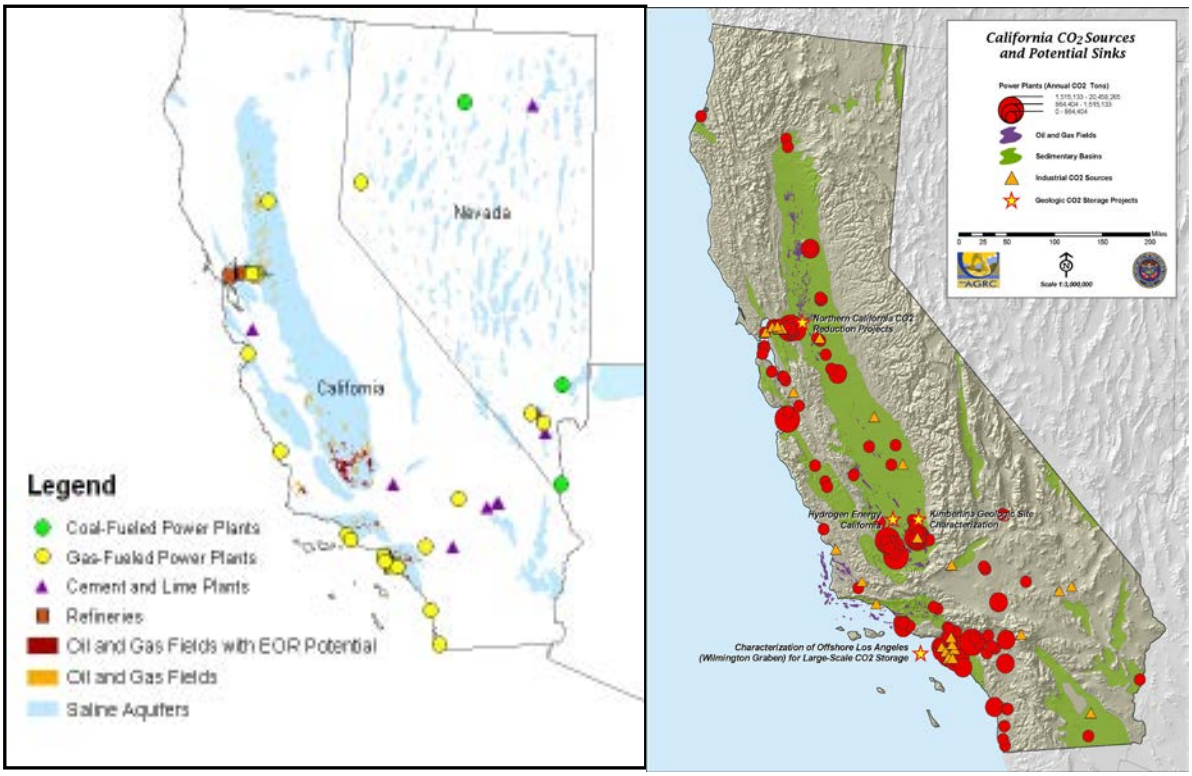
established. Delays in these processes could severely impede the adoption and deployment of many technologies.

These common themes are vital metrics for beneficial use technologies that could initially be addressed generically by the relevant California state agencies involved in permitting and regulation of CO_2 sources and CO_2 emissions, including the ARB, CPUC, the Department of Oil and Gas and Geothermal Resources in the Department of Conservation (DOGGR), and the Energy Commission.

For other utilization technologies, those which can reduce the costs of capture and transport would have significant price advantages, for example, those that include the CO_2 separation from flue gas as a part of their process or those that can co-locate near sources so that lengths of pipeline are minimized. Otherwise, it is likely that the economies of scale for capture and transport will limit one-to-one source-sink CCUS projects to the largest sources in the state (see Figure 3: Fifty Largest CO_2 Point Sources in California.Figure 3). For these sources, there are only a few beneficial use technologies that may be appropriate matches to the characteristics of the CO_2 emissions stream.

In the context of matching technologies to sources, several factors are of importance. The ability of the technology to utilize the volume of CO_2 emissions is one such factor. For some sources, however, the supply of CO_2 will vary over time (for example for peaker power plants) or may vary in composition (for example if fuel types vary). These inconsistencies will have to be accommodated by a utilization facility.

Figure 8: Locations of Point Sources for CO_2 Emissions, Saline Aquifers, and Oil and Gas Fields



Source: Herzog et al. (2007)

The alternative approach to one-to-one source-sink matching is building infrastructure networks. In this approach, multiple sources would be linked through a common pipeline network connecting to a variety of CO_2 users, including beneficial use facilities and geologic sequestration sites. The proximity of CO_2 sources and geological sinks in California is shown in Figure 8. Networks allow any fluctuations in CO_2 supply or quality to be moderated for utilization applications and economies of scale could be realized for smaller sources and smaller CO_2 users. A case study of how to produce such a network was done for Pennsylvania (Clinton Climate Initiative 2009).

4.1.1 Enhanced Oil or Gas Recovery

The goal of EOR or enhanced gas recovery (EGR) is to increase the production of fossil fuel from existing sources. Both may use carbon dioxide to sweep additional oil or gas from the reservoir. EOR is a well-established technology used in oil production, but is restricted in use to areas that have available sources of carbon dioxide, generally pipelined from natural sources. Although oil fields suitable for CO_2-EOR exist in California, the technology is not used due to a lack of available CO_2.

Deployment of CO_2-EOR presents some specific additional challenges. The potential demand for CO_2 is large and dispersed within the southern San Joaquin Valley region and Los Angeles Basin. Estimates of the number of fields and capacity for CO2 are given in Table 6. A CO_2 pipeline network connecting these oil fields with the collective sources necessary to meet the demand is lacking. There are also significant geographic barriers separating the San Joaquin Valley oil fields from the locations of the largest point sources in the coastal areas of the state.

Table 6: EOR potential in California oil fields

Type of Reservoir	Number of Fields	Estimated Total Capacity (MMT CO_2)
Oil fields with miscible CO_2-EOR potential	121	3,186
Oil fields with immiscible CO_2-EOR potential	18	178

Sources: Herzog, H.J., 2005, *West Coast Regional Carbon Sequestration Partnership CO_2 Sequestration GIS Analysis.* Topical Report West Coast Regional Carbon Sequestration Partnership (WESTCARB), DOE Contract No.: DE-FC26-03NT41984; Downey and Clinkenbeard (2006)

Both CO_2-EOR and CO_2-EGR benefit the state by enhancing oil and gas production and the state's revenues from those operations, but also boost the state's production of fossil fuels and any associated fugitive greenhouse gas emissions. EGR is a much less mature technology that aims to extract additional gas from gas reservoirs. It has been the object of several modeling studies and pilot studies, but needs to be demonstrated at a commercial size. California has gas fields appropriate for such field projects. In addition, CO_2 could be used to help upgrade heavy crude oils, which are common in the state. CO_2 fluids might also be used for hydraulic rock fracturing (or "fracking") to produce additional natural gas.

Oilfield production in California during 2009 was approximately 194 Mbl, of which 101 Mbl was from the southern San Joaquin Valley (Energy Information Agency 2011). California has 76 onshore oilfields favorable for miscible CO_2-EOR that held a total of 28 Bbl from which primary and secondary recovery is expected to be about 8.8 Bbl, leaving 19.4 Bbl underground. (Kuuskraa 2011) calculate that 6.5 Bbl can be recovered economically assuming oil prices remain above $85/barrel

and CO_2 can be sold at $40/tonne at pressure. Given recent historically high oil prices and forecasts for their continuation, CO_2 for enhanced oil recovery (EOR) in 2010 is priced at about $30-40/ton. In California, oilfield operators have expressed that CO_2 would need to be similarly priced to interest them in undertaking CO_2-EOR.

Absent a sufficiently high price on carbon set by a carbon tax or sustained by a carbon market, the price for CO_2 obtained for EOR or EGR is likely to be an important factor in enabling a business case for many early CO_2 capture projects in California. These technologies also present a sufficiently large market to begin to justify the private or public investment in a pipeline infrastructure system in the state which might eventually enable the integration of a wide variety of small volume demand beneficial use facilities at dispersed locations. EGR is a much less mature technology that aims to extract additional gas from gas reservoirs. It has been the object of several modeling studies and pilot studies, but needs to be demonstrated at a commercial size. California has gas fields appropriate for such field projects. In addition, CO_2 could be used to help upgrade heavy crude oils, which are common in the state. Both CO_2-EOR and CO_2-EGR benefit the state by enhancing oil and gas production and the state's revenues from those operations, but also boost the state's production of fossil fuels and any associated fugitive greenhouse gas emissions.

4.1.2 Enhanced Geothermal Systems (EGS)

This concept is to replace the normal aqueous working fluids of geothermal systems with fluids composed primarily of carbon dioxide that would circulate to depths and serve as the heat transfer medium. CO_2 has some favorable properties relative to water and although in the short term the CO_2 simply re-circulates, over the long term, CO_2 would react with the host rocks to form carbonate minerals which provide the ultimate sink for the carbon. Currently there is significant uncertainty as to the rate at which CO_2 reacts to form carbonates. Without this parameter, the amount of CO_2 that can be sequestered using this technology is uncertain also.

The benefit of this technology is the production of electric power, which displaces an equivalent amount of fossil fuel burning. In addition, it would reduce the water use of geothermal power production, which has been an issue for expanding geothermal energy use in California. Water is lost in geothermal power plants that flash water to steam to drive turbines, currently the most efficient plant design. The flashed steam is lost and in many systems must be replaced with local water supplies.

Because California has abundant geothermal resources, CO_2-EGS technology ranks highly as one technology advancement that could have significant impact on meeting the state's carbon reduction goals and increasing its ability to take advantage of its geothermal resource.

4.1.3 Building Materials

The goal of these technologies is to convert carbon dioxide into solid materials that can be used as building materials, such as cements, gypsum-based products, and others. A key advantage of these technologies is that the market sizes of building materials are large and commensurate with the scale of the problem. The materials can be made into forms such as carbonates that are stable under atmospheric conditions and therefore provide reliable long-term storage of CO_2 with relatively low risk. The materials have market value that can potentially offset the cost of CO_2 capture, although the prices for many of the possible products are low.

One of the barriers to deployment is the lack of a low-cost source of alkalinity needed to convert gaseous CO_2 into carbonate or other solid forms. Natural as well as man-made sources, including alkaline waste streams, have been investigated.

Further development of building materials should be encouraged based on the market size, favorable economic drivers, and the existence of start-up companies in California already working in this area. As with CO_2-EOR, this opportunity provides a relatively straightforward, market-based entry into carbon capture.

4.1.4 Biochar

Biochar refers to pyrolyzed plant remains and biochar as a beneficial use refers mainly to the incorporation of biochar into soils as soil amendments. Carbon sequestration takes place because the biochar tends to be inert in the soil relative to oxidation by microbes. Thus biochar provides long-term storage for CO_2 that originally was removed from the atmosphere by plants. A summary of the role of biochar in established negative emissions is summarized by (Woolf 2012).

Because of the complex carbon life cycle associated with biochar, a broader analysis is required to evaluate the potential for this technology to have an impact of the state's GHG reduction goals. Because biochar has significant fundamental differences from the other beneficial use technologies and much in common with methods of terrestrial sequestration and changing land use practices, it deserves its own analysis. In particular, the life-cycle analysis is very complex and comparable to that of ethanol biofuel production. The biochar concept might also be extended to include new energy cycles involving coal gasification and carbon residues.

4.1.5 Biological and Chemical Conversion

These technologies utilize CO_2 directly from flue gas or from concentrated streams including bicarbonate, to serve as the carbon source for microbiological activities that are then harvested to provide fuels to replace traditional fossil fuels.

The significant development of these technologies show promise for California for transportation fuels. Because the ultimate source of energy is solar, they do not need significant energy from the electrical grid. They appear to be close to commercialization and therefore have the potential to have a significant impact on meeting California's greenhouse gas reduction goals.

Major limitations include the need for large areas in order to capture sufficient solar energy (the efficiency of biological conversion is low), and the need for supplemental nutrients in order to grow a vigorous microbiological community. In addition to land resources, biological conversions will also require water. How well these technologies can be incorporated into California's complex water-energy nexus is an area that needs analysis in order to help identify biological-based technologies that have the greatest potential benefit.

Another aspect of biological conversion involves mimicking the biological processes to process synthetic chemicals to make products such as fuels or plastics. Chemical conversion accomplishes similar conversions and molecular synthesis through use of catalysts.

Advanced biofuel technologies could in 2050 be about 80 percent less carbon intensive than fossil fuels, but the amount of biomass likely to be available, both imported and from in-state, would meet

only half of the required demand for fuel. A similar amount of 7.5 billion gallons of gasoline equivalent (bgge)/year would come from imported biofuel was included, for a total of 13.0 bgge/year available biofuel. This figure is a median for a rather wide range of values depending on biomass availability.

Currently, biofuel is produced from food crops such as corn, sugarcane and soybean with a process that results in about 40 percent to 50 percent of the emissions of fossil fuel; 2050 technologies may reduce this to 80 percent over current fossil fuels. The California Renewable Fuel Standard has set caps on the production of corn ethanol and conventional biodiesel production to 85 percent ethanol/15 percent gasoline. The net GHG emissions from biofuel production are not well characterized and require more data. Greenblatt and Long (2012, Table 15) provide a general approximation of emissions compared with biomass supply. The California 2012 Bioenergy Action Plan (O'Neill, 2012) describes approaches for California to create energy from biomass. Developing technologies for biomass utilization is a priority for the Electricity Power Investment Charge research effort (California Energy Commission 2012).

There are numerous regulatory and economic challenges facing biomass use, and these are in several instances not dissimilar to the challenges faced by standard CCUS ventures. For example, there are energy costs and emissions generated by the transportation of biomass to power plants or processing facilities, as well as by energy distribution from multiple small power plants. It has been shown that biomass processing is effective only at a large scale, and that collection of biomass material from beyond a radius of approximately 80 km brings the costs to a critically high level as well as contributing to emissions. Smaller plants more widely distributed in order to reduce the collection transportation to below 80 km lack cost effective economies-of-scale.

In-state biomass resources from waste products, crop residues, and marginal lands not usable for agriculture is between 3 and 10 bgge/year of liquid and gaseous biofuels. Greenblatt and Long (2012) estimate that 7.5 bgge/year in-state production, of which 2.0 bgge/year would be burned directly as biomass for electricity, leaving 5.5 bgge/year available for fuel production.

Capturing biomass energy CO_2 emissions would further enhance the value of this resource as a mitigation measure. These fuels would be from low-carbon sources so they would not be subject to CCUS. According to the CCST analysis, there will be a need by 2050 for approximately 27 bgge of liquid and/or gaseous fuel for both mobile and stationary uses after all possible transportation and heat needs have been electrified. These technologies utilize CO_2 either directly from flue gas, or from concentrated streams including bicarbonate, to serve as the carbon source for microbiological activities. The organisms then are harvested to provide either fuels or carbon feedstocks that replace those traditionally sourced by fossil fuels.

There has been significant development of these technologies, and they look very promising. In California, their outputs could provide transportation fuels and thus lower the need for petroleum imports. The ultimate source of energy is solar, so that they do not need significant energy from the electrical grid. They appear to be close to commercialization and therefore have the potential to have a significant impact on meeting California's greenhouse gas reduction goals.

Major limitations include the need for large areas in order to capture sufficient solar energy (the efficiency of biological conversion is low), and the need for supplemental nutrients in order to grow

a vigorous microbiological community. In addition to land resources, biological conversions will also require water. How well these technologies can be incorporated into California's complex water-energy nexus is an area that needs analysis in order to help identify biological-based technologies that have the greatest potential benefit.

Chemical conversion technologies have similar purposes to biological conversion, but differ in that instead of using solar energy they use some other form of energy, in most cases from the grid, for their energy requirements. Their end products are either fuels or feedstocks that are produced from a feedstock of carbon dioxide. Much of the R and D to develop these technologies involved identifying effective catalysts to lower the energy barriers of converting CO_2 back into higher energy forms.

There are many research and development efforts underway on these technologies. Those that hold most promise are those that generate high value products such that the overall process has the greatest likelihood of being economically favorable.

A major disadvantage is the energy lifecycle for these technologies. They essentially convert CO_2 back into a high energy form, with an energy level comparable to that of the original fossil fuel. The inefficiencies of energy conversion, plus the energy needs of carbon separation weigh against both the energy use and the economic benefit of these technologies. The key question is the net carbon footprint of the process. Does the process, overall, actually result in a net decrease in carbon? Does the use of a technology of this type require substantial energy from the grid? An alternative to this is presented by the Fuels from Sunlight Hub approach where solar energy is used for the conversion, however again, whether it makes more sense to make electricity rather than chemical products from the solar energy should be investigated. Although we recommend that the Commission consider chemical conversion technologies because of their high payoff in high value products and ability to create replacements for products now made from fossil fuel, we suggest that a fairly detailed energy- carbon life-cycle analysis be undertaken prior to or as part of any funding for technology development in this area.

4.1.6 Working Fluids in Energy Generation

This concept is to replace working fluids such as steam or hydrocarbons with carbon dioxide. Laboratory studies and small-scale tests have shown improved energy efficiency for energy cycles such as supercritical carbon dioxide Brayton cycle turbines.

Significant work has already been carried out to develop this technology. A key question is whether existing energy plants can readily be retrofitted to take advantage of this improvement.

A downside is that the carbon dioxide is not sequestered in the process, it is re-cycled and only small amounts are needed. The advantage is that the improved efficiency decreases the amount of CO_2 released from the plant for an equivalent energy output compared to a plant using less efficient cycles.

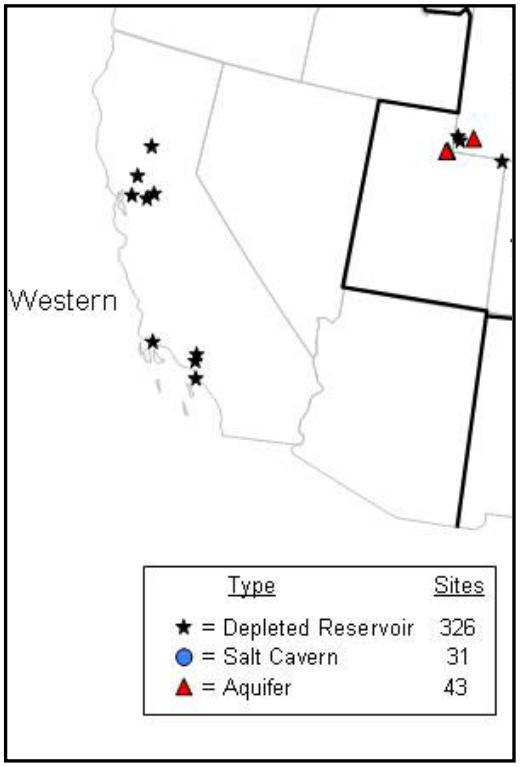
4.1.7 Cushion Gas

It may be possible to use compressed CO_2 or air storage as a way to store energy from non-baseload power sources such as wind and solar (e.g., McGrail et al., 2013 analysis of this technology in the Pacific NW). CO_2 can also be used as a 'cushion gas' for natural gas storage. In either application,

most of the gas remains in the reservoir and expands or contracts as needed as the reservoir charges and discharges, providing pressure maintenance. CO_2 has favorable physical properties for this application.

This technology has merit in California both because of the existence of numerous natural gas storage reservoirs and the likely increased use of non-baseload, intermittent renewable energy sources such as wind and thermal. The technology is at a developmental stage where funding pilot or demonstration projects could provide the proof-of-concept needed for commercialization. The downside is that the potential CO_2 demand for this application probably is not significant relative to the state's inventory.

Figure 9: Locations of Natural Gas Storage Facilities



Source: Energy Information Administration, Office of Oil and Gas, Natural Gas Division, Gas Transportation Information system, December 2008.

Similar issues arise in use of CO_2 as a cushion gas for natural gas storage. Demand for cushion gas is seasonal. California has 12 underground natural gas storage sites (Figure 8) with a working capacity of 266 billion cubic feet (Bcf) and a daily withdrawal capacity of 6875 million cubic feet (MMcf) (Energy Information Administration, 2008). Seven of these are owned by the two principal gas distributors in the State, Southern California Gas Company and PG & E. Most of their storage capacity is used for system balancing and to maintain a steady and high-utilization of pipeline capacity directed from Canada and the Southwest.

CHAPTER 5:
Advances in Storage Technology

Not all locations in the subsurface are good for storage, so careful site selection and characterization of the subsurface geology are key to mitigation of risks. Knowledge of how hydrocarbons have accumulated and remained trapped for millions of years provides a basis for defining the geologic attributes of storage sites that will prevent leakage. The goal of site selection and characterization is to find sites with those same attributes. Geologic attributes mitigating the risk of leakage include the presence of a thick, unfractured, low-permeability seal. The presence of structural closure, required for hydrocarbon accumulation, is not essential for CO_2 storage because of the action of secondary trapping mechanisms. Faults can be good if they form barriers to leakage, but bad if they can conduct CO_2 and provide a potential pathway out of the storage reservoir.

5.1 Site Characterization

A key part of assessing the capacity for storing CO_2 is identifying subsurface locations, such as deep geologic formations such as oil and gas reservoirs, and saline formations that are essentially leak-proof. In addition to identifying subsurface locations, an estimate of the total storage capacity of active onshore oil and gas reservoirs for the state of California using historical production and 2005 reserve data. Estimates were made on a field level and do not include State- or Federally-owned offshore fields.

The principles used to estimate CO_2 storage capacity of oil and gas reservoirs are outlined Best Practices Manuals for DOE (e.g., (National Energy Technology Laboratory 2010)). The fundamental assumption for estimating the storage resource is that the volume in the reservoir that was occupied by the produced hydrocarbons (oil or gas) becomes depleted oil and gas reservoirs until the reservoir pressure is brought back to the original reservoir pressure.

The California Department of Conservation ((Downey and Clinkenbeard 2011) developed estimates for onshore CO_2 resource storage potential using volumetric information for fields and basins. This involved calculating the volume of each field beneath a threshold depth, applying reservoir properties such as porosity) and assuming a subsurface CO_2 density of 700 kg/ m3 (equivalent to an average depth of 800 meters).

A revised methodology was selected to perform the resource estimate calculations. This methodology is presented in the DOE Best Practices Manual ((National Energy Technology Laboratory 2012) and is based on using production and reserve records (rather than volumetric data). High and low estimates were made for both onshore oil and gas reservoirs in California on a field basis based on historical production and field pressure and temperature data obtained from the 2005 annual oil and gas report by the California Department of Conservation (California Department of Conservation 2005). The sum of the estimates obtained from oil and gas data gave a total estimate for the CO_2 storage capacity in a given California field. Estimates were also obtained for each California basin by summing the estimates of the fields within each basin, and for the entire state of California. These estimates were subsequently adjusted and the corrected estimates are in Table 5.1 (Hwang 2010, Thomas 2008). The total oil and gas records obtained for 2005 by basin show that three basins – the Central Valley, Los Angeles and Ventura – contribute 86 percent and 94

percent of the total oil and gas for the State, respectively. The total resource estimates range from 0.33 Gt (low) to 6.45 Gt (high). The potential storage in oil fields contributes the majority of these total estimates (up to 99 percent). The largest potential is found in the Central Valley Basin (63 percent of the total for the high estimate) and Los Angeles (22 percent of the total for the high estimate).

Table 7: Summary of the low and high estimates for CO_2 resource potential for oil fields, gas fields and combined by basin using both produced and reserve capacities. In millions of tonnes.

Basin	No. of Fields	Oil		Gas		Total	
		Low	*High*	*Low*	*High*	*Low*	*High*
Central Valley	276	124.19	770.913	1,842.57	3,285.95	1,966.76	4,056.86
Cuyama	9	8.404	43.362	55.24	113.23	63.64	156.59
Eel River	2	<0.01	<0.01	18.15	18.15	18.25	18.25
La Honda	4	0.099	0.121	0.05	0.06	0.15	0.18
Livermore	2	0.088	0.187	28.2	34.82	28.29	35.01
Los Angeles	70	137.643	326.887	705.1	1,076.52	842.74	1,403.41
Orinda	2	<0.01	<0.01	0.12	0.12	0.22	0.22
Salinas	11	4.939	8.085	5.77	6.33	10.71	14.42
Ventura	87	59.906	127.204	380.68	643.77	440.59	770.97
TOTALS	**463**	**335.269**	**1276.76**	**3,035.88**	**5,178.95**	**3,371.35**	**6,455.91**

Source: Hwang (2010) and Thomas (2008).

Available technologies that can provide the information needed for site characterization include geologic mapping, seismic surveying supported by other geophysical technologies, and wells, both historical and drilled for purpose. It is impossible, however, to interrogate the subsurface at a sufficient level of detail to remove absolutely all uncertainty about properties and structure—hence the need for monitoring.

5.2 Monitoring, Verification, and Reporting (MVR)

In the context of geologic CO_2 storage (GCS), Monitoring, Verification, and Reporting (MVR) refers to activities for collecting and reporting data about the characteristics and performance of geologic carbon sequestration projects. For purposes of state regulatory policy, MVR should verify that projects perform as expected—that ecosystems, local populations, livestock, and natural resources such as groundwater and recoverable oil and gas are protected, that damages from seismicity do not

result from injecting CO_2, and that the proposed reduction in CO_2 emissions is achieved. Monitoring for leakage from the subsurface is paramount to protecting people, resources, and the environment, as well as for assuring emissions reductions. Even though monitoring of surface facilities is important, focus is on the subsurface where the technical issues are less well defined. Many measurement techniques are available for detection of leakage and the overarching approaches combines these techniques into a monitoring program.

The major components to be addressed by monitoring in geologic carbon sequestration projects include: (1) injection rates and pressure, (2) injection well integrity, (3) subsurface distribution of the CO_2, and (4) the local environment. For on-shore geological storage reservoirs, monitoring can take place in the storage reservoir itself or in shallower formations, in the vadose zone, in terrestrial ecosystems, and in the atmosphere. Offshore monitoring of storage projects will address the same components for the subsurface, but will need to take into account potential dissolution into seawater, transport with the water column, and sea-air interface.

Practical and cost-effective approaches to MVR will rely on a combination of measurements and model predictions, tailored to the geological attributes and risks of specific storage sites. Many current geologic carbon sequestration projects involve research elements to further develop or adapt existing measurement tools to the characteristics of CO_2 storage or to test new techniques. This research aims to enhance our understanding of geologic carbon sequestration, lower costs, gain lessons learned from field testing, and expand the options of an already robust monitoring toolbox.

The inherent variability in geologic environments call for flexibility in the MVR methods employed, the types and numbers of parameters measured, and the temporal and spatial frequency of their measurement. A consistent monitoring policy among regulatory entities will be essential to enable project developers to build unified, tailored monitoring programs that will allow geologic carbon sequestration projects to move forward in a cost- and time-effective manner, while ensuring protection of the public, the environment, and natural resources.

The value of a tailored approach to monitoring is threefold: first, optimum performance of many techniques depends on site-specific geologic attributes; second, the risks that need to be monitored will vary from site to site; and third, a tailored approach will enable the most cost-effective use of monitoring resources. From a regulatory perspective, a tailored approach will lead to regulations that are largely performance-based and non-prescriptive with regard to measurement methods. The downside of a tailored approach is that it will add considerable time and uncertainty (from the perspective of a project developer) to the regulatory process. The time required for an agency to review a tailored plan, and potentially coordinate reviews amongst several agencies, is much more than would be required for a prescriptive approach. In addition, regulatory staff will have to have a higher level of knowledge and expertise in the scientific underpinnings of a broad range of monitoring methods, as well as potential risks, in order to evaluate the efficacy of tailored approaches.

Monitoring of off-shore sequestration projects will involve many of the same techniques used in on-shore projects, however, operation in the off-shore environment will influence costs. In general, acquisition of 3-D seismic data is less expensive off-shore than on-shore, particularly for large-scale surveys. Off-shore seismic surveys involve ship-towed systems while on-shore surveys involve

wheeled vehicles and manual labor. Well-based measurements, however, are more expensive off-shore because of rig costs.

Many of the measurement technologies for monitoring GCS are drawn from other applications such as the oil and gas industry, natural gas storage, disposal of liquid and hazardous waste in deep geologic formations, groundwater monitoring, safety procedures for industries handling CO_2, and ecosystem research. These established practices provide numerous measurement approaches and options—a monitoring toolbox—which enables development of tailored, flexible monitoring programs for geologic carbon sequestration (see Table 8). Explanations of these various techniques were included in the AB1925 report (Burton, et al. 2008).

At a conceptual level, a tailored approach implies no distinction between saline formation MVR and MVR for EOR combined with storage— in each case the program is developed according to the site-specific circumstances. Practically, there are important differences between EOR with storage and saline formation storage. Saline formation storage involves only injection of CO_2 while EOR involves production of CO_2 along with oil and other fluids, and separation and re-injection of CO_2. So, there are additional measurements and accounting steps associated with surface handling of CO_2 for EOR. Regarding the subsurface, the leakage risks for saline formation storage and EOR with storage will likely be different, leading to a different monitoring program. The risk of leakage arising from uncertainties in the geology of the site will be much less for an EOR project because of the knowledge about the subsurface obtained during development of the field for oil production. On the other hand, the potential risk of leakage from pre-existing wells may be higher for the EOR project.

Even if a tailored approach is followed, there are a minimum set of measurements associated with the injection well and injection operations, that would be appropriate. These include CO_2 detection sensors on the surface at the well site, pressure, temperature, and volume flow rate at the wellhead, downhole pressure and temperature at the injection interval, and mechanical integrity pressure testing of the casing and subsequent monitoring of annulus pressures. A performance-based approach that allows for a tailored measurement program with a minimum set of required measurements has been followed in developing the proposed U.S. Environmental Protection Agency (EPA) Underground Injection Control (UIC) Class VI regulations and the EPA proposed rule for mandatory reporting of greenhouse gases for injection and geologic storage.

Table 8: Monitoring Approaches

System Component	Monitoring Methods	Benefits	Drawbacks
Storage reservoir	Seismic Gravity Well logs Fluid sampling	History match to calibrate and validate models Early warning of migration from the storage reservoir	Mass balance difficult to monitor Dissolved and mineralized CO_2 difficult to detect
Shallower saline formations below secondary seals	Seismic Pressure Gravity Well logs Fluid sampling	Good sensitivity to small secondary accumulations (~10^3 tonnes) and leakage rates Early warning of leakage	Detection difficult if secondary accumulations do not occur Dissolved and mineralized CO_2 difficult to detect
Onshore			
Groundwater aquifers	Seismic Pressure EM Gravity SP Well logs Fluid sampling	Sensitivity to small secondary accumulations (~10^2-10^3 tonnes) and leakage rates More monitoring methods available Detection of dissolved CO_2 less costly with shallow wells	Detection after significant migration has occurred Detection after potential groundwater impacts have occurred
Vadose zone	Soil gas and vadose zone sampling	CO_2 accumulates in vadose zone making detection easier compared to atmospheric detection Early detection in vadose zone could trigger remediation before large emissions occur	Significant effort for null result (e.g., no CO_2 from storage detected) Detection only after some emissions are imminent Does not provide quantitative information on emission rate
Terrestrial ecosystems	Vegetative stress	Vegetative stress can be readily observed using routine observation Satellite and plane-based methods available for quick reconnaissance	Detection only after emissions have occurred Vegetative stress can be caused by other factors Land use change could alter the baseline Does not provide quantitative information on emission rates May not be useful in some ecosystems (e.g., deserts)
Atmosphere	Eddy covariance Flux accumulation chamber Optical methods	Good for quantification of emissions	Distinguishing storage emissions from natural ecosystem and industrial sources necessitates comprehensive monitoring May not be best suited for detecting anomalous emissions due to relatively small footprint compared to the size of the plume Significant effort for null result
Offshore			
Water Column	Onboard fluid sampling and analysis Autonomous vehicles with	Direct measurement of water column and fluxes (using inverse models)	Distinguishing storage related fluxes from natural variability requires comprehensive monitoring Quantifying separate phase CO_2 flux Significant effort for null result

System Component	Monitoring Methods	Benefits	Drawbacks
	CO_2, pH and carbon cycle sensors		
Atmosphere	Optical methods Eddy covariance	Direct measurement of emission rate	Technology not well developed for CCUS Quantification of emissions may be impractical Changing emission footprint from ocean currents Likely to be costly to maintain Significant effort for null result

Source: (Burton, et al. 2008)

Establishing a baseline is an essential early step for successful monitoring of geological carbon sequestration. CO_2 is ubiquitous in the environment, both at the surface and in the subsurface, so it is important to establish initial levels before injection operations begin. Moreover, many of the parameters that can be used to monitor a storage project are not uniquely and directly indicative of the presence of CO_2; instead, it is the changes in these parameters over time that can be used to detect and track migration of CO_2 and its reaction products. For this reason, a well-defined baseline includes not only the average value of these parameters, but accounts for how they vary in space and over time before the project begins. Referred to as "time-lapse," this approach is the foundation for monitoring CO_2 storage projects.

Without time-lapse measurements, it may not be possible to separate storage-related changes in the environment from the naturally occurring spatial and temporal variations as seen in the monitoring parameters. For most geological carbon sequestration projects, baseline data will be obtained during the pre-injection phase of the project. This is particularly important for storage projects in deep saline aquifers, for which there is less prior data than for depleted oil and gas fields.

Collection and analysis of monitoring data continues throughout the injection phase and into the post-injection and site closure phases. It is a dynamic and iterative process in which model predictions play a critical role. One of the key outputs of site characterization is a subsurface model. Comparisons of monitoring measurements with model predictions are made repeatedly to determine if the project is performing as expected, and what adjustments can be taken if it is not. Monitoring data are used to improve the initial subsurface model, which leads to increased confidence in subsequent model predictions. As knowledge and confidence in the performance of a project increase, monitoring may be scaled back, and the spatial and temporal frequency of monitoring measurements and types of measurement may be changed to reflect this increased understanding.

5.3 Seismic Hazards

A part of site selection and characterization in California should be to establish the natural seismicity in the area of a potential site and to assess the change, if any, in seismicity due to the project. Because of the importance of seismic hazard assessment in California and public perception, a group at Lawrence Berkeley National Laboratory undertook an analysis of this issue. Their report is summarized here and reproduced as Appendix D.

Energy resource development has a history of association with induced seismic events. In June 2010, U.S. Senator Jeff Bingaman, Chairman of the Senate Committee on Energy and Natural Resources, asked the Department of Energy to initiate a National Academy of Sciences and National Academy of Engineering study of the scale, scope, and potential consequences of seismicity induced by energy technologies. Including geothermal energy production, hydraulic fracturing to extract shale gas, enhanced oil recovery, and geologic carbon storage. These energy technologies all involve the injection or withdrawal of fluids, which can change the pressure in the pore space between the mineral grains or solid matrix of the rock. In June 2012, the National Research Council (NRC) of the National Academies released its report, *Induced Seismicity Potential in Energy Technologies* (National Research Council 2012).

The *hazard* of induced seismicity is a description or calculation of the probability of occurrence of an earthquake with a specified minimum magnitude, or specified minimum severity of ground shaking. The *risk* of induced seismicity is the probability of hazard times the consequence, i.e., the damage or injury that could occur to structures or people as a result of the human activity that produces a seismic event ((National Research Council 2012).

Since the 1920s, it has been recognized that some earthquakes can be associated with human activities such as impounding water behind dams, controlled explosions related to mining and construction, injecting fluids deep into the Earth, or withdrawing fluids from deep in the Earth. The number of these human-induced earthquakes is small compared to the thousands of earthquakes that occur naturally around the world every day. As seismic monitoring technology has improved, scientists have observed that the vast majority of natural and induced earthquakes (frequently called *seismic events* among earth scientists) are of such low magnitude that they are not felt by people.

However, the relatively rare induced seismic events that are *felt* can alarm and/or annoy people, raise public concerns about safety, and occasionally cause property damage. In 2006, an enhanced geothermal energy project in Basel, Switzerland, involved pumping cold water into hot basement rock at a depth of 4.8 km (3 miles). It induced a magnitude 3.4 earthquake that cracked house walls and collapsed part of an unreinforced masonry church. Public outcry stopped injection and the project was terminated by authorities in 2009 after completion of a seismic hazard study that found significant risk of induced seismicity that could result in costly damage to structures. It is unlikely that the project would ever have been approved if the study had been completed as part of initial site characterization. Basel is known to sit atop an active fault that produced an earthquake with an estimated magnitude of 6.0-6.9 that destroyed most of the city in 1356.

An earthquake is the result of slippage on a fault when shear stress exceeds frictional force along the fault. This can occur from an increase in pore pressure that reduces normal stress across the fault and/or reduces cohesion of the fault or from tectonic or thermal stress changes. Many types of rock contain pore space, which is the ”empty” space among the mineral grains or within the solid rock mass. Sandstone, a common reservoir rock for oil and gas, and a likely candidate for CO_2 storage, can have up to about 40% open pore space. Volcanic rocks may contain voids created by gas bubbles. Denser metamorphic rocks such as granite may contain little or no native pore space, but all rock types may be fractured at various scales, providing void space and permeability. Except at shallow depths, this pore space will be filled with water (usually salty at depths below drinking water aquifers), or other fluids, such as oil, natural gas, CO_2, nitrous oxides, and radon. Pore

pressure is the pressure of these fluids in the pore space of the rock. On average, pore pressure increases about 0.46 pound per square inch (psi) per foot of depth (~10.4 kPa/m), but can vary significantly depending on geologic and hydrologic conditions, and from human injection or withdrawal of fluids.

Thus, the important criteria for predicting the likelihood of induced seismic events from fluid injection or withdrawal "include the amplitude and direction of the state of stress in the Earth's crust in the vicinity of the fluid injection or withdrawal area; the presence, orientation, and physical properties of nearby faults; pore fluid pressure… ; pore pressure change; the rates and volumes of fluid being injected or withdrawn; and the rock properties in the subsurface" (National Research Council 2012). The critical stress necessary to trigger slippage on a particular fault is difficult to assess, however, in part because frequently the fault plane is not a simple flat frictional surface, but a curving feature with varying surface properties.

The moment magnitude "**M**" of an earthquake is related to the total energy released at the source (hypocenter) of a seismic event. The total energy released is related to the surface area that slips and the amount of slippage on the fault. Large magnitude earthquakes necessarily have fault rupture that extends to great depth because the movement of a large fault surface is required to release a high level of accumulated stored energy. Another earthquake gauge is "intensity," often measured on the Modified Mercalli scale, which is a qualitative measure of the ground motion, or shaking, at a particular location. Intensity is a measure of whether and how an earthquake will be felt by people and whether and how it will damage structures. The intensity is determined by many factors, including the magnitude **M**, location and depth of the source, distance and direction with respect to the orientation of fault rupture, and subsurface structure and physical properties of the rocks between the hypocenter and the location of interest. Most events with **M**<2 are not felt by people unless the hypocenter is shallow and directly below them, whereas higher magnitude events may be more widely felt and may damage property.

Public awareness of, and sensitivity to, earthquakes, will likely result in special attention being paid to the part of a project monitoring program focused on detecting any seismicity that might occur at a CCS site. The major concern is that CO_2 injection will cause earthquakes, where use of the term "earthquake" for most people outside of the scientific community, infers ground motion that people can feel and likely causes some harm. In fact, the number of natural seismic events that are not felt by the public far exceeds the number which are felt, and the same can be said for seismicity induced by subsurface operations.

Nonetheless, there are a number of well documented cases to show that subsurface pressure increases, either from direct injection of fluids in the subsurface for waste disposal and geothermal energy development, or impoundment of large volumes of water at the surface in reservoirs, have caused seismicity that people can feel, and in some rare instances, caused harm. Even though, to date, there are no documented instances in which CO_2 injection has induced seismicity which has caused harm, appropriate design, operational and monitoring steps need to be taken to mitigate the possibility of any such events.

The Intergovernmental Panel on Climate Change issued a report on CCS ((Intergovernmental Panel on Climate Change 2005) in which an international group of 37 earth scientists wrote a consensus

section on induced seismicity. They recognize that injecting large quantities of fluid in deep wells at pressures substantially above background pressure can induce fracturing and fault slippage, with potential risks of 1) increasing fracture permeability that can allow the fluids to flow into unwanted locations, and 2) producing earthquakes that may be large enough to be felt and do damage. They also recognize that there is extensive experience throughout the world with deep-well injection of very large quantities of fluids: CO_2 for EOR, brines from oil and gas production, aquifer wastewater, hazardous waste, and natural gas. With the exception of natural gas injection, which is for temporary seasonal storage, the cumulative quantities of these injected fluids rival the quantities needed for effective CO_2 storage, and these injections have resulted in an exceptionally low frequency of felt and damaging seismic events. They conclude that this empirical evidence suggests that regulatory limits on injection pressure are effective and the seismic risk from CCS is expected to be low. They acknowledge that some aspects of CO_2 storage differ from the other deep-well injection practices, so commercial-scale CO_2 projects will be needed to quantify risk levels.

Regarding geologic CO_2 storage, the NRC report points out that the risk of induced seismicity is difficult to assess because there are only a few projects worldwide and these have injected small quantities of CO_2 relative to the large quantities that would be required to have an impact on climate change. The report states, "Given that the potential magnitude of an induced seismic event correlates strongly with the fault rupture area, which in turn relates to the magnitude of pore pressure change and the rock volume in which it exists, large-scale CCS may have the potential for causing significant induced seismicity. CCS projects that do not cause a significant increase in pore pressure above its original value will likely minimize the potential for inducing seismic events. (National Research Council 2012)." The report concludes that more research is needed. It is instructive, however, to compare CCUS, which has little history, with the experiences of induced seismic events for the other energy technologies discussed in the NRC report:

- Shale gas recovery, ~35,000 wells in the US; one felt induced event (in OK); M 2.1 The process of hydraulic fracturing ("fracking") of a shale formation as presently performed for shale gas recovery involves injection of a relatively small volume of fluid over a short time. Once the formation is fractured, pressure is reduced to promote the flow of gas into the well. This process does not pose a high risk for inducing felt seismic events.
- Secondary oil and gas recovery (waterflooding), ~108,000 wells in the US; one or more felt events at 18 sites (in AL, CA, CO, MS, OK, TX); maximum M 4.9 Pore pressure increase is the likely mechanism for the induced events, but reservoir pressure is generally balanced by fluid withdrawal while water is injected. Considering the large number of wells and fields where secondary recovery is used, the incidence of felt events is relatively low.
- Tertiary oil and gas recovery / enhanced oil recovery (EOR), ~13,000 wells in the US; no known felt event EOR projects involve the injection of steam, chemicals, or gases (including supercritical CO2) while producing fluids at other wells, thus minimizing pressure changes in the reservoir. Projects designed to maintain a balance between the amount of fluid injected and withdrawn, such as most oil and gas development projects, generally produce fewer seismic events than projects that do not maintain fluid balance.

- Oil and gas withdrawal, ~6,000 fields; felt events at 20 sites (in CA, IL, NB, OK, TX); maximum M 4.6 Pore pressure decrease has been responsible for stress changes from reservoir volume contraction or weight reduction, initiating slippage on pre-existing faults.
- Wastewater disposal, ~30,000 wells in the US; eight felt events (in AR, CO, OH); maximum M 4.8 The M 4.8 event noted above occurred in 1967 near Denver following 1,500 lower magnitude events resulting from five years of wastewater injection into relatively impermeable crystalline rocks beneath the Rocky Mountain Arsenal. But most wastewater disposal wells reinject water produced with oil and gas (including shale gas), and typically this wastewater is injected at relatively low pressures into large porous aquifers that are selected to accommodate large volumes of fluid, or back into the production reservoir to maintain pressure. Considering the large number of wells and large quantities of wastewater injected, only a small fraction of these wells have been linked to felt events. However, the incidence of induced seismicity that does occur appears to be higher for injection into basement rocks or other hard lithologies. There have been few felt events for several decades, but the effects of continued injection over longer periods are unknown.
- Geothermal, Liquid-dominated: 23 projects (in CA); 10-40 felt events/year; maximum M 4.; Vapor-dominated: The Geysers, CA; 300-400 felt events/year; maximum M 4.; Enhanced geothermal system (EGS): 8 pilot projects (in CA, NV); 2-10 felt events/year; max. M 2.6 Induced seismicity in conventional liquid-dominated geothermal projects has been relatively infrequent, likely the result of maintaining a moderate level of fluid balance with reinjected water. For the vapor-dominated field at The Geysers, high levels of induced seismicity may be the result of large volumes of cold make-up water being injected into hot reservoir rocks, making them contract. At some EGS sites in the U.S., low levels of induced seismicity have been felt.

While the rare high magnitude seismic events cited above can be problematic, the much more frequent microseismic events (not felt) can provide valuable information to guide field operations. At The Geysers geothermal area, where large quantities of water are injected to sustain reservoir pressure and fluid content, microseismicity has been useful for tracking fluid flow in the subsurface ((Majer, et al. 2012) and for managing the field (i.e., selecting among the array of wells, those to be used for production and injection, and the flow rates, at a particular time). Induced microseismicity has also proven to be beneficial for tracking fluid flow and reservoir management at other geothermal areas, as well as at secondary and tertiary oil production sites, and CCS sites.

Of the few CO_2 storage projects worldwide to-date, some, but not all, have experienced low levels of micro-seismic events. These projects are too small to provide a basis for long term projections of seismicity. Unpublished studies by the United States Geological Survey suggest that the *maximum* magnitudes of induced earthquakes that *do* occur are frequently related to the total quantity of fluid injected at a site, so with continued injection over long periods of time, the seismic hazard would be expected to increase. However, it is unknown how this relationship scales with increasing volumes that would be required for CCS, and for the reservoir formations that would be selected. The largest magnitude events identified in the USGS study (**M** 4.0-5.7) were for wells injecting wastewater into crystalline basement rocks and/or the aquifer immediately above basement.

The induced seismicity mechanism of primary concern is pore pressure increase. For CO_2 injection, particularly into saline reservoirs, low-amplitude pore pressure increases will be found at lateral distances far exceeding the extent of the CO_2 plume as brine is displaced by the expanding CO_2 front (Zhou and Birkholzer 2011). For potential CO_2 storage reservoirs that are geologically confined (surrounded on all sides by low permeability rocks), brine withdrawal has been proposed to limit pressure increase. Hence, pressure monitoring and pressure control are essential.

While increased pore pressure will reduce the confining force normal to a fault and/or reduce the fault frictional resistance, the component of stress parallel to the fault needs to exceed the frictional force before there will be a seismic event. Thus, the existing state of stress acting on a fault and the frictional force inhibiting slippage play critical roles in the safety of large scale projects involving the injection or withdrawal of fluids. Both of these are areas of active research. It is understood that regional stress in the Earth's crust is dominated by forces at tectonic plate boundaries and in other tectonically active areas. But it is not usually known how regional stress is accommodated locally and how it affects the stress on a particular fault at a particular time. The release of stress from an earthquake on one fault will change the stress field affecting other faults in the area. However, at a specific location and depth, the magnitude and orientation of the stress field can be measured with tests performed in a deep well.

Zoback and Gorelick recently asserted that, in the upper brittle part of the Earth's crust, faults in active tectonic areas and in the interior of the continent are critically stressed and ready to fail. So large-scale CO_2 injection, whether in seismically active areas or not, could trigger earthquakes that might fracture overlying caprocks and allow the CO_2 to escape. Hence, they conclude, CCS at a scale to mitigate climate change will be unsuccessful because of "triggered fault slip" on unidentified and/or ancient faults. However, the NRC report and numerous geophysicists refute their assertions. See Appendix 3 for a full discussion.

When evaluating a possible site for CO_2 storage, the potential for induced seismicity needs to be addressed and then managed if the site is selected. Best practice approaches for assessing the potential for, and management of, induced seismicity have been grouped into the following, often overlapping, six categories (Myer and Daley 2011):

- Site selection and characterization including collection of existing data: geologic structure based on well logs and seismic surveys; mapping of fault locations; historical seismicity (location, magnitude and frequency of earthquakes); and if available, regional hydrologic boundary conditions, and in-situ fluid pressures and stress state.;
- Public outreach to assess and address the concerns of local people on induced seismicity, including an open and straightforward discussion (in layman's terms) of natural and induced seismicity, monitoring activities, and mitigation plans;
- Hazard risk assessment which includes the likelihood of injury to people and damage to property, and the value of that damage. The traditional approach to estimating potential seismic hazard from *natural* earthquakes is a Probabilistic Seismic Hazard Analysis (PSHA), which is based on 1) an historical record of earthquake frequencies and magnitudes in an area, 2) an earthquake rupture forecast to evaluate the probability of all possible earthquake ruptures (fault offsets) throughout the region and over a specified time span, and 3) an

earthquake shaking model to estimate the probability that an intensity-measure type will exceed some level of concern for a given earthquake rupture (Myer and Daley 2011);

- Passive seismic monitoring using an array of microseismic monitoring stations in the vicinity of the proposed injection site to assess the level of natural background seismic activity. Monitoring for at least a year before injection begins, while exceptionally short in geologic terms, can still be useful for seeing current activity on known faults or identifying unknown faults. Monitoring for induced seismicity begins with establishing a record of the natural background seismicity in the region encompassing the project. This record is fairly good in many parts of California because an earthquake monitoring network is already in place. This network consists of seismometers located on the ground throughout the state and connected by satellite to a data collection facility. In most instances the existing network would need to be augmented by a local network designed specifically for the site, and consisting of seismometers located on the ground surface or in shallow boreholes.
- Managing reservoir pressure to protect Underground Sources of Drinking Water (USDWs), by never exceeding the pressure that will fracture the reservoir rock at the injection point. The EPA stipulates a maximum permissible downhole CO_2 injection pressure that is significantly below the fracture pressure, and requires continuous monitoring and recording of the injection pressure.
- Establish seismic event response and mitigation procedures working with regional and local regulators and authorities to agree on specific procedures and actions to be taken if earthquakes of a specified magnitude or shaking intensity occur.

The DOE has sponsored "Protocol" and "Best Practices" documents for enhanced geothermal system (EGS) projects, with the objective of providing "guidance for geothermal developers, public officials, regulators and the general public to evaluate and manage the effects of induced seismicity related to EGS projects. The Protocol and Best Practices documents provide detailed descriptions of the six numbered topics above. They provide guidance without being prescriptive, recognizing that for each project site there will be a unique set of circumstances – geologic conditions, prior seismicity, locations of faults, proximity of people and diverse structures, planned depth and quantity of fluid injection, etc. This will also be the case for potential CO_2 storage sites.

The DOE/NETL Carbon Storage Program has published a set of Best Practice Manuals for CCS, which provide lessons learned from the research carried out by the Program and guidance to future operators on the topics of site selection and characterization, drilling and well management, monitoring, simulation and risk assessment, and public outreach. A recently released revised edition of the Best Practice Manual on monitoring for geologic CO_2 storage ((National Energy Technology Laboratory 2012) specifically addresses the NRC report recommendations on induced seismicity. Future updated versions of the other Best Practice Manuals will also address the NRC recommendations.

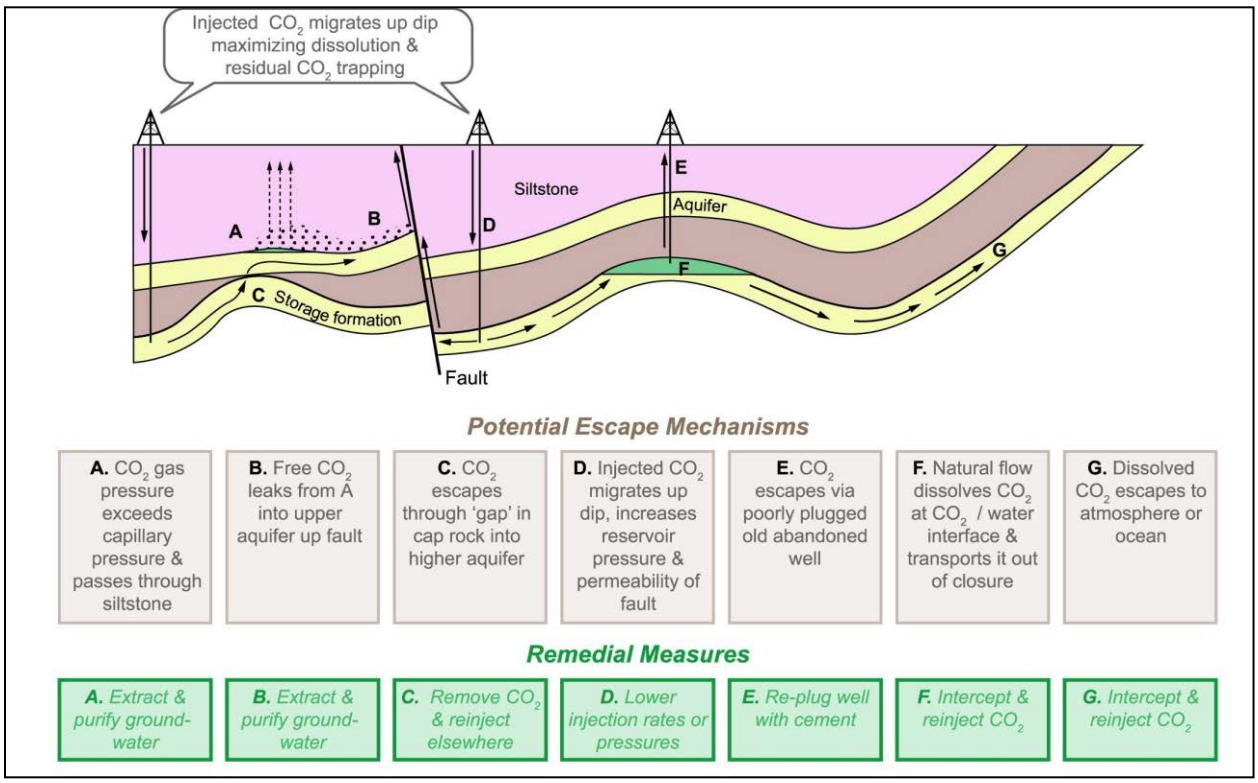
5.4 Leakage Risks

Many of the risks of geologic storage are associated with the potential for leakage, during pipeline transport or during deep subsurface storage. In order for CO_2 stored in the deep subsurface to have

an adverse impact on humans, animals, vegetation, groundwater or other resources, it must reach these locations via a pathway. The primary paths for leakage from a deep reservoir would be improperly installed and/or abandoned wells, and undiscovered geologic discontinuities such as faults. There are two primary driving forces to move CO_2 away from the injection well and to locations where there might be potential leakage pathways. The first is pressure – CO_2 must be injected at a pressure greater than the pressure in the fluids already present in the rock. The second is buoyancy – in most cases CO_2 will be less dense than the fluids already present in the rock, and will therefore try to rise upward (Figure 10: Potential leakage routes and remediation techniques for CO_2 injected into saline formations).

It should be noted that these driving forces do not remain constant over the life cycle of a storage project. After injection stops, fluid pressures in the reservoir will begin to decrease, approaching pre-injection levels. The amount of pressure recovery depends on many factors, including the size of the reservoir, and the hydrologic conditions at the boundaries of the reservoir. Buoyancy forces do not decrease, but the amount of CO_2 subject to buoyancy will decrease, both during the injection phase of a storage project and after injection stops. Over time, several processes, referred to as secondary trapping mechanisms, work to immobilize the CO_2 in the reservoir, including physical (capillary trapping) and chemical (solubility and mineral trapping) processes. After the CO_2 is immobilized, buoyancy forces are no longer a factor.

Figure 10: Potential leakage routes and remediation techniques for CO_2 injected into saline formations



Source: IPCC (2005)

Verification that a storage site does not leak is paramount to protecting people, resources, and the environment, as well as for assuring long term emissions reductions and compliance with emissions caps. Identification and assessment of potential leakage pathways during site characterization serves as a basis for developing appropriate operational standards as well as monitoring and verification requirements that address site-specific conditions. The most commonly encountered risks of leakage from storage sites arise from existing and new wellbores and fractures and faults that penetrate the sealing cap rock formations.

Proper well construction will be essential in mitigating leaks. Decades of experience in commercial CO_2- EOR operations provide a substantial knowledge base of construction methods and technologies, though questions remain about the need for more conservative approaches, such as those prescribed by the EPA Class VI rules, for storage wells. Some key technical issues are associated with the specifications for the casing and the cement used to fill the annular space behind the casing. Discussions continue about whether to use corrosion resistant steels and cement and to fill the annular space from top to the bottom of the well.

Because there is as yet little experience with CCUS projects, the datasets needed for quantifying leakage risk can be borrowed from other industries. Natural gas storage reservoirs are, in many ways, analogous to CO_2 storage projects. Of the approximately 600 natural gas storage projects operated in the United States, Canada, and Europe, only nine were identified as having experienced leakage: three from caprock issues, five from well bore integrity issues, and one from poor site selection (too shallow) (Perry 2005). Well integrity issues accounted for most leakage incidents with poor cement jobs, corrosion, and improperly plugged old wells as specific causes.

Studies of oil and gas field experience also point to well integrity issues as primary causes for leakage. In Alberta, Canada, about 4.5 percent of oil and gas wells leak either from the formation through the cement behind casing into the well or by flow outside the casing to surface (Bachu and Gunter 2009). CO_2-EOR experience in the Permian Basin, Texas shows that a major cause of wellbore leakage is failure of mechanical components in the injection equipment and loss of control during "work-over", or well maintenance operations (Duncan, Nicot and Choi 2009).

Approaches for monitoring for wellbore leakage include:

- Pressure monitoring in a closed well to establish that the casing is not leaking and overlying formations where leakage of CO_2 will result in an increase in formation pressure.
- Careful monitoring of temperature profiles along the well to identify temperature anomalies that indicate leakage.
- Geophysical wireline logs, used routinely in the petroleum industry, provide data on the integrity of the cement filling the space between the well casing and the rock. If CO_2 were to leak through the cement between the casing and the rock, it could travel up the wellbore behind casing to enter rock formations above the injection interval. Geophysical wireline logs and can detect the presence of CO_2 in the rock within about a meter of the wellbore.
- Tracers can be injected behind the casing and their movement monitored to indicate the presence of leak paths at the casing-cement-rock interface.

- Water samples extracted from monitoring wells or groundwater wells and analyzed for CO_2 or reaction products of CO2-water-rocks.
- Air monitoring by sensors placed at the ground surface in the vicinity of the well to measure CO_2 concentrations.

Approaches to mapping the movement of CO_2 in the subsurface, which can also detect leakage out of the storage reservoir from fractures and faults, include:

- Geophysical monitoring methods: seismic, electromagnetic, and gravity
    - Seismic surveys produce images of subsurface properties by generating and recording induced sound waves as they travel through the earth. Although the size of a leak that can be detected using seismic surveys depends on many site-specific parameters, field experiments such as the Frio Brine Pilot tests in Texas and the Weyburn project in Canada suggest that seismic methods can detect leaks on the order of a couple thousand metric tons, a volume which is roughly equivalent to the size of a municipal swimming pool.
    - Gravity and electrical methods create lower-resolution images of the subsurface, and are less widely tested for CO_2 applications, but can provide additional information on movement of the CO_2 plume. Gravity methods use the difference in density between CO_2 and water as a means of detection, whereas electrical methods use the difference in electrical conductivity between CO_2 and water.
    - Land-surface deformation, satellite, and airplane-based monitoring: injection of CO_2 into the reservoir causes increases in the pressure of the water in the rock, which extend far beyond the extent of the CO_2 plume. Recent work at the In Salah project in Algeria has demonstrated that small ground surface displacements, measurable from satellite-based systems, can be translated into images that show the migration of the CO_2 and would be able to show leakage via fractures and faults.

Statoil's Sleipner project, located offshore in the North Sea, has been injecting about a million tons of CO_2 per year since 1999 and has used geophysical monitoring to tract the movement of the CO_2 underground. The CO_2 is produced along with natural gas from a deep reservoir, separated from the natural gas in offshore facilities, and re-injected into a saline formation located about 3000 feet beneath the seafloor. The use of 3D time-lapse seismic surveying, repeated about every two years, shows the vertical and lateral spread of the CO_2 and has confirmed that the reservoir is not leaking.

The In Salah project, onshore in Algeria, provides examples of successful detection of a leak by monitoring and simulations. In Salah is a commercial storage project in which CO_2, produced along with natural gas, is separated and re-injected into a saline formation. About 800,000 to 1 million tons per year are injected. A small amount of leakage occurred from an unused exploration well, KB5. The amount of leakage was estimated to be less than 1 metric ton before the well was remediated. KB5 was drilled in 1980 and, in accordance with Algerian hydrocarbon regulations, was decommissioned but not plugged. Reservoir simulations initially indicated that CO_2 would not migrate very far in the direction of KB5. After injection started and monitoring data became available, including satellite observations of surface deformation in 2006 and 200, updated

simulations suggested that CO_2 was migrating quickly in the direction of KB5. Based on this information, a close inspection of the well was carried out during a routine surveillance visit. Because the well gauge and flange had been stolen, the CO2 that had built up in the unplugged wellbore leaked into the atmosphere (Dodds, Watson and Wright 2011).

Consideration of potential reporting requirements needed to obtain credits for subsurface storage of CO_2 logically raises the issue of quantification of leakage. Many, if not most, of the measurement techniques discussed above for detection of a subsurface leak, also provide information which can be further analyzed to quantify the leak, though additional assumptions and data from other measurements may be needed. Site specific conditions, once again, will heavily influence the sensitivity and uncertainty in results. A handful of studies have been carried out to look at the sensitivity of pressure measurements and seismic measurements to the volume of a leak, and, as noted above, field studies to date suggest that under some circumstances, seismic methods can detect leaks of a few thousand tons of CO_2. In general, however, quantification of leakage is more challenging than leak detection. More experience and study are needed before definitive statements can be made about the ability of various techniques to detect minimum volumes.

CHAPTER 6:
Non-technical Considerations

Non-technical considerations include outreach, statutes and regulations, and business case elements. All of these elements affect the risks associated with CCUS technology deployment generally and in the case of specific projects.

6.1 Outreach and Education

Despite growing awareness of CCUS in the energy, agriculture/forestry, environmental science, and policy communities, the general public remains largely uninformed about CCUS technology. The first step to meaningful public engagement on CCUS is facilitating public understanding of the technology, separate from outreach and education that is project-specific. It is natural for people unfamiliar with a technology to approach it with skepticism and concern, and it is the obligation of CCUS policy and project stakeholders to invest in general outreach and education.

Project-specific outreach is a critical activity for project planners and for the agencies tasked with permitting and regulation of the project. Understanding and addressing the project risks inherent in outreach activities is critically important. There are several examples of CCUS projects that were cancelled because of failed community outreach.

The various components of a CCUS system, capture, transport, manufacturing, and/or injecting CO2 underground, will likely cause varying degrees of concern for stakeholders and the public. Because implementing CCUS technologies as a system is not yet widespread enough to be familiar and has not been comprehensively demonstrated at a commercial scale, there is generally discomfort by policymakers, regulators, the public and local communities when they are first presented with a project or with decisions as to whether CCUS technologies are part of climate change mitigation solutions.

The Warren-Alquist State Energy Resources Conservation and Development Act in California requires public agencies to have open meetings and to allow public comment. The California Resources Agency contains many of the commissions and departments that play important roles in regulating CCUS. Among them are the California Public Utilities Commission (CPUC), the California Energy Commission, the California EPA (including the State Water Resources Control Board and the Air Resources Board), and the California Department of Conservation. Some of these agencies, in addition to public outreach associated with specific CCUS projects that have come under their jurisdiction, have included CCUS in their general outreach and education activities focused on energy and climate change policy decisions. For example, on January 21, 2010, as part of an ongoing series of public forums, the CPUC held a panel discussion on "Carbon Capture and Storage and the Role It Plays in Climate Change Mitigation." The CCS Review Panel, convened by the CPUC, the Air Resources Board and the Energy Commission, held publicly open meetings and produced policy recommendations in a publicly available report ((California CCS Review Panel 2010).

Federal regulatory agencies involved with CCUS project regulation, such as EPA Region 9, also require a public posting, hearings, and a comment period as part of permitting procedures. Local

permitting agencies, such as counties, may also require public hearings as part of the process to obtain land use permits for CCUS projects. A federal interagency task force also produced a report on CCS that is publicly available ((Force 2011)

In addition to the general guidelines for outreach management structure for CCUS projects, NETL has developed a list of potential topics and messages (National Energy Technology Laboratory 2009) that could be used in outreach and education activities and materials. The following list is modified to fit the experience to date and the specific issues relevant to California (Table 9).

Table 9: Possible Outreach Topics and Messages for CCUS Projects

Potential topics	Potential Messages:
Role of CO_2 storage in mitigating CO_2 build-up in the atmosphere and meeting 2030 and 2050 goals	CCUS technologies are part of the portfolio of GHG reduction technologies the state needs; California is a leader in moving toward global adoption of these goals, which must be adopted to stabilize atmospheric CO_2 concentrations
Global experience in CO_2 storage, including related analogs and projects	Engineered geologic storage of CO_2 has been safely practiced for 30 years in the oil industry; Natural geologic CO_2 storage has occurred for millions of years; Pipeline transportation of CO_2 is a mature and safe technology; Injection and reservoir monitoring are mature technologies
Standard and new practices are being used to ensure public and environmental safety, including seismic hazards	Site selection and characterization assure that geology is suitable; Operating conditions are chosen so that projects are conducted safely; Protecting public safety is a priority for project developers and the state agencies involved in permitting and regulating them
Role of government in overseeing/regulating CO_2 storage	A lot of research has been done to help develop guidelines for permitting and regulation of CO_2 storage projects; California has a strong history of protecting its people, environment, and property rights, a tradition which continues in relation to CO_2 storage projects
Potential costs and benefits to the community from CCUS (as applicable)	The surface facilities involved with storage create minimal surface disturbance compared to many other types of operations; Jobs are created during construction and operations; New high-tech jobs may be brought to the community by manufacturing utilizing CO_2.

6.1.1 CCUS Education

CCUS technology education must begin in the context of other major energy and climate change policy initiatives. When CCUS is presented in this manner, the public can better weigh its potential

relative to other options to contribute to the state's goal of fostering economic growth and opportunity while protecting human health and the environment.

It may not be necessary to invest in extensive efforts to convey technical information in simple terms. Experience in the United States suggests that public understanding of technical issues is not as important as is commonly believed by industry and government (CO2 Capture Project n.d.). Rather, public trust in the developer, regulators and government to deliver truthful information, operate a fair decision process, be accountable and treat the public fairly in the distribution of economic benefits is most important when engaging the general public.

It also may not be necessary to address risks, but rather to educate on risk perceptions related to new and unfamiliar technology and event likelihoods. A recent survey of public perceptions of CCS in Indiana noted that those people for whom climate change and alternative energy sources were important tend to support CCS (Carley, et al. 2012). Surprisingly, concerns about risk were not as important as the researchers anticipated. The perception of risk may not equate to actual risk. Emotional objections to technologies can be formidable and understandable, given the magnitude of consequences for rare events that have occurred (e.g., concern about a repeat of the Fukushima nuclear plant accident even though the chances of a similar coincidence of natural events and structural/operations failures is extremely low).

6.1.2 Project Outreach

Simply put, an outreach program for a CCUS project, to assure project success and acceptance, must get "the right information to the right people at the right time." This simple statement should be taken literally. Successful outreach means good management of communications with all affected parties. Outreach will not be successful if poor management leads to incidents where information is withheld or skewed, affected parties are ignored, or communications are not timely.

The right people are defined as the project stakeholders. A stakeholder generally is an individual, group or organization that has an interest, whether they recognize it or not, in CCUS policy or in a specific CCS project. The term "public" is used to refer to the general public at a national, state, or regional level. The term "community" refers to local stakeholders, comprising both individuals and groups in the vicinity of or that may be affected by a particular CCUS project (International Energy Agency 2012). Stakeholders also include policymakers and regulators who must ensure that projects move forward while preserving and protecting public safety and health, natural resources, and the environment. Businesses, investors, and industries that may profit or sustain losses from CCUS policies or projects also are stakeholders.

A survey in California determined that local communities most want empowerment and engagement (Wong-Parodi and Ray 2011). The analysis urged that project developers engage in early and open-ended engagement with the community to achieve active acceptance rather than passive acceptance, or worse, opposition and recognize that there are several "publics" to be reached. Understanding community history and material and asset base is important to understanding sense of empowerment. The extent of community empowerment should be considered in project planning, communications, and risk assessments. Queries related to empowerment, voice, transparency, and past community experiences should be incorporated into social characterization activities.

An outreach program has four general objectives in communicating with stakeholders. It is incumbent upon CCUS project proponents to reach out to all stakeholders to (1) provide accurate information, (2) promote a transparent decision-making process, (3) make sure that accountability is understood, and (4) make thoroughly clear the relationships between the project and its stakeholders (Wade and Greenberg, 2011). The protocols of various federal and state permitting and regulatory agencies require and facilitate achieving all four of these objectives. Obtaining permits for all aspects of the CCUS system, from power plant construction, capture facilities, pipelines, to injection wells at a storage site, requires rigorous public disclosure and opportunities for public feedback. Most project developers also engage in further outreach activities with all stakeholders, aimed to increase the understanding of CCUS and project specifics.

Timeliness of communication is also very important. Lack of transparency or intent to withhold information is frequently inferred when there is unreasonable delay in release of information. Timeliness is particularly important when an unusual event or a crisis happens.

CCUS projects may encounter opposition that is not directly related to the project itself. CCUS projects typically involve industry sectors, specifically the power and the oil and gas industry, that may be perceived negatively by some communities. Opposition may have nothing to do with the project itself, the project developers, or CCUS, but occurs because of other activities by those industries which have historically been issues of contention for those communities, such as air pollution from stack emissions, and congestion from truck traffic. CCUS technology also may encounter opposition from some environmental groups that view it as a mechanism to prolong usage of fossil fuels. This view, however, is balanced by that of other environmental organizations that support CCUS as a crucial tool in the fight to reduce global GHG emissions (ENGO 2012).

CCUS projects have been cancelled because outreach programs were unsuccessful in gaining the support of the local communities. Analysis of case studies is an important element to understanding how to avoid future project failures due to stakeholder opposition. Even when outreach and all other project elements have been successful, CCUS projects are sometimes still cancelled. All of these cancellations, regardless of the reasons, make the job of outreach for the next CCUS project more difficult.

The outreach team must be integrated into the overall project management structure to assure consistency between outreach and all other project elements. Key component of integrating public outreach with project management is building in the time necessary to accomplish the various steps in advance of engaging the public. Questions such as the timing for engaging various stakeholders must be integrated into the overall project management plan and is especially critical during the early stages of a project. It is essential to establish a strong outreach team with a clearly defined structure that delineates roles and responsibilities covering both internal and external communications (National Energy Technology Laboratory 2009).

Accuracy, transparency, and accountability are inter-related and best achieved when outreach is integrated into project management. The accuracy of the information shared in outreach communications must be assured by constant internal communication among the outreach team and other project teams, particularly technical or operations teams. Public perception of transparency and accountability will be influenced by the extent to which the project teams are well coordinated

and are perceived to communicate openly and be responsive. Thus, accountability demands the establishment of a structure for the outreach team that includes an informational "chain-of-custody" with cross-checks to relevant project experts to assure up-to-date accuracy of content, consistency and frequency in outgoing communications, and prompt and accurate follow-up on incoming information requests.

The outreach team should devise an internal process that will be used to construct, review, and revise outreach materials and formulate a communications plan. These materials should be flexible to accommodate adjustments in response to information gathered through outreach events and as projects evolve in response to other factors. Updates also will be needed to reflect project progress or lessons learned. The development of an outreach plan will: promote integrating outreach activities and other aspects of the project; identify the issues of various stakeholder groups; allow customizing outreach approaches for specific audiences; and lay out an overall strategy for communications at all stages of the project. The strategy specifics should include objectives, tasks, and events that coincide with each project stage, a timeline for outreach activities that complements and is consistent with the overall project timeline, and defining the roles and responsibilities of members of the outreach team (National Energy Technology Laboratory 2009).

A component of the outreach strategy is a communications plan that focuses on representing the project directly to the public and the media. It should include plans for everyday communications, high visibility communication periods, and communications in the event of a crisis. Crisis communications should cover who has responsibility for specific tasks in the event of an emergency, how emergency services will be handled, and what safety procedures will be followed (National Energy Technology Laboratory 2009).

An outreach program should make sure that efforts do not diminish once the operational phase of the project is underway. Interactions with the community and other stakeholders should continue for as long as the project affects the community after completion of the operational phase. The community will feel the need for assurances, once the project developer has left and the facilities are dismantled, that there is someone to provide information about post-injection monitoring results and be held accountable for any post-operations events. The final phase of the project outreach program should integrate with any outreach activities of the entity that will assume the long-term stewardship responsibilities for the sequestration site (National Energy Technology Laboratory 2009).

Communications from the outreach program encompass a wide variety of technical fields such as geology, engineering, finance, legal, and risk analysis. The outreach team must establish protocols for developing and reviewing outreach materials in consultation with the technical team, followed by review by the management team and relevant external parties. This review process can take a substantial amount of time and must be accounted for in planning. Identifying a set of key messages that can be consistently repeated in outreach activities and materials can help stakeholders develop a clear understanding of the project despite the technical complexity (National Energy Technology Laboratory 2009).

6.1.3 News Media

The news media, including online, print and TV/radio have the task to report news, with a focus usually on bad news. There is usually little coverage of CCUS technology in news media, with the exception of an occasional negative story. For example, a scientific paper on a CCUS issue will be covered if a science reporter attends a science conference and deems the topic noteworthy in a negative way. An example is the coverage of induced seismicity potential of CCUS projects by the San Francisco newspapers covering the American Geophysical Union meeting in that city (See Appendix D for further discussion.).

Educational media, such as magazines and public television programming, have provided scant coverage of CCUS technology. It is rarely included or mentioned in the context of articles or programs on energy and climate change.

For projects, the local news media will likely provide coverage because project activities are of interest and concern to their customers. For project outreach teams, the local news media are a therefore are a particularly important community stakeholder group because – despite the best outreach efforts – a large portion of the local public is likely to first hear about a project, an event, or an incident associated with a project through the local media. This coverage may also be picked up by other news media and spread. The strategic tradeoff inherent in media engagement is that the media provide wide distribution of project information at little cost (compared with advertising or direct mailing) in exchange for the loss of control over the message. The best chance of the media conveying the message desired by the project team results from well-prepared and well-executed media outreach efforts, but no effort can ensure success.

The nature and depth of stories for print and broadcast media varies depending on the type; for example, magazines allow for greater depth than newspapers generally; short capsulated messages and pictures are obviously more critical for television than print. The level of media interest also is heavily dependent upon the background, interests, and attitudes of reporters and their editors. In small communities, individual reporters may cover every type of story. At major daily newspapers in metropolitan areas, reporters have topical "beats," and a CO_2 storage project might be covered by a reporter specializing in science or energy issues.

An understanding of the news media's business environment can assist the outreach team in crafting and supplying project information in a manner that eases the reporter's task in "seeing the news hook" and writing the story, and build relationships for further news coverage. Gauging interactions with media according to the level of technical awareness of the reporter cannot be overemphasized. If materials are too technical, the reporter may fail to understand what is presented and unintentionally misrepresent facts; material that is too simplistic may leave a reporter feeling patronized. The outreach team must balance the level of detail to provide an adequate understanding to construct a solid story but not overwhelm a busy reporter who might drop the story in favor of others that can be more quickly completed. Journalists also tend to seek all sides of a story, and as a result, despite efforts by an outreach team to be objective, it is common for news stories to also contain quotes or viewpoints from a project opponent or skeptic. The opportunity for review to check facts is generally lacking.

6.1.4 Social Characterization

Social characterization, or social site characterization, is a term that the Regional Carbon Sequestration Partnership Program (National Energy Technology Laboratory, 2009) defines as gathering and evaluating information to obtain an accurate portrait of stakeholder groups, their perceptions, and their concerns about CO_2 storage. This information can be used to identify the factors that will likely influence understanding of a specific CO_2 storage project. The information gathered will enable the project team to develop better insights into the diversity of the community, local attitudes, and types of project concerns, with the aim of determining what methods of outreach and communication will be most effective.

Social characterization begins in the early planning stages and continues throughout the project. Examples of information collected during social characterization may be: economic conditions; levels of political awareness or activism; educational levels; prior experience with industry, government and large projects; views on energy, environment and climate change; levels of trust toward outside entities; key media organizations; relevant local infrastructure; cultural diversity and constituencies; and important local landmarks or hazards.

The process of gathering social data is iterative. The first round of information may be gathered from readily available sources including government and civic group websites, local media, published demographic data, local blogs, published surveys and opinion papers, and polling or interviews with potential stakeholders at all levels (local, state, and national). This preliminary social information provides the project developer with an initial understanding of community concerns. A second round of information collection includes identifying key representatives or organizations that may provide venues to communicate with community stakeholder groups.

Stakeholders and stakeholder groups may be divisible into categories that are useful for crafting communications targeted toward addressing their specific issues. Categories may be, for example:

- Business sector (e.g. partners, contractors, competitors, investors),
- Technical experts (e.g., technology developers and environmental experts),
- Government sector (e.g., regulators, politicians, authorities),
- Special interest groups (e.g., consumers' association, labor organizations, industry associations, environmental NGOs, churches, schools, media)
- Individuals (e.g., community members, local landowners)

Categories might also be constructed based on other factors that may be more applicable to a project's needs. Choosing the right categorization scheme demands a high degree of familiarity with the various stakeholders in order to assess whether the stakeholder categories employed actually group stakeholders with common concerns. To give a simple example, a labor organization special interest group may be interested in communications about job opportunities; an environmental group may be interested in understanding potential project impacts on wildlife habitats. While both are categorized as special interest groups, the focus of outreach communications obviously should be substantially different for each group. In other cases, it may be more difficult to determine how stakeholders should be parsed or grouped. After categories are established, they can be used in

developing the communications plan. Within the plan, each stakeholder category can be associated with specific concerns, customized messages and information, and the most appropriate venues.

There are few studies of whether socio-demographic attributes affect attitudes toward CCS projects and CCS technology. A survey in 2005 of over 1,000 people in Australia, at a time when two CCS projects were under development in the country, examined the effects of gender, age, socio-economic status (income and educational attainment) on attitudes toward CCS (Miller, Bell and Buys 2007). The sample population was skewed toward women and an educational and economic status above average for Australia. Results of this study lacked noteworthy trends but underscores the need to embrace the diversity of "publics." The concern that locations of CCS projects in rural and industrialized areas may result in an unfair and biased burden on certain socio-economic populations is discussed further below.

6.1.5 Environmental Justice

California state law defines environmental justice (EJ) to mean "fair treatment of people of all races, cultures, and incomes with respect to the development of environmental laws, regulations, and policies." Similarly, the EPA defines environmental justice as "the fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies." The EPA (United States Environmental Protection Agency 2014) defines the terms 'fair treatment' as meaning that "no group of people should bear a disproportionate share of the negative environmental consequences resulting from industrial, governmental and commercial operations or policies," and 'meaningful involvement' as "people have an opportunity to participate in decisions about activities that may affect their environment and/or health."

Environmental Justice seeks to address the demographic imbalance in who bears the impacts of environmental degradation or of the side effects of legislation designed to prevent it. For example in recognition of the fact that policies enacted to meet the state's GHG reduction goals may harm disadvantaged communities disproportionately, the AB32 legislation required the formation of an Environmental Justice Advisory Committee to advise CARB on the Climate Change Scoping Plan and the measures involved in meeting the 2020 goal.

The EJ movement has been championed by a diversity of demographic groups, including African-Americans, Latinos, Asians, Pacific Islanders, and Native Americans. Pollution of air, water, or land is at issue, but also domination of local resources such as land or water by industrial facilities. The health effects resulting from exposure to pollution are widely recognized for all groups, but communities in close proximity to industrial facilities experience statistically significant higher levels of illness, disease, and premature deaths than communities in other areas.

Activities that contribute to local air pollution appear to be the greatest concern of EJ advocacy groups. Emissions that affect the communities that EJ groups represent include stack exhaust from power plants, refineries, cement plants, and chemical plants, but also include emissions associated with truck and other traffic in and out of these facilities and associated activities such as dumping, incineration, and wastewater treatment. Fossil fuels are often at the center of EJ concerns for a number of reasons that include environmental and health effects associated with their extraction or

production (e.g., coal mining or oil/gas wells), refining or combustion, and waste byproducts (e.g., coal ash and petroleum coke).

Commercial-scale CCUS implementation is an issue for environmental justice because the storage of the CO_2 may be done underneath communities that are already affected by the surface activities of the industrial facilities generating the CO_2. Thus, a community's previous experience with industrial activities and facilities is likely to affect a community's reaction to CCUS proposals. In general, EJ groups are supportive of technologies that reduce GHG emissions, but this support is generally outweighed by "not in my backyard" (NIMBY) and "not under my backyard" (NUMBY) concerns.

Capture facilities may use potentially harmful chemicals (e.g., amines) and require extra energy which results in increased criteria air pollutant emissions. Compression also uses energy that produces additional emissions. Trucks or trains used for transport increase congestion, noise, and air pollution. Transporting CO_2 at commercial-scale will require pipelines carrying much larger volumes than most industrial pipelines currently in place through most urban areas. EJ groups have raised the issue of the effects of leakage from pipelines and possible adverse health effects. In California, pipeline safety issues are receiving a great deal of scrutiny by EJ groups and the general public after the San Bruno pipeline explosion and fire in 2010. While the San Bruno incident involved natural gas, not CO_2, and CO_2 is not flammable, such accidents heighten community concern and potential opposition toward any new industrial pipeline project.

The storage of CO_2 requires minimal surface infrastructure that is unlikely to have much adverse impact on local communities. At the injection site, infrastructure is comprised of a concrete or gravel well pad constructed for drilling and maintenance of an injection or monitoring well. During drilling or workovers, there will be significant truck traffic and noise, but these activities typically occur only for a few days or weeks.

Possible catastrophic leakage events have figured into EJ opposition to policy and projects. For example, the EJ community launched a successful campaign in 2006 against a piece of California legislation, Assembly Bill 705, which would have defined statutory and regulatory issues for CCS projects in California. The risks of leakage of a CCS storage site were compared to the catastrophic overturn in 1986 of Lake Nyos in Cameroon, where volcanic CO_2 gas "erupted" from the lake, killing over a thousand people and thousands of livestock. Despite scientific evidence that such catastrophic natural events are not analogous to carbon storage projects, the EJ tactics contributed to the Bill's failure.

6.2 State and Local Statutes and Regulations

In California, there are currently no state policies or regulations designed specifically for CCUS. However, the regulation of various elements of CCUS systems falls under the jurisdiction of about half a dozen state agencies. Legislation has been introduced several times that would require CCUS-specific regulations to be created, but as of 2012 none has become law. Some other states have developed their own rules or regulations. At the federal level, there are some CCUS-specific regulations, such as injection well classification and emissions accounting by the U.S. EPA.

Lack of regulations or statutes designed specifically for CCUS may prevent or delay CCUS permitting and project implementation. Currently, any CCUS projects proposed in California follow

the same permitting process used for industrial development projects that involve surface and subsurface energy facilities. However, certain aspects of CCUS projects do not easily fit into permitting procedures designed for other types of projects.

The current permitting process involves over a dozen federal, state, regional and local agencies, each with its own regulatory authorities and requirements (Table 10). Often, the agencies involved in permitting act independently of one another, and permitting timeframes may not be closely coordinated. The timing of when a permit application is filed, and which permitting agency is the first to act on a permit, is the responsibility of the project developer.

All permits must assess how the project affects the environment. The current regulatory framework in California allows a project developer to approach different agencies at different times to initiate permit applications that rely on the environmental documentation requirements of the California Environmental Quality Act (CEQA). Typically, the first state agency to act on a permit application by a developer becomes the lead agency for CEQA. The lead agency coordinates its review of an Environmental Impact Report or Negative Declaration with the other responsible permitting agencies. The CEQA includes determining the environmental impacts from GHG emissions.

Table 10: California Permitting Agencies and Authorities CCS Projects

Agency	Permit Required	Regulatory Authority
County or City	Conditional Use Permit Building Permits Usually lead agency for CEQA for power plants under 50 MW if built by a regulated utility.	Various Local Ordinances affecting land use
Regional Water Control Boards	Waste Discharge Requirements (in compliance with water quality control plans) NPDES Permits	California State Constitution, Article X, Chapter 2. California Water Code, Sections 13263 and 13260 CA Code of Regulations, Title 23, Division 3, and Title 27 (Solid Waste) Federal Water Pollution Control Act 33 U.S.C. sections 1342 and 1370. Section 1342(b)(1)(D) specifically authorizes states with NPDES authority "to issue permits which . . . control the disposal of pollutants into wells." **Note, however, that the definition of "pollutant" in section 1362(6) excludes "water, gas, or other material which is injected into a well to facilitate production of oil or gas, or water derived in association with oil or gas production and disposed of in a well," *so long as* the "state determines that such injection or disposal will not result in the degradation of ground or surface water resources." Code of Federal Regulations, Title 40, sections 122.21, 122.28, 123.25, 123.28 California Water Code, Sections 13377 and 13376

California Energy Commission	License for thermal power plants sized at 50 MW or greater Compliance with greenhouse gas emission performance standards for base load power plant purchase contracts (municipal utilities only). Current EPS is 500 kg of CO_2 per MWh	Public Resources Code section 25519 and section 21000 et seq. Senate Bill 1368 (Chapter 598, Statutes of 2006) Section 2904 of Chapter 11, GHG Performance Standard, Article 1, sets annual average CO_2 emissions standard.
California Public Utilities Commission	Approval of utility rate recovery for investor-owned utility projects; approves or denies ratepayer funding for CCS activities by utilities. Certificate of Public Convenience and Necessity authorizes a utility to spend ratepayer funds. Compliance with greenhouse gas emission performance standards for base load power plant purchase contracts (investor-owned utilities). Approval of pipelines that offer "transportation services" to the public and qualify as "common carrier utility." Sets safety requirements for certain intrastate natural gas pipelines.	Public Utilities Code Sections 1001-1005 Section 2904 of Chapter 11, GHG Performance Standard, Article 1, sets annual average CO2 emissions standard. Public Utilities Code Sections 211, 212, 216, 227 and 228. CPUC General Order 112-E adopts Federal standards from 49 CFR Sections 191, 192 and 199, including reporting requirements.
California Air Resources Board	Approve plans to reduce GHG emissions by large industrial sources, such as power plants, refineries, and cement plants. Lead regulatory agency for enforcing compliance with California's GHG reduction goals.	Assembly Bill 32, the Global Warming Solutions Act of 2006 (Nunez, Statutes of 2006) sets an economy wide cap on California GHG emissions at 1990 levels by 2020. Governor's Executive Orders establishing long-term GHG reduction goals and the LCFS) Various regulations that govern the LCFS, mandatory reporting requirements, and a California Cap and Trade program
Local air districts	Authority to Construct and Permit to Operate	Various regulations adopted by the district governing boards
State Water Resources Control Board	Approval of water rights	Division 7 of the California Water Code (Section 13000 et sequitur)
Division of Oil, Gas and Geothermal Resources	Permits for the drilling and operation of wells associated with oil and gas production and geothermal drilling. Permits for Enhanced Oil Recovery Delegated authority from U.S. EPA for Class II wells within the UIC program.	California Code of Regulations, Title 14, Division 2, Chapter 4. Public Resources Code Section 3106 CA Code of Regulations 1724.6 through 1724.10 No specific requirements for CO_2 injection. Only for natural gas storage. Federal Safe Drinking Water Act. Section 40: Code of Federal Regulations 144.6

State Fire Marshal	Regulates intrastate hazardous liquid pipelines, and establishes reporting requirements. No specific authority for regulating the safety of CO_2 pipelines.	Elder California Pipeline Safety Act of 1981; California Government Code Section 51010 et sequitur.

To justify capital and societal investments in CCUS technology, there must be certainty in how CCUS should be regulated, how carbon will be valued as a commodity, and how the emissions reductions from geologic storage or utilization will be treated under California's cap-and-trade program. For project investors and developers, the costs and risks of project design elements related to compliance cannot be evaluated if regulatory or statutory issues are unresolved. Regulators who are asked to review CCUS projects without having CCUS-specific rules for reference may delay or deny permit applications if there are unresolved questions about the extent of their authority relative to other agencies over various project elements or if they lack the expertise and personnel to evaluate CCUS project components. For society to choose CCUS as a GHG reduction technology, and for local communities to accept CCUS projects, there must be certainty that the regulatory and statutory processes in place will assure projects are safe and effective.

6.2.1 GHG Emissions Permitting and Regulation

Widespread adoption by industry of any GHG mitigation technology depends on inclusion within ARB's compliance methodologies. Starting in 2013, the state's cap-and-trade program covers industrial sources emitting more than 25,000 MT CO_2e/year and electricity generation, including imports. In 2015, the program will expand to include transportation fuels, industrial combustion at facilities emitting less than 25,000 MT CO_2e per year, and all commercial and residential fuel combustion of natural gas and propane. Sources will be required to surrender compliance instruments equal to their annual emissions at the end of each compliance period, each of which is three years in length (2012–2014, 2015–2017, and 2018–2020).

The cap-and-trade regulation sets a statewide cap on GHG emissions from covered entities (California Air Resources Board 2010). The total number of allowances created equals the cap set for cumulative emissions from all covered sectors for that year. ARB distributes allowances to capped entities, either through direct allocation or through auction. In addition to allowances, a limited amount of emission reductions (offsets) from sources that are outside the cap are authorized. Both allowances and offsets can be traded among entities. Each covered entity is required to submit to ARB one allowance for each tonne of its CO_2 equivalent (MT CO_2e) emissions.

Until 2015, most affected industries will receive the majority of their allocations from the state for free, but will have to purchase additional allowances or use offset credits to cover all their emissions. There is no cap on individual facilities; the cap is for total emissions statewide for all of a company's facilities. Over time the total cap decreases, making allowances scarcer and providing an incentive to find cost-effective ways to cut emissions. Economic analysis estimates an allowance price of around $21 in 2020; to date, prices at auctions have been around $10 to $13.

Regulations of GHG emissions also affect the process for facilities permitting. The Energy Commission, counties, and other "lead agencies" under CEQA consider whether CO_2 emissions

from a project constitute a significant impact that affects the granting of the facilities permit. Regional air quality districts can also apply their own GHG standards to emissions. Specifically, the CPUC (in the case of investor-owned utilities) and the Energy Commission (in the case of public power) implement the Emissions Performance Standard (EPS), which was instituted under Senate Bill 1368. CCUS is recognized under SB1368 as a compliance mechanism for the EPS and the CPUC modified its rules for implementing the EPS in July 2009 to further clarify the content of the plan a load-serving entity must file as part of an application for using CCUS to comply with the EPS. However, no precedents are as yet available for regulators to use as guidance for permitting a power plant equipped with CCUS technology; therefore delays are to be expected for early mover CCUS projects negotiating the permitting process.

6.2.2 Capture Facility Permitting

Prior to 1975, utilities were required to go through a multi-agency process to obtain permits from numerous federal, state, and local agencies before constructing new power plants. The Legislature established the Energy Commission in 1975 and mandated a comprehensive, single-agency state permitting process for new power plants. The Legislature gave the Energy Commission the statutory authority to license thermal power plants of 50 MW or greater along with the transmission lines, fuel supply lines, and related facilities to serve them. The Commission also serves as the lead agency under the CEQA. The Energy Commission's 12-month, one-stop state permitting process is a certified regulatory program under the CEQA. The Energy Commission's license and certification process subsumes the requirements of state, local, or regional agencies otherwise required before a new plant is constructed, while federal permits are issued within the timeframe of the Energy Commission's licensing process. However, there have been cases where federal and state permitting timelines have not been closely matched. The Energy Commission coordinates its review of the facility with other permitting agencies to ensure consistency between their requirements and its own conditions of certification.

Until the HECA permit, CCS had not been a factor in the Energy Commission's siting process. In the case of a new power plant project that involves carbon capture, the CEC considers the entire facility and incorporates permit conditions to ensure the CO_2 injection process is conducted in an environmentally safe manner. Retrofits of existing power plants with CO_2 capture technology would require modifications to existing permits and possibly new permits.

The need for new or modified permits, plans, and reports at an existing NGCC facility will be affected by both the design of the existing facility as well as the detailed design of the retrofit CO_2 capture technology. The major environmental permits and plans that would require modification by the retrofit of CO_2 capture technologies at a NGCC facility include the air permits (Authority to Construct and Permit to Operate), Approval of Water Rights, and National Pollutant Discharge Elimination System wastewater discharge permit (See Table 10.).

Retrofitting new CO_2 capture equipment at an existing NGCC facility also will likely require re-evaluating potential community impacts of the power plant in its retrofit configuration, including compliance with local or state noise codes, traffic impacts, and assessing visual impacts due to installation of new equipment and changes in stack plume visibility during certain meteorological conditions. (Stacks operate at temperatures closer to the water dew point with CO_2 capture technology.) Local traffic impacts will occur during construction and may continue if the CO_2

capture technology requires ongoing supplies of large quantities of chemicals. The existing NGCC facility may also need to modify or amend certain plans (e.g., Emergency Response Plans, Spill Prevention Control and Countermeasures Plans, Occupation Safety and Health Programs) due to the presence of new chemicals on-site associated with the CO_2 capture technology process.

Modifying these existing permits and plans for existing NGCC facilities retrofit with CO_2 capture and compression technologies follows the same processes for permitting new power plants. As these are well-established processes, they should not present obstacles to the development of a CCUS project.

6.2.3 Storage and Pore Space Rights

Geologic CCUS projects are contingent upon the project operators obtaining the right to inject and store CO_2 within subsurface pore space. California courts have not addressed the issue of whether pore space is part of the surface or mineral estate, however, common law from other states indicates that pore space typically belongs to the surface owner.

Under this scenario, implementation of a carbon storage project that underlies the properties of multiple owners could be stopped by a single owner's refusal to participate. This issue creates potential barriers for CCUS projects in California. To better enable deployment of CCUS, the State should consider addressing two issues related to pore space rights: 1) clarification of pore space ownership and 2) creation of mechanisms to acquire pore space rights.

Gaps currently exist in how California regulations will apply to geologic CCS projects, and especially CCS project that do not involve EOR. The U.S. EPA is the lead agency for the UIC program and the lead agency for environmental documentation required under the NEPA. DOGGR has the authority delegated by EPA for Class II wells, including CO_2 injection wells for EOR. The U.S. EPA Region 9 issues permits for all other UIC classes in California, including Class VI for geologic sequestration projects.

California can submit a request that the U.S. EPA grant "primacy" to a designated state regulatory agency for the permitting of Class VI wells. Under current authority, DOGGR has primacy for regulating Class II wells (oil and gas production). As of 2012, no state has made a request to U.S. EPA for primacy for Class VI wells. DOGGR, because of its long-standing involvement in regulating oil and gas resources, may be in the best position to regulate the injection of CO_2 into subsurface formations. Several attempts to assign state agency authority to regulate CO_2 storage projects have failed (e.g., Assembly Bill 705, Huffman, 2006; Senate Bill 34, Rubio, 2012).

In 2010, the Department of Conservation, the department which oversees DOGGR, concluded that it had sufficient authority to regulate CO_2-EOR projects, but not the authority or staff to regulate CCS projects without EOR. For example, CCS projects involving saline formations or even depleted oil or gas fields no longer in production, are not currently within the purview of DOGGR; only those projects wherein there is active recovery of oil or gas (Class II wells) would be permitted by DOGGR and regulation of the aspects of CO_2 storage in such projects would still fall outside current DOGGR regulations.

Numerous state regulations from ARB, the Energy Commission, CPUC, and DOGGR could be modified or applied to establish MVR requirements for CCUS projects. None of the current

regulations specifies MVR requirements for CCUS projects, although DOGGR does have requirements for MVR as it relates to protecting underground sources of drinking water during oil and gas recovery operations. Since the current requirements only measure volumes and not specific content, these requirements would need to be revised for a CCUS project. MVR requirements could be coordinated between the agencies as necessary to meet their respective statutory mandates. Methodologies for MVR have been developed by different organizations for different purposes. U.S. EPA, the European Union, the Intergovernmental Panel on Climate Change, non-profits, industry organizations, and others are developing or have developed MVR plans for GHG accounting programs, injection safety programs, or for other purposes.

California could use these models as a starting point for its own regulatory efforts. Revisions may be necessary to ensure the MVR requirements are in line with California regulations, policy, and geologic conditions. Any revisions would likely need to include a public review process. In the case of MVR in accounting methodologies, ARB has harmonized its mandatory reporting of GHGs with EPA reporting methodologies and incorporated third-party offset protocols after a public review and revision process. For MVR for CO_2 injection, the state agency applying for primacy over Class VI wells (assuming California seeks primacy) must have authority equal to or more stringent than the EPA regulations. The MVR requirements of the different state agencies could be coordinated to ensure consistency and reduce administrative burden, as long as all the program goals and requirements are met.

6.2.4 Crediting and Regulating Storage at CO_2-EOR Sites.

CO_2 is not used in EOR operations in California today because there are no CO2 sources obtainable at reasonable cost. As noted previously, there are significant numbers of oilfields that could apply CO_2-EOR in the state. The opportunity to use captured anthropogenic CO_2 is heightening interest in CO_2-EOR among the state's oil producers. Policies encouraging and regulating CCS must address how to treat EOR and its existing industry, infrastructure, and regulations.

In particular, policymakers must determine whether and how active CO_2-EOR sites should be credited with storage. There are many ways that California could address this question, but these fall into two main categories: the first requires CO_2-EOR to meet all of the same regulatory standards as sequestration in saline formations (i.e. Class VI requirements), including site permit requirements, human health and safety protections, and monitoring, verification, and reporting plans; and the second customizes these kinds of standards to allow CO_2-EOR to receive sequestration credit while remaining within the regulatory framework already established for EOR operations.

In addition to the broad question of how to treat CO_2-EOR in the context of CCS, specific programs in California in which this question might arise include:

- The cap-and-trade program
- The GHG Emissions Performance Standards for long-term power purchases established by Senate Bill 1368;
- The Low Carbon Fuel Standard established by Executive Order S-01-07; and

The long-term success of CCS as a climate protection strategy depends on limiting sequestration credit to situations where there is assurance that injected CO_2 will be permanently contained. However, the success of CCS also depends on establishing the viability of the technology and deploying it commercially in time and at a scale to help meet California's GHG emissions reductions goals. Therefore, the question of how to treat EOR under CCS regulations requires balancing the need to engage and utilize the existing infrastructure of EOR without compromising the integrity of GHG emissions reductions long-term. Some of the key questions to consider are:

- What kind of permitting requirements should there be for active CO_2-EOR facilities that seek credit for CO_2 sequestration while oil production in ongoing?
- Should permitting requirements for CO_2-EOR facilities seeking sequestration credit be the same as other EOR facilities, the same as sequestration in saline formations, or something in between?
- What kind of transition mechanisms may be necessary or useful for a development to change from a regulated CO_2-EOR project to a regulated CO_2 storage project?
- What kind of MVR requirements should there be for CO_2-EOR facilities that seek credit for CO2 sequestration?
- Sould injected CO_2 count as avoided emissions or emissions offsets under the cap-and-trade program?
- Would sequestration credits from CO_2-EOR be sufficient to allow a power plant to pass the GHG-intensity screen imposed by SB 1368?
- Can CO_2-EOR assist with compliance of produced oil or gas with the Low Carbon Fuel Standard?

As noted above, DOGGR has authority to permit a CO_2-EOR project, but it does not have any specific authority related to sequestration or assuring permanence of sequestration. That means it is unclear what role a DOGGR Class II permit will play in helping a CO_2-EOR project get sequestration credit under any of California's GHG emissions reduction programs.

In order for CO_2-EOR to receive credit for sequestration for any of the above-described programs, appropriate standards must be developed that will measure the quantity of CO_2 sequestered and demonstrate that sequestration is permanent. The analysis presented here focuses on regulatory frameworks for crediting CO_2-EOR with sequestration. Because sequestration naturally occurs as part of the EOR process, a Class II permit issued by DOGGR for a CO_2-EOR project might be able to include monitoring requirements that would aid in demonstrating sequestration. Under the California Environmental Quality Act (CEQA), DOGGR can impose such additional mitigation measures to assure safe operation.

The advantages and disadvantages of two potential regulatory frameworks are discussed below. The first approach would only credit CO_2-EOR with sequestration only when it meets the same standards as sequestration projects in saline formations. The second approach would establish customized standards for CO_2-EOR that would better accommodate on-going oil production, but still provide sufficient verification of sequestration.

We do not consider two more extreme approaches – 1) where CO_2-EOR would receive sequestration credit without providing any verification beyond the business-as-usual requirements for EOR, or 2) where CO_2-EOR would never be eligible for sequestration credit. The first would arguably undermine California's climate policies by allowing sequestration credit without verification. The latter would arbitrarily exclude a potentially important CCS technology.

It is possible then, for example, that a DOGGR Class II permit could include sufficient monitoring requirements to demonstrate permanent sequestration for purposes of the SB 1368 Emissions Performance Standard. But CARB could have different requirements for crediting under AB 32 cap-and-trade program. Multiple California regulatory agencies potentially could be involved in determining standards for giving sequestration credit (or not) to CO_2-EOR sites for purposes of compliance with any or all these programs. The Energy Commission has authority to enforce the EPS for municipal utilities and has established regulations for screening long-term facilities for compliance with the EPS. The regulations do not define permanence for sequestration nor do they address whether CO_2 derived from a power plant and sequestered at an EOR site would meet the criteria for successful sequestration.

The CPUC has jurisdiction under SB 1368 to enforce the EPS on investor-owned utilities. CCUS potentially could be used to help fuel providers comply with the LCFS standard either as a method to directly to reduce the carbon intensity of certain fuels or generate tradable compliance credits. ARB's LCFS regulations only directly address CCUS in a limited way. They allow for consideration of use of CCS technology in determining the carbon intensity value of crude oil and the associated compliance obligations of the fuel provider. A DOGGR permit for a CO_2-EOR project related to a power plant subject to the EPS may or may not include sufficient standards to meet the Energy Commission or CPUC's screen for determining compliance.

Rules designed to accommodate oil production would harness the infrastructure and know-how of the established industry EOR industry. Encouraging CO_2-EOR as storage with customized rules might expedite CCS as an option for California to achieve its 2050 GHG emissions reductions goals. Some of the issues and benefits are:

- **Recognizing the EOR knowledge base**: EOR site operators have extensive knowledge about their reservoirs, which means less risk and uncertainty in subsurface characterization;
- **Encouraging CO_2-EOR in California**: There is no CO_2 being used for EOR in California today. At the right price, CO_2 from anthropogenic sources would provide a source that would facilitate production of significant amounts of unrecovered oil. The state would benefit from the increase in tax and royalty revenues and from the economic and employment boosts in local communities.
- **Regulatory inconsistency:** Regulations for storage at CO_2-EOR sites might mean establishing different requirements than for storage in non-producing oil and gas reservoirs or in saline formations. There is a risk, particularly if these requirements are administered by different agencies, that one set of requirements would be less stringent than another.
- **Time-scales of compliance verification vs CO_2 residence times and cycling:** GHG emissions reduction compliance occurs typically on an annual basis. If CO2 is injected solely

for storage, accounting is a relatively straightforward issue of calculating the net stored from the difference between injection volumes and any measured leakage. However, in CO_2-EOR operations, the accounting on an annual basis is complicated by the fact that injected CO_2 may be cycled through the reservoir and surface facilities multiple times over several years or more—ARB or other agencies will need to define at what point in time or in the system such cycled CO_2 can be counted as permanently stored.

- **Stakeholder discord:** Even if stakeholders agree that there should be a way for CO_2-EOR to receive storage credit while remaining within the EOR regulatory framework (i.e., Class II), there is no consensus on what MVR or other standards would be appropriate or acceptable for UIC agencies and agencies implementing GHG reduction verification.
- **Mutiple source-storage site networks: A**ccounting and verification methodologies must address complex situations wherein multiple CO2-EOR sites receive CO_2 from multiple sources through pipeline networks. These networks should be encouraged because they provide economies of scale and optimize infrastructure. Sources must have confidence that participation in such networks does not compromise their ability to meet annual compliance obligations; similarly CO_2-EOR operators must have assurance that compliance accounting and verification methods do not interfere with oil production operations.

6.3 Pore Space Rights

A finding in California that pore space for CO_2 storage belongs to surface owners would be consistent with legislation in other states (Montana, North Dakota, and Wyoming) and existing treatment of pore space in California in the context of oil and gas production and natural gas storage. Alternatively, the legislature could declare pore space to be a public resource or choose to recognize private interests in pore space only when the property owner has a reasonable and foreseeable use of it.

A second issue—mechanisms to acquire pore space rights—could be addressed by establishing authority for CCUS projects to obtain these rights either by eminent domain or by unitization. Eminent domain is commonly used to acquire property rights for projects that have a public purpose. Unitization is a long-established mechanism used in the context of oil and gas production, whereby hold-out property owners share in the revenues from production but cannot stop production from occurring. Louisiana has established a process by which to use eminent domain for carbon sequestration, and Montana, North Dakota, and Wyoming have authorized the use of unitization.

6.4 Long-term Stewardship and Liability

Long-term stewardship of CCUS sites is required to protect the public and to properly assess the efficacy of the permanent removal of CO_2 from the atmosphere. Another major barrier for industry to undertake CCUS projects is the undefined and open-ended liability for the site.

Although operational risks associated with the transport and injection of CO_2 in the subsurface during EOR operations have been successfully managed for many years, the long-term liability for CCUS sites – post-closure – may be unique to CCUS. It is important to note that the entity accepting the liability will likely (without the development of institutional initiatives) be responsible for

expenses of continuing MVR activities, any mitigation or remediation required, and compensation for any damages if leakage occurs. It is generally recognized that, from a legal perspective, there are three issues involved. First, there is regulatory liability from post-closure activities that broadly covers monitoring, verification, and accounting as well as any remediation. Second, the tort liability obligates compensatory damages as a result of harm or injury. Third, there may be liability for any CO_2 leakage requiring deficit or retirement from emission reduction programs.

There are several existing approaches for addressing long-term liability and stewardship that have been used by the federal government to reduce the financial risk of other types of development projects. In addition, other states have enacted legislation specific to stewardship and liability in CCUS development. Some of the options include:

- Private and self-insurance to guard against the financial risk of an accident or release, to be paid by the project developers. Self-insurance is standard in the oil and gas industry and its terms are well understood.
- A federal insurance program, such as the Price Anderson Act indemnity program for nuclear power plants or the National Flood Insurance Program, which are financed by taxpayers.
- A state administered insurance program, which assesses fees on well operators or developers, similar to the well cleanup or abandonment fund for California's orphan wells.
- Other bonding or insurance mechanisms funded by industry.
- Assumption of all liability by the state (or federal government).
- Identify a lead state agency charged to administer and oversee long-term MVR and to certify post-injection site closure.
- The lead state agency for administering long-term MVR and for certifying well closure would also be responsible for initial permitting of the CCUS project.
- Create a fee-based geological sequestration Trust Fund administered by the state (or contractor thereof), the provisions for which would be solely for long-term MVR – and remediation if necessary. An independent, scientific framework for designing and conducting post-closure MVR would need to be established.

6.5 Federal Statutes and Regulations

At the federal level, CCS and CO_2-EOR are affected by efforts to establish regulations for wells used for geologic sequestration of CO_2 under the long-established UIC program under the SDWA and emerging regulations designed to control GHG emissions under the Clean Air Act.

On August 12, 2010, the White House's Interagency Task Force on CCUS (Task Force) delivered its report to the President of the United States (White House Interagency Task Force on CCUS 2010). Co-chaired by EPA and DOE, the Task Force was charged with proposing a plan to overcome the barriers to widespread, cost-effective deployment of CCUS within ten years, with a goal of bringing five to ten commercial demonstration plants online by 2016. The report reflects input from fourteen federal agencies and departments, as well as hundreds of stakeholders and CCUS experts.

The principal conclusions of the Task Force report remain important and focus on the federal role for establishing a coordinated national regulatory framework. The conclusions are summarized as follows:

- Establish a federal agency roundtable and technical committee to facilitate early projects to ensure the success of early projects, including five to ten commercial CCS demonstrations by 2016. DOE should determine if early projects will sufficiently demonstrate an adequate breadth of capture technologies and classes of storage reservoirs to enable widespread cost-effective CCS deployment. This assessment will allow the Administration to target any remaining technology gaps in a manner consistent with addressing market failures.

- Create a federal agency roundtable to act as a single point of contact for project developers seeking assistance to overcome financial, technical, regulatory, and social barriers facing planned or existing projects.

- Create a technical committee composed of experts from the power and industrial sectors, NGOs, state officials, and academia. This group could provide input on a range of CCS technical, economic, and policy issues.

- Increase coordination in applying drivers and incentives to enhance the Government's ability to assist early projects that will:

    - Enhance the government's ability to tailor federal funding and assistance to each project's market context;

    - Improve the clarity and transparency of eligibility criteria for projects to receive federal support; and enable the Administration to allocate resources efficiently and more effectively consult with Congress and the States on the efficacy of existing incentives.

- Ensure that relevant agencies work quickly and collaboratively to propose, finalize, and implement the *regulatory framework* to ensure safe and effective CCS deployment by:

    - Finalize rulemakings for geologic sequestration wells under SDWA and GHG reporting for CO_2 storage facilities under CAA;

    - Propose RCRA applicability rule for CO_2 that is captured from an emission source for purposes of sequestration;

    - Develop guidance to support implementation of these rules;

    - Formalize coordination and prepare a strategy to develop regulatory frameworks for onshore and offshore federal lands.

- Federal agencies should work together to enhance *regulatory and technical capacity* for safe and effective CCS deployment.

    - Enhance and Coordinate Public Outreach to Raise Awareness of CCS.

    - Coordinate among Federal agencies, States, industry, and NGOs to gather information and evaluate potential key concerns around CCS in different areas of the United States.
    - Develop a comprehensive outreach strategy between the Federal government, industry, and NGOs: a broad strategy for public outreach, targeted at the general public and decision makers, and a more focused engagement with communities that are candidates for CCS projects.
    - Immediately establish a clearinghouse for public access to unbiased, high-quality information on CCS.
    - Develop outreach tools for project developers and regulators.
- Congress should enact comprehensive energy and climate legislation, and the Administration should apply the key principles in the report and lessons learned from early projects to evaluate whether further drivers and incentives are needed to enable widescale deployment of advanced CCS technologies as a potential climate change mitigation option.
- Enhance regulatory and long-term liability and stewardship framework. Congress should consider whether changes to statutory authorities to facilitate regulatory development and implementation are necessary, such as (1) assessing revisions to SDWA could provide enforcement and compliance assurance and financial assurance authorities necessary to support wider CCS deployment, (2) seeking ratification of the London Protocol and associated amendment of the Marine Protection, Research, and Sanctuaries Act as well as amendment of the Outer Continental Shelf Lands Act will ensure a comprehensive statutory framework for the storage of CO_2 on the outer continental shelf.
- Further evaluate and provide further recommendations to address long-term liability and stewardship in the context of existing and planned regulatory frameworks. Of the seven options identified by the Task Force, the following four approaches should be considered:
    - Reliance on the existing framework for long-term liability and stewardship.
    - Adoption of substantive or procedural limitations on claims.
    - Creation of a fund to support long-term stewardship activities and compensate parties for various types and forms of losses or damages that occur after site closure.
    - Transfer of liability to the Federal government after site closure (with certain contingencies).
- Promote international collaborative efforts on CCS to assist in global penetration of CCS technologies, leverage U.S. funding, and increase access to international expertise and experiences. In addition, international cooperation on CCS could potentially open markets to U.S. companies, while demonstrating U.S. leadership.

Congressional legislation has been introduced but not yet passed to establish a carbon storage stewardship trust fund financed by fees from operators to ensure compensation for potential damages. At least one private insurer is making short term insurance policies available. Long-term

liability schemes have been adopted for other industries, including bond provisions by the UIC program, trust accounts funded through fees to operators that are administered by state or industry organizations such as the Acute Orphan Well Account, the Price-Anderson indemnity program that pools risk for the nuclear industry, or the National Flood Insurance Program that is federally funded.

Until Congress adopts a national cap-and-trade program or similar legislation, the only federal authority to regulate GHG emissions comes from the Clean Air Act (CAA). Sources of GHG emissions are subject to CAA regulation pursuant to the decision of the United States Supreme Court in *Massachusetts v. EPA*, 549 U.S. 497 (2007), which held that GHGs met the CAA's definition of "air pollutant." On December 15, 2009, EPA issued an " Endangerment Finding," which concluded that six GHGs—CO_2, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride—may reasonably be anticipated to endanger public health and welfare. On the same day, EPA issued what is known as its "Cause or Contribute Finding," in which it defined the applicant "air pollutant" as the same six GHGs, in aggregate.

On April 2, 2010, EPA published a notice that is known as the "Johnson Memo Reconsideration." In that notice, EPA interpreted the CAA term "subject to regulation," which is one of the regulatory triggers for permitting under the CAA's Prevention of Significant Deterioration (PSD) program. The Johnson Memo Reconsideration concluded that EPA's imposition of GHG tailpipe emission standards for certain mobile sources (which were subsequently published on May 7, 2010), would trigger PSD applicability for GHG-emitting stationary sources on or after January 2, 2011, which is the date when the GHG tailpipe emissions standards took effect.

EPA has established thresholds for requiring New Source Review PSD Permits and Title V Operating Permits for new and existing industrial facilities. Very large GHG emissions sources will begin needing GHG emission permits in 2010. Sources emitting 50,000 tonnes per year or less will not require permits until at least 2016. Thus, even a very modest leakage rate at an EOR or geologic sequestration site could eventually trigger Clean Air Act regulations. For example, an annual leakage rate of 0.1 percent per year at a site injecting 10 Mt of CO_2 per year would have 10,000 tonnes per year of CO_2 emissions.

EPA regulations address CCUS as both a source and emissions reduction technology. From the source perspective, on October 30, 2009, EPA published its final rule requiring the mandatory reporting of GHGs including "Suppliers of CO_2," which encompasses, in part: (i) facilities with production process units that capture and supply CO_2 for commercial applications or that capture and maintain custody of a CO_2 stream in order to sequester or otherwise inject it underground; and (ii) facilities with CO_2 production wells that extract a CO_2 stream for the purpose of supplying CO_2 for commercial applications. On December 1, 2010, EPA finalized a rule that included CCUS explicitly in the mandatory reporting of emissions under the GHG Reporting Program. All CO_2 injection facilities would be required to report: the amount of CO_2 received onsite from offsite sources, the amount of CO_2 injected into the subsurface, and the source of the CO_2 (if known).

Facilities injecting CO_2 for the purpose of long-term sequestration would have enhanced reporting requirements, including 1) reporting the amount of CO_2 geologically sequestered using a mass

balance approach, and 2) developing and implementing an EPA approved site-specific MVR plan. EOR facilities would have the option to adopt enhanced reporting and MVR plan requirements.

From the emissions reduction perspective, in November 2010, EPA issued non-binding best available control technology (BACT) guidance for stationary sources of GHG emissions that trigger the PSD effective January 2, 2011, and this guidance points out that CCUS is a promising technology in the early stage of demonstration and commercialization. However, the guidance identifies CCUS as an expensive technology unlikely to be selected as a BACT, in most cases. Thus, the EPA does not include any capture technologies as BACT for stationary source emissions.

With regard to transportation, there is no federal regulatory framework for siting CO_2 pipelines on private land, however, CO_2 pipelines on federal land can be sited under both the Federal Land Policy and Management Act and the Mineral Leasing Act. Thus, state or local regulations must address pipeline construction permitting.

With respect to pipeline safety, the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA) has primary authority to regulate interstate CO_2 pipelines under the Hazardous Liquid Pipeline Act of 1979. The Federal Pipeline Safety Reauthorization Act of 1988 included a provision for the regulation of CO_2 pipelines. The PHMSA regulations address design, construction, operation and maintenance, corrosion control, and reporting requirements. The PHMSA defines supercritical CO_2 as a fluid consisting of more than 90 percent CO_2 molecules compressed to a supercritical state. Although PHMSA does not define CO_2 as a hazardous liquid, it is subject to the same regulatory framework as hazardous liquids. These regulations address design, construction, operation and maintenance, corrosion control, and reporting requirements. CO_2 pipelines used to distribute CO_2 within an oil field for EOR are excluded from the Department of Transportation's regulation. These pipelines thus fall under state regulation.

Carbon dioxide pipelines have been operating in the U.S. for almost 40 years, and there are approximately 6400 km of CO_2 pipelines in operation today, most all of it serving EOR operations in oilfields. The CO_2 pipeline safety record, with respect to both the frequency and consequence of failure, is better than that of traditional gas transmission and hazardous liquids pipelines. Carbon dioxide transported by pipeline differs from other pipeline systems such as natural gas in that the CO_2 product is conveyed at very high pressures (approximately 2000 psi compared to natural gas transported at pressures of up to 1500 psi). Pipelines transport CO_2 as a supercritical liquid that allows high volume transport with minimal pipe diameter. Apart from the risks associated with high pressure, because CO2 is not flammable or toxic, the risk profile for CO_2 pipelines is lower than for natural gas transmission and hazardous liquids pipelines. However, there are a variety of design, operational, and human safety considerations related to CO_2-specific issues, such as corrosion or asphyxiation at high concentrations.

Under the authority of the Safe Drinking Water Act's (42 U.S.C. §§ 300f to 300j-26),(SDWA) Underground Injection Control (UIC) Program, US EPA has set permitting requirements for geologic sequestration, including the development of a new class of wells, Class VI. These requirements, known as the Class VI rule, are designed to protect underground sources of drinking water, building on existing UIC Program requirements but adding extensive tailored requirements

that address CO_2 injection for long-term storage. The requirements are meant to ensure that wells used for geologic sequestration are appropriately sited, constructed, tested, monitored, funded, and closed.

For purposes of the geologic sequestration regulations under the SDWA, the US EPA defines a "CO_2 stream" as "CO_2 that has been captured from an emission source (e.g., a power plant), plus incidental associated substances derived from source materials and the capture process, and any substances added to the stream to enable or improve the injection process. (Federal Register 2008)." According to the US EPA, CO_2 is not a hazardous substance under the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA or Superfund) (42 U.S.C. §§ 9601 to 9675). Thus, CCUS operations liabilities should not give rise to CERCLA liability due to CO_2, but CERCLA liability could arise in specific cases where the CO_2 stream contains constituents that are CERCLA hazardous substances or if the CO_2 stream reacted with groundwater to produce a CERCLA hazardous substance.

The Class VI rule affords owners or operators injection depth flexibility to address injection in various geologic settings in the United States in which geologic sequestration may occur, including very deep formations and oil and gas fields that are transitioned for use as storage sites. Currently, oil and gas wells, including those used for injection as part of CO_2-EOR operations, fall under UIC Class II. The elements of the EPA Class VI final rule include, but are not limited to:

- Specific criteria for completion of Class VI wells, including using materials that are compatible with and can withstand contact with CO_2 over the life of the geologic sequestration project
- Extensive site characterization requirements
- Comprehensive monitoring of all aspects of well integrity, CO_2 injection and storage, and groundwater quality during the injection operation and the post-injection site care period
- Financial responsibility requirements to assure the availability of funds for the life (including post-injection site care and emergency response) of the geologic sequestration project.
- Periodic re-evaluation of the area around the injection well to incorporate monitoring and operational data and verify the movement of CO_2 according to prediction
- Extended post-injection monitoring and site care to track the location of the injected CO_2 until it is demonstrated that underground sources of drinking water are no longer endangered
- Considerations for permitting wells that are transitioning from Class II (EOR) to Class VI that clarifies the primary purpose of the well.

Class VI rules apply to any well in which CO_2 is injected for the purpose of storage, including wells in saline formations or in oil or natural gas fields. Class II rules continue to apply for permitting of CO_2 injection for EOR purposes as long as the injection is for the purpose of fossil fuel production. However, it is unclear what completion or plugging and abandonment criteria would apply to Class II wells within a depleted oilfield used for storage if the wells are not used for CO_2 injection in a storage operation. The applicability of Class II or VI also is ambiguous in cases where hydrocarbons

continue to be produced by CO_2-EOR and the operator synchronously seeks storage credit for the injected CO_2 under cap-and-trade or another GHG accounting system. MVR requirements for Class II, unlike Class VI, are not designed to track or verify CO_2. How much hydrocarbon production is required to allow a Class II designation also is not specified.

Subpart RR of the GHG reporting rules requires facilities that inject CO_2 for the purpose of geologic sequestration or EOR to report basic information such as the quantity of CO_2 injected. Facilities that are claiming geologic sequestration will be subject to additional reporting and monitoring requirements including a mass balance estimation of CO_2 sequestered and an EPA- approved MVR plan. The EPA-approved MVR plan must be performance based, reflecting the site-specific geology and conditions and must include the following:

- An assessment of risk of CO_2 leakage to the surface
- A strategy for detecting and quantifying any CO_2 leakage to the surface
- A strategy for establishing pre-injection environmental baselines
- A summary of how the facility will calculate site-specific variables for the mass balance equation, calculating the amount of CO_2 sequestered

The overall performance standard for the monitoring plan is to detect and quantify CO2 leakage from the subsurface to the surface. Each part listed above helps achieve the overall standard. Leakage assessment must include "a combination of site characterization and realistic models that predict the movement of CO_2 over time and locations where emissions might occur." It must account for the appropriate spatial area, all potential leakage pathways, and include active and abandoned wells. A model overview including sensitivity and uncertainty analysis must be provided. The second part, a strategy for detecting and quantifying CO_2 leakage to the surface, must include the methodology, rationale, and frequency of monitoring. Incorporation of unexpected leakage pathways, detection limits, monitoring locations, spatial array, and frequency of monitoring are all components. The plan must outline what measurements will occur if a leak is detected and should be conservative. For example, the facility must assume the duration of the leak to be equal to the time since the last monitoring event. The third part will set a baseline that will enable quantification of leakage and eliminate false positives. The final part will ensure that all above-ground emissions are not counted as stored. Overall, these four requirements ensure that all emissions will be detected and quantified.

The UIC rules for Class VI wells include prescriptive and performance-based standards which are more stringent than Class II requirements. For example, the owner or operator must demonstrate internal and external mechanical integrity of the well. The internal integrity tests require use of continuous "monitoring of injection pressure, flow rate, and injected volumes as well as the annular pressure and fluid volume." The external mechanical integrity test can be done in a variety of ways, but must be approved in the permitting process. Plume and pressure front monitoring requirements are performance based with the operator required to show a monitoring plan to ensure that the injectate is safely confined in the intended subsurface geologic formations and that underground sources of drinking water are not endangered. In addition, there are some requirements that pertain to all wells and some that are site-specific. The monitoring requirements cover the types of analysis

that must be included (i.e., groundwater quality and geochemical changes above the confining zone), but do not specify the exact testing or location of monitoring. These should be "based on the identification and assessment of potential CO_2 leakage routes complemented by computational modeling of the site."

6.6 Business Case Elements

CCUS comprises a system of sophisticated engineering, transport, and subsurface projects that together form a complex and expensive management venture. CCUS adds significant capital and operational costs to any extant project, which will need to be passed on to the customer base, although these costs usually are less than other GHG mitigating measures in the long run, especially if the metric used is "CO_2 costs avoided" (Global CCS Institute, 2012). Such projects require a reliable market and incentives to justify such investment, especially for "early mover" projects. In general, the incentives may include some or all of capital grants, research on cost reduction measures, carbon price minima, tax credits, utilization revenue, and policies that provide a stable regulatory environment. CO_2 for EOR activities is a clear commercial driver for CCS projects in the U.S. and, increasingly, elsewhere in the world.

Although there are beneficial uses for CO_2 apart from EOR activities, the fact remains that CO_2 is otherwise a waste to be sequestered away from the atmosphere where is plays a climatically detrimental role. In the case of CO_2 as waste, it is not inappropriate to consider the societal and environmental cost of this waste much as happens in the solid waste arena. Solid waste treatment survives only because it charges a fee (either pay-as-you-throw, property taxes, or utility fees) to all customers, and even then capital costs are subsidized by local districts. This could be a tax on carbon paid directly and proportionately by the users. Carbon taxes have been implemented in Norway, Australia ($23/tonne), Denmark ($18/tonne), Finland ($24/tonne), and British Columbia ($25/tonne). In the Republic of Ireland the carbon tax has been a critical component of the national economic recovery over the past three years while also serving as a mechanism to lessen the nation's carbon footprint, both of which have proved politically expedient (Rosenthal, 2012).

The commercial success of a CCUS project will depend on a combination of technical, financial, operational, and commercial factors that can be characterized as follows:

- Commercial factors
- Project cost
- Grant eligibility
- Financing strategy
- Resourcing plan
- Project and contractual structure
- Public engagement
- Storage liability issues
- Project permitting

- Environmental approvals
- Regulatory approvals
- Risk management plan
- Financial factors
- Delivering an adequate net present value/internal rate of return
- Sizing and timing of debt and equity contributions
- Financial covenants
- Project accounts
- Project reserves
- Financial structuring
- Technical factors
- Capture process
- Capture integration
- Capture rate
- Pipeline technical specification
- Storage characterization
- Operational factors
- Capture performance (e.g., capture rate, operating cost, energy penalty (if relevant))
- Transport performance (leakages, operating cost)
- Storage performance (MMV)
- Outages and chain risk
- Closure arrangements

A CCUS project business plan will need to address each of these factors as economic risk as well as direct budget costs. As indicated elsewhere in this report, the HECA project in Kern County has submitted such a business plan to the Energy Commission for their approval. If successful, this project will accomplish much to demonstrate the economic vitality of its business plan and where improvements, if any, might be implemented.

CHAPTER 7:
CCUS Projects in California

The following case studies have been chosen to illustrate the development of CCUS in California; however, the examples are not intended to be exhaustive. A comprehensive listing of all planned and active CCS projects around the world is maintained by the Global CCS Institute. The case studies presented here include California projects. Significant projects in North America and globally are included in Appendices A and B.

7.1 HECA (Hydrogen Energy California)

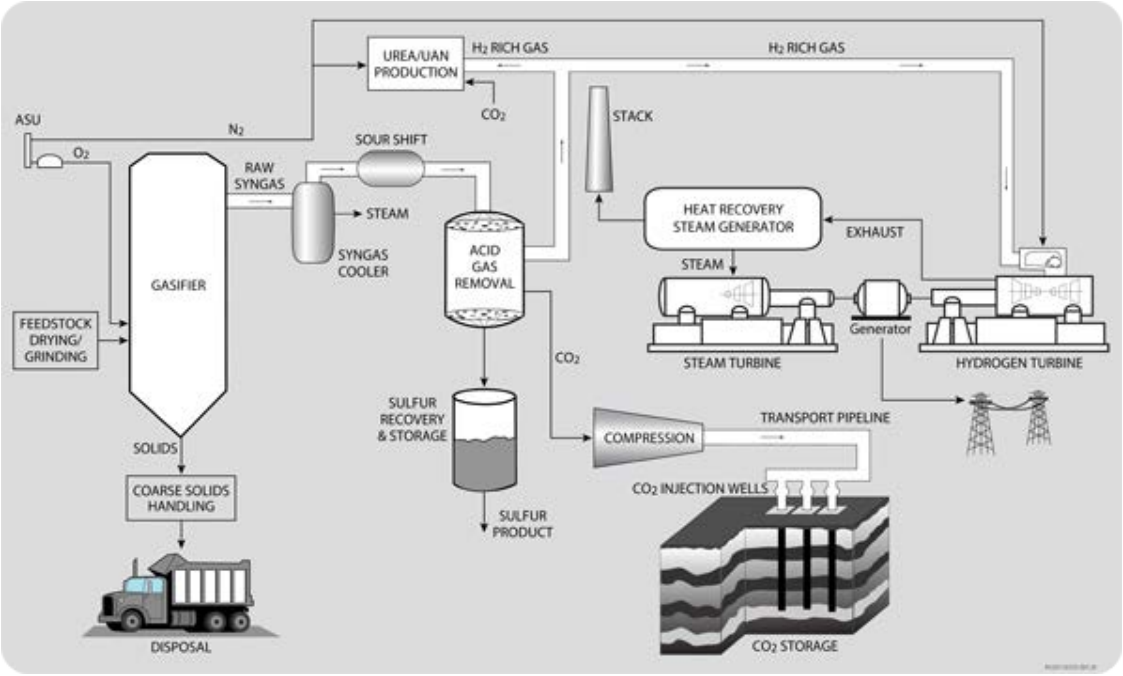
Hydrogen Energy California LLC (HECA LLC, owned by SCS Energy California LLC) is a proposed Integrated Gasification Combined-Cycle (IGCC) polygeneration project that will gasify a 75 percent coal and 25 percent petroleum coke (petcoke) fuel blend to produce synthesis gas (syngas). Syngas produced via gasification will be purified to hydrogen-rich fuel, which will be used to generate low-carbon baseload electricity in a Combined Cycle Power Block, low-carbon nitrogen-based products in an integrated Manufacturing Complex, and CO_2 for use in EOR.

SCS Energy California LLC acquired 100 percent ownership of HECA in September 2011. A revised Application for Certification was submitted on May 28, 2009 for the current site, and deemed data adequate on August 26, 2009. Since acquiring the project, SCS has modified the former HECA design to improve its economic viability and better serve market needs, while continuing to adhere to the strictest environmental standards. In addition, HECA has selected Mitsubishi Heavy Industries' oxygen-blown dry feed gasification technology as a key component of the project.

The project is located on 453 acres near the unincorporated community of Tupman in western Kern County, California. The proposed plant plans to use a blend of California produced petroleum coke (a waste product currently exported) and western coal and non-potable water and convert them to hydrogen and CO_2. The hydrogen will then be used to fuel a combined cycle power plant to generate low-carbon electricity or be sent to for the manufacture of 90 percent carbon free fertilizer (Figure 11). Ninety-percent of the CO_2 will be captured during steady state operations, sent via pipeline, and injected deep below ground in oil reservoirs within the Elk Hills oil field for enhanced oil recovery and permanent storage.

The products and power produced by the project have a lower carbon footprint than similar products traditionally produced from fossil fuels. This low-carbon footprint is accomplished by capturing more than 90 percent of the CO_2 in the syngas and transporting CO_2 for use in EOR, which results in simultaneous sequestration (storage) of the CO_2 in the adjacent Elk Hills Oil Field (EHOF), operated by Occidental of Elk Hills, Inc. (OEHI).

Figure 11: Schematic of the HECA Project



Source: HECA

Highlights of the Project are as follows:

- The Project is designed to operate on a fuel blend consisting of 75 percent western sub-bituminous coal and 25 percent California petcoke based on thermal input to the gasifier higher heating value basis for the life of the Project.
- The integrated Manufacturing Complex will produce approximately 1 million tons per year of low-carbon nitrogen-based products, including urea, urea ammonium nitrate and anhydrous ammonia, to be used in agricultural, transportation and industrial applications.
- The feedstocks will be gasified to produce syngas that will be further processed and cleaned in the Gasification Block to produce hydrogen-rich fuel.
- More than 90 percent of the carbon in the raw syngas will be captured in a high-purity CO2 stream during steady-state operation, amounting to about 3 Mt of CO2 per year, equivalent to emissions from 650,000 cars.
- High purity CO2 will be compressed and transported by pipeline to the EHOF for injection into deep underground hydrocarbon reservoirs for CO2 EOR.
- The Combined Cycle Power Block will generate approximately 405 MW of gross power and will provide a nominal 300 MW of low-carbon baseload electricity to the grid during operations, feeding major load sources and supplying power for over 160,000 homes.
- The Sulfur Recovery Unit will convert sulfur compounds into a saleable sulfur product.

- Increasing California's production of oil when the state is currently importing approximately 50 percent of its oil and 90 percent of its natural gas needs each year. An estimated 2 barrels of oil can be recovered for every ton of CO2 injected for EOR. According to this estimate, output from the HECA Project will help California extract an otherwise unrecoverable 5 million barrels of oil each year or 150 million barrels over the first 30 years of the Project.
- Helping to restore a local aquifer by using brackish water that currently threatens local agriculture. HECA's use of brackish water from Buena Vista Water Storage District is expected to improve local lands for agricultural use by physically lowering the brackish water table and allowing better water from the east to penetrate the area.
- Boosting the local and California economy with an estimated 2,500 jobs associated with peak construction and approximately 200 full-time positions associated with Project operations, plus ancillary jobs and businesses to support the Project.
- Increasing the supply of hydrogen available to support the state's goal of energy independence and diversity as expressed in California Executive Order S-7-04, which mandates the development of a hydrogen infrastructure and transportation system in California.

The Energy Commission is responsible for reviewing and approving the HECA Project under the Warren–Alquist Act, Cal. Pub. Res. Code § 25500 *et seq*. In addition to issuing a license for the HECA Project, the Energy Commission will act as lead agency under the California Environmental Quality Act (CEQA) for the environmental review of the "whole of the Project," including the HECA Project and the OEHI EOR Project. This review is conducted in accordance with the administrative adjudication provisions of the Administrative Procedure Act, Cal. Gov't Code § 11400 *et seq*., and its own regulations governing site certification proceedings, 20 California Code of Regulations § 1701, *et seq*.

DOGGR will separately permit the OEHI EOR Project. DOGGR has statutory responsibility under Division 3 of the Public Resources Code to regulate all oilfield operations in the State of California. DOGGR is authorized by law to approve the injection and extraction wells and associated well facilities, to regulate downhole operations, and to be responsible for appropriate regulation of surface activities relating to the OEHI CO_2 EOR. The wells to be used for injection of the CO_2 are Class II injection wells under the UIC program in the Federal SWDA, 42 United States Code § 300h-4. DOGGR has primacy to approve Class II injection wells in California under Section 1425 of the SDWA. The wells and associated well facilities for the OEHI CO_2 EOR will be approved pursuant to authority provided to DOGGR in the Public Resources Code and the SWDA and in accordance with applicable DOGGR regulations.

The DOE is providing financial assistance to HECA for the definition, design, construction, and demonstration of the HECA Project under the Clean Coal Power Initiative. Because the Project is receiving funding from a federal agency, it is subject to the National Environmental Policy Act (NEPA). The construction milestones for the Project are (1) begin pre-construction and construction activities by June 2013, (2) completion of construction by February 2017, and (3) start of commercial operation of the Project in September 2017.

The permitting exercise, both original and amended, has been a major investment in time and resources and is an indication for future project developers of what could be anticipated. Many of HECA's regulatory and permitting experiences were conducted in an evolving regulatory framework, both at the state level (for example, the implementation of cap and trade program) and at the federal level (notably, the introduction of the UIC Class VI regulations).

As of 2014, the HECA project is the only project in California that has reached the permitting phase, which relies on CCUS for a power plant/industrial facility to meet GHG emissions caps and that proposes active sequestration using EOR. The success of this project will be a significant milestone in California by demonstrating a pathway through the regulatory, public acceptance, and technical aspects.

Currently, the vast majority of all California nitrogen-based fertilizer feedstocks are imported into the state. Due to these transportation costs, California nitrogen-based fertilizers are priced 20 to 30 percent higher than in other United States regions. Therefore, the presence of a nitrogen-based fertilizer producer is likely to benefit local consumers through increased competition and the lowering of transportation costs.

The HECA project has had an active outreach program both under its BP-Rio Tinto ownership and, since 2011, under SCS Energy. Outreach activities also have been assisted by Occidental Petroleum. HECA's outreach includes aspects required by public agencies as well as a diverse program of voluntary efforts aimed at stakeholders spanning from the state's top policymakers to children in the local community. HECA has been required to submit large numbers of documents for public posting and to participate in open review meetings as part of the permitting process for agencies such as the California Energy Commission and the California Public Utilities Commission. Other agencies involved in permitting include the California Department of Conservation, EPA Region IX, US Department of Fish & Wildlife, California Department of Fish and Game, and the California Air Resources Board. The project team has engaged the California Governor's office, state and federal legislative members, and environmental organizations. In Kern County, HECA officials have met with the County Board of Supervisors, labor and trade organizations, community leaders, local environmental organizations, area business associations, and local homeowners' associations.

The HECA site lies in a relatively sparsely populated region, but the outreach program has extended throughout the entire southern San Joaquin Valley through informational meetings, newspaper articles, newsletters, email outreach to interested parties, a visitor's center, and a website. A visitor center in Buttonwillow serves to provide information and assists in recruiting locals into the workforce for project construction and operations.

Some of the concerns raised about the local impacts of the HECA project include further degradation of the air quality in the southern San Joaquin Valley, which ranks among the worst in the United States. The plant plans to burn coal or petcoke, which will be brought in by rail. This aspect raises concerns ranging from the global objection to society using CCUS to prolong its dependence on fossil fuel and to local objections to traffic congestion and noise.

HECA has acquired much experience with Environmental Justice groups opposed to CCUS. At its first proposed location in Carson, California, EJ advocacy groups expressed concern about added impacts that CCUS would have on local disadvantaged communities already adversely impacted by

the local BP refinery and truck traffic to the nearby Long Beach commercial harbor. While the EJ opposition was not the primary reason, HECA relocated the project to the San Joaquin Valley. The first San Joaquin Valley location was determined to have environmental impacts on sensitive species; the project has remained at the second location since 2010. At its second and third proposed locations, HECA also encountered EJ advocates opposed to the project. They represented the low-income, predominantly Hispanic population employed in the agricultural sector and who are unlikely to derive much benefit from the project. Because the oil industry is a dominant presence in this part of the state, there is generally a basic level of comfort with subsurface drilling projects and since the Elk Hills field already exists, there has been little opposition to the subsurface storage side of the project. Demographic groups predominantly employed by the oil industry may directly or indirectly benefit from the project. The project itself will need to employ people with the types of skill sets who support the oil sector; the project also may pave the way for a renaissance in the local oil industry made possible by the availability of CO_2 for EOR.

The HECA project has received over $400 million in funding from the Federal Stimulus Package of 2010. Negative media coverage called attention to the fact that the co-owners of the project at that time, BP and Rio-Tinto, were large foreign corporations (The Sacramento Bee 2010). However, policymakers and regulators publicly cite the importance of the project award in bringing federal funding into the state. The coeval oil spill in the Gulf of Mexico did not enhance the BP image in the media, a reminder that non-project specific events can affect public perceptions of projects.

7.2 Kimberlina

Clean Energy Systems, Inc. (CES) has recently demonstrated high temperature oxy-fuel technology applicable to gas turbines, gas generators, and re-heat combustors. In 1999, the Energy Commission awarded an Energy Innovation Small Grant to CES to experimentally establish a "proof-of principle" high-pressure oxy-fuel combustor. CES built a nominal 110 kWth (1-cm internal diameter) combustor and operated it successfully at temperatures up to 1480^{o} C (2700^{o} F) and pressures up to 21bar (305psia In 2000, DOE funded CES to design, fabricate, and test a 20 MWth (10-cm internal diameter) oxy-fuel combustor to operate on methane, oxygen and water, which was successfully demonstrated at temperatures from 315 to 1650°C and pressures from 76 to 106 bar (1100 to 1540 psia). The combustor successfully functioned at a range of power settings, from 20 percent of rated power to full load (20MWth), in more than 95 tests.

In August 2003, CES acquired an idle 5MWe biomass power plant at Kimberlina, near Bakersfield, California. In conjunction with Siemens Energy, Inc. and Florida Turbine Technologies, Inc. , CES has been working to develop and demonstrate turbo-machinery systems that accommodate the inherent characteristics of oxy-fuel (O-F) working fluids. Commissioning of an integrated O-F combustion system was completed in 2004 using natural gas as the fuel. Durability and performance testing was conducted through 2006. During this time, the combustor was started over 300 times and accumulated over 1,300 hours of operating time with power exported to the electrical grid at levels from 0.5 to 2.7 MW. Subsequently, CES has developed and demonstrated a larger combustor (170 MWth) and a modified aeroderivative turbine (GE J79 turbine). The CES-Siemens-Florida Turbine Technologies team also is working on efficiency improvements by including a reheat combustor and studying the performance of the system‘s materials.

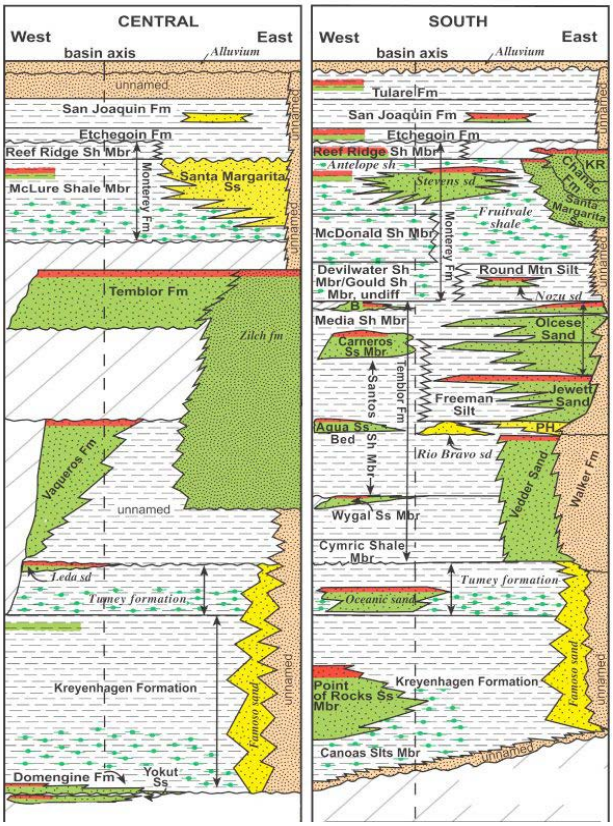
In 2012, a modified Siemens SGT-900 gas turbine engine arrived at the Kimberlina test facility. As in previous generation systems, the expander section of the engine is used as an advanced intermediate pressure turbine and the can-annular combustor is modified into a O-F reheat combustor. Adaptation of this equipment to accept steam/CO_2 drive gases and to serve as an intermediate pressure turbine in the O-F cycle requires specific changes to system components. These gases must be routed to the reheat combustion system for heat addition and subsequent expansion through the SGT-900 turbine, the latter of which forms the IPT of the O-F cycle. Most prominently, the O-F cycle does not require compression of the working fluid, so the SGT-900 compressor can be eliminated. With the removal of the compressor, the turbine is capable of producing 150MWe as an O-F IPT, requiring a larger reduction gearbox/generator set.

Alternative candidate fuels have included simulated syngas, hydrogen depleted syngas, and liquid fuels co-fired with natural gas. Non-power demonstrations have included production of high-pressure, high-temperature steam and CO_2 products for potential use to enhanced recovery of natural gas, coal-bed methane, oil, and bitumen.

The Kimberlina site lies within the southern part of the San Joaquin Basin, which is filled by more than 7000 m of Tertiary marine and nonmarine sediments that bury the down-warped western margin of the Sierra Nevada metamorphic-plutonic terrane. The stratigraphic section is generally thin and predominately continental on the east side of the basin, but it thickens into largely deepwater marine facies to the west (Figure 12).

The structure is basically a monocline dipping toward the west, characterized by block faulting and broad, open folds. A major feature of the basin is the Bakersfield Arch, a westward-plunging structural bowing on the east side of the basin. This structure plunges south-southwest into the basin for approximately 25 km, separating the basin into two sub-basins. The structural feature is the site of several major oil fields, some of which are suitable for CO_2-enhanced oil recovery. A geological assessment, construction of a static geomodel, dynamic simulations, and a thorough risk assessment were undertaken for the Kimberlina site (Wagoner 2009).

Figure 12: Generalized Stratigraphic Section for the Southern San Joaquin Basin



Source: Scheirer and Magoon (2007).

Figure 13: Kimberlina Geologic Framework Model at 50 Km Scale and 10 Km Scale

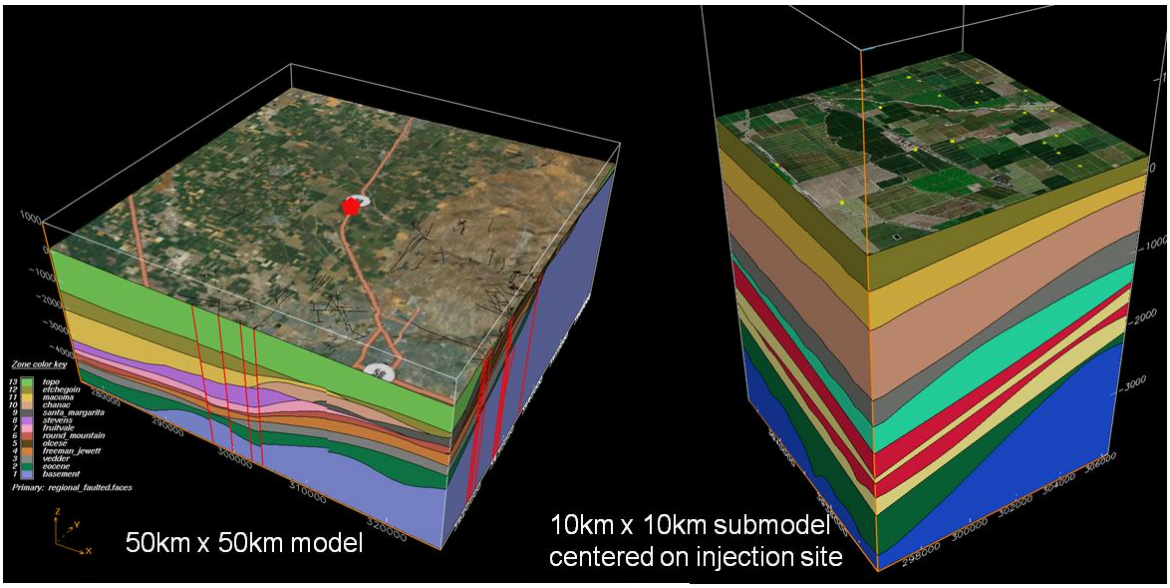


Figure shows stratigraphy of the southern San Joaquin basin and surface geography. Well locations used to inform the model are shown as red vertical lines in the lefthand model.

Source: Wagoner (2009)

WESTCARB constructed a regional 3D geologic model of the southern San Joaquin basin encompassing an area within a 50 km radius of the Kimberlina site (Figure 13). This regional model was developed to improve our understanding of the location and character of potential sequestration targets in this part of the basin. This model provides a framework for constructing smaller, more detailed models of potential injection sites. The regional framework model is approximately 84 km x 112 km in size. Mapped geologic units included Quaternary basin fill, Tertiary marine and continental deposits, and pre-Tertiary basement rocks. Detailed geologic data, including surface geologic maps, borehole data, and geophysical surveys, were used to define the geologic framework. Fifteen time-stratigraphic formations were mapped, as well as more than140 faults. The free surface is based on a 10 m lateral resolution. Most of the geologic information integrated into this model originated from the oil and gas industry and is available from the DOGGR. Individual fault data are taken from DOGGR documents on specific oil and gas fields in the basin. Our current understanding of the faulting between the oil and gas fields is poor, and this is an area in which more work is required.

Definition of the lithology and lithologic properties was provided by well logs from a reference well. Target sequestration formations, the Stevens, Olcese, and Vedder formations at 2,330 m, 2,660 m, and 3,000 m, respectively, were identified and capacity estimates made (Table 11). The 135-m-thick Stevens Sandstone, was deposited in a deep-water marine fan environment. The Olcese is a regionally continuous, fluvial-estuarine unit of moderate injectivity. Its thickness at the site is on the order of 500 m. The Vedder, which is also regionally continuous, is a braided stream unit with a thickness of about 300 m. Thick shale units provide good overlying seals at the site and surrounding areas.

Table 11: Capacity Estimates for Kimberlina Formations

Formation	Capacity Type	Capacity (Mt CO_2)
Vedder	Dissolved and Residual	207
	Physical	715
Olcese	Dissolved and Residual	214
	Physical	739
Stevens	Dissolved and Residual	382
	Physical	1,320
Total	Dissolved and Residual	c. 800
	Physical	c. 2,800

Storage capacity of the target formations were made assuming that 5 percent of the pore volume contained dissolved fraction CO_2, 8 percent contained residual phase-trapped CO_2, and 65 percent was available for free phase trapped by physical processes (seals). Injectivity measures are high (20-300 mD). These initial estimates show a very significant and effective (due to stratal continuity and functional seals) potential in the Kimberlina region of up to 800 Mt of CO_2.

7.3 C6 Resources-WESTCARB Pilot Project in Solano County

C6 Resources, LLC was awarded a grant from DOE under the American Recovery and Reinvestment Act to examine the potential of commercial CCS for an industrial source of CO_2 in the Montezuma Hills of Solano County. The setting is a rural area where surrounding lands are used for agriculture, grazing, open space and wind energy production.

WESTCARB collaborated with C6 Resources to perform a pilot injection study of the formations at the Montezuma Hills site. C6 Resources submitted a plan for the well to permitting agencies, proposing to inject into deep sandstone formations containing saline formation fluids at 6,000 – 7.500 m depth and injecting up to 6,000 tonnes of CO_2. Permitting the project involved obtaining an experimental UIC permit from EPA, Region 9, and a conditional land use permit from Solano County. Because of the involvement of federal funds, the U.S. DOE also needed to make a determination regarding the need for an Environmental Impact Statement under NEPA, while Solano County, the local CEQA lead agency, needed to make the determination on whether an Environmental Impact Report (EIR) was needed to satisfy CEQA. C6 subsequently withdrew from the project, and WESTCARB drilled a well further east to characterize the storage potential of the formations in the Sacramento Basin.

7.4 WESTCARB Northern California Characterization Project

WESTCARB performed site characterization work in California in collaboration with the California State Geologic Survey and various industry partners with an interest in CCS development. WESTCARB developed a set of geologic and geographic criteria and nontechnical/logistical criteria to rank potential characterization well sites.

The methods for site down-selection for a characterization well include developing criteria for site selection and collecting relevant available data that address those criteria (Table 12). Based on these data, a ranking of sites can be made. Criteria include elements of the geology and geography that define the suitability of the site for geologic storage including location relative to sources and presence of storage and sealing formations, how representative the formations at the site are of the major geologic storage targets in the region, as well as non-geologic criteria that must be met to assure a successful project. Such criteria include site access, liability assumption, and permitting constraints.

The criteria that sites be within reasonable proximity to large volume CO_2 sources was addressed through use of the GIS NATCARB databases, which WESTCARB has assembled. Urbanization is concentrated on the coasts, predominantly in the San Francisco Bay Area and Los Angeles Basin and many large CO_2 sources are also within these regions. The Central Valley of California, composed of the Sacramento basin in the north and San Joaquin basin in the south, contains numerous saline formations and oil and gas reservoirs that are the state's major geologic storage resources. The saline formations alone are estimated to have a storage capacity of 100 to 500 Gt CO_2, representing a potential CO_2 sink equivalent to greater than 500 years of California's current large-point source CO_2 emissions.

Table 12: Characterization Well Site Selection Criteria

Category	Criteria Description
Geologic and Geographic Criteria	Well-defined stratigraphy or structure that should minimize CO_2 leakage
	No impact on low-salinity (<10,000 mg/L TDS) aquifers; minor impact on a deep, high-salinity aquifer beneath a confining seal formations
	Location is unlikely to cause public nuisance (noise, traffic, dust, night work, etc.) and does not disturb environmentally protected or other sensitive areas
	Well will intersect formations identified as potential major storage resources for the region
	Area is in sufficiently close proximity to large volume CO_2 sources
	Sufficient preliminary geologic data (hydrogeologic data, well logs, seismic surveys, rock and fluid properties) available to inform site down-select process yet not so much as to make characterization well unnecessary to fill knowledge gaps
	Major faults in area are known and can be assessed for their potential as leakage pathways
	Depth of storage formations are greater than 800 m (~2,600 feet) to keep CO_2 in dense supercritical state
	Potential for CO_2 utilization at site improve likelihood of early CCS development opportunities
Non-technical/ Logistical	Surface owner grants project access
	Subsurface (mineral rights or well) owner grants project access and accepts well liability
	Pre-existing roads and easy access for heavy equipment
	Pre-existing well pad or well to eliminate or minimize surface disturbance and easy access for heavy equipment
	Ease of permitting process

The formations of interest in California for geologic storage have been the subject of many previous investigations by WESTCARB and its partners. These formations include the Mokelumne, Starkey, Winters, Domengine, and Vedder sandstones. The methodologies used to assess these units as potential storage resource are exemplified by a WESTCARB study done by the California Department of Conservation, California Geological Survey (CGS), which conducted a preliminary regional geologic assessment of the carbon sequestration potential of the Upper Cretaceous Mokelumne River, Starkey, and Winters formations in the southern Sacramento Basin (Downey and Clinkenbeard, 2010) Approximately 6,200 gas well logs were used to prepare a series of three maps for each formation. Gross sandstone isopach (thickness) maps were prepared to define the regional extent and thickness of porous and permeable sandstone available within each formation. Depth-to-sandstone maps were then generated and used to identify areas of shallow sandstone that might not be suitable for supercritical-state CO_2 injection. Finally, isopach maps of overlying shale units were prepared for each formation to identify areas of thin seals. The maps were digitized and GIS overlays were used to eliminate areas where sandstone has been eroded by younger Paleocene submarine canyons, areas of shallow sandstone, and areas exhibiting a thin overlying seal, to arrive at an estimate for each formation meeting minimum depth and seal parameters. The maps reveal that approximately 2,675 km^2 are underlain by Mokelumne River sandstones, 2,355 km^2 by Starkey Formation sandstones, and 3,722 km^2 by Winters sandstones, which meet minimum depth requirements of 1,000 m and seal thickness of over 30 m and may be suitable for carbon

sequestration. Since the formations are vertically stacked, only 5,169 net surface km^2 meet depth and seal criteria. However, stacking provides the potential for much thicker total sandstone sequences than individual formations. The estimated storage resource for the portions of the three formations meeting depth and seal criteria is 3.5 to 14.1 Gt of CO_2.

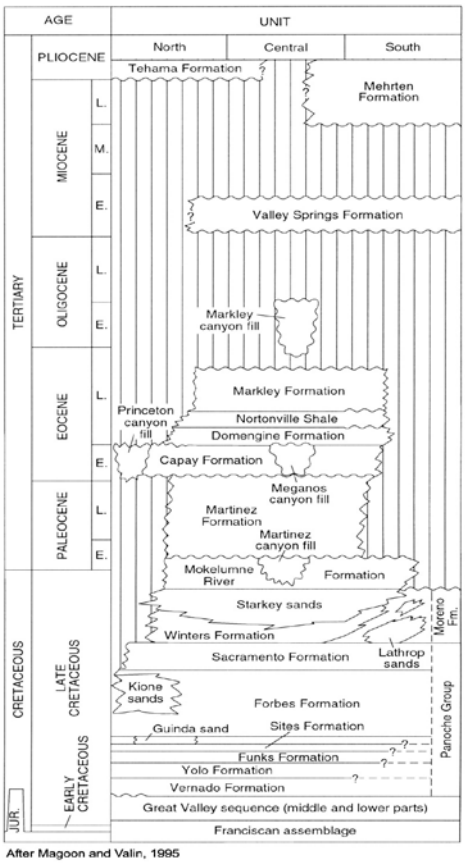
Given that early opportunities for commercial-scale CCS are likely to be linked to opportunities for CO_2-EOR or other CO_2 utilization, such as enhanced gas recovery, cushion gas for natural gas storage or as compression gas for energy storage, another criteria used for site screening was to look for sites where such opportunities were available. Depleted petroleum reservoirs are especially promising targets for CO_2 storage because of the potential to use CO_2 to extract additional oil or natural gas. The benefit of EOR using injected CO_2 to swell and mobilize oil from the reservoir toward a production well is well known. Enhanced gas recovery (EGR) involves a similar CO_2 injection process, but relies on sweep and methane displacement. CO_2 injection may enhance methane production by reservoir re-pressurization or pressure maintenance of pressure-depleted natural gas reservoirs or by preferential desorbing more methane in any gas-bearing formation. Thus, potential sites that are near oil fields, gas fields, natural gas storage sites, or areas being studied for compressed gas energy storage were given preference in the ranking process.

Another criterion was to locate an area where the data gathered by a characterization well would have high value through filling knowledge gaps balanced against the need to have sufficient data available for selected sites for informed decision-making. In other words, areas that were already rich in subsurface data would rank lower than areas where a characterization well would significantly improve knowledge of the character of storage formations and sealing units. However, this automatically did not preclude selecting sites in the oil and gas-bearing regions of the state. Although the oil and gas regions in California have been extensively drilled and studied, the focus of data gathering has been on the hydrocarbon-bearing formations that typically overlie the deep saline formations of interest for CO_2 storage. Of the gas exploration wells drilled to the depths needed for CCS site characterization, few have collected sampling and logging data for these deep formations. In addition, the characteristics of the sealing units are typically neglected in traditional oil and gas exploration. Because CO_2 for enhanced natural gas recovery remains experimental, the types of data needed for dynamic modeling of CO_2 behavior are not typically collected in the gas-bearing formations.

At the field level, criteria include establishing that storage and sealing formations meet general thickness requirements, incorporating any data on geohydrologic properties, including permeability and formation water salinities, and examination of the properties of any faults in the area. Methods include reviewing existing well or seismic data to create a preliminary geologic model. However, at this level, other criteria related to site access, permitting, liability, and minimizing new construction activities also are part of the ranking. For example, being able to use existing well pads and roads may favor one site for well drilling within a field over another site where formations are predicted to be of greater thickness. Side-tracking the well might be used to plan a project to balance these competing objectives. Similarly, a field where the owner may be willing to take liability and obtain permits would rank more highly than one where WESTCARB would have to purchase an insurance bond or take permitting responsibility.

Three sites in Northern California were considered: King Island, Thornton, and Montezuma Hills. The candidate sites are located in the Great Valley Geomorphic Province, a structural trough or basin filled with up to 12.2 km of Jurassic to Holocene marine and nonmarine clastic sediments. Marine and deltaic sediments were deposited along the western convergent margin of the Cordilleran Mountains, which underwent rapid uplift and erosion during the Late Jurassic to Late Cretaceous Cordilleran Orogeny.

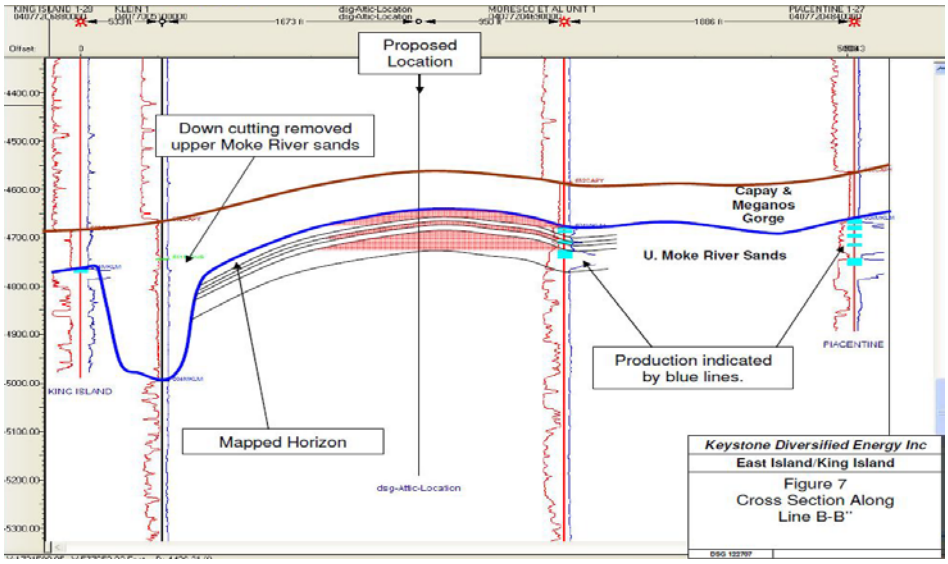
Figure 14: General Stratigraphic Section for the Sacramento Basin, California.



After Magoon and Valin, 1995

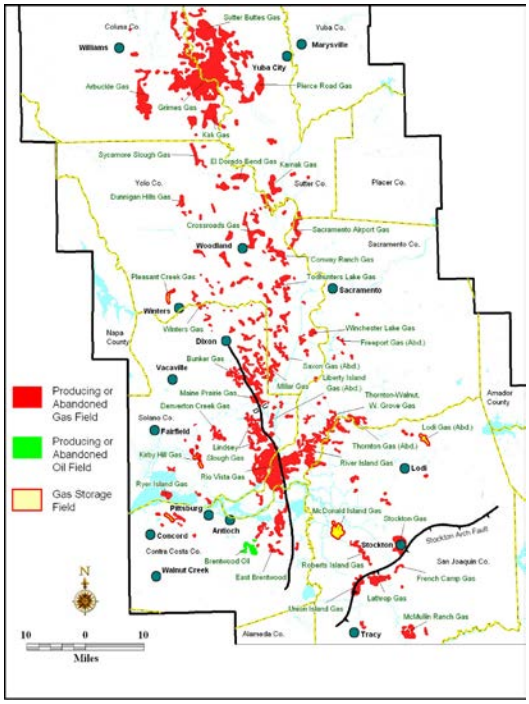
Thick marine sediments continued to accumulate along the Farallon-North American Plate boundary during the early Cenozoic era before the California Coastal Range began its rapid uplift during the middle Cenozoic. Cenozoic evolution of the Coastal Range, characterized by intense faulting and alternating periods of uplift and subsidence, created the western boundary of the structural trough. Corresponding uplift and subsidence of the Central Valley resulted in deposition of alternating layers of undifferentiated nonmarine and marine sediments, respectively, across the Sacramento-San Joaquin Basin (Figure 14 and 15).

Figure 15: Cross-section of the East Island-King Island gas fields



Cross-section shows inferred formation tops from resistivity logs of several gas wells within these fields. The proposed characterization well site is shown as a vertical well, however, to avoid surface disturbance, the project team decided to drill a deviated well to utilize and existing well pad and well head.

Figure 16: Oil and Gas Fields of the Southern Sacramento Basin



Source: Downey and Clinkenbeard (2011)

These formations are the producing zones for dozens of gas-producing fields in California, including King Island (Figure 16). The cumulative storage capacity of these fields is estimated at 1.7

Gt CO_2. Storage capacity of the largest, the Rio Vista field, is estimated to be over 300 Mt CO_2, sufficient to accommodate CO_2 emissions for over 80 years from the nearest large (650 MW) gas-fired power plant. Depleted natural gas reservoirs are attractive targets for sequestration of CO_2 because of their demonstrated ability to trap gas, proven record of gas recovery (i.e., sufficient permeability), existing infrastructure of wells and pipelines, and land use history of gas production and transportation.

All sites met the geologic/geographic criteria, however the geology at King Island and available data offered some advantages over the other sites. King Island site meets the scientific objectives better than the other three sites considered. Furthermore, King Island is the only site that completely fulfills the nontechnical/ logistical criteria. King Island meets the criteria, related to liability, permitting, site access and other non-technical factors necessary to assure successful completion of the project. In the case of the other sites selected, as is described in more detail below, these non-technical factors were the criteria that eliminated the sites from further consideration.

There are over 11 Mt per year of CO_2 emissions from sources within the southern Sacramento Basin alone, and the King Island area lies in close proximity to numerous power plants and large industrial sources in the San Francisco Bay Area, the California Delta, Stockton, and Sacramento areas. In addition to saline formation storage opportunities, there is the possibility for enhanced hydrocarbon recovery or CO_2 utilization in gas storage or energy storage. The southern Sacramento-northern San Joaquin basin contains producing gas fields and gas storage reservoirs. It is important to note that the gas zones in much of the Sacramento Basin are structural traps against sealing faults; however at King Island, the trap is stratigraphic. There are very few faults identified in the immediate vicinity of the candidate sites. At King Island, WESTCARB had site access permission from both the well and mineral rights owner and, through that company, the land owner. The mineral rights beneath the King Island site and the well are owned by WESTCARB's key collaborator (Princeton Natural Gas), who is providing free access to the well and the rights.

King Island was "drill-ready" in that it had existing gas wells, well pads and access roads, and is in a rural agricultural area. The mineral rights and well owner has procured the drilling permit at his own expense and has taken the legal liability for the well. The owner assumed ownership and responsibility for the well after completion of the WESTCARB project.

In the area near King Island, demographic highlights from the 2000 U.S. Census indicate that the population is about 50 percent Hispanic or Latino, 45 percent White, 3 percent Asian, 2 percent Black or African American, and less than 1 percent American Indian and Alaska Native. The King Island site is located west of the Interstate 5 and south of Kettleman Lane (State Highway 12). The nearest communities are Stockton (290,000), about 11 km away, and Lodi (63,000), about 8 km away (Figure 16). The immediate vicinity is a rural area. The Thornton site is approximately 37 km north of Stockton, but only three km north of the unincorporated town of Thornton, California, (population 1467). It is about 20 km north of the King Island site.

The King Island site is at an elevation of minus 2 meters below mean sea level. The site is located within the Sacramento River drainage basin, which joins the San Joaquin River (which drains the southern part of the Central Valley) to form the Sacramento-San Joaquin River Delta system. The project site is located in a low-lying area protected by levees that have been installed along the rivers

to prevent the property from flooding during winter and spring, when peak precipitation and surface runoff occur.

The King Island well was drilled as a deviation to take advantage of an existing well pad from an operational but no longer productive well, the Source Energy Corporation's "King Island" 1-28 well. There are no residences anywhere near the well pad which is 80 m by 40 m. Permitting was facilitated at the King Island site by the well owner. A California DOGGR permit for drilling the characterization well was obtained. DOGGR has developed regulations governing the drilling, disposition or abandonment of oil, gas, geothermal, and injection wells in compliance with CEQA, NEPA and EPA UIC regulations as applicable. The California Code of Regulations specifies the requirements.

The well was permitted to a target depth of 2,500 m. A service rig was deployed to pull old casing over the interval necessary for subsequent deviated drilling (approximately 167 – 235 m) and to plug back the existing well. The integrity of the cement plug and the surface casing (0 to 167 m) was tested in compliance with DOGGR permitting requirements.

WESTCARB technical staff and scientists at LBNL worked to assure that the down-selection process resulted in a well site and test plan that would be able to meet the scientific objectives for the Phase III characterization well projects. Even though CO_2 injection in the field is not part of the project, a test plan was developed to include field measurements, sample collection, laboratory measurements and testing, and development of simulations that could be used to provide information about the formations' suitability for a large volume CO_2 storage project.

Both core samples from gas-bearing and saline units were collected at King Island. These samples are undergoing laboratory testing at LBNL to obtain some of the information about CO_2-rock interactions that would have been gathered through field tests. While field tests are arguably the only method for testing and verifying monitoring techniques, LBNL will be able to perform some laboratory tests on the King Island samples to test petrophysical responses to injected CO_2 which will contribute critical information to developing some new monitoring tools.

The King Island characterization well will provide core and fluid samples from the same zones that were identified for the pilot injections at the Thornton site as well as additional zones at greater depths. Fluid sampling and analysis of deep and shallow hydrocarbon and aqueous gas and liquid phases is important in order to establish whether flow paths exist from the deep subsurface to shallower formations. Fluid analyses may include bulk composition, trace gases, and isotopic composition to establish relationships between the fluids, their origins, and their ages. Shale cap rock and storage sandstones were included in the core sampling program. The samples were transported to laboratory test facilities at LBNL where CO_2 injection tests have been done to provide data on CO_2-rock-fluid interactions at the core scale, to provide data for geohydrologic simulations of CO_2 fate and transport, and to inform development of new monitoring techniques. At Sandia National Laboratory, shale samples were tested to improve understanding of the geomechanical behavior of cap rocks. Other samples will be analyzed at commercial laboratories to acquire specific data to inform simulation activities. Part of the research outcome of the King Island studies will be to improve understanding of the scalability of laboratory and field logging data.

In addition, earth science researchers at LBNL will use sophisticated numerical codes, TOUGH2 and TOUGHREACT, for modeling the movement of fluids in geologic formations (Pruess, 2004; Xu et al. 2006). Simulation of the CO_2 injection and storage based on detailed site-specific hydrogeological models has been performed. The well constrained stratigraphy and structure from nearby wells and seismic surveys, multiple stacked sands, including gas-bearing and saline zones, and the acquisition of a robust set of petrophysical and geochemical data from the characterization well logs and samples will allow for a significant simulation effort. A geologically realistic mathematical model of the multiphase, multi-component fluid flow produced by CO_2 injection is indispensable for determining the viability of a potential storage site, because capacity and trapping ability are both strongly impacted by the coupling between buoyancy flow, geologic heterogeneity, and history-dependent multi-phase flow effects, which is impossible to calculate by simpler means. Modeling may also be used to: 1) optimize CO_2 injection by assessing the impact of various rates, volumes, and depths; 2) choose monitoring sensitivity and range by providing the expected formation response to CO_2 injection; and 3) assess the state of understanding by comparing model predictions to field observations.

WESTCARB undertook several studies of the perceptions of the local communities near the proposed drilling sites at Thornton, Montezuma Hills (Rio Vista) and King Island. Thornton is an agricultural community, more dominantly minority, with a lower income and a lower level of educational attainment than Rio Vista. It is also unincorporated, which means that any revenue funds generated by local industry or projects go to the county, not the community. These factors are active catalysts for disempowerment. Thornton also had a recent history of severe drinking water quality problems that had not been resolved, which created mistrust of a regulatory process which was supposed to protect the community. Even though the proposed CCS project was a small-scale pilot injection, the community reception of the project, and of CCUS in general, was either negative or resigned.

Rio Vista scored on average higher on factors that suggest community empowerment. However, the town consists of two very different demographic groups, the "old" Rio Vista area and a new retirement community. The "old" community has historic ties with the natural gas production and storage industry, which has generated economic growth and familiarity and comfort with the concept of development in the subsurface. The "new" retirement community has higher educational levels than both "old" Rio Vista and Thornton, higher average income, higher age, and is more politically active.

There were distinct differences in the ways these communities perceived project risk mitigation even though their perceptions of risks were similar. The main difference between the communities related to belief in their power of voice and redress, which can be traced to historical experiences by the communities respectively. The ability to influence risk mitigation so that it addresses specific community concerns gave Rio Vista a sense of empowerment that was absent in Thornton. Both communities identified similar technical and social risks from CCS. Technical risks included concern about potential physical harm, CO_2 leaks, and increased seismicity. In general, both communities doubted the validity of expert knowledge, particularly industry experts. They were less skeptical of academic experts. Social risks included concerns about a change in the nature of the community/quality of life caused by increased traffic, reduced property values, and other potential

side impacts. Also, both communities expressed concern about the trustworthiness of governments and corporations. In general, both communities expressed preferences for receiving information from trusted sources and/or multiple sources. Also, both communities expressed greater concern about the social risks than the technical risks. Direct benefits and some community control were considered important to community support for a CCS project.

7.5 Wilmington Graben Project

The Los Angeles Basin provides both a strong demand and significant potential for large scale geologic storage of CO_2. The geologic setting is one of the most prolific oil and gas producing basins in the U.S., and the region is home to more than a dozen major power plants and oil refineries that produce more than 5 Mt of fossil fuel related CO_2 emissions each year.

Massive interbedded sandstone and shale sequences of Pliocene and Miocene age in the Los Angeles Basin are known to provide excellent and secure traps for oil and gas. The area contains several billion-barrel oil and gas fields, including the giant Wilmington Field in Long Beach (more than two billion barrels produced to date). These formations have been used by the Southern California Gas Company for very large scale underground storage of natural gas at half a dozen locations throughout the Los Angeles Basin for more than 50 years, demonstrating both the storage potential and security of these formations for CO_2 sequestration if properly characterized and selected.

Given the population density (and complex land ownership), it is impractical to site a large scale CO_2 storage project onshore beneath the city. More than a 1,000 m of Pliocene and Miocene sediments are present in the large Wilmington Graben directly offshore from the Los Angeles and Long Beach Harbor area, at appropriate depths for CO_2 sequestration (about 1,000 to 2,500 m). This zone is easily accessible yet geologically isolated from the nearby Wilmington Field and onshore area, reducing the risk of migration.

The Southern California Carbon Sequestration Research Consortium (www.SoCalCarb.org) led by Terralog Technologies, Inc. has undertaken comprehensive research to better characterize these Pliocene and Miocene sediments in the Wilmington Graben and surrounding areas for high volume CO_2 storage. This effort (see Young, 2011) includes:

- A detailed evaluation of the logs from existing wells in the area
- An improved interpretation of both 2D and 3D seismic profile data, and the acquisition of additional 2D seismic lines
- Drilling and coring of two evaluation wells into the Wilmington Graben and one well on the landward side of the THUMS-HB fault line
- The development of 3D geologic, geomechanical, and CO2 injection and migration models for the region
- An analysis of the 20 primary industrial sources of CO2 in the region
- An engineering study of pipeline systems to transport CO2 from sources to potential sequestration sites

- A risk analysis comprising an assessment of formation seal performance, existing well integrity, seepage potential along fault planes, and natural and induced seismicity

CHAPTER 8:
Deployment Considerations for CCUS in California

Widespread deployment of geologic CCUS in the state will require integrated assessments that include engineering analysis of sources, analysis of pipeline, rail, or other transportation alternatives, and geologic characterization of the subsurface at sequestration sites. One preliminary assessment, currently being undertaken by the West Coast Regional Carbon Sequestration Partnership (WESTCARB), focuses on existing and newly permitted natural gas combined cycle power plants, which predominate in California's electricity generation mix. Any future energy infrastructure planning or assessments done by the state that include fossil fuel sources could also include provision for such integrated CCUS assessments.

8.1 Sources

For 2008, the state's GHG reporting data show that the largest in-state emissions come from refineries, natural gas electricity production, and cement plants. For the electric power sector, it is important to note that emissions counted in the state's inventory include in-state and out-of-state GHG emissions. Plans for CO_2 emissions reduction in the transportation sector typically focus on using lower net carbon fuels, such as electric-powered vehicles, which would shift emissions from the transport to the power sector.

Effective initial deployment of CCUS to achieve the greatest impact on the state's GHG emissions might best be focused on the largest in-state point sources, and also on out-of-state sources in the context of regional climate change initiatives and in consideration of the western regional energy infrastructure. By 2050, assuming moderate economic growth, achieving the 2050 target level of about 90 Mt/year would require reducing emissions by 10 Mt/year each year starting in 2010, or 14 Mt/year starting in 2015 (Schiller, 2007). While it seems evident that CCUS technology must play an important role in achieving these reductions, deployment may not be rapid enough (even with policies that enable an economically favorable case for CCUS adoption) if it is not accompanied by sufficient understanding of the sequestration resource potential or transport and other infrastructure development.

8.1.1 Electric Power Generation

In order for the State to achieve its aggressive GHG reduction goals, the electricity sector needs to build low-carbon generation. There are three possible approaches to decarbonizing the electricity sector, which can be used in combination:

- Renewable energy--Renewable energy development is required under California's Renewable Portfolio Standard, and will likely play an expanding role in the state's energy portfolio. However, permitting for new sites and transmission lines is meeting opposition in some instances, and the intermittent output profile of wind and solar, without significant investments in energy storage, raises questions of grid reliability.
- Nuclear energy--New nuclear power is banned in California until there is a permanent federally managed repository for nuclear waste or reprocessing of spent nuclear fuel has

been demonstrated and approved in the United States. Finding safe and socially acceptable ways to deal with nuclear waste remains a challenge for nuclear power.

- CCUS--A Low Carbon Portfolio Standard is needed to reward utilities for purchasing electricity with CCUS.

At this point, it is extremely difficult to accurately determine the costs of CCUS to the electric utilities and their ratepayers. However, early adopters' financial numbers show that the addition of CCUS adds considerable expense to the operation of those facilities. For the utilities, the costs of CCUS will be passed on to ratepayers through Power Purchase Agreements. This issue will need to be addressed by the state government and the CPUC, working with consumer advocates and the utility sector.

In recognition of the advantages to the State that come from being in a leadership position in deploying CCUS technologies and of the public-interest benefits of early mover projects, which will be shared by all Californians, the costs could also be spread to all Californians. For the electric sector, this would ease concerns that CCUS could pose undue financial burdens to any single utility and its ratepayers.

8.1.2 Other Industries

To date, technologies making use of CO_2, including EOR, have had a negligible impact on overall anthropogenic CO_2 emissions (IPCC, 2005; Koljonen et al., 2002). Eventually, new technologies that facilitate the use of CO_2 may increase the market demand for CO_2 captured from power plant and industrial sources, thus improving the economic viability of CO_2 capture, while reducing GHG emissions and providing useful products to the public.

Possible CO_2 use technologies include those that combine geological storage of CO_2 and energy production, in a manner somewhat analogous to EOR, such as enhanced gas recovery or enhanced geothermal systems, where CO_2 replaces water as a heat exchange fluid. In this general category of CO_2-use technology, CCUS is joined to the enhanced recovery of a geological resource, such as oil, natural gas, geothermal heat, minerals, or water.

There are other types of CO_2-use technologies, where the CO_2 is either stored non-geologically, or is used in such a way as to reduce net GHG emissions. The former include the synthesis from a CO_2 feedstock of solid materials such as plastics, or carbonates that can be used in cement or construction materials, which result in the carbon being trapped within the solid material.

These new requirements are designed to promote transparency and national consistency in permitting CCUS activities while maintaining flexibility, as appropriate. It is unclear if the final regulations will allow states such as California to have primacy enforcement authority over the new Class VI wells. Section 1422 of the SDWA provides that the states may apply to EPA for primary enforcement responsibility to administer the UIC program; governments receiving such authority are referred to as "primacy states."

8.2 Transport of CO_2

Where large point sources do not overlie suitable sequestration sites, CO_2 will be transported via pipelines or on trucks, trains, ships, or barges. In today's commercial markets, CO_2 is routinely

transported in tanker trucks as liquid CO_2; however, for the large quantities of CO_2 involved in CCUS, tanker transport is impractical and uneconomic. Rail has been considered viable in some cases, but pipelines are the most likely mode of CO_2 transport for commercial-scale sequestration operations.

The technical, economic, and permitting issues associated with CO_2 compression and pipeline transport are well understood because of the large-scale use of CO_2 for over 20 years in EOR operations in many other states. To assure single phase flow and optimize volumetric flow, the CO_2 is typically compressed at the source to a supercritical state—150 bar (2200 psi) or more, and non-condensable gases (nitrogen and oxygen, for example) are removed. Booster compressors may be necessary along lengthy pipelines. To avoid corrosion and hydrate formation, water levels are typically kept below 50 parts per million.

The need for CO_2 pipelines may not be limited to geologic storage projects, as pipelines would likely be needed to transport large quantities of CO_2 for any other process that may be developed for beneficially reusing, or otherwise handling CO_2 at commercial scales. In many instances, CO_2 capture and CO_2 storage or utilization will not occur at the same site.

Developing a transportation infrastructure to accommodate future CCUS projects may encounter challenges regarding technology, cost, regulation, policy, rights-of-way, and public acceptance. However, given that CO_2 pipelines exist today and the similarity of this infrastructure to others that have been developed, such as natural gas pipelines, none of these challenges is expected to be a major barrier to deployment.

There are established methods to acquire or use rights-of-way for CO_2 pipelines. Although California does not have a statute specifically addressing the siting of CO_2 pipelines on state or private land, it is possible they could fall under Pub. Util. Code §227 and §228, which address "pipeline corporations." There is already an extensive system of other pipelines crisscrossing the state. These rights-of-way could be shared by CO_2 pipelines in many urban areas, eliminating the need to establish new routes.

However, CO_2 pipelines to connect some sources with storage sites may cover long distances. Establishing the siting for long pipelines can be extraordinarily complex, and construction through populated or environmentally sensitive areas poses significant challenges. It may be difficult to obtain rights to existing rights-of-way and the lack of eminent domain rights may necessitate costly rerouting. California does not have a statute and there is no federal authority specifically authorizing the use of eminent domain for CO_2 pipelines. Although public utilities in California can exercise the power of eminent domain in certain circumstances, a determination must be made that the eminent domain siting for such a pipeline is a "public utility," in the public interest. Without state condemnation authority, project developers may propose rights-of-way that cross public (federal or state) lands. The ability to get a land use agreement across government lands without the need for eminent domain determination will be a significant incentive but may result in less optimal routing or storage site choices. Long CO_2 pipelines may prove to be impractical, if not impossible, to site without the power of eminent domain.

Current regulations govern the safety of CO_2 pipelines in California. The State Fire Marshal has "exclusive safety regulatory and enforcement authority over intrastate hazardous liquid pipelines"

under the Elder California Pipeline Safety Act of 1981 and has adopted PHMSA's safety regulations for this purpose. While there is some ambiguity (because CO_2 is not a hazardous liquid), it does appear that the State Fire Marshal has the authority to implement these requirements and regulate the safety of any intrastate CO_2 pipelines in California.

There is a particular need for flexibility in any law providing for the rate regulation for services provided by CO_2 pipelines. The need for regulatory flexibility should be balanced with a need to provide potential industry participants with some degree of certainty concerning the applicable regulatory regime. It is unclear because of the current uncertainty as to who will own and operate such facilities, and what business model the providers of these services will use.

The approaches presented below illustrate the range of possible ways to regulate the rates, terms, and conditions of service of CO_2 pipelines and storage facilities.

- CO_2 pipelines' rates and services would be left to commercial contracts.
- An "open access/transparency" model of regulation would require CO_2 pipelines to provide open and non-discriminatory access both to owners of the facilities and to non-owners. This model would also emphasize public disclosure of commercial transactions and terms and conditions of service, but leave the negotiation of the specific rates, terms, and conditions of service to the mutual agreement of the commercial parties.
- A traditional utility model of regulation would establish more detailed regulatory oversight of rates and terms and conditions of service along the lines of traditional public utility regulation. This approach would give a regulator the maximum amount of control over the rates, terms, and conditions of service.

8.3 Utilization for Enhanced Oil Recovery and Storage

As part of the WESTCARB project, the California Geological Survey (CGS) developed a preliminary screening method to identify sedimentary basins in California with the greatest geologic potential for CO_2 sequestration ((Downey and Clinkenbeard 2011). The CGS initially identified and cataloged 104 sedimentary basins that underlie approximately 33 percent of the area of the state. For basins that passed the initial screening, available data were used to make preliminary determinations of potential storage resource capacity.

A total of 27 basins met the screening criteria. Using the methodology developed to support National Energy Technology Laboratory's *Carbon Sequestration Atlas of the United States and Canada,* the CO_2 storage "resource" for the 10 onshore basins was calculated to be between 75 and 300 Gt of CO_2. For oilfields, preliminary estimates are on the order of 1.3 to 3.4 Gt CO_2, and for natural gas fields, from 3.0 to 5.2 Gt CO_2. The preliminary estimates indicate that the resource for geologic storage of CO_2 is ample. For comparison, the CO_2 emissions from power and industrial sources in California are currently about 0.08 Gt per year.

Final selection of any sequestration site in California will require detailed site-specific data and detailed analysis of the subsurface. Clearly, early deployment of CCUS in California will likely involve utilization of captured CO_2 for enhanced oil recovery.

Enhanced oil recovery using CO_2 is commonly practiced in Texas and New Mexico but not in California, due to a lack of local, large-volume CO_2 supplies. The potential for commercial-scale anthropogenic supplies of CO_2 from capture processes applied to in-state facilities is creating increased interest in CO_2-EOR by California oil and gas producers. When CO_2 is used during EOR, sequestration occurs as part of the process. For this reason, public policy that encourages the use of anthropogenic CO_2 for EOR will also be supporting GHG emissions reductions, along with increased domestic energy production.

The technology, operating procedures, and regulatory requirements that have been developed for CO_2-EOR are extensive, mature, and generally appropriate for CCUS. The underground injection of CO_2 for enhanced recovery of hydrocarbons is fully and adequately regulated by U.S. EPA under the Clean Water Act's UIC Program and other environmental regulatory programs (i.e., air, water, and solid waste programs).

In California, regulations may have to clarify whether any CO_2-EOR project seeking sequestration credit (e.g., under AB 32, SB 1368, or the LCFS) must obtain Class II or Class VI permits and what additional state-imposed requirements above EPA Region iX requirements there might be for saline formation sequestration sites. In order to protect business as usual for the EOR industry, many CCS policies (and model policies) in other states categorically exempt all EOR operations from new CCS regulations. However, such exemptions could be interpreted to mean that a CO_2-EOR site would need to meet all standards imposed on saline formation sequestration sites in order to receive sequestration credit. For example, the Interstate Oil and Gas Compact Commission (IOGCC) published model state legislation for regulating geologic sequestration of CO2 that has been followed closely by several states. Under IOGCC's proposal, CO_2-EOR projects would be exempt from the regulations for saline formations unless the site operator wanted to engage in production and sequestration simultaneously, in which case the saline formation sequestration regulations would apply. The CCSReg project developed model federal legislation in 2010 that would require an EOR facility to meet all the permit requirements required of any other geologic sequestration facility in order to be credited under any federal GHG emissions reduction program.

Some early moving states followed the IOGCC model legislation approach. For example, Montana and Wyoming categorically exempt EOR sites from most aspects of their new policies governing geologic sequestration, but provide guidance on how an EOR site could be converted to a geologic sequestration site.

Requiring CO_2-EOR compliance with the same permitting and MVR requirements as saline formation sequestration would ensure that sequestration credits have equivalent environmental value. The climate change mitigation purpose of geologic sequestration in a saline formation is the same as it would be in an oil reservoir. Different MVR standards are difficult to justify unless there is assurance that the standards are can be equally effective. CCS and EOR have fundamentally different purposes (climate protection versus oil production). Regulations attempting to serve both purposes might shortchange one or the other. EOR business-as-usual is most securely protected by a blanket exemption for EOR from sequestration regulations. Under this approach, no additional regulatory requirements would be imposed on CO_2-EOR sites unless they make a choice to become sequestration sites and follow those rules. The extensive knowledge and characterization of oil reservoirs from years of production might justify different kinds of site characterization and MVR

requirements for sequestration in oil and gas reservoirs compared to lesser known saline formations.

Different requirements for CO_2-EOR do not have to be lesser requirements. CO_2-EOR sites are attractive for early projects because of greater availability of site characterization information and the opportunity to offset costs with oil production and sales. Regulations that are not well-designed to accommodate ongoing oil production might be a disincentive for these early projects. If CO_2-EOR sites become regulated as emissions sources (e.g., under the Clean Air Act), fairness would suggest that their sequestration achievements should be acknowledged without requiring the site to meet otherwise inapplicable CCS permit requirements. Otherwise, CO_2-EOR might become uneconomic. An alternative regulatory approach is to assume that EOR and sequestration can and should occur simultaneously at the same site. This approach would require developing regulations that would accommodate active oil production while providing for sufficient MVR and other permitting standards to justify sequestration credits. This type of approach would allow CO_2-EOR to receive credit for CO_2 sequestration while remaining within the EOR regulatory framework (i.e., remaining a Class II injection well). However, for sequestration credit to be given, sufficient MVR and permitting standards will be required, even if they are different than those imposed on saline formation sequestration sites.

In California, this approach might take the form of DOGGR permitting CO_2-EOR injection wells under its Class II authority. Then any CO_2-EOR site wishing to receive sequestration credit would have to opt into additional MVR and other standards that satisfy other regulatory agencies charged with giving sequestration credit for purposes of AB 32, the SB 1368 EPS, of the LCFS. These other agencies might coordinate with DOGGR to have these enhanced standards be included in the Class II permit. As previously discussed, most early CCS policy and policy proposals do not create a method for crediting CO_2-EOR sites with sequestration unless they follow rules established for saline formation sequestration. But there are some examples of policies and proposals that take this approach of customizing regulations for CO_2-EOR:

- Mandatory Greenhouse Gas Reporting Rule, Proposed Subpart RR. As described above, EPA's proposed GHG reporting rule for CO_2 injection would have CO_2-EOR sites opt into the enhanced requirements for saline formation sites if they wish to receive credit for sequestration. Choosing to comply with the enhanced MVR requirements would not require changing the sites regulatory status under the UIC (i.e., changing from regulation under Class II to Class VI) MSD Recommendation. As described above, the Carbon Sequestration Council's MSD group's widely regarded recommendations would alter EPA's proposed geologic sequestration rules to accommodate simultaneous oil production and sequestration under Class II permits.

8.4 Long Term Stewardship and Liability

Although there have been bills introduced on this subject in Congress, there is no federal program for the long-term stewardship of geologic storage sites during the site's "post-closure phase," which is also sometimes referred to as the "stewardship period." This issue remains one of the major challenges for CCS projects. Defining a financially acceptable risk profile for a project is inherently

problematic for CCS projects as by definition CO_2 is to be stored indefinitely or without a defined closure date.

There are three possible approaches in order to provide required insurance for long term stewardship and liability for projects: (1) have the government, state and/or federal, assume all liability and costs, (2) establish a fund by operators and other stakeholders, and (3) purchase insurance coverage. The first has been introduced, at least for initial demonstration projects, but in economically constrained times, both state and federal legislative bodies view the theoretical financial exposure with trepidation. Senate Energy and Natural Resources Committee Chairman, Jeff Bingaman, introduced a bill in 2009 that would establish a national indemnification program for the long-term liability of the US's first large-scale CCS projects. Under this bill,the project operators would pay a small fee per tonne of CO_2 into an industry-wide trust fund that would accumulate money to pay for any future public claims against a sequestration site. It would also allow site operators to transfer liability to the federal government 10 years after their CO_2 plume has stabilized and would allow DOE to incur up to $10 billion in indemnification for any damage that could occur at one of 10 sites. The second approach would place a heavy burden on initial operators due to their small number and the potential large fund that would be required. Thirdly, the insurance industry, as noted above, is wedded to the notion of risk profiles and project closure. Without satisfactory demonstration projects and closure dates of 1,000 years, their ability to provide coverage is limited. The view of insurances companies such as the Zurich Insurance Group is to offer project insurance in stages, recognizing that the highest point on the risk profile is during construction and initial injection, whence thereafter the risks decline. Offering insurance coverage on an annual or three-year basis offers, therefore, a constrained risk profile after which, when risks decline, so too do premiums.

8.5 Improving CCUS Policies and Regulations

Any legal or regulatory framework that is established for permitting CCS projects should be clear and transparent, providing necessary guidance to project developers on specific regulatory requirements. In addition, such a framework should balance regulatory certainty with protecting public health and safety and the environment. Such a framework should aim to:

- Maintain consistency in state permitting requirements for all types of geologic CCS projects.
- Clarify the respective roles and boundaries of each of the agencies while reducing regulatory uncertainty.
- Define and prescribe specific MVR requirements that are appropriate, clear, and effective and that govern the long-term performance of the reservoir.
- Define specific regulatory requirements that provide guidance for early, first-of-its kind geologic CCS projects, until a permanent statutory or regulatory framework is established.
- Quantify and verify the GHG reductions possible through permanent storage of CO2 using advanced and emerging CCS technologies.
- Address facility decommissioning issues in the permitting and regulatory process.

A September 2007 Report by the Interstate Oil and Gas Compact Commission (IOGCC) made a series of specific recommendations for establishing Model General Rules and Regulations which provide a useful starting point for new California laws or regulations. More specifically, the IOGCC recommended rules which:

- Define carbon dioxide as "anthropogenically sourced CO_2 which is produced as a byproduct of combustion in the industrial process" and not geologically occurring CO_2.
- Recommend that a single state regulatory agency be identified with full authority to regulate CCS projects, which involve oil and gas development and deep saline formations, and issue a permit to operate a CO_2 storage facility.
- Recognize that the designated state regulatory agency have the authority to require an operator to submit any data necessary to evaluate a proposed CO_2 storage project.
- Specify model procedures and standards for permitting and operating CCS projects.
- Identify as an issue what happens when an oil and gas EOR project operating under oil and gas leases converts to a CO_2 storage project for purposes of regulation.
- Identify the need for a comprehensive monitoring and verification process for the sub-surface reservoir operation that provides for early detection of any leakage or any releases of CO_2, and prescribes mitigation measures to protect public health and safety.

In addition, guidance on how to establish a model permitting process for CCS projects can be found in proposed California state legislation, Assembly Bill 705, as proposed in 2007, which were previously discussed.

The California Permit Streamlining Act of 1977 was enacted as a way of addressing a complicated and often uncoordinated permit process. This Act added a series of timelines and deadlines to expedite government permitting of industrial development projects. In other words, it enacted a calendar of events by which a permit applicant could expect prompt review of a development project.

Under the Act, if a public agency does not approve or deny a project within the statutory time limit, the project is deemed approved. The Act establishes that the lead agency must approve or deny a project within six months of certifying an Environmental Impact Report (EIR), or within three months of adopting a Negative Declaration. Other agencies, who are not the lead agency, must the act within six months from the time a permit application is filed.

In California, the permitting process is coordinated with the environmental review process required by CEQA. A lead state agency, typically the first agency to act on a given project, determines whether a project is exempt from CEQA or whether it must require a negative declaration, mitigated negative declaration, or an EIR. It is the responsibility of the lead agency to involve other permitting agencies so that a coordinated environmental review results.

However, multi-agency permitting, if it is not conducted on parallel timeframes or closely coordinated by the lead agency, can be time-consuming and costly for developers, including CCS project developers. If public opposition to a given project surfaces during the permit or

environmental review process, the project can be further delayed. Furthermore, court challenges of a permit decision made by a permitting agency can add considerable time to the development process. Lastly, permitting agencies can reject applications from developers as incomplete, which increases the time frame for completing the process, or they can deny a permitting application within the required timeframes. As a result, the permitting timeframes established in the 1977 Permitting Act are not always strictly adhered by permitting agencies, and are difficult to enforce.

Coordination among regulatory agencies can be further improved through Memoranda of Understanding, especially where there is overlap or the potential for duplication of regulatory requirements. In California, MOUs have been established for the permitting of geothermal energy projects on federal lands, the joint review of Solar Thermal Power Plants, and the review of wave energy projects by the Federal Energy Regulatory Commission and California agencies. Similar MOUs for the permitting of CCS projects in California would be helpful in clarifying regulatory jurisdiction and in improving interagency coordination. An MOU can also serve to designate the lead agency. However, an MOU cannot cure inherent statutory conflicts in existing laws and regulations, and must be evaluated further on a case-by-case basis.

The California CCS Review Panel identified a number of key legal and regulatory issues that require greater clarity and possible legislative action before CCS can be broadly deployed as a GHG mitigation measure under state laws and policies to reduce CO2 emissions. Key questions identified by the panel include:

- Will CCS be eligible to meet the requirements of AB 32 or other relevant California laws and policies?
- Is there a clear regulatory framework and related permitting pathway for CCS projects in California?
- Are there clear agency rules that would allow for early CCS demonstration projects in California?
- What additional considerations must be addressed and resolved to allow for deploying CCS?

The panel made recommendations for consideration by the three principal agencies that created the panel as well as the state legislature (California Carbon Capture and Storage Review Panel, 2010), as follows:

1) The state should recognize appropriately regulated CCS as a measure that can safely and effectively reduce atmospheric emissions of CO_2 from relevant stationary sources, including power plants and other industrial sources. To that end, and conditioned on compliance with all applicable federal and state requirements, CARB should:

a) For capped sources under AB 32, recognize CO_2 sequestered by CCS projects as having not been emitted to the atmosphere (with the result that an allowance is not required to be held for each tonne of CO_2 that is captured and geologically stored) and define accounting protocols for sequestered CO_2; and,
b) For uncapped sources under AB 32, decide whether offset protocols for CCS projects within the State should be adopted.

2) The state should evaluate current EPA regulations and determine which, if any, State agency should seek "primacy" for permitting Class VI wells under the UIC program.

3) The state should designate the Energy Commission as the lead agency under the CEQA for preventing significant environmental impacts in CCS projects (both new and retrofit projects).

4) The state should clarify that the State Fire Marshall is indeed the lead agency for regulating the safety and operation of intrastate CO_2 pipelines.

5) The Energy Commission should consult with the responsible permitting agencies in carrying out its responsibilities as the CEQA lead agency for CCS projects. Specifically, the Energy Commission should:

a) Designate the DOGGR to be the responsible agency for activities related to the subsurface.

b) Coordinate the development of performance standards for CCS sites that would include design requirements and other operational measurements consistent with the goals of protecting the groundwater and preventing emissions of CO_2 to the atmosphere.

c) Designate CARB as the responsible agency for air related aspects of CO_2 MVR requirements.

d) Designate the State Fire Marshall as the responsible agency for CO_2 pipelines.

e) Designate the State Water Board as the responsible agency for impacts to water quality.

f) Designate other agencies as appropriate.

6) The state should consider legislation establishing an industry-funded trust fund to manage and be responsible for geologic site operations in the post-closure stewardship phase. In addition, California should proactively participate in federal legislative efforts to enact similar post-closure stewardship programs under federal law.

7) The state legislature should declare that the surface owner is the owner of the subsurface "pore space" needed to store CO_2. The legislature should further establish procedures for aggregating and adjudicating the use of, and compensation for, pore space for CCS projects.

8) The state should consider whether legislation is needed to extend to CO_2 transportation infrastructure for CCS projects the current authority for acquiring the rights of way for the siting of transportation infrastructure for natural gas storage projects.

9) It should be state policy that the burdens and benefits of CCS be shared equally among all Californians. Toward this end, the permitting authority shall endeavor to reduce, as much as possible, any disparate impacts to residents of any particular geographic area or any particular socio-economic class.

10) The panel endorses the need for a well-thought-out and well-funded public outreach program to ensure that the risks and benefits of CCS technology are effectively communicated to the public.

11) The state legislature should establish that any cost allocation mechanisms for CCS project should be spread as broadly as possible across all Californians.

12) The state should evaluate a variety of different types of incentives for early CCS projects in California and consider implementing those that are most cost-effective.

The California CCS Review Panel (2010) concluded that CCS-related site access rights could be legislatively addressed through a relatively small change to the language in existing statutes that provide authority for natural gas storage. The legislative action would be to amend the current language to include CCS. The authority in existing California law for underground natural gas storage condemnation is in the CPUC. A few extra steps are necessary to include such language in the statutory authority of the Energy Commission. The California CCS Review Panel's technical advisory committee prepared a white paper *Establishing Eminent Domain Authority for Carbon Storage in California*, which provides sample amendments to extend condemnation authority to carbon sequestration facility operators following the natural gas storage model. The Review Panel concluded there are pros and cons to legislative action in this area, and such legislation should be approached with caution due to the public interests and sensitivities. However, legislation authorizing the use of eminent domain for CO_2 pipelines would likely further the implementation of carbon sequestration to the extent it does not lead to opposition against projects.

8.6 Financial Support

Financial incentives to encourage investment in CCUS demonstrations and early commercial projects tend to address one of three cost centers: capital cost, financing cost, and operating cost. Examples of federal incentives that reduce the capital cost of CCUS projects are investment tax credits and DOE cost share grants. An example of an incentive that reduces the cost of financing (and increases the likelihood of financial closure) is the DOE loan guarantee program. Examples of incentives that reduce net operating costs are federal carbon sequestration tax credits (i.e., the Section 45Q credits in the Energy Improvement and Extension Act of 2008) and accelerated equipment depreciation schedules.

State government incentives can also address these cost centers through programs similar to those offered by the federal government, such as investment tax credits and accelerated depreciation, and through credits or exemptions to taxes uniquely imposed at the state/county level, such as property taxes. California currently offers, for example, a property tax exemption for certain investments in renewable energy technologies.

Utility rate regulation is another area where states traditionally have jurisdiction. In many states, Public Utilities/Service Commissions have authority over cost recovery for power plants built or owned by investor-owned utilities, and for long-term power purchase contracts by investor-owned utilities from plants developed and operated by independent generators. Public Utility Commissioners can approve "above market" costs for power from generation sources deemed to be in the public interest, although such above-market costs may adversely affect regulated utilities' competitiveness in the retail electric market. In states where customers have access to energy service providers other than a local investor-owned utility, such as California, cost allocation mechanisms may be needed to socialize the above-market costs to all customers so that investor-owned utility customers alone do not bear the cost for the public-interest benefit. Because the CPUC has jurisdiction over only a portion of the California's electricity service providers, the Legislature would need to establish such cost allocation mechanisms for power plant CCUS applications.

The CPUC has authorized rate recovery for feasibility studies of integrated gasification combined cycle plants with CCUS in exchange for public release of study results. Other states have a mixed record of support for such study costs, with some regulatory commissions approving, and some denying, rate recovery requests.

Where CO_2 emissions are regulated, annual allowances for emissions have been distributed to affected sources on the basis of historic emissions or benchmark values or via auction, or some combination thereof. In cases where allowances are auctioned, various proposals have been made to direct the resulting revenue to new technology demonstrations. For example, revenue from the NER300 in the European Trading Scheme will be directed toward renewables and CCUS demonstrations. Elsewhere, energy bill assistance for low-income households has been proposed. Bonus allowances for early CCUS adopters have also been proposed as a means to offset competitive challenges in the years immediately following application (e.g., proposed Waxman-Markey federal legislation in 2008). ARB could designate, within the California cap-and-trade program, that allowance value is used to encourage early applications of CCUS through allocation schemes or through the designation of CCUS as a GHG-reducting technology. It could allow allowance auction or electrical distribution utility auction proceeds, to be used to facilitate CCUS.

One rationale for California "topping off" federal CCUS incentives is the recognition that costs for land, labor, materials, and utilities tend to be higher in California than the national average (by perhaps 20 percent on a blended average basis), and thus a higher total value of incentive may be required to engender the desired degree of market response. Given current budget challenges and the myriad approaches available for incentives, California should evaluate its options to encourage early CCUS projects in California and consider implementing those expected to be the most effective.

Because CCUS changes the production cost profile of power plants or other industrial manufacturing operations, they may be temporarily uncompetitive relative to plants without CCUS, particularly in the era immediately after regulations take effect, when allowance price caps and other measures limit the price of CO_2 emission allowances. For power plants with CCUS, for example, high dispatch rates are essential to minimizing levelized cost impacts on a per-kWh basis. The California Independent System Operator (dispatch center) has mechanisms to prevent dispatch curtailment for fossil power plants with CCUS, typically designation as "must run" units. There has been considerable activity on the federal level that impacts CCUS from a regulatory and institutional perspective. However, politic ambivalence about the seriousness of climate change and the role of CO_2 is its cause has limited legislative progress.

In September 2012, federal Senate bipartisan legislation to advance deployment of CO_2-EOR in the U.S was based upon recommendations of the National Enhanced Oil Recovery Initiative (NEORI) to spur new EOR projects by modifying the existing carbon capture and storage tax incentive that would provide a credit of $10 per ton of industrial CO_2 used in EOR projects and $20 per ton for CO_2 placed directly in secure geological storage. Such tax credits result in a scaled cost reduction. For the first power plant to capture and deliver CO_2 would face a cost of $70 per tonne, according to NEORI. Projects two through five would face costs of $60 per tonne, and for projects six and on, the costs would fall to $55 per tonne. If the technology moves down the learning curve rapidly, the market could take over. Oil companies would buy the new, cheaper CO_2. To get into that market, more and

more factories would use carbon-capture technology, reducing its costs even further. As the power sector causes some 40 percent of U.S. carbon emissions, it would offer the biggest potential addition to CO_2 supplies. NEORI has estimated that the tax credit alone will quadruple EOR oil production to 400 mbl while cutting CO_2 emissions by 4 Bt over 40 years.

Some policymakers, environmentalists and energy producers think CCS could piggyback on oil production and create a CO_2 market that does not really exist today. Until quite recently, EOR has never been considered a leading source of oil, but now many consider that it can play a larger role to assist at a significant level oil production. In May 2012, DOE said that EOR accounts for about 5 percent of U.S. oil production currently, but an expanded practice could supply 20 to 30 percent. One principal limitation is the shortage of CO_2. About 65 percent of the CO_2 for EOR comes from natural sources in the ground, and another 20 percent comes from CO_2 that arises naturally during natural-gas drilling. Increasingly, EOR operations are looking to anthropogenic sources of CO_2 to provide ample supplies and in turn reduce its market price, a step toward catalyzing a new market that could very quickly be taken over by the private sector. EOR could provide a huge new market for CO_2, providing a financial incentive for factories and power plants to capture the gas. This approach targets a major weakness of CCS: the current high cost of capturing CO_2. If power plants and factories could sell the CO_2 on the market, that could help them cover some of the high cost of the technology.

CHAPTER 9: Conclusions

The study team reviewed the case for implementing CCUS in California based upon recent technical advances, economic conditions, and GHG mitigation strategies both within California and in other parts of the world serving as examples from which to adopt or avoid. They have posed the following questions and suggest the following responses:

1. *In what sectors does CCUS have the most potential to assist the state in reducing its CO2 emissions?*

   CCUS has potential application to the power, transportation and industrial sectors in California. Studies show that increasing electricity demand will continue, with aggressive energy efficiency measures expected to contribute only about up to about half of the GHG reductions necessary by 2050. For refineries and cement plants, there are no options other than carbon capture to address process-related emissions. Applications to transportation, including to biofuels, hold promise to create net-negative emissions to assist in offsetting emissions from sources where no technology or method exists to reduce emissions.

2. *Do policies to facilitate CCUS enable continued use of fossil fuels even where there may be other viable options for energy generation?*

   Given the substantive efforts underway to diversify California's energy portfolio away from carbon-intensive fossil fuels, it appears likely that CCUS may only be included by policy when studies have demonstrated that no other options are available to decarbonize the electricity, transportation or industrial sectors. Given that both transportation and industrial sectors are likely to decarbonize by using carbon-free electricity, these sectors become dependent on the power sector for their energy supplies. Thus, it will become even more vital to California's economy to assure the reliability and sustainability of low cost electricity supplies.

   Facilitating CCUS should not be viewed as a substitute for non-fossil fuel based solutions to reducing GHG emissions in contributing economic sectors. However, economies developed since the Industrial Revolution on fossil fuels and are inherently designed to take advantage of the benefits that fossil fuels provide. Among these benefits are high energy density, on-demand power generation, and relatively low cost. As fossil fuels have been exploited to improve the economic well-being, there are down sides—local to global environmental consequences and, in particular, CO_2 increases leading to an unprecedented and unintended global experiment in climate change. Given the difficulties of integrated large fractions of any other alternative energy sources (e.g, nuclear, renewables), CCUS provides a compromise solution for economies to remain strong while eliminating one of the negative consequences of continued fossil fuel use. CCUS is not a substitute for development of CO_2-free technologies, but it deserves consideration and inclusion by policymakers as a bridging technology.

3. *Are CCUS technologies, specifically subsurface storage elements, safe and effective over the long term?*

CCUS projects worldwide and analog projects provide data which support the assertion that CO_2 can be stored safely in the subsurface for sufficiently long periods of time t mitigate climate change. Furthermore, these projects have tested a number of tools, including monitoring technologies, simulations, well completion methods and well and cap rock integrity monitoring to give regulators confidence that risks are measureable and monitor-able. For California, areas of particular concern are assuring safety of groundwater resources from contamination and seismic hazards, including whether pressure buildup can induced felt-earthquakes and if the presence of stored CO_2 is likely to exacerbate risks of natural seismic hazards

4. *How can California agencies and lawmakers assure that CCUS projects are appropriately permitted, regulated, monitored, and verified?*

   Regulations and statutes require some changes to accommodate permitting and regulatory oversight of CCUS projects. There is a robust and growing body of knowledge worldwide that can be drawn upon to formulate permitting and regulatory requirements that assure the safe and effective operation of CCUS projects. With the enactment of policies requiring attention to climate change impacts, agencies are now tasked with safety and effectiveness responsibilities that encompass both traditional local environmental and, now, global climate change mitigation responsibilities.

   An important priority for regulation is including CCUS as an option for meeting obligations set by compliance or standard requirements. Beyond mentioning CCUS as an option, methodologies that describe how storage or utilization technologies must account for CO_2 must be developed so that project developers can incorporate them into business cases. Policies that support a sustainable and predictable value for CO_2 are critical to enabling CCUS technologies.

5. *Can the state's industrial and energy infrastructure accommodate the changes necessary to integrate CCUS?*

   In general, CCUS requires less change in existing energy infrastructure than most other options for decarbonizing the power, transportation, and industrial sectors. Infrastructure requirements include capture facilities at CO_2 emission sources, pipelines, and injection and monitoring wells at storage sites. In addition, a labor force with expertise in power plant, pipeline, and well drilling engineering is necessary. Capture facilities will be paid for by power producers. It is a policy decision as to whether these costs should be passed on to consumers by investor owned utilities.

   California will require substantial investment in pipeline infrastructure for CCUS to become widespread. Because a readily available supply of low cost CO_2 would benefit California's oil industry, that industry and federal subsidies for oil production may be sources of capital for pipeline development. California's CCUS project developers may be able to repurpose or co-utilize some existing infrastructure at California's numerous oil and natural gas fields if storage is done in conjunction with CO_2-EOR or by conversion of depleted reservoirs to storage sites. Storage in saline formations will require new infrastructure and development to assure safe and effective long term storage. California has plentiful geologic storage

resource to accommodate captured emissions, according to studies by the California Geological Survey.

California's labor force includes people with the right expertise to support a CCUS industry. The state is home to many small start-up companies, universities and other research organizations developing utilization technologies, and there is sufficient venture capital to fund the most promising ones. The Energy Commission has already made some investment of public funds to support growth of this sector. More public funding, possibly through cap-and-trade or EPIC programs, would accelerate development of better more cost-effective capture and innovative utilization technologies. California lacks experience in construction of high capacity CO_2 pipelines, and experts may need to be brought in from other states—over 6,400 km of pipeline carry gas from natural CO_2 domes to major oilfields throughout the Rocky Mountain, central and southern states.

6. *If CCUS is to be relied on to reduce significant fractions of California's future emissions, at what rate should CCUS projects be coming on line, and what pathways to commercialization can accommodate this rate?*

If CCUS is to be a viable option for the state to use to address GHG emissions to meet its 2050 reduction goal, a large number of projects must be initiated within the next ten years. CCUS projects are large, industrial projects that require decades to plan, finance, permit, and construct. Given that over 50 percent of CCUS projects worldwide have been halted at various points within early project phases prior to actual construction, many more projects should be in development than might actually be needed to reach the 2050 goal. Capture, injection, utilization, and storage operations must then continue for at least several more decades in order to have a measureable cumulative impact on GHG emissions reductions. The size of each project is limited by the size of the point sources, and number of point sources in the case of networks, that supply CO_2 to one or more storage sites. The number of injection wells and additional pipeline to connect a well array will depend on the injectivity and storage capacity of the formation(s); thus storage site development may continue for many years after injection operations begin.

Rates of CCUS technology adoption must be sufficient to create a declining trend in GHG emissions with the right slope to intersect 80 Mt or less total emissions by 2050. It is an oversimplification to assume that technology adoptions between 2013 and 2050 will result in a linear reduction of emissions with time, but it serves to give a first-order approximation of the size of the task. With every year of delay in implementation of GHG reduction technologies, the slope becomes steeper. If the 2020 cap on new emissions is maintained after 2020, about 10 Mt per year must still be removed every year to reach the 2050 goal. This is equivalent to removing several of California's largest point sources from the emissions inventory every year.

The most expedient way to enable CCUS from an economic and infrastructure perspective is to enable utilization of captured CO_2. The largest potential uses for CO_2 are for EOR, followed by building materials as a distant second. At current oil prices, CO_2 commands about $40/tonne for EOR. The state could benefit from substantive royalty revenues and job

creation through the enhanced production that might be realized by using captured CO2 in this way. Oilfield infrastructure might shorten the lead time for CCUS projects to become operational. While enabling fossil fuel production via CO_2 storage seems ironically counterproductive, there is actually significant CO_2 storage accomplished during EOR operations, and locally produced oil is preferable for several reasons over importing oil into the state. While the need for crude oil- based transportation fuels will presumably decline to zero by 2050, it is unlikely that the need for petroleum for manufacture of plastics and other materials will be completely eliminated by biologically based feedstocks. Estimates of CO_2-EOR potential in California's oilfields suggest that there should be a large enough demand for CO_2, provided oil prices remain high in the coming decades, to accelerate CCUS commercialization. Furthermore, building material CO_2 utilization technologies under development may prove to be some of the most cost effective ways to separate CO_2 from power plant flue gas, even though end products may not support paying high prices for CO_2—it may be a more cost-effective option for emitters than capture and sales for other utilization purposes.

7. *In state planning for future energy infrastructure, should CCUS be included as a component? What is the risk in not doing so?*

California regulatory agencies and policymakers have acknowledged the potential importance of CCUS technology to assist the state in meeting its GHG emission reduction goals. However, CCUS has not been given as high a priority as many other mitigation technologies when it comes to incentivizing adoption through policies or regulation. Without actions prior to 2015 that would incorporate CCUS into the portfolio of accepted mitigation technologies, especially actions to develop accounting and regulatory methodologies, it becomes less and less likely that enough CCUS projects will be up and running to contribute substantive emissions reductions in time to meet 2050 goals. All studies done to date of California's future energy options suggest that the 2050 goal cannot be met without CCUS; therefore the risk of missing the target is high unless CCUS is included. Inclusion of CCUS means adding it to planning of future energy infrastructure.

Admittedly, because CCUS is a composite of technologies and comes in a variety of incarnations, accommodating it in planning is a complex task. Given the complexity of future energy infrastructure and the extreme nature of its makeover over the next decades, it will be almost impossible to patch in additional technology options after long term plans are adopted. For these reasons, California will lower its GHG emissions risk by accelerating policy, regulatory and practical actions that contribute to including CCUS as a GHG emissions reduction option.

GLOSSARY

Term	Definition
ADB	Asian Development Bank
ANL	Argonne National Laboratory
BACT	Best Available Control Technology
Bbl	Billion barrels oil
Bcf	Billion cubic feet
Bgge	Billions of Gallons of Gasoline Equivalent
Bt	Billions of tonnes
BTU	British Thermal Units
CAA	Clean Air Act
CARB	California Air Resources Board
CCCT	Combined Cycle Combustion Turbine
CEQA	California Environmental Quality Assessment
CERCLA	Comprehensive Environmental Response, Compensation, and Liability Act
CES	Clean Energy Systems, Inc.
CCS	Carbon Capture and Storage
CCST	California Council on Science and Technology
CCUS	Carbon Capture, Utilization, and Storage
CO_2	Carbon Dioxide
CO_2e	Carbon Dioxide Equivalent
CO2e/MJ	Carbon Dioxide Equivalent per Megajoule
CPUC	California Public Utilities Commission
DoD	U.S. Department of Defense
DOE	U.S. Department of Energy
DOGGR	California Division of Oil, Gas, and Geothermal Resources
ECBM	Enhanced Coal Bed Methane
EGR	Enhanced Gas Recovery

EGS	Enhanced Geothermal Systems
EIA	Energy Information Agency
EJ	Environmental Justice
EMR	Electricity Market Reform (UK)
EPA	U.S. Environmental Protection Agency
EPC	Engineering, Procurement, and Construction
EPS	Emissions Performance Standard
EOR	Enhanced Oil Recovery
ETS	Emissions Trading Schedule
EU	European Union
GCCSI	Global Carbon Capture and Storage Institute
GHG	Greenhouse Gas
GIS	Geographic Information System
Gt	Gigatonnes (10^9 tonnes)
GWh	Gigawatt hour
HECA	Hydrogen Energy California
HRSG	Heat Recovery Steam Generator
HPT	High Pressure Turbines
HVAC	Heating, Ventilation, and Air Conditioning
Hz	Hertz
ICCS	Integrated
IEA	International Energy Agency
IGCC	Integrated Gasification Combined Cycle
IOGCC	Interstate Oil and Gas Compact Commission
IPCC	Intergovernmental Panel on Climate Change
IPT	Intermediate Pressure Turbines
ITC	International Test Centre, Canada
Kg/m^3	Kilograms per cubic meter
KHz	Kilohertz (10^3)

KWth	Kilowatt hour
LBNL	Lawrence Berkeley National Laboratory
LCFS	Low Carbon Fuel Standard
LIDAR	Light Detection and Range-Finding
LNG	Liquified Natural Gas
LPT	Low Pressure Turbine
Mbl	Million barrels oil
mD	Millidarcy
MEA	Monethanolamine
Mgge	Million gallons gas equivalent
MMscf	Million standard cubic feet
MOU	Memorandum of Understanding
Mscf	Million Standard Cubic Feet
Mt	Million tonnes
MSD	Multi-Stakeholder Discussion Group
$MTCO_2e$	Metric ton of CO_2 Equivalent
MVR	Monitoring, Verification and Reporting
MW	Megawatt
MWe	Megawatt Electrical
MWth	Megawatt hour
NATCARB	National Carbon Atlas
NASA	National Aeronautic and Space Administration
NEORI	National Enhanced Oil Recovery Initiative
NEPA	National Environmental Policy Act
NER300	New Entrants Reserve Program
NETL	National Energy Technology Laboratory
NGCC	Natural Gas Combined Cycle
NGO	Non-governmental Organization
NRL	National Renewable Laboratory
OECD	Organisation for Co-operation and Development

O-F	Oxygen Fuel
PG&E	Pacific Gas and Electric Utility Company
PHMSA	Pipeline and Hazardous Materials Safety Administration
Psia	Pounds per Square Inch Absolute
PSD	Prevention of Significant Deterioration
R and D	Research and Development
RCSP	Regional Carbon Sequestration Program
ROAD	Rotterdam Opslag en Afvang Demostratieproject (Holland)
RPS	Renewable Portfolio Standard
SECARB	Southeast Regional Carbon Sequestration Partnership
SMUD	Sacramento Municipal Utility District
SWDA	Safe Drinking Water Act
TCEP	Texas Clean Energy Project
Tcf	Trillion Cubic Feet
TCM	Technology Centre Mongstad (Norway)
TRL	Technology Readiness Level
TWh	Trillion Watt hours
UIC	Underground Injection Control
USDW	Underground Sources of Drinking Water
WESTCARB	West Coast Regional Carbon Sequestration Partnership
μm	Micrometer (10^{-6})

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APPENDIX A:
Review of Relevant CCUS Activities in North America

Projects

During the past decade significant investment has been made in an effort to prove and improve CCUS technology in time for full-scale commercial use. Although CO2 injection has been used for enhanced oil and gas production for decades, permanent geological storage integrated with power plants and industrial facilities is considered to be emerging technology. Accordingly, CCUS must be successfully demonstrated with an array of small, and intermediate and large-scale CO2 injection field tests in diverse geologies to adequately characterize and validate the geologic resource.

In the United States, building on the extensive experience with EOR and natural gas storage, the U.S. Department of Energy, led by National Energy Technology Laboratory (NETL), is pursuing the Sequestration Research, Development, and Demonstration Program in partnership with industry and academia. A key element of the Program is the Regional Carbon Sequestration Partnership (RCSP) program, which encompasses 43 states and four Canadian provinces represented by seven RCSPs. This program includes key field tests throughout the United States and Canada to fully characterize geologic storage sites, to validate models, to validate prior findings, to develop MVR instrumentation. The field-scale investigations underway as part of the RCSP program will provide direct observations on the behavior of CO2 underground, building confidence that the key phenomena are well understood and that CO2 can be injected and stored safely. The DOE has completed a comprehensive effort on risk assessment that utilizes these investigations (along with a strong science base) to develop a sound framework for ensuring that each specific storage site is properly chosen and developed for safe, long-term storage.

The development of these seven projects has since their inception in 2005 reflected to some large degree the variable geology across North America, access to CO2 supplies for demonstrations. The fragmented, heterogenous geological structure of the western states has made the characterization and selection of suitable sequestration sites more challenging, especially in remote areas where oil and gas well data are sparse or non-existent. In this section we present a summary of a selection of projects by the regional partnerships and other entities in order to put the development of CCS in California within a broader North American context.

While progress has been made at the technical level in many projects, the policy and regulatory frameworks applicable to these projects has not progressed as quickly. Anticipated carbon prices that are consistent with a stable policy environment and comprehensive regulatory mechanisms remain an urgent need in order for capital investment to move this industry forward at a pace to meet GHG targets.

The US leads the world in terms of commercial-scale CCUS projects that are either in the final stages of project planning or have taken final investment decisions and moved into a construction phase (Myer, 2011). What distinguishes projects in the US (and Canada) from the rest of the world is that virtually every active project incorporates a significant EOR consideration.

Evidence suggests that CO2 can command, in the right circumstances, a price of up to US$40 per ton at the plant gate under long-term off-take contracts. These pricing signals (far in excess of the EU ETS price) when coupled with other government support mechanisms are sufficient to drive CCUS project financing for at least some projects. The current low natural prices have stalled the development of CCS as applied to coal-based power plants, hindering the anticipated rapid deployment of CCS commercial demonstrations.

Regional Carbon Sequestration Partnership Program

The Midwest Geological Sequestration Consortium is an alliance of Archer Daniels Midland, the Illinois State Geological Survey, Schlumberger Carbon Services, and Richland Community College with funding from the DOE. This partnership was established to assess the safety and capacity of geologic carbon storage options in the Illinois Basin, a 155,400-km2, oval-shaped, geologic feature. Within the basin there are deep, uneconomic coal resources, numerous mature oil fields, and deep saline formations with potential to store CO2. The Midwest Geological Sequestration Consortium is testing the capability of the three types of reservoirs identified within the basin to serve as storage formations for some of the more than 265 Mt of annual CO2 emissions from major industrial stationary sources in the Illinois Basin. The Illinois Basin region contributes about 11 percent of the total U.S. CO2 emissions from electric power generation plants. Coal is the dominant fossil fuel for these plants and contributes 97 percent of the Illinois Basin CO2 emissions from stationary sources of electricity.

This CO_2 is a product of fermentation from an ethanol plant and is being injected into a site adjacent to the plant. The ICCS project will demonstrate commercial-scale carbon capture and storage through the construction and operation of a collection, compression and dehydration facility capable of delivering 2,755 tons per day of carbon dioxide to the injection and sequestration site. The project will capture a total of more than 2.5 million tons of carbon dioxide and store it approximately 2,335 m underground in the Mount Simon Sandstone.

The commercial-scale ICCS project will build on the knowledge and infrastructure from the Illinois Basin—Decatur project, which was announced in January 2008. The Illinois Basin—Decatur project will inject carbon dioxide from Archer Daniels Midland's Decatur ethanol facility into the Mount Simon Sandstone at a rate of 1,100 tonnes per day for a total of 250 million tonnes. The ICCS project is a full-scale commercial project designed to capture and store two and a half times more carbon dioxide than the initial Illinois Basin—Decatur project.

Over the course of three years, the Illinois Basin—Decatur and ICCS projects together will inject up to 3.6 Mt of CO2 – roughly the same amount generated by more than 715,000 automobiles in a year – into the Mount Simon rock formation.

Public outreach and communication has been and continues to be a priority during both the Validation Phase and Development Phase efforts. During the Validation Phase, the MGSC produced project-specific brochures for local landowners that focused on describing the project and the type of activities landowners could expect to see in the area during the project. Monitoring, verification, and accounting personnel, project management, and field personnel spoke with local officials and landowners to notify them of activities associated with the project and to answer any questions. Since the announcement of Development Phase, the MGSC has focused on outreach surrounding

the Illinois Basin-Decatur Project. A variety of outreach materials, including fact sheets, posters, presentations, and models, have been utilized to provide information about the project specifics and CCS in general to all major stakeholders in the Decatur area.

The Plains CO2 Reduction Partnership (PCOR) is working in northwestern Alberta, Canada, at the Zama oil field, a site of acid gas (approximately 70 percent CO2 and 30 percent H2S) injection for the simultaneous purposes of commercial EOR, H2S disposal, and storage of CO2. The target injection zone at Zama is a Devonian age carbonate pinnacle reef structure with the seal provided by a thick overlying anhydrite. Continuous injection has taken place at a depth of 1,635 m into the carbonate pinnacle reef structure since December 2006. As of January 11, 2011, approximately 63,500 tons of CO2 had been injected while oil production totaled about 51,400 stock tank barrels.

The PCOR Zama project has focused on three primary issues: 1) determination of CO2 and/or H2S leakage, or lack thereof, from the pinnacle; 2) development of reliable predictions regarding long-term fate of injected acid gas; 3) generation of data sets that will support the development and monetization of carbon credits associated with the geologic sequestration of CO2.

Geological, geomechanical, geochemical, and engineering work has been used to fully describe the injection zone and adjacent strata and to predict the long-term storage potential of this site. Results of geological investigations showed that the natural regional hydrologic flow is extremely slow, so that migration of CO2 out of the basin by this process would take on the order of thousands to tens of thousands of years. The potential for leakage through existing wellbores was also evaluated and found to be very low. Geomechanical evaluations showed that the caprock is unlikely to fracture when subjected to injection pressures well beyond the maximum allowed. Geochemical modeling indicated that the impact of mineralization on the overall storage capacity of the Zama system is negligible and will occur very slowly over geological time scales.

PCOR concludes that confidence in the ability of the Zama oil field to provide long-term containment of injected gas has been achieved (Smith et al., 2009). While this project has been focused on one of the hundreds of pinnacles that exist in the Zama Field, many of the results obtained can be applied not only to additional pinnacles in the Alberta Basin, but to similar structures throughout the world.

From 2007 to early 2010, the Southwest Regional Partnership on Carbon Sequestration conducted an EOR, combined with sequestration injection, into the Aneth Oil Field in the Paradox Basin. The Partnership injected approximately 630,000 tonnes into formations approximately 1,935 m deep, in the Aneth Oil Field in San Juan County near Bluff, Utah. The injection schedule ran for over two years and post-injection monitoring continues. The source of CO2 for this project comes from the McElmo Dome, a natural CO2 reservoir located in southwestern Colorado.

In the San Juan Basin in Northwest New Mexico, approximately 16,700 tonnes of CO2 was injected into the unmineable Upper Cretaceous coal seams at depths greater than 900 meters. It was observed that the injection rate declined, which was attributed to coal swelling that can be a result of the CO_2 being adsorbed onto the coal while it is displacing methane. A variety of monitoring methods were deployed to track the CO_2 plume migration, including tilt meters, CO2 sensors, and tracers, which were injected along with the CO_2. The arrival of perfluorocarbon tracers at offset wells, in conjunction with observed nitrogen increases, provided indications of preferential

breakthrough paths. Analysis of available 3D seismic data did not reveal any faults or fracture zones that could provide leakage pathways. A very thorough simulation model was built and was able to replicate the production and injection behavior of the injection zone, showing an incremental methane production of 26MMscf due to injection.

The Southeast Regional Carbon Sequestration Partnership's (SECARB) Gulf Coast Stacked Storage project has demonstrated the concept of phased use of subsurface storage volume that combines the early use of CO_2 for EOR with subsequent injection into associated saline formations, resulting in both short- and long-term benefits. There is the immediate commercial benefit of EOR as a result of the injection of CO2 (offsetting infrastructure development costs), followed by large volume, long-term storage of CO2 in saline-bearing formations. Saline formations are the primary CO2 geologic storage options for the SECARB region because so many underlie power plants in the area. In fact, SECARB's research estimated a total of 2,274 Bt of potential sequestration in saline formations in the region underlie Alabama, Florida, Louisiana, Mississippi, East Texas, and Tennessee. The Mississippi Test Site project was successfully conducted in October 2008 and examined a regionally significant deep saline reservoir for geological storage of CO_2. In this area, the Massive Sand Unit of the Lower Tuscaloosa Formation has been identified as a high capacity CO_2 storage option. Mississippi Power Company's Victor J. Daniel Power Plant, located near Escatawpa, Mississippi, was the site for the demonstration. The project team is led by the Electric Power Research Institute and Southern Company.

As part of the RCSP Validation Phase, over 1 Mt of CO_2 has been injected into the lower Tuscaloosa Formation in the Cranfield unit, located in southwestern Mississippi, at a depth of 3,700 meters. CMG-GEM, a multiphase compositional flow simulator, has been used for modeling the behavior of the CO_2 in the reservoir (Choi et al., 2010). As part of the monitoring program, high resolution pressure data, collected in the reservoir at a dedicated observation well, showed a response to increased injection rates at a distance of over 1 km. Results showed that, although the fluvial reservoir is stratigraphically complex with multiple incised channels, pressure communication is good (Hovorka et al., 2010). The depth of this well presents challenges for monitoring the injectate behavior: Electrical Resistance Tomography has been applied in this well and has been effective in providing near real-time assessments of CO_2 movement at depth, which is valuable for pressure monitoring and active risk management (Carrigan et al., 2013)

This project is significant in that it has demonstrated the capability and value of utilizing pressure data collected in monitoring wells to establish compartment boundaries, which would be of particular value in future sequestration projects which lack production history. The advantages of this phased development are short-term, large-volume injection with immediate commercial benefit to support research and infrastructure development, followed by use of underlying or adjacent brine-bearing formations for large-volume, long-term storage

In 2008, SECARB also conducted an additional small-scale injection test at Mississippi Power Company's Plant Daniel located near Escatawpa, Mississippi. The project injected 2,720 tonnes of CO2 into the lower Tuscaloosa Formation at an approximate depth of 2895 m. Although testing the same formation as the Gulf Coast Stacked Storage test, this test was significant because it evaluated a suitable saline formation for storage of CO2 in close proximity to a large coal-fired power plant along the Mississippi Gulf Coast. As part of the characterization activities, the project team

developed detailed geological and reservoir maps to assess the test site and conducted reservoir simulations to estimate injectivity, storage capacity, and long-term fate of injected CO2.

SECARB began a ten-year Phase III program in October 2007. The Lower Tuscaloosa Massive Sand Unit is a large, regionally extensive saline formation with potential to hold centuries of CO2 emissions in the Southeast that is suitable for safe, long-term geologic storage of CO2.

Following the "Early Test" at Cranfield Oilfield, located near Natchez, Mississippi; Phase III continues with an "Anthropogenic Test" at the Citronelle Dome injection site (Citronelle, Alabama) near Southern Company's CO2 capture test location at Plant Barry. The second project is a fully integrated carbon dioxide capture, transportation, and geologic storage project. CO2 is captured at Alabama Power Company's Plant Barry, a 2,657 MW coal-fired power generating facility located in Bucks, Alabama, and transported by pipeline and sequestered within a saline formation at the nearby Citronelle Oil Field operated by Denbury Resources. During the Anthropogenic Test, Denbury will inject approximately 100,000 to 150,000 tonnes of CO2 per year for up to three years. The SECARB team will deploy an extensive monitoring, verification, and accounting program that will commence pre-, during, and post-injection. Injections began in August 2012, making it the world's first large-scale coal-fired CCS facility. CO2 injection will take place over two years at a rate of up to 550 tonnes of CO2 per day. Several monitoring technologies will be used to track the CO2 plume, measure the pressure front, evaluate CO2 trapping mechanisms and ensure that the CO2 remains in the formation. The site will be closed in 2017 following three years of post-injection monitoring. When that happens, the wells will either be plugged and abandoned according to state regulations, or re-permitted for CO2-enhanced oil recovery and CO2 storage operations. If it is re-permitted, the CO2 would be used to recover stranded oil while also being sequestered in a geologic formation

SECARB estimates that 31 percent of the nation's CO2 stationary source emissions come from within its region, which comprises all or part of 13 southeastern states: Alabama, Arkansas, Florida, Georgia, Kentucky, Louisiana, Mississippi, North Carolina, South Carolina, Tennessee, Texas, Virginia, and West Virginia. The region's deep saline and oil and gas formations offer safe and permanent storage capacity for these emissions.

Both the West Coast Regional Carbon Sequestration Partnership (WESTCARB) and Midwest Regional Carbon Sequestration Partnership have completed Validation Phase activities, which are analogous to exploration activities in the petroleum industry. The Appalachian Basin First Energy R.E. Burger Power Plant and the Northern Arizona Project near the Cholla Power Plant, both demonstrated that subsurface conditions may not always prove to be as anticipated, particularly in areas with little prior oil and gas exploration. In both cases, there was insufficient porosity and permeability for CO2 injection. The findings at these specific sites do not preclude the potential for storage in the regions surrounding the sites; instead, the tests confirm the complex nature of the formations within the basins. The work demonstrates the importance of extensive drilling, formation evaluation, and testing to characterize and identify appropriate formations for CO2 storage nationwide prior to injection. Other WESTCARB activities were described in Chapter 7.

Texas Clean Energy Project

The Texas Clean Energy Project (TCEP) established by the Summit Power Group, one of U.S. DOE's leading CCUS projects, is a 400 MW IGCC polygeneration project that will produce 700,000 tons per year urea for the U.S. fertilizer market and capture 90 percent of its CO_2 – approximately 2.5 Mt per year – for EOR in the West Texas Permian Basin. The U.S. DOE selected TCEP for a $450 million award as part of its Clean Coal Power Initiative program. Construction is scheduled to begin once the financing is finalized in late 2013 on a 600-acre plot of land in Penwell, Texas, just west of Odessa.

Engineering, procurement, and construction (EPC) contract for TCEP's gasification and chemical block, which Summit intends to award to the Sinopec Engineering Group , a subsidiary of Sinopec Group that has extensive experience in the design engineering of coal conversion projects and other major oil, gas, and chemical plants in more than 50 countries worldwide. Siemens will provide a state-of-the-art Siemens high-hydrogen combustion turbine

To support Sinopec Engineering Group's new EPC contract, they and Summit disclosed that the Export-Import Bank of China ("Chexim") is to be the sole financial lender to TCEP, subject to completion of the EPC contract and Chexim's customary due diligence. The Chexim loan amount, which will be based on a percentage of the dollar amount of Sinopec Engineering Group's EPC contract, will be sufficient to satisfy all of TCEP's needs for project debt.

Whiting Petroleum Corporation has executed a contract to purchase a major portion of TCEP's captured carbon dioxide for use in Whiting's enhanced oil recovery operations in Texas. TCEP's total sales of captured CO_2 for EOR will be approximately 2.5 million tonnes per year. In Texas EOR operations, the captured CO_2 is effectively a solvent that helps release trapped oil for recovery. Any injected CO_2 that comes to the surface with the produced oil is re-captured, re-compressed, and re-injected, resulting ultimately in permanent geological sequestration of CO_2.

Minnesota-based CHS Inc. is the purchaser of TCEP's entire urea output, which is expected to reduce annual U.S. imports and U.S. dependence on foreign urea fertilizer by more than ten percent. CHS, a Fortune 100 company owned by farmers, ranchers, and cooperatives across the United States, has signed a long-term off-take agreement with Summit. CHS also announced that it will make a small equity investment in the project

The long-term power purchase agreement with CPS Energy of San Antonio, the largest municipal electric and gas utility in the United States, and a contract with Houston-based Shrieve Chemical Company to purchase TCEP's output of sulfuric acid.

Because of TCEP's high carbon capture rate, the power CPS Energy buys from TCEP for San Antonio consumers will have less than one-tenth the CO_2 emissions per kilowatt-hour of power from a plant that burns coal and less than one-quarter the CO_2 emissions per kilowatt-hour of power from a plant that burns natural gas. CPS Energy is the first utility in the U.S. to enter into a PPA that will provide power with such ultra-low CO_2 emissions from a commercial scale, hydrocarbon-based power plant. Shrieve Chemical Co. will market all of the approximately 50,000 tonnes per year of merchant-quality sulfuric acid that would otherwise have been vented to the atmosphere as sulfur dioxide in the absence of TCEP's low-emissions gasification technology.

The total cost of TCEP will be approximately $2.9 billion. Of this amount, $450 million will be provided by a cost-sharing award announced in 2010 by the DOE under it's Clean Coal Power Initiative, a Congressional program to aid development of power projects that capture their carbon dioxide. The Siemens and Linde equipment used at TCEP are commercially proven and allow CO_2, sulfur, and mercury to be removed from the project's gas stream prior to combustion, leaving only a high-hydrogen/low-carbon clean "syngas" as the sole fuel that is burned.

TCEP has been repeatedly described by DOE officials as one of it's "flagship" projects that will prove the commercial viability of carbon capture, utilization and storage (CCUS), whereby carbon dioxide is used to increase domestic oil production instead of being released to the atmosphere and will ultimately be stored safely and permanently in the ground - at least 99 percent of it for at least 1,000 years, as mandated by Texas State Law. Carbon dioxide emissions would amount to about 91 kg per MWh, making the Texas plant far more climate-friendly than even the best combined-cycle natural-gas plants, which emit about 386 to 454 kg per MWh.

Port Arthur Project

The country's first large-scale, integrated CCS project was brought online in Texas in late 2012 byAir Products and Chemicals as an *industrial* capture and storage operation at a Valero Energy Corp.-owned hydrogen production facility in Port Arthur. It will pipe captured CO_2 through Denbury Resources' Green Pipeline to the West Hastings oilfield southeast of Houston EOR operations..

The $430 million industrial capture retrofit onto a hydrogen production facility where capture operations began at one of the facility's two steam methane reformers in mid-December 2012 after Air Products retrofitted the unit with a vacuum swing adsorption system to separate the CO_2 from the process gas stream. Air Products is conducting monitoring, verification and accounting work to ensure the storage of the injected CO_2 in the subsurface. The facility is expected to capture roughly one million metric tonnes of CO_2 annually, ultimately helping produce up to three million additional barrels of oil annually for Denbury.

NRG Energy W.A. Parish Retrofit Project

The NRG Energy's W.A. Parish post-combustion retrofit in southeast Texas plans a final investment decision by the end of 2013 with and plant construction by fall 2013, and operational by 2015. The, company has access to $167M in stimulus cost-share funding for the project. The utility plans on utilizing the 1.6 Mt of CO_2 captured from the facility for EOR operations at Hilcorp Energy's West Ranch oilfield near the Gulf Coast.

This project is the only remaining post-combustion project under development after American Electric Power closed its Mountaineer project in 2011. What was initially planned to be a 60 MW-equivalent slipstream from the pre-existing W.A. Parish Generating Station southwest of Houston, is now, in light of the Mountain closure, upgraded to a 250 MWe unit that would capture, using advanced amine post-combustion capture system, 1.6 Mt of CO_2.

NRG decided to engage early an 80 MW natural gas turbine that will eventually power the capture unit's compressors, in order to generate peaking power for stressed Texas' grid for the coming summers.

Kemper County (Mississippi)

The IGCC project was created in order to make use of cheap and local lignite, and thus from the fuel source perspective it has a limited value for comparisons in California. However, the power plant financing and some engineering aspects are instructive. It has been under construction in the eastern portion of Mississippi since 2009 and is expected to come online in spring 2014. It is the most mature large-scale CCS project for power generation in DOE's demonstration project portfolio. Mississippi Power said that it has spent more than $1.1 billion on construction to date and confirmed contracts for an extra $1.5 billion. Plant Ratcliffe has garnered nearly $700 million in government grants, tax incentives and loan guarantees, including $270 million in funding under the DOE's Clean Coal Power Initiative. It plans on selling its captured CO_2 for enhanced oil recovery operations and transporting the CO_2 via existing pipelines to south of Houston on the Texas Gulf Coast. The costs to the ratepayers for this project have been challenged in the courts and a final decision in favor of a partial rate increase has recently been approved.

Kemper County Project is an electric power plant using an IGCC design developed over the last 15 years at the Power Systems Development Facility in Alabama. A unique feature of this high-efficiency design is that it sends lignite (a low rank coal, which accounts for more than half of the world's vast coal reserves) that is not converted to gas in the initial process back for a second round of gasification. This allows a high rate of lignite-to-gas conversion to take place at a lower temperature - and thus lower cost - than what's possible with other available gasification technologies. This gas is used to produce electricity while making it easier to remove emissions.

This specific technology also produces more power and offers lower capital cost as well as lower operation and maintenance cost than what is possible with other available gasification technologies. The Kemper Project will turn Mississippi lignite into a clean gas while reducing emissions of sulphur dioxide, nitrogen oxides, carbon dioxide and mercury. The TRIG™ technology will reduce carbon dioxide emissions by 65 percent - making CO_2 emissions equivalent to a similarly sized natural gas combined cycle power plant.

Enhanced Gas Recovery Test, Kentucky

The DOE has been looking at the idea of sequestering carbon via EGR in earnest for several years, the field has largely remained stagnant, primarily due to cheap and plentiful natural gas using more conventional extraction efforts and the lack of a price on carbon. Geologists, however, have long touted depleted natural gas reservoirs as promising host sites for CO_2 storage projects due to their generally well-characterized geologies and natural propensity for storage given that they naturally held hydrocarbons for thousands of years. Eastern Kentucky could be a prime area for EGR operations because of a continuous black shale resource play that has been producing for over 100 years. There are some 8,000 or more producing wells, many of which are only producing a little bit of gas, thus if gas operators have a cheap source of CO_2 and a sufficiently high price of gas, it could be economic to inject CO_2 to enhance production. In Eastern Kentucky, most gas wells are enhanced with nitrogen, but CO_2 injection has the potential to be a cheaper and more effective tool for producing additional gas while storing CO_2 long-term in shale formations.

Small-scale injection of carbon dioxide into a depleted natural gas well in eastern Kentucky began in August 2012 as a way to both stimulate additional gas production and trap CO_2 underground. The research consortium from the University of Kentucky, the Kentucky Geological Survey and

Advanced Resources International began injecting 300 tonnes of CO_2 into a Devonian Ohio shale formation as a way to test the feasibility of enhanced gas recovery (EGR) operations. It will primarily analyze the process through a pressure transient test over several weeks to allow for reservoir pressure to build while the CO_2 is being pumped underground. Once injection stops and the methane rises to the surface, the well's pressure falls off, which will document the behavior of the reservoir and how it manages the CO_2. They will allow the injected CO_2 to flow back through the test well to ascertain the difference between the amount of CO_2 injected and the quantity that stays trapped in the well. Monitoring will occur through several surrounding wells.

Weyburn-Midale (Saskatchewan, Canada)

The IEA GHG Weyburn-Midale CO_2 Monitoring and Storage Project is a commercial CO_2 EOR project which has injected between 1 and 2 Mt CO_2 per year into an oil reservoir since 2000. The source of the CO_2 for the Weyburn project is the Dakota Gasification Great Plains Synfuels Plant, North Dakota, USA. Monitoring and storage began in 2000 and is considered a commercial technology and, since its research focus is on storage in conjunction with EOR, the Weyburn CO_2 EOR flood is likely the most intensely studied operation of its kind in the world.

The CO_2 EOR reservoir consists of a layer less than 30m thick of fractured carbonate rock at a depth of about 1500m overlain by a seal of evaporate rocks. The Midale reservoir has been under oil production for decades, and at the end of primary production in 1964, water flooding was begun to enhance production. CO_2 injection began in 2000, since when more than 15 Mt of CO_2 have been stored, with 2010 total field injection rates of 13,000 tonnes per day ((White 2009). The CO_2 (a byproduct of gasification of lignite) is purchased from the Dakota Gasification synthetic fuel plant in Beulah, North Dakota, and transported through a 320 km pipeline to Weyburn.

Phase I consisted of geological characterization, prediction, monitoring, and verification of CO_2 movements, CO_2 storage capacity and distribution predictions and the application of economic limits, and long-term risk assessments of the storage site ((Preston, et al. 2005).

Phase II focused on monitoring the geology, geohydrology, and geochemistry of the Weyburn field. Additional geophysical monitoring data has been collected and work done to extract as much information as possible from the new and existing monitoring data (White 2009).

The reservoir simulation was built upon a detailed geologic model derived from data from the dense network of wells put in place for primary and secondary oil production. Reservoir simulation using a multi-phase, multi-component compositional computer simulation package (Preston et al., 2005, Law, 2004) was key in predicting the movement of the CO_2. The reservoir simulations were validated, and the geologic model refined, by both laboratory-scale and field-scale measurements. Further "ground-truthing" of the reservoir models was provided by seismic and other monitoring data. Geochemical modeling was also carried out, which predicted that in 5000 years, no free-phase CO_2 would be present in the reservoir (Gunter and Perkins, 2004). The geochemical fluid sampling campaign at Weyburn has been comprehensive, and over the past decade samples have been collected on 15 occasions from a suite of 50-60 wells. Samples of produced brines were analyzed for over 40 compositional and isotopic parameters, generating a unique, comprehensive database. The spatial and temporal changes in pH, alkalinity, concentrations of Ca and Mg, and carbon isotopes were found useful in monitoring the movement of the CO_2 in the subsurface and providing

indication of incipient CO_2 breakthrough at wells (Emberley et al., 2005, Gunter and Perkins, 2004). Figure 14 shows results for the pH and alkalinity. Samples of produced hydrocarbons were also analyzed in order to refine the equation of state for the specific hydrocarbon-CO_2 mixture in the Midale reservoir.

The 3D time-lapse seismic data was also analyzed to evaluate caprock integrity and to look for CO_2 which might have migrated vertically from the reservoir (White, 2010). While some anomalies were found between the reservoir and the regional seal (Watrous Formation), few (if any) significant anomalies were found above it to suggest the presence of CO_2 in the overburden (White, 2010).

Though limited in array size, passive seismic, or microseismic monitoring has been underway since 2003 in the Weyburn-Midale project. During this time period, about 100 events occurred, with 97percent of these prior to early 2006 during the early stages of CO_2 injection (White, 2010). The microseimicity rates were found to correlate with periods of elevated CO_2 injection rates, and also with changes in production activities in nearby wells (Verdon et al., 2010). Coupled fluid flow-geomechanical simulations for a Weyburn-based model concluded that the seismicity was likely due to stress-arching effects rather than CO_2 escaping from the reservoir (White, 2010).

International Test Center for CO_2 Capture (Saskatchewan, Canada)

The International Test Centre for Carbon Dioxide Capture (ITC) and the IEA Weyburn CO_2 Monitoring Project are both located at the University of Regina. The ITC will bring together findings from around the world to develop economically viable technologies for capturing CO_2 emissions. It conduct technology development-scale tests at two multi-million dollar pilot plants for post-combustion capture research and demonstration at the University site, and industry-scale tests at a demonstration plant at SaskPower's coal-fired Boundary Dam Power Station. The unique features about the ITC as a research centre for CO_2 capture is that it includes all aspects of the CO_2 capture process, including corrosion prevention and management, amine degradation and reclamation, process control and modeling, and even artificial intelligence applications for monitoring and control of post-combustion capture plants. The ITC for CO_2 Capture latest innovation is a catalyst-aided process that could virtually eliminate the energy penalty for post-combustion CO_2 capture. The ITC is the only facility in the world where engineers and scientist can be trained in the complete operations of large-scale CO_2 capture operations. This provides industries around the world with an excellent source of highly qualified personnel to help them make decisions about the application of CCS in their operations and design potential CCS projects. Catalyst-based hydrogen production allows hydrogen production to be both feed flexible and process flexible that can be used to switch between feedstocks without disrupting plant operations. The catalyst can convert unprocessed feedstocks, like raw ethanol and low-grade natural gas, into hydrogen. This means that many waste products, such as glycerol, fuel oils, and biogas, can become value-added fuel feedstocks. The process also incorporates capture, recycling, and storage of CO_2, making it CO_2 neutral when used with fossil fuels and a CO_2 sink when used with biofuels.

A new catalyst-aided process dramatically increases the efficiency of the post-combustion capture process using hot water instead of steam, which virtually eliminates the energy penalty associated with post-combustion capture, allowing a business case for carbon capture based on added value rather than regulatory requirements. Carbon capture plants can be operated without substantially

affecting the efficiency of the original process, and the captured CO_2 can be sold for use in EOR operations, making this an ideal means of obtaining CO_2 for EOR.

The IEA Weyburn Project is a large, multifaceted research project that includes 19 research organizations from Canada, the United States and Europe, as well as seven industry members. The Government of Canada will invest $5 million in the Weyburn CO_2 Monitoring Project. The Weyburn oil field in Saskatchewan uses an innovative technology called CO_2 Enhanced Oil Recovery that will extend the life of the field. Over the life of the project, 14 Mt of CO_2 will be stored.

Carbon capture is the most expensive component of CCS. CCS will only be economic when an energy efficient system for post-combustion capture is proven on a commercial scale. Conventional fossil fuel combustion facilities generally have extremely long life spans (as many as 50 years) and are so cost-effective compared to alternative technologies that it would be impossible for most economies to suddenly shift to alternative, clean energy processes without incurring unsustainable economic penalties. The underpinning of the global economy is fossil fuels, and it will remain so for decades to come. A retrofit of conventional fossil fuel combustion facilities for carbon capture represents the best hope of making dramatic, large-scale reductions in industrial CO_2 emissions without significantly increasing costs of energy and manufactured goods or disrupting the global economy.

Saskatchewan's economy is one of those that depend heavily on fossil fuels.. Saskatchewan may have the world's largest per capita CO_2 emissions (about 73 tonnes per person – twenty more than Qatar, the nation with the highest per capita emissions). However, Saskatchewan's actual CO_2 emissions are only about 75 Mt per year, which is small compared to the actual emissions of many countries, such as Iran, whose per capita emissions are around 8 tonnes per person but total emissions are 574 Mt. About 70 per cent of Saskatchewan's electricity is generated via fossil fuel combustion, which cannot transition to other energy sources due to constraints of their climate, geography, and population demographics. Nuclear power, for example, is a very large-scale technology only economically and technically viable when used in areas with high electricity demand, thus not feasible in a province that could be supplied by a single plant. Moreover, having the entire electricity production from a single source is not a good idea in terms of energy security nor in an area unable to sustain power outages in cold weather. Geography limits hydro power as an alternative, and although wind is abundant it does not always blow when electricity demand is peaking and electricity storage technology hasn't reached a solution to this. Biomass technologies are in their infancy, and it will be decades before they are ready to meet current energy demand.

For Saskatchewan, at least for now, fossil fuel-generated power is the only viable option, which means that carbon capture is an essential technology for this province. SaskPower will be among the first electric utilities in the world to operate a commercial-scale power plant with a fully-integrated carbon capture and storage operating system. The $1.24 billion project to rebuild a coal-fired unit at the Boundary Dam Power Station and equip it with a fully-integrated carbon capture system will allow for the generation of low-emission electricity and the capture of carbon dioxide for oil extraction

QUEST (Alberta, Canada)

Shell Canada proposed a $1.3 billion project to install facilities at the Scotford Heavy Oil Upgrader facility that would capture CO_2 from all three of the Upgrader's hydrogen plants. The hydrogen plants combine steam and natural gas (methane) to produce hydrogen used for upgrading. Around 1.2 million tonnes per annum of CO_2 would be captured at the upgrader. The CO_2 would be transported by pipeline and injected into deep saline formations, at a depth of 2 km and using 3 to 10 CO_2 injectors. The sale of up to 49 percent of captured CO_2 to third parties may be considered. Injection of CO_2 could start by the end of 2015. The plant would be operational for 25 years

Quest will become Shell's "flagship" CCS project, heading up the company's CCS research program and helping develop Shell's CO2 capture technology. While the company is also involved in CCS research projects in Norway and Australia, this is the first in which Shell has majority ownership. The Athabasca Oil Sands Project, is a joint venture among Shell Canada Energy (60 percent), Chevron Canada Limited (20 percent) and Marathon Oil Canada Corporation (20 percent)

Alberta has some of the most promising geology for CO_2 storage in Canada. CO_2 will be injected more than two km underground into the deepest saline formation known as the Basal Cambrian Sands dissolving into the brine of the saline formation. There are multiple, impermeable shale and salt sealing rocks above the storage formation that will ensure the injected CO_2 remains securely trapped deep underground.

Regulators approved the first proposal to pump greenhouse gas emissions from Alberta's oil sands deep into the ground and indicated that it is not likely to cause significant adverse environmental effects.

Shell reviewed the economics of the project with its partners, Chevron Canada and Marathon Oil, and has made a final decision to proceed with the project. Shell's caveat about reviewing the economics of Quest followed an announcement in April by TransAlta Corp. that it was pulling out of the separate $1.4 billion Project Pioneer carbon capture project because of financial concerns. At the time, TransAlta said initial studies showed the technology works and that the capital costs were acceptable, but there were not enough customers to buy the CO_2 generated from coal fired power plants and the price was not good enough. The company wanted to sell some of the captured carbon dioxide to nearby energy producers, who would inject the gas into their fields as a means to get more oil out of the ground. The emissions would have been prevented from entering the atmosphere.

Shell will begin construction in the autumn of 2012. Shell Canada, along with its project partners Chevron and Marathon Oil, formally gave a green light to its $1.35 billion "flagship" CCS project, the world's first to retrofit the technology onto an existing oil sands upgrader. The project has received all federal and provincial regulatory approvals and is in position to begin operations in late 2015.

The project, which has been guaranteed $865 million in provincial and federal government funding, will capture roughly one-third of emissions, or one million tons of CO_2 per year, from Shell's Scotford Upgrader located near Edmonton, Alberta. That facility processes roughly 250,000 barrels a day of bitumen, or heavy crude oil, produced from Shell, Chevron and Marathon's Athabasca oil

sands project. Shell and its partners will then transport the captured CO_2 roughly 80 km north via an underground pipeline for injection into a deep saline aquifer.

This project has the potential for CCS to allow for the continued development of Alberta's oil sands, a controversial energy source maligned by environmental groups due to its high carbon footprint compared to traditional oil production. CCS could play a large role in helping Canada achieve its goal of reducing greenhouse gas emissions 17 percent below 2005 levels by the end of the decade while also still allowing for the development of fossil fuel sources like the oil sands.

The Canadian government is supportive of the project in order to advance carbon capture and storage deployment and has invested $120 million in Quest through its Clean Energy Fund in spring 2011. The project has received from the Alberta government, which allocated the project a $745 million share of the province's $2 billion CCS fund, a critical investment from a province whose economic future intimately relies on the development of its fossil fuel resources. The province is itching for one of its remaining CCS projects to proceed after TransAlta Corp. announced that it would be abandoning plans for its $1.4 billion Project Pioneer. The other two projects being funded by the provincial government, Swan Hills Synfuels and the Alberta Carbon Trunk Line, are considered to have promise but are both further behind Shell in terms of planning. To sweeten the deal for Shell to proceed, last year the Alberta government said it would temporarily give Quest double the amount of credits on the province's carbon offset program for each ton of CO_2 stored. With offset prices currently at $15 per ton of CO_2 and accounting for Quest's one million tons of CO_2 buried per year, that could help earn the project $30 million over 10 years. In total, the $865 million in federal and provincial funding will help cover about two-thirds of Quest's costs for construction and the first decade of operation.

Regulations and Policy

As of 2012, twenty states had enacted policies related to CCUS that address at least one of the major regulatory issues for CCUS such as incentives, property rights, permitting rules, or long-term stewardship. Ten states have delegated permitting responsibility to various state agencies, most of which concern oil and gas regulation with input from environmental agencies. Only Montana, North Dakota, Wyoming, Oklahoma, and Louisiana have enacted policies with regard to pore space rights. In these states, there is little consistent application of pore ownership nor of eminent domain, but access to pore space is generally linked to the surface owner. Long term liability and stewardship has been addressed in Montana, North Dakota, Wyoming, Kansas, Texas, and Louisiana, and in particular in the creation of a special fund to pay for long term monitoring costs and, with the exception of Wyoming, to cover partial or full remediation costs associated with leaks. North Dakota and Montana have legislation that provides for compensatory damages and obligations to submit allowances under a GHG reduction program. In Utah, Montana, Wyoming, North Dakota, Kansas, Oklahoma, Texas, Louisiana, and West Virginia, geological sequestration policies are exempted for EOR operations, protecting business as usual. Of these, Montana, North Dakota, Texas, and Wyoming allow for conversion from EOR to deep saline sequestration, and North Dakota and West Virginia policies allow credits for CO_2 sequestered using EOR.

In Texas, policy governing geologic sequestration of CO_2 is evolving to encourage pairing with EOR. For example, Texas HB 469 (2009) provides various tax incentives designed to encourage use of anthropogenic CO_2 for EOR. The incentives are available to CO_2-EOR that conduct monitoring and verification to reasonably demonstrate that 99 percent of the injected CO_2 will be sequestered for 1,000 years. In addition to incentives, Texas is developing regulations that will accommodate simultaneous sequestration and oil production. In SB 1387 (2009), the Texas legislature directed the Railroad Commission to develop rules governing geologic sequestration of CO_2. The legislation directs that UIC Class II wells are to be exempt from these rules. Further, converting a well from EOR use to geologic sequestration is not to be considered a change in the purpose of the well. But the rules proposed by the Railroad Commission are designed similarly to the Carbon Sequestration Council's MSD recommendation. The new regulations would not apply to a Class II CO_2 injection well permitted "for the primary purpose of enhanced recovery operations from which there is a reasonable expectation of more than insignificant future production volumes of oil, gas, or geothermal energy and operating pressures no higher than reasonably necessary to produce such volumes or rates." The proposed rules would, however, allow an operator to propose to permit a project as an EOR project and a geologic storage facility simultaneously. That means EOR projects that also apply for geologic storage permit would be subject some additional siting and MVR requirements to which other Class II wells would not otherwise be subject.

Other states, such as the State of Montana, have independently enacted laws that govern how carbon sequestration will be regulated. For example, Senate Bill 498 (Chapter 474, Statutes of 2009) authorizes the state oil and gas regulation to issue permits for the injection of carbon dioxide and assesses fees for administering a carbon sequestration program. As part of its program, the Board of Oil and Gas Conservation solicits comments from the Department of Environmental Quality prior to issuing an injection permit. It also contains certain provisions that allow the transfer of liability for post-injection sequestration to the State of Montana.

Six states have addressed long term liability and stewardship of which North Dakota and Montana have established an industry fund and will assume all liability beyond closure. Kansas, Louisiana, Texas, and Wyoming have also established a fund, but their long term liability is limited. There has been little consistency in the time frames or agreement as to where the liability should ultimately reside. In some cases the risk and performance of the CCUS site is linked to liability transfer. The funds generated by these states for long-term stewardship all have a fee-per-tonne injected component, and three states have additional fees (e.g., application, annual).

During the past decade significant investment has been made in an effort to prove and improve CCUS technology in time for full-scale commercial use. Although CO_2 injection has been used for enhanced oil and gas production for decades, permanent geological storage integrated with power plants and industrial facilities is considered to be emerging technology. Accordingly, CCUS must be successfully demonstrated with an array of small, and intermediate and large-scale CO_2 injection field tests in diverse geologies to adequately characterize and validate the geologic resource.

In the United States, building on the extensive experience with EOR and natural gas storage, the U.S. Department of Energy, led by National Energy Technology Laboratory (NETL), is pursuing the Sequestration Research, Development, and Demonstration Program in partnership with industry and academia. A key element of the Program is the Regional Carbon Sequestration Partnership (RCSP)

program, which encompasses 43 states and four Canadian provinces represented by seven RCSPs. This program includes key field tests throughout the United States and Canada to fully characterize geologic storage sites, to validate models, to validate prior findings, to develop MVR instrumentation. The field-scale investigations underway as part of the RCSP program will provide direct observations on the behavior of CO_2 underground, building confidence that the key phenomena are well understood and that CO_2 can be injected and stored safely. The DOE has completed a comprehensive effort on risk assessment that utilizes these investigations (along with a strong science base) to develop a sound framework for ensuring that each specific storage site is properly chosen and developed for safe, long-term storage.

The development of these seven projects has since their inception in 2005 reflected to some large degree the variable geology across North America, access to CO_2 supplies for demonstrations. The fragmented, heterogenous geological structure of the western states has made the characterization and selection of suitable sequestration sites more challenging, especially in remote areas where oil and gas well data are sparse or non-existent. In this section we present a summary of a selection of projects by the regional partnerships and other entities in order to put the development of CCS in California within a broader North American context.

While progress has been made at the technical level in many projects, the policy and regulatory frameworks applicable to these projects has not progressed as quickly. Anticipated carbon prices that are consistent with a stable policy environment and comprehensive regulatory mechanisms remain an urgent need in order for capital investment to move this industry forward at a pace to meet GHG targets.

The US leads the world in terms of commercial-scale CCUS projects that are either in the final stages of project planning or have taken final investment decisions and moved into a construction phase (Myer, 2011). What distinguishes projects in the US (and Canada) from the rest of the world is that virtually every active project incorporates a significant EOR consideration.

Evidence suggests that CO_2 can command, in the right circumstances, a price of up to US$40 per ton at the plant gate under long-term off-take contracts. These pricing signals (far in excess of the EU ETS price) when coupled with other government support mechanisms are sufficient to drive CCUS project financing for at least some projects. The current low natural prices have stalled the development of CCS as applied to coal-based power plants, hindering the anticipated rapid deployment of CCS commercial demonstrations.

Canada introduced recently national regulations limiting CO_2 emissions from coal plants, but more pertinent regulations to this report have been implemented at the provincial level. Alberta, which is the most active province for CCS projects, established a CCS Regulatory Framework Assessment in 2011 that should conclude by the end of 2012, in which it will identifies and addresses regulatory gaps with respect to (1) geological site characterization and site closure, (2) financing post-closure activities, (3) MVR requirements, (4) pore space management, and (5) various environment issues.

APPENDIX B:
Review of Relevant CCUS Projects Worldwide

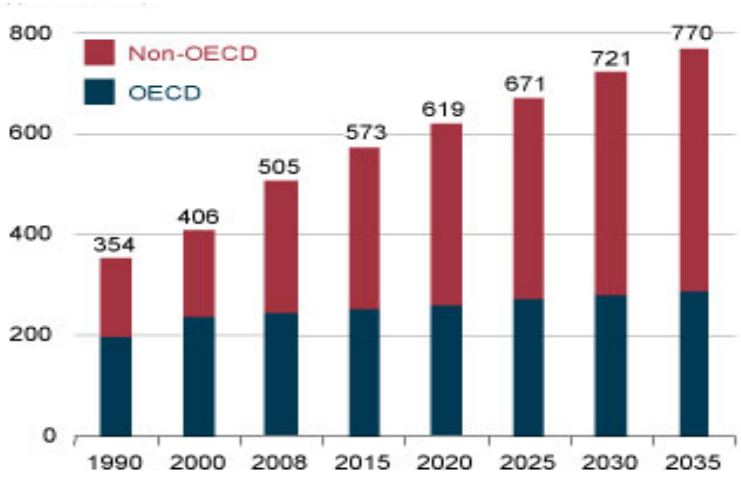
The Global Context

Numerous studies reference the unrelenting global trends of rising energy use and carbon emissions as compelling evidence of the need to accelerate adoption of CCUS technologies. Despite these studies, the number of CCUS projects appears to be declining worldwide. Most investment to date has been fueled by government programs; recent trends show such investments also are declining.

Forecasts of Energy Use and Carbon Emissions

Although energy efficiency measures may result in constant or declining per capita energy use in developed countries, the overall trend in world energy use is upward significantly as the world population increases and electricity reaches a much larger fraction of that population. About 84 percent of the global energy supply came from fossil fuels in 2008, which contributed 32 Gt of CO_2 to the atmosphere (IEA, 2013b). The most recent International Energy Outlook report shows a simple projection of considerable and steady growth in global energy consumption through 2035 (Figure 17).

Figure 17: Actual (1990-2008) and Forecast (2009-2035) World Energy Consumption



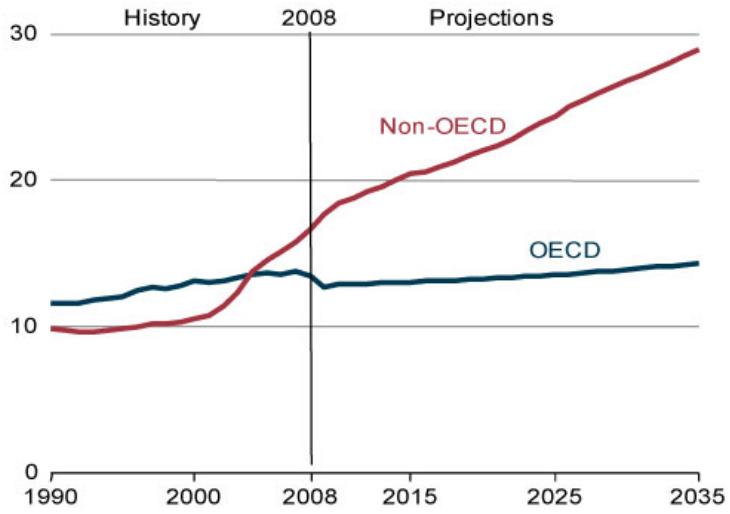
Actual (1990-2008) and forecast (2009-2035) energy consumption in quadrillion Btu for Organisation for Economic Co-operation and Development (OECD) and Non-OECD countries.

Source: (International Energy Agency 2012)

Developing nations will be a significantly greater contributor to CO_2 emissions in the future, having overtaken developed nations in 2005 (Figure). A major reason for this increasing shift is the greater use of coal in developing nations, especially India and China where large coal reserves occur (Figure). The greater use of natural gas, especially in the USA, accounts in large part for the near flat level of CO_2 emissions projected for the developed nations in the coming decades. Overall, however, the

use of coal is expected to increase faster than the rate of natural gas usage, at least through 2035 (Figure).

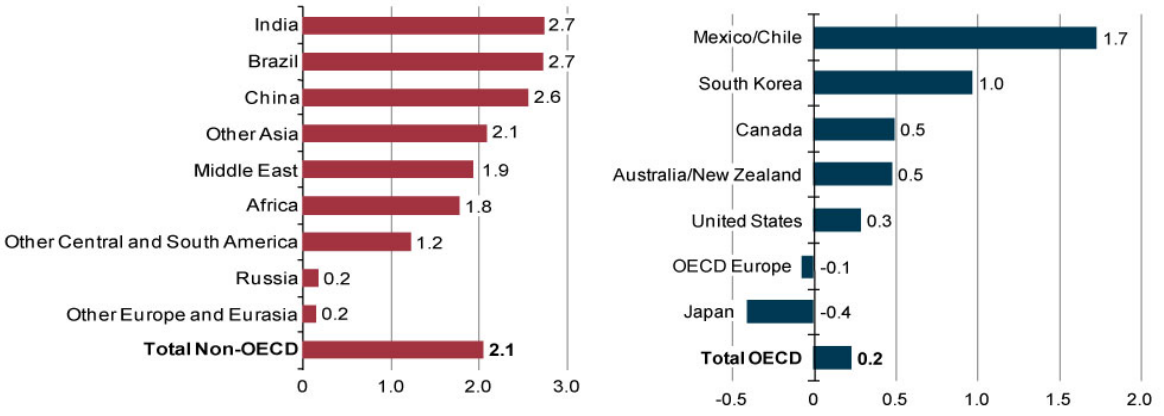
Figure 2: Actual (1990-2008) and Projected (2009-2035) World Energy-related CO2 Emissions



Actual (1990-2008) and projected (2009-2035) world energy-related CO_2 emissions in million metric tons by OECD and non-OECD countries.

Source: (US Energy Information Administration 2011)

Figure 3: Projected Growth from 2008-2035 of Energy-related CO2 Emissions by Country



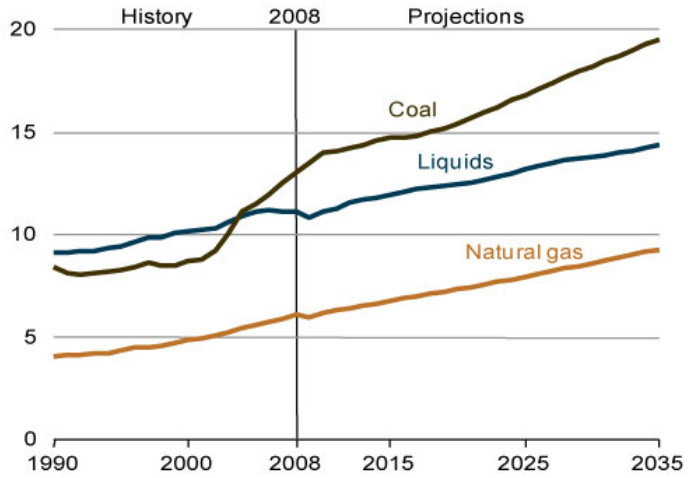
Projected average annual growth from 2008-2035 of energy-related carbon dioxide emissions in non-OECD (left) and OECD (right) economies (percent per year).

Source: (US Energy Information Administration 2011).

The United States appears likely to continue its dependence on fossil fuels, although with a shift from coal to natural gas. There has been a remarkable growth in the U.S. domestic fossil fuel supply. In 2000, domestic natural gas production was two percent of the market, but, by 2012, production had risen to 37 percent, due mainly to shale gas development. However, it is unclear how

sustainable gas production will remain as many wells have high initial production but quickly become exhausted. The expense of a high number of wells per gas produced may raise the price of natural gas in the USA. Oil production in the U.S. has risen by 25 percent since 2008, amounting to an additional 1.6 million barrels per day. The U.S. has the largest coal reserves in the world and, while these reserves have been the mainstay for electricity generation in the country, more stringent air quality regulations and lower recent prices for natural gas, along with concerns about potential future carbon mitigation requirements, have prompted a shift to natural gas for power generation. Inherent in these data is that the U.S. is reducing the rate of increase of its carbon footprint through efficiencies and an increasing reliance on natural gas. Nevertheless, this reduction remains too slow to meet 2050 targets for GHG mitigation.

Figure 4: Actual (1990-2008) and Projected (2009-2035) World CO_2 Emissions by Fuel Type



Actual (1990-2008) and projected (2009-2035) world energy-related carbon dioxide emissions by fuel type in billion metric tons.

Source: (US Energy Information Administration 2011)

In 2011, slightly over four percent of global power was generated from renewable sources, including wind, solar and geothermal ((BP Statistical Review of World Energy 2012). Growth over the last 10 years has exceeded 10 percent, with OECD countries accounting for over three fourths of the total. 14 countries have renewable shares in excess of 10 percent. At the individual country level these sources are already playing an important role in some countries. For example, wind power generation has a significant share in total electricity generation in Denmark (28 percent), Portugal (17 percent), Ireland (16 percent), Spain (15 percent) and Germany (8 percent); geothermal sources account for more than a quarter of total electricity generated in Iceland, and more than a fifth in El Salvador and Kenya.

Some countries have considered strategies for converting their entire electricity sector to renewable generation, but have not found it to be a feasible option. An analysis in Australia determined it was not realistic for the country to depend on renewable energy sources alone. In 2011, Germany adopted a strategy to replace its nuclear power stations, generating about 20 percent of the nation's power, with renewable sources, specifically wind and solar by 2022 through heavy subsidies and giving renewable power preferential access to the nation's electric grid for base load. The resultant

electric prices are among the highest in the world. This has created pressure on the utility industry which is unable to generate rapid response demand from traditional power plants in order to secure reliable base load for heavy industrial users.

The International Energy Agency (IEA) estimates 2009 global CO_2 emissions to be approximately 32 Gt and projects that by 2050 emissions will reach 58 Gt in a business-as-usual scenario. The IEA models indicate that these emissions result in a 6°C increase in the global mean temperature, alarmingly high compared to the goal of a 2°C increase, which requires a 16 Gt emission level. That is, in order to limit temperature increases by just 2°C, the world needs to reduce its emissions by 15 Gt, or 52 percent, which would stabilize atmospheric CO_2 at 450 parts per million. Table 13 shows these numbers for the U.S., China, and India, as well as for California.

Table 13: Actual 2009 Emissions Compared To Projected Business-As-Usual (BAS) and Target Emissions In 2050 For The World, Selected Countries, and California (In Gigatons).

	World	China	India	USA	California
2009	31	8.3	1.7	5.4	0.50
2050 BAS	58	18.0	7.4	5.4	0.80
2050 Target	16	4.1	2.4	1.3	0.08

Source: http://www.technologyreview.com/graphiti/428893/the-carbon-capture-conundrum/

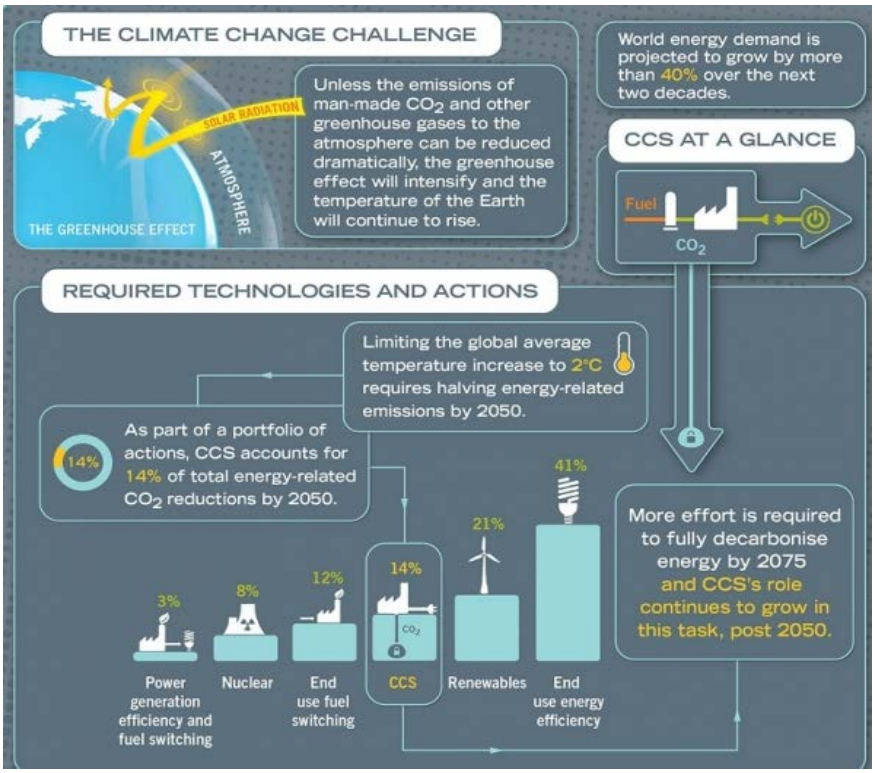
A recent report by the IEA emphasizes the need to acknowledge that CO_2 emissions result not only from electricity generation, but also from other industrial facilities, such as cement production, iron and steel mills, natural gas processing, biofuels, and other chemical production (IEA, 2013). In California, approximately 30 percent of its CO_2 emissions are from power generation.

The IEA also notes that the climate goal of limiting warming to 2 °C becomes more difficult and more costly with each year that passes without rapid deployment of energy-efficient or low carbon energy technologies. Almost four-fifths of the CO_2 emissions allowable by 2035 are already locked-in by existing power plants, factories, buildings, etc.; if action is not taken before 2017, all the allowable CO_2 emissions would be locked-in by energy infrastructure existing at that time. Rapid action could postpone this complete lock-in only to 2022 (International Energy Agency 2012).

Role of CCUS in Achieving CO_2 Reduction Goals

Figure shows the relative contribution that different energy technologies, including CCS, can be expected to make toward decarbonizing world energy (Global CCS Institute 2012). Studies by a broad range of governmental and non-governmental organizations show that CCS is a critical and cost effective component for achieving these stringent global GHG emission reductions before or by 2050. The Fourth Assessment Report of the IPCC recognizes that GHG reduction will require a wide portfolio of technologies which includes CCS (Intergovernmental Panel on Climate Change 2007). The IEA has estimated that CCS could contribute one-fifth of the global emissions reduction needed by 2050, while, without CCS, overall costs to halve CO_2 emissions levels by 2050 would be higher by 70 percent and higher in the electricity sector by 40 percent (International Energy Agency 2012). In the longer term, the role of CCUS in mitigating CO_2 emissions from energy intensive industrial activities will be vital as no other practical reduction mechanisms may be possible.

Figure 5: Required Technologies and Actions to Address the Climate Change Challenge



Source: (Global CCS Institute 2012)

A recent study by the National Research Council shows that CCS can play a prominent role in cost-effective strategies to reduce U.S. GHG emissions to 80 percent below current levels by 2050 (National Research Council 2010). Chu and Majumdar argue that CCUS will be necessary in order to achieve a low-carbon emission energy future, emphasizing that the inevitability of continued fossil fuels for electricity generation means that carbon emissions from stationary point sources must be reduced significantly (Chu and Majumdar 2012).

Several studies have been done to examine whether a developed country or state can attain its energy and stringent carbon goals by abandoning fossil fuel generation altogether before or by 2050, eliminating the need for CCUS. For example, a recent detailed analysis of the energy future in Australia determined it was not realistic for the country to depend on renewable energy sources alone (Trainer 2012). Fossil fuel will remain an essential part of Australia's energy generation, which is why that country has made heavy investments in CCUS. However, Jacobson & Delucchi (2011) and Delucchi & Jacobson (2011) make a case that renewable energy sources could provide global energy needs by 2050 if policies could be adjusted to accommodate renewable energy ecosystem rather than the prevailing fossil fuel policy framework. Trainer (2012b, 2013) contests this analysis, specifically intermittency challenges of most renewable generation and electric storage limitations.

In developing countries, where use of fossil fuels is enabling rapid modernization and economic growth, concurrent GHG reduction may only be possible by CCUS implementation. In fact, of the total GHG reduction projected for CCUS, 70 percent must be implemented in developing countries.

To achieve the required reductions by other methods, a 40 percent increase in investment (on the order of $3 trillion) would be required (International Energy Agency 2012).

Furthermore, the IEA asserts that meeting the 2050 goal of 16 Gt will require implementation of CCUS on a much wider range of sources than coal burning power plants. For example, the Norwegian Zero Emission Resource Organisation notes that a demonstration of a natural gas plant with CCUS is urgently needed. CCUS is the only technology on the horizon today that would allow industrial sectors (such as iron and steel, cement and natural gas processing) to meet deep emissions reduction goals. In the power sector, the average CO_2 intensity through 2030 must fall below the average emissions of non-CCS natural gas power plants, thus at some point, the shift from coal to natural gas in the electricity sector will not be sufficient to achieve needed reductions (International Energy Agency 2012).

A broad, global-scale analysis of the potential for sequestered CO_2 from biomass (or bio-CCS) to alleviate GHG emissions concludes that there is a technical potential to create negative emissions of up to 10.4 Gt CO_2 e annually, which is approximately 30 percent of the global energy-related CO_2 emissions (Koomneef, et al. 2012). The economic potential, however, is considered to be 3.4 Gt CO_2 e per year. The data presented by Koornneef et al. contain many uncertainties and general assumptions, but their work indicates that a combination of low-cost sustainable biomass and CCS technologies has much value in most parts of the world.

The IEA also notes the lack of progress worldwide in CCUS commercialization (International Energy Agency 2012). Only eight CCUS commercial-scale projects have become operational and some of these have discontinued operations. Over 75 projects have been under consideration or in various stages of planning.. and even if all planned projects come to fruition on schedule and each sequesters 2 Mt CO_2 per year, there will remain a significant shortfall in the rate of CCUS implementation necessary to reach 2050 emission reductions goals (International Energy Agency 2012).

Activities in Europe

Much of European electricity is generated from fossil fuels with a traditionally heavy emphasis on coal; the current low price of coal in Europe will ensure that coal will remain a principal energy source for some time yet. Opportunities for carbon sequestration are abundant in many, but not all countries, from a general geological perspective, but this is tempered by the high population concentrations and lack of public acceptability. Renewable energy has a strong mandate, but the financial and environmental costs incurred are proving to be higher than expected. Several countries have pursued CCS and have initiated projects (e.g., Germany, Holland, France, Italy, Norway, Romania, Spain, and the United Kingdom). However, funding for these projects has been difficult for a variety of reasons, thus there are no current commercial CCS projects in Europe. We present here three examples (Germany, Norway, United Kingdom) of CCS developments, and the potential and challenges that each faces.

The European Union's central bank announced in October 2012 that it had completed the sale of 200 million CO_2 allowances on the European Trading Scheme (ETS) in order to help fund its carbon

capture and storage and renewable energy projects. Since the inception of the trading scheme, the cost of natural gas has dropped from $40 to below $5 per tonne, thus the funds generated are well below original expectations and below the price point (~$30) at which the trading scheme could be an effective incentive for clean energy adoption, including CCUS. Moreover, the trading scheme oversupplied the market with credits, further reducing incentives to mitigate carbon footprints of participating entities. Attempts to shore up the price of carbon to revive the scheme failed in April 2013, creating a challenging political situation for the region's emissions mitigation strategy.

The New Entrants Reserve (NER300) program was established from the sale of auction proceeds and was to provide 50 percent of relevant costs (co-funding) under the first call for proposals, anticipated to be about three carbon capture and storage demonstration projects and up to 16 innovative renewable energy demonstration projects. The amount of funding was approximately $1.7 to 2.0 billion and would leverage a considerable amount of private investment and/or national co-funding across the EU, and thus boost the deployment of innovative low-carbon technologies, and stimulate the creation of jobs in those technologies in the EU. No project would receive funds corresponding to more than 15 percent of the available allowances over the two rounds of calls for proposals. In case the funds should amount to $1.7 billion the 15 percent cap would amount to $392 million, with $1.3 billion the corresponding cap would be $453 million. However, in December 2012, the NER300 award schedule for CCS projects was halted for the first cycle due to a lack of promised government or industry partner support on prospective projects, and funds were instead awarded to renewable energy projects; see Bellona Foundation et al. (2013) for a clear analysis of problems facing CCUS in Europe. Aside from structural issues with the ETS (notably the lack of a carbon price floor), the lack of policy support for CCUS in the manner as was developed for renewable energy generation resulted in a political and populist self-defeating image for this technology. Remaining funds will be rolled into the second cycle, which was announced in April 2013.

In a roadmap released by the European Commission (European Commission, 2013), a vision is planned for a reduction of GHG emission across the region by 80 percent of the 1990 levels by 2050. The mechanisms to be invoked to achieve this reduction are broadly similar to those envisioned for California, with a reduction of traditional fossil fuel generation, but a significant increase in renewables, efficiencies, and electrification of the transport sector. Whether this ambitious goal can be met given current trends in energy generation investments, remains to be seen. Coal will continue to play a major role in European energy generation, and if CCUS is not implemented rather aggressively, the EU will exceed its own GHG mitigation targets if it wishes to sustain economic strength.

Norway

The Norwegian government established a carbon tax in 1991 that prompted Statoil to start the world's first commercial CO_2 storage project, Sleipner, in the North Sea in 1996, followed by Snøhvit in the Barents Sea in 1998. These projects are in response to Norway's plan to reduce GHG to 30 percent below 1990 levels by 2020. On 1st January, 2013 the Norwegian government increased the tax on CO_2 from its continental shelf to $73/tonne, one of the highest in the world (compare Australia at $24/tonne until recent political changes).

The Sleipner CO_2 storage project is the world's longest running geologic storage projects, which since 1996 has stored 12 Mt of CO_2 injected from a single well drilled into the saline water-saturated Utsira Formation (Alnes et al., 2010) about 240 km off the coast of Norway in the North Sea. The Sleipner storage project is being carried out in conjunction with a commercial natural gas production project operated by Statoil where natural gas is produced from the Sleipner West field from a reservoir below the Utsira. In order for the natural gas to be sold, its CO_2 content is reduced from about 9 percent to 2.5 percent (Nooner et al., 2007).

The Utsira Formation and overlying units have been well characterized from nearly 14,000 km of 2D seismic data and over 300 wells (Chadwick et al., 2000). The Utsira sand is approximately 250 m thick at the injection site and stretches about 450 km from north to south and 40-90 km west to east (Arts et al., 2008). The Formation is poorly consolidated, highly porous (30 – 40 percent) and very permeable (1 – 3 Darcy) (Arts et al., 2008). The very high permeability, high porosity, and large reservoir volume has resulted in negligible pressure increases in the reservoir. Overlying the Utsira sand is a shale drape, which is a tabular, basin-restricted, seal (Chadwick et al., 2000).

This is the first project to clearly demonstrate the potential utility of seismic surveys for monitoring CO_2 storage. Repeat 3D seismic data were acquired in 1999, 2001, 2002, 2004, 2006, and 2008 (Eiken et al., 2010) that show a steady expansion of the plume over time. The threshold for use of seismic acquisition and processing at this site to detect leaks is considered to be on the order of 1,000 tonnes of CO_2 (Eiken et al., 2010). Significant findings of the Sleipner project have been the effect of internal structure and heterogeneity of a reservoir on the movement of the plume. The expansion of the plume is significantly influenced by the topography of the interface between the sand reservoir and the caprock, which undulates and has created topographic highs. Under buoyancy drive, the CO_2 fills one high spot before spilling laterally to fill the next. This process can be monitored using the seismic data: Sing et al. (2010) compared the results of two commonly used commercial simulators, Eclipse 100 and Eclipse 300, and all three simulators were able to reproduce the plume migration reasonably well, though the northern migration was best matched by the MPath Migration simulator while the Eclipse simulators better matched the southern migration pattern.

This is the only project to employ gravity methods as part of the monitoring program. Gravity measurements have much lower spatial resolution than seismic measurements. However, gravity can provide information in situations where seismic methods do not work as well, and gravity measurements can be used to assess the amount of dissolved CO_2, to which seismic measurements are insensitive. Alnes et al. (2010) concluded that the rate of dissolution of the CO_2 into the water did not exceed 1.8 percent per year.

In 2011 a three km fracture was discovered during research cruises in the central North Sea, some 25 km north of the Sleipner storage site. These cruises revealed that the 1 – 10 m wide fracture penetrates 150 - 200 m deep into the sub-surface and allows methane gas from the subsurface to rise, which then dissolves in near-surface pore fluids. Where the fracture meets the seabed it is covered with soft sediments and patches of bacterial mats up to three meters wide. Surface sediment samples were taken at these bacterial mats, which revealed that the microorganisms completely convert the dissolved methane into CO_2. When the entire fracture area is considered, about one ton of methane-derived CO_2 is released into the overlying seawater per year. Similar natural seeps, where methane ascends from sub-seabed geological formations to fuel rich and diverse microbial

ecosystems at the sea bed, have previously been documented in the North Sea. Together with other available evidence, this indicates that the fracture is a natural structure that formed in the geological past and is not linked to injection activities.

Computer models and observations from monitoring surveys imply that the CO_2 stored in the Utsira Sand at Sleipner will never reach the fracture area. Furthermore, the available seismic data show that the fracture is vertically separated from the Utsira Sand by several thick, low permeability sedimentary seals. The ECO2 project will continue to investigate and monitor the fracture in order to evaluate its permeability for methane gas and CO_2. It demonstrates the importance, both for ongoing and planned storage projects, to map and monitor the seabed using available cutting-edge technologies.

The Snøhvit project is a commercial natural gas production project in which natural gas, produced from three offshore fields, Snøhvit, Albatross, and Askeladd, is pipelined onshore and processed into liquefied natural gas (LNG) condensate, and liquefied petroleum gas (LPG). It is located to the north of Norway in the Barents Sea. Like Sleipner, the natural gas contains CO_2 that must be removed, which is then stored in a saline formation, the Tubåen Formation, associated with one of the offshore fields. The plan for the Snøhvit CO_2 storage project is to inject about 23 Mt of CO_2 in the saline formation underneath the natural gas producing reservoirs in the Snøhvit field (Maldal and Tappel, 2004). About 0.8 Mt of CO_2 have been injected since operations commenced in 2008 (Eiken et al., 2010).

The Tubåen Formation was chosen in part by data available from numerous wells having been drilled into it for hydrocarbon exploration. The formation is primarily sandstone with a thickness ranging from 45 – 75 m and a porosity of about 13 percent. The Tubåen Formation is overlain by a shale considered to be an adequate seal against vertical migration of the CO_2. There is extensive faulting in the region, adding considerable complexity to the geologic structure of the project and challenging the injection design CO_2 storage capacity at Snøhvit. The Tubåen could not be well defined based on available data prior to injection causing uncertainty about how well the porous sand bodies in the reservoir are connected. Faulting divides the reservoir into compartments, and results of seismic data collected prior to injection suggest that the faults are not completely sealed (Linjordit & Olsen, 1992).

Modeling by Pham et al. (2010), in which the heterogeneity in porosity and permeability derived from well logs was included in the reservoir model along with sealed faults, revealed that planned injection rates from a single well would result in excessive pressure build-up greatly in excess of the pressure required to fracture the formation.

Simulations undertaken by Estublier and Lackner (2009) to evaluate the long-term behavior of the CO_2 plume at Snøhvit concluded that it was unlikely that all 23 Mt could be stored if the faults were sealed. If the faults are not sealed the CO_2 could migrate up into the Stø Formation where the long-term containment of the CO_2 would be dependent upon the sealing capacity of the formations overlying the Stø.

A series of pressure build-ups and fall-offs have been observed at Snøhvit due to frequent injection stops at the site, but pressure increase over the injection period indicates there is moderate effective permeability in the reservoir. A 4D seismic data set collected in 2009 suggest that only a fraction of the main formation is receiving most of the CO_2, probably due to lateral sedimentological heterogeneities barring effective permeability.

In 2006, the Norwegian government and Statoil agreed to build a center for testing of carbon capture technologies at Mongstad near Bergen, in Norway. The Technology Centre Mongstad (TCM) is a joint venture between Gassnova, on behalf of the Norwegian state, Statoil, Shell and Sasol. TCM's main purpose is to become a global resource centre for carbon capture technologies and to share experience and knowledge gained from testing with owners, vendors and the global research community. It will be one of the largest of its kind, and is the most advanced and flexible installation for testing of carbon capture technology in the world. TCM's unique flexibility allows for testing of two or more different technologies with access to flue gas from the gas-fired combined heat and power plant and the flue gas from the refinery catalytic cracker. Aker Clean Carbon and Alstom will test their respective technologies in the first phase. Recently, TCM invited vendors in the field of carbon capture technology internationally to compete for a role in a second phase of testing programs at TCM. Through testing, verification and demonstration of technologies, TCM aims to reduce both the operating and capital expenditures, and to improve performance and reliability. Increasing knowledge on the chosen capture technologies will allow for a reduction in technical and financial risk uncertainty, and provide qualified technologies capable of wide scale international deployment. The response has been overwhelming, and TCM is positioned to play a key role in developing carbon capture technologies internationally.

TCM's partners have made a clear commitment to technology improvement and invested 5 billion Norwegian kroner for the construction and development of the technology centre. Designed to capture about 100,000 tonnes per year of CO_2, the project will be the largest demonstration of CO_2 capture technologies to date. The recently elected government controversially chose to de-fund the large –scale demonstration, which will not now proceed.

The Nordic Energy Technology Perspectives study explores how the Nordic region can achieve a CO_2 -neutral energy system by 2050 by addressing, amongst others, the role of CCS. The five Nordic countries want to cut emissions by 85 percent compared to 1990 levels until the middle of the century. This study asserts that CCS technology must be fitted to 50 percent of cement plants and 30 percent of steel and chemical factories, but it acknowledges that so far the progress has been slow. Between 20 percent and 30 percent of the reduction in industrial CO_2 emissions would be achieved by implementing CCS in the iron and steel, pulp and paper, chemicals, and cement sectors by 2050, mostly in Sweden and Finland. Since neither Finland nor Sweden has CO_2 storage sites the study identifies the development of the infrastructure for transporting CO_2 to the North Sea or other sites as one of the main challenges. The study recommends removal of possible legal barriers that could hamper the development of offshore pipeline infrastructure across country borders. The study identifies bio-CCS as a promising option in the pulp and paper industry that would result in net negative CO_2 emissions. The NETP 2012 stresses that it is particularly important that future policies include bio-CCS as an option to reduce greenhouse gases.

United Kingdom

A CCUS program in the UK is facilitated by having in place a UK Clean Energy Policy Mix to drive low-carbon outcomes. The overarching framework identifies comprehensive emissions targets supported by plans addressing buildings, transport, industry, electricity and agriculture, land use, forestry and waste.

The British government has acknowledged the significance of CCUS in reaching GHG reductions particularly in view of the historical importance of coal-based energy production in the UK. Furthermore, the depleting reservoirs in the North Sea hydrocarbon fields create viable EOR/EGR targets for CO_2 in addition to deeper saline formations.

The government published a CCS Roadmap in April 2012 (Watson et al., 2012) that sets out the Government's goal of seeing commercial CCS deployment in the next decade, and identifies actions that need to be taken to achieve this ambitious goal. Crucially, the Roadmap recognizes the industry ambition of at least 20-30 GW of installed capacity of fossil fuel power plant fitted with CCS by 2030 – as set out by the Carbon Capture and Storage Association (2011). The CCUS program is supported by a range of technology-related initiatives, including $1.6 billion in capital funding to support CCS projects; Electricity Market Reform, including Contracts for Difference tailored for CCS generation; emissions performance standards which in effect require partial fit of CCS to coal-fired generation; requirements to apply to all new build generation of over 300 MW capacity; and $195 million over four years for research and development focused on cost reduction. Of the numerous awards under the latter scheme, one of note has been to create a new $3 million high-tech laboratory to develop carbon capture and storage at Cranfield University that will house a range of near industrial-scale equipment for research and development of clean and renewable energy technologies. It will support research into carbon capture and transport systems, clean fossil fuel technologies, bioenergy and energy-from-waste by being able to test technologies used for process development, examine materials performance and the reliability of systems and components such as heat exchangers, gas turbine blades and CO_2 pipelines. The range of new equipment will enable industry and other universities to develop and test ideas through to pre-commercial scale across a wide spectrum of energy from technologies.

The UK Government have a focus on the economic benefits from such investment, which they estimate will sustain 100,000 UK jobs by 2030 and generate up to $10 billion per year and ultimately be of a similar size to the oil and gas industry. The potential for North Sea EOR and subsequent tax revenue is also important.

In the UK, the commercial case for early and long-term CCS projects will be determined to a large extent by the UK's Electricity Market Reform (EMR) that was introduced in 2011 to create an overarching framework by which all low-carbon electricity generating technologies can compete for a level of support. Key to EMR is the Feed-in-Tariff Contract-for-Differences mechanism, which will provide a level of top-up to the wholesale electricity price to support nuclear, CCS and renewables on a similar and comparable basis.

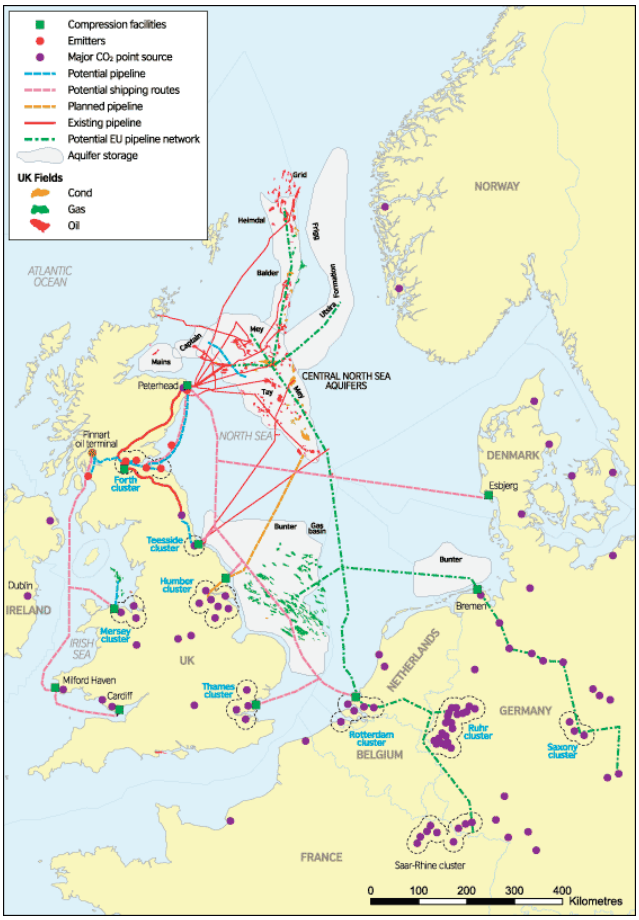
The government is focused on the long-term commercialization of CCS, with the high-level aim of enabling CCS to compete cost-effectively with other low-carbon technologies in the 2020s. Crucially, the program states clearly the need for projects to demonstrate their contribution to the

development of early transport and storage infrastructure which will support CCS projects into the future, an issue which has long been at the forefront of industry discussions. Current estimates suggest that CCS is already cost-competitive with some low-carbon forms of electricity generation; however, as with any emerging technology, CCS must go through a process of cost-reduction to reach commercial maturity. Once momentum behind building the first CCS plants is established, the process of technology optimization and cost reduction can take place more quickly. Accordingly, the government has set up a CCS Cost Reduction Task Force that will look at key areas in achieving cost reduction in CCS in the immediate future. The original Energy Bill states that all new coal-fired power stations must have a proportion of their capacity equipped with CO_2 capture and storage infrastructure. A recent amendment would oblige electricity companies to eliminate any coal or gas-fired power plants from their networks by 2030 unless they are fitted with CO_2 capture equipment, CCS is becoming an increasingly necessary option for industrial sectors such as steel, cement, chemicals and oil refining, which will soon be faced with tough decisions regarding their continued operation in a carbon constrained world. For many of these sectors, there is no realistic means of decarbonization other than CCUS, because the CO_2 is process as well as fuel generated.

An independent think tank, Carbon Connect, analyzes an electricity future for the UK sustained by fossil fuels in which the GHG emissions are mitigated by CCS (Carbon Connect, 2013). A principal finding is that de-carbonizing the power sector beyond 2030 without CCS would be expensive and politically challenging. Meeting the UK's 2050 carbon targets without CCS could cost the UK economy $45-60B per year.

The $1.56 billion CCS commercialization competition identified four short-listed projects in 2012 that were also in the running for EU support under its NER300 funding program. Unfortunately, the government did not commit its funds to any of these projects prior to the deadline for EU funding, thus these projects (as well as proposals from other parts of Europe) were shelved until the government does commit funds to all or some of these projects in time for the next round of EU awards. The maximum support available for CCS projects would have been around $390 million per project, which is a significant loss for the UK CCS initiative. They may be eligible for the next round of NER300 funding, but the funding level may be lower; the one year delay will also impact the UK's ambitious to establish itself as a leader in CCUS technologies and demonstration projects. The proposed CCUS projects in the UK all take advantage of depleted North Sea oil and gas fields that are close to the geologically near-perfect, and technically diverse, sub-surface CO_2 storage sites available within Central North Sea. Deep beneath the waters of the Moray Firth, the Captain Sandstone alone has already been shown to have enough capacity to safely store the next fifty years of emissions from UK fossil fuelled power plant. Nearby, another ten reservoirs can easily hold one hundred years worth of Europe's CO_2 emissions. A long term vision for 2050 shows how a networked system of pipelines connecting the industrial heartlands of NW Europe could significantly mitigate the CO_2 emissions in Europe (Figure).

Figure 6: The 2050 vision for a North Sea Centered Pipeline System for Transporting CO_2



Pipeline is to connect capture sites to sequestration sites in the North Sea gas fields.

Source: Scottish Enterprise, 2012.

In March 2013 the UK government announced two finalists. The White Rose Project is a consortium is being led by Alstom, Drax, and National Grid and aims to capture about 2 Mt of CO_2 from a 426 MW coal-based power plant using oxyfuel combustion technologies. The CO_2 would be transported via pipeline to, in the first case, deep saline formations offshore, but also depleted oil and gas reservoirs using EOR and EGR. The pipeline would serve a cluster of six power plants in the region plus a steel making facility. It is planned that this facility would come on line by 2016. The Peterhead Gas CCS Project is a post-combustion CO_2 capture project in which Shell and Scottish and Southern Energy will work together. From the 385 MW power plant at the Peterhead Power Station, NE Scotland, approximately one million tonnes per annum of CO_2 is expected to be captured, then transported to the Shell-operated Goldeneye gas field in the North Sea using, as far as possible, existing pipeline infrastructure. The project is expected to become operational in 2015.

In addition, the Captain Energy Project led by the US company, Summit Power, proposes to build a new 570 MW IGCC power plant at the Port of Grangemouth, west of Edinburgh, which would be a technical replication of Summit Power's Texas Clean Energy Project (see above). Up to 90 percent of the plant's CO_2 emissions would be captured using post-combustion capture technology would be transported by pipeline to the North Sea for storage, and possibly for enhanced oil recovery. Agreements have been signed with National Grid and CO2DeepStore for the transport of

CO_2 onshore and offshore respectively. The financing structure for this project differs from its Texas counterpart in that the EOR market in the UK is not as mature as in Texas thus limiting the sale of CO_2. In addition, the urea market is tighter and it also has a smaller potential to generate funds. Capital funding through a proposed feed-in tariff with a contract for difference, will secure longer term viability. The project could become operational in 2018.

Another project that was not chosen as a finalist, but which is on the reserve list, is the Teeside CCS Project for a 850MW IGCC coal-based power plant that would capture approximately 5 Mt of CO_2 annually from a 400 MW pre-combustion slipstream mechanism. The CO_2 would be transported via pipeline system that eventually would allow additional CO_2 emitters to transport gas to offshore saline formations that are currently being assessed. This project may seek second round NER300 funding.

Germany

Germany is Europe's largest economy and leading exporter; it is also Europe's heaviest energy consumer and biggest carbon emitter, thus exhibiting its enormous potential and responsibility. Germany emits over 400 Mt of CO_2 from stationary sources, of which energy production is the dominant component. The role of CCUS in Germany ought to be promising, but public, and therefore political, acceptance is proving a challenge.

The German government wants 80 percent of its energy to be produced by renewable sources by 2050 and is accordingly subsidizing it heavily ; biomass, wind, and solar currently make up about 25 percent of the country's electricity supply. The country has begun to take fossil fuel power stations offline and is planning to phase out nuclear energy by 2022. German figures on the actual productivity of the country's principal renewable energy source, wind power, over the last ten years is 16.3 percent. Due to the inherent intermittent nature of wind, their wind power system was designed for an assumed 30 percent load factor versus some 85-90 percent for coal, natural gas, nuclear and hydroelectric facilities. Thus for a 3 GW of wind power, they expect to actually get merely 900 MW, but in reality, after ten years, they have discovered that they are actually getting only 16.3 percent. Moreover, Germany's total combined solar facilities have contributed just 0.084 percent of Germany's electricity over the last 22 years. Data on the real economic and environmental benefit of renewable in Germany are evolving and complex and subject to highly variable analyses. We feel that it will be important for California to follow the aggressive adoption of renewable in that country, and should be targeted by a fuller analysis than this report can offer.

The actual cost of Germany's wind and solar electricity is a good deal higher than its cost of coal and nuclear power. The cost of these changes has resulted in up to 800,000 households not being able to pay their bills and placed a strain on existing capacity in the electrical grid. Although Germany has made significant investment in wind and solar power, it faces an energy shortfall, partly because it has insufficient transmission lines to bring wind power from the North Sea to the industrial centers in the south and partly because of the intermittency of wind and solar sources. Electricity prices in Germany in 2013 are expected to increase by more than 10 percent. Much of this increase is driven by a surcharge to cover the costs of using more renewable energy. The renewable surcharge is the difference between guaranteed prices mandated to be paid for renewable energy and market prices for conventional energy. The renewable surcharge will increase by 47 percent. To put this in perspective, in the United States, the average residential retail price of electricity is 11.80 cents per

kilowatt hour, so Germany's renewable surcharge in 2013 alone will be 58 percent of the *total* cost of residential electricity in the United States (Institute for Energy Research, 2012). Residential electricity rates in Germany are almost triple those in the United States, at over 33 U.S. cents per kilowatt hour.

Under challenging economic circumstances, the government is emphasising the importance of not weakening the economy by increasing the cost of energy; it is also concerned that Germany should not become dependent on imports of electricity. While the government policy of requiring 35 percent of its electricity to come from renewable sources in the next eight years is proceeding, there remains 65 percent to come from other sources. Accordingly, the government is allowing the building of more than 20 coal-fired power stations - without CCS provisions. The new coal and gas power plants would be cleaner and more efficient than the old lignite (brown coal) plants, although it is unlikely to be German coal. In the 1950s, there were 607,000 miners in almost 150 mines, producing 150 Mt of coal. Cuts to the coal industry have reduced the workforce to about 20,000 miners producing approximately 10 Mt - and falling as subsidies fade to nothing in the next five years. It is likely that coal will instead come from Poland, South Africa, and possibly America. The development of new coal-based power plants without CCS will lock Germany into a high-carbon economy for the foreseeable future; the option of retrofitting these plants will be an expensive option should priorities change.

In April 2011 the German Federal Cabinet reached a compromise on CO_2 storage and in 2012 approved a CCS Act. This law restricts storage to test projects and excludes demonstration projects and storage for commercial purposes, both in the short term and on a larger scale, limiting the annual, national storage of CO_2 to 8 Mt and each individual facility to a maximum of 3 Mt per annum. Germany has the potential to store much larger amounts of CO_2, thus the proposed ceiling is very low compared to the estimated potential to store more than 20 Gt of CO_2 underground. Germany currently has no CCS projects despite targets in its German Energy Concept, where the government aims at establishing two to three demonstration projects by 2020. The government is also obliged to establish a CCS Act under the conditions of the European Union's CCS Directive, which was adopted by the European Parliament in 2009.

The Act would be evaluated in 2017 so that CCS could be used on a larger scale if things have gone positively. Operators must set aside funds from the moment they initiate storing, to safeguard against potential long-term risks. There is also careful attention paid to public acceptance – 'better protection of the rights of land owners is ensured' and 'municipalities affected are to receive financial compensation'. This law allows each state government to decide whether CCS can take place under their jurisdiction. Four states are considered to have good storage potential – Brandenburg, Lower Saxony, Schleswig-Holstein and Mecklenburg-West Pomerania, of which the latter has banned storage of CO_2 underground, and Scheswig-Holstein is considering such a move.. Brandenburg is home to Germany's only CCS pilot project, Ketzin, and a former leading demonstration project at Jänschwalde. It is also home to one of Europe's most prominent cases of public resistance to storing of CO_2 in which a subtle connection has been drawn in storage site areas between storing carbon and storing nuclear waste. Posters and signs remain prominently displayed around the storage site communities, using the colors, symbols and terminology of anti-nuclear campaigns and nuclear waste.

The pilot CO_2 injection project in Ketzin near Berlin, Germany, is a major research effort funded through the European Union's CO2SINK Project (Martens et al., 2011). Monitoring CO_2 in the subsurface and feasibility of sequestration will provide information for future policy making in EU. The project started in 2004 and three injection wells were completed in 2007 with injection starting in June 2008. The project is operated under CO2MAN (CO2-Reservoir Management). CO2MAN started in September 2010 and will continue until August 2013. Ketzin was previously operated by CO2SINK, which ended in March 2010. The project involves 18 partners from nine countries, and as of December 2012 has injected over 60,000 tonnes of CO_2. The target formation for CO_2 injection is located at a depth of about 650 m and is on average 80 m thick and is heterogeneous, consisting of sandstones of good reservoir properties alternating with shales of poor reservoir quality (Arts et al., 2010). Understanding the detailed geometry of these alternating layers, and their impact on flow and other monitoring measurements, has represented a major challenge at Ketzin.

The Ketzin pilot is interesting because of the heterogeneity of the geology and the unique technologies that have been employed in reservoir modeling and monitoring. For reservoir simulation, a commercial 3D streamline simulator was used (Pamukcu et al., 2010). A good match was achieved in predicting the bottom hole pressure of the injection well and CO_2 breakthrough time at the first observation well. The observed breakthrough time at the second well was considerably less than expected, bringing into question the accuracy of the description of the heterogeneity in sandstone and shale layering in the reservoir. The unique monitoring approach applied at Ketzin is the use of electrical geophysical methods. For monitoring of CO_2 in saline formations, electrical methods should be applicable because CO_2 has a much lower electrical conductivity than saline water; hence electrical measurements should be sensitive to the saturation of the CO_2. Since seismic measurements are not very sensitive to saturation, use of electrical measurements in conjunction with seismic measurements could provide additional understanding of the movement and distribution of the CO_2 in the subsurface.

Work at the Ketzin site has demonstrated that on-shore CO_2 storage is safe and reliable, and outreach efforts have built local confidence and awareness in this technology. However, Martens (2013) reports that Ketzin successes have not had any positive influence on national confidence or national implementation of CCUS.

Jänschwalde was selected by the European Commission for significant financial support of €180 million. It is, therefore, considered one of the leading projects in Europe. However, the Swedish state-owned energy company Vattenfall announced on 5 December 2011 that it will cancel its project for a carbon capture and storage demonstration plant in Jänschwalde, and also cancels its plans to explore possible storage facilities in Eastern Germany. According to Vattenfall, the project stopped due to lack of political will to implement the necessary legislation for CCS. With new coal and gas fueled power plants starting up every week, Vattenfall's decision is seen as a step backwards in the global process of up-scaling the CCS technology that will be indispensable in the combat against climate change in a worldwide perspective.

The Netherlands

Located within the Maasvlakte section of the Rotterdam port and industrial area, the Rotterdam Opslag en Afvang Demostratieproject (ROAD) is one of the first industrial, integrated CCS chains that may act as a stepping stone for the sustainable economic development of the Rotterdam CCS

network for chemical and energy-intensive industries. This demonstration project will generate new technical, legal, economic, organizational and social knowledge and experience, the value of which has been recognized by the GCCSI with a $5 million award. Due to its 'first of a kind' nature, the ROAD project poses an array of challenges that can be considered uncommon to other utilities projects. The total cost of the project will be $1.6 billion, which includes $242 million from EU Government and $201 million by the Dutch Government for 2010-2020 in May 2010. This project includes the construction of a new 1070 MW coal- and biomass-based power plant.

Approximately 1.1 Mt per annum of CO_2 would be captured for storage in offshore depleted gas reservoirs at a depth of 3,500 m under the sea bed. Strategically located near the North Sea and the Rotterdam harbor area, the new power plant can maximally profit from seawater for cooling and deep waterways for supply of coal and biomass. The power plant will have an efficiency of approximately 46 percent.

The development work to put in place the commercial and funding arrangements of the project plus a risk analysis to enable the project proponents and its partners to make a final investment decision on advancing to the next phase of the ROAD project.The ROAD project submitted its original application in July 2009; the environmental and permit applications were completed by two years later, and the final investment decision completed in late 2012. The engineering should be completed by 2014 and test operations should begin in 2015 with demonstrations lasting until 2020 when full commercial operations begin.

A report on lessons learnt thus far by the project (Buyesee and Fonteijn, 2012) emphasized the need for a stakeholder management approach to the project as ROAD is a partnership of two principal companies with a larger number of stakeholders that needed to be integral to the project's momentum. In addition clear organizational structures from the start were imperative to preclude tensions and misunderstanding.

Given negative experiences with CCS in The Netherlands, primarily with the Barendrecht project, it was essential that public outreach and proactive stakeholder management be undertaken from the outset.

Netherlands

A number of studies have analyzed public perceptions of proposed CCS projects within Europe, all of which included outreach activities (Brunsting et al., 2011a; Brunsting et al., 2011b; de Best-Waldhober et al., 2012). In some cases, acceptance by local communities played a major role in project continuation or cancellation. For example, the experience of a CCUS project in the Netherlands is instructive and parallels findings for California projects.

Studies of Dutch perspectives to guide policy on CCS (Van Alphen et al., 2007) during the 1990s to 2006 analyzed opinions of stakeholders and analyzed CCS coverage by Dutch print media between 2005 and 2006. The authors used the media as a proxy for the opinions of the lay public, arguing that media portrayals have a dominant influence over the lay publics' understanding of CCS. They claimed that questionnaires provide unreliable data due to the limited information provided and the varied understanding by those surveyed.

Over the time period studied, media articles that were positive toward CCS increased dramatically (from 8 percent to 59 percent), while those expressing a neutral opinion decreased by more than half (from 75 percent to 31 percent). The proportion of negative articles declined by almost half (17 percent to 10 percent). Positive views of CCS were overwhelmingly related to the technology's CO_2 emissions mitigation potential and, to a lesser extent, cost effectiveness compared with renewal energy investments. Negative opinions expressed in the media were mainly concerned with the high costs of CCS and its enabling of continued dependence on fossil fuels rather than being a final solution to the problem of GHG emissions. In short, costs and purpose dominated CCS coverage in the Dutch print media; fear and safety concerns were minor. Surveys were also conducted in relation to a CCS project proposed for Barendrecht. In 2007, the Dutch government released a request for bids for a CCS demonstration project with a budget of $40 million. Shell Oil was selected for a project to store CO_2 from a refinery near Rotterdam with the CO_2 to be transported via pipeline 17 km to the southeast for storage in a depleted gas reservoir beneath the town of Barendrecht.

A survey was conducted in May 2010, during the permitting process, after local opposition had developed. The survey indicated that the local community felt that the planning process had been unduly influenced by Shell and the national government. They felt that they had too little input into the process, and this led to a lack of trust in the fairness of the decision-making process. This is clearly another example of a community's inclination to respond negatively when it does not feel empowered by the process.

Concerns about safety and property values were raised. Safety concerns arose after an apparent misunderstanding of the storage depth. Over half of those questioned thought the depth to be less than 500 m or were not sure; few knew that it would be below 1500 m. Opponents described the project as resulting in their town "sitting over a CO_2 bomb." Many expressed fear that their houses would lose value. Similar issues were raised as questions in outreach activities related to California projects; however neither issue was seized upon for escalation by activist groups and thus, neither issue became a focal point for opposition.

The response of Shell and the Dutch national government did little to calm the local fears, which activists took advantage of to influence the public. The project proponents held two public meetings, supported a website, and a local information center. The activist groups produced a television documentary that was especially influential even though the coverage was biased and contained misinformation.

The survey analysis pointed out that the public inherently trusts small, local groups more than large, outside organizations, especially those benefitting from an outcome. Shell and the national government viewed the project as important from a techno-economic perspective; the municipality viewed it from a social and local perspective. During this period, the national government passed a law that allowed it to expedite planning permission for large projects and even to overrule local permitting decisions. This was done in order to speed up industrial development during a period of economic challenges, but it was perceived as an attempt to remove power from the local community.

In 2010, the national government lost the election, and the new government decided to abandon the Barendrecht project in November of 2010. The government said that the delay of the CO_2 storage

project for more than three years and the complete lack of local support were the main reasons it decided to stop the project. The government noted that such experiences are extremely valuable for the further development of CCS in the Netherlands, but that the continuation of this relatively small project in Barendrecht was no longer essential to CCS development. The ROAD project (see Chapter 4) will proceed.

It may be noteworthy that reducing the CO_2 emissions in order to mitigate climate change was not considered important by the Barendrecht community. This same lack of interest by a local community in accepting projects for "global good" was evident in California project outreach results. The scale of the Barendrecht project was perhaps too small to be viewed as having significant effect in reducing global emissions, and the notion that approving this project would pave the way for more and larger projects was either not considered or was not important to the community. The focal point of the community's concerns was that they were being "dumped on" by untrustworthy organizations with no visible benefit to themselves.

Activities in Africa and the Middle East

Algeria: In Salah

The In Salah project, located in the Sahara in central Algeria , was a commercial natural gas production project in which CO_2 is removed from the natural gas in order to meet the gas export specification of 0.3 percent CO_2. More than 3.8 Mt were stored between 2004 and 2011, with an original goal to store 17 Mt of CO_2. An extensive monitoring program has been undertaken, both to meet the commercial needs of the project, and to support development of monitoring, modeling, and verification practices. This project was a pioneering case because of the unique monitoring technologies applied, and because of a small amount of leakage detected due to the unexpected migration of CO_2 to an exploration well drilled more than 20 years prior to project start-up. There were no adverse impacts from the leakage. Project partners suspended storage operations in 2011 after a review of data raised concerns about seal integrity at the site even though no leakage was reported

The reservoir was a sandstone that is on average about 20 m thick and has a porosity of about 13 percent and a permeability of 10mD. It is overlain by about 900 m of mudstone that acts as a seal against vertical migration of both the natural gas and the CO_2. Structurally, it is a dome in which the hydrocarbons have accumulated at the high part. An extensive 3D seismic survey was carried out in 1997 defined the overall structure of the reservoir and provided information about its internal architecture and distribution of the sandy portions with the best porosity and permeability (Iding and Ringrose, 2009).

Reservoir simulations carried out during the design phase of the project indicated that the CO_2 would not migrate very far in the direction of the old exploration well. After injection started and monitoring data became available, additional focus was placed on understanding the impact of fractures and faults on the movement of the CO_2 in the subsurface, and a leak was discovered. The geologic model of an area around one of the CO_2 injectors, KB-14, was modified to incorporate a network of fractures. The 3D seismic data was reprocessed using techniques designed to help identify faulting, and a possible fault was identified which trended from another injector toward the leaking well. This fault was incorporated into a numerical model of the reservoir as a high

permeability corridor and the commercial reservoir simulator, Eclipse, was used to demonstrate that the unexpected, rapid migration of the plume to KB5 could be explained by the presence of such a feature (Iding and Ringrose, 2009).

Geomechancial simulations were coupled to the fluid flow simulations (Rutqvist et al., 2010) that showed that the pattern of uplift of the ground surface consistent with injection-induced deformation in a fault zone. The geomechanical analyses further show that the stresses induced by the injection are not sufficient to cause the fault to slip. Thus, even though a fault is present, the integrity of the seal, and long-term containment of the CO_2, is not threatened by movement on the fault. The original monitoring program was designed with key risks in mind, of which four were related to leakage and long-term containment, either through wellbore leakage or though the seal. Early CO_2 breakthrough that can be caused by flow along a fault, can also result in less effective use of the storage space in the reservoir, affecting its ultimate storage capacity.

A cost/benefit assessment was applied to a number of monitoring technologies, including physical surveillance, fluid sampling, well logging, satellite detection, and 3D seismic (Mathieson et al., 2010). Repeat 3D surface seismic technology had the highest benefit and the highest cost, but because seismic proved challenging at this location, other methods, such as InSAR (satellite airborne radar interferometry), which can provide information on the behavior of the plume at large distances from wells, take on greater importance in the monitoring program. The tracer monitoring approach involved injection of small amounts of perflurocarbons along with the CO_2, and sampling of well bore fluids in observation wells.

During the design phase of the JV project in 2001, reservoir simulations indicated that CO_2 would not migrate very far in the direction of KB5 (a decommissioned but uncemented well) from the closest injector, KB502, which intersected the water saturated portion of the Carboniferous formation that also host injected CO_2. After injection started and monitoring data became available, additional simulations, coupled with satellite observations of surface deformation suggested that CO_2 was migrating more quickly than expected in the direction of KB5. A perfluorocarbon tracer was injected into KB502 and a close inspection of the KB5 well was carried out during a routine surveillance where the operators estimated the leak as a few m^2 day – a very small volume compared to the approximately 30 million ft^3/ day being injected (Ringrose et al., 2009). KB5 has been completely decommissioned but surface flux and soil gas monitoring are currently ongoing at KB5.

Saudi Arabia

Although Saudi Arabia remains the world's largest producer and exporter of petroleum products, the domestic consumption is growing rapidly and is projected to continue doing so for some time. So too are the GHG emissions, which on a per capita basis puts Saudi Arabia as one of the highest emitters in the world at 16.2 tonnes per person, compared to a global average of 4.3 tonnes per person and 9.8 tonnes per person for OECD countries (Liu et al., 2012). Saudi Arabia is a signatory to the Kyoto Protocol and thus is taking seriously its commitment to reduce GHG emissions and transform to a low-carbon, which create special challenges for such an oil-dependent economy.

All natural gas produced is used domestically, mostly for power generation from inefficient gas turbines that account for 61 percent of the power generated. Because so much power is from these

older single gas cycle units, the potential for carbon capture from them is significantly more expensive. More efficient combined cycle units account for only 6 percent of the countries generation. Aside from power generation and desalination, which account for 40 percent of total CO_2 emissions, other significant sources of CO_2 emissions include refineries, cement, aluminium, and other industrial facilities.

Unsurprisingly, Saudi Arabia is thought to have a very large potential storage capacity for CO_2, mainly in deep saline formations, but also in the extensive depleted oil and gas reservoirs. No good estimate exists for the Saudi capacity, but it is thought certainly to exceed 1,000 Gt CO_2, possibly as high as 2,000 Gt CO_2. The oil reserves for production in Saudi Arabia are still abundant and there is no requirement for EOR for the foreseeable future. However, Saudi Aramco is undertaking a CCS project for sequestration capabilities with a target injection of 40 MMscf/day of CO_2 transported by a dedicated pipeline from a natural gas recovery facility some 80 km away (Liu, 2012).

A survey of key stakeholders in Saudi Arabia's energy future (mostly energy-related professionals, and not the general public) urge the strategic use of energy efficiency, renewable energy generation, and CCS to assure the country's long term energy future. However, the government has shown interest in investing in renewables, energy efficient technologies, and nuclear power.

United Arab Emirates

Masdar (Abu Dhabi Future Energy Company) and Emirates Steel Industries (ESI) have proposed to recover high purity CO_2 from Emirates Steel Industries' Direct Reduced Iron facility, which will be fed to Masdar's CO_2 compression and dehydration facilities, which are sized to handle the 800,000 tonnes per annum of CO_2 that will be captured at the plant. A 50 km pipeline will transport the CO_2 to a selected oil field in Abu Dhabi. The CO_2 will initially be injected for pressure maintenance, followed by EOR in the long term. That will be the first section of a planned 500 km carbon emissions pipeline network connecting 6 Mt per year of emissions from aluminium smelters and other industrial sites to oilfields.

There, the carbon can be injected underground to pry oil from ageing fields or simply buried. An agreement was recently signed for a 270 MW coal-burning power plant at Ras Al Khaimah designed to capture 1.1 Mt of carbon a year with a combination of chemicals and algae, which would then be converted to biofuel.

Feasibility studies were completed in 2009, and front-end engineering design for the CO_2 recovery plant at ESI and the emirate-wide pipeline network was completed in 2010. Full-scale operation is scheduled to be reached by 2015.

The project is part of the Abu Dhabi CCS Network being promoted by Masdar to reduce Abu Dhabi's emissions in an economical way, and the Abu Dhabi CCS Network aims at capturing existing CO_2 emissions from power and industrial sites, as well as developing a network of CO_2 pipelines to transport the CO_2 to Abu Dhabi's oil reservoirs for EOR.

Bahrain

The oil and gas reserves in the small Gulf nation are depleting and EOR is seen as a mechanism to extend the life of the reservoirs. However, much of Bahrain's oil is heavy and thus not immediately amendable to CO_2 flushing, but depends more on steam-based EOR. This is both water and energy

intensive, thus a combination of CO_2, which is available in large volumes from local aluminum smelters, and other surfactants, may prove to be viable.

Asia and the Pacific

Australia

Until recently Australia invested heavily in CCS technologies and their adoption domestically and overseas. In addition to the projects described below, the former government sponsored the Global Carbon Capture and Storage Institute (GCCSI) which established itself as a global clearinghouse for international CCUS activities. With the recent change of government, the level of government sponsorship will be reduced significantly in coming years. Australia adopted a price of carbon that ultimately proved too high a political hurdle for the prior government, and is being removed by a new government more supportive of the coal industry and less accepting of climate change impacts than its predecessor.

The Gorgon Carbon Dioxide Capture and Storage Project (Western Australia) is supported by Australia's Federal Government, which together with the Western Australia state government, has accepted liability for the project, together leading Japanese utilities companies and three global oil companies. Chevron Australia Pty Ltd, the Australian subsidiary of Chevron Corp., is the project's operator with 50 percent interest. ExxonMobil and Shell each hold 25 percent interest (Bunch, 2013).

The Greater Gorgon Fields lie 130-200 km offshore and contain about 40 Tcf of gas. The gas contains about 14 percent CO_2 and will be piped and separated onshore at a processing facility on Barrow Island, NW Australia. The project plans to capture up to 3.3 Mt per year of CO_2 over the 36 year life of the project and store it in deep formations about 1,300 m below Barrow Island. Injection into the saline formation is planned to be via 8-9 injection wells with approximately four pressure management wells. The proposed injection site was selected to maximize the CO_2 migration distance from major faults and limit environmental disturbance.

Chevron Australia says the Gorgon carbon capture and storage project will reduce net global greenhouse gases by about 45 Mt per year, the equivalent of removing two-thirds of all vehicles from Australian roads. The Greater Gorgon Area is estimated to have resources of 40 Tcf of natural gas, the equivalent of 6.7 bbl of oil. The resource contains enough equivalent energy to power a city of one million people for 800 years. The Gorgon project is estimated to cost approximately $43 billion for the first phase of development and about $50 billion overall. The GE Oil and Gas contract alone is worth over $400 million. Chevron and its partners will assume liability for leakage and damage during operations, and for 15 years following injection cessation. Thereafter the national and state government will assume the long-term liabilities.

To date, the Gorgon partners have signed sale and purchase agreements for LNG export into Japan and South Korea, the world's two largest LNG import markets, as well as India and China. China signed a contract to purchase Gorgon liquefied natural gas worth an estimated $50 billion over the next 20 years. The project will produce LNG for export and natural gas for the domestic market. LNG production is expected to commence in 2014 and domestic gas production by the end of 2015.

With $1.6 billion in funding from the Federal Government's the Cooperative Research Centre for Greenhouse Gas Technologies (CO2CRC) Otway Project is Australia’s first CCS demonstration

project and the first intensely monitored pilot site for CO_2 storage in a depleted gas reservoir (e.g., Bunch, 2013). The Otway Project site is located onshore in southeastern Australia, and to date, 65,000 tonnes of CO_2-rich gas (80 percent CO_2; 20 percent methane) have been injected into the reservoir (Sharma et al., 2010). The CO_2 is produced from the nearby Buttress Field, compressed at the surface, then transported 2.25 km in an underground pipeline and injected into the depleted Naylor Gas Field. The reservoir is a 25-m-thick sandstone located at a depth of about 2 km. It is a 0.5 km^2 compartment located in a tilted fault block, with migration prevented by faults.

One of the objectives of the Otway project has been to improve capabilities for predicting CO_2 plume movement in saline reservoirs. The initial pre-injection geologic model was primarily based upon 3D seismic data and information from two wells (Bouquet et al., 2009, Ennis-King et al., 2010). Using data from the injection well drilled for the project, a suite of models was developed based on different choices for the depositional environment and permeability variograms. The numerical simulation models were then validated and refined by history-matching with monitoring data (Ennis-King, 2010). The predicted breakthrough time was six months, or less, and the observed breakthrough occurred between four to four and a half months after CO_2 injection (Ennis-King et al., 2010). Among the many parameter variations explored, adjustments to the overall reservoir permeability were the most effective at improving the history match with the pressure data (Ennis-King et al., 2010).

Use of seismic methods was challenging at Otway for two reasons. First, the reservoir is small, located relatively deep, and thin. Second, injection of CO_2 into a depleted gas reservoir would not be expected to generate significant changes in the seismic signals because changes in the elasticity of the reservoir rock would be small (Urosevic et al., 2010). The first challenge was overcome by combining 3D VSP with 3D surface seismic, and through use of high spatial data density, high fold, and high quality processing of the data. The second challenge could not be overcome, and it was concluded that the time-lapse response was too small to be reliably estimated and analyzed from repeated seismic measurements (Urosevic et al., 2010).

If CO_2 were to migrate into formations overlying the Waarre C Formation, the changes in elasticity of the rock would not be an issue since the rock is saturated with water. An extensive study of the seismic response over the Belfast shales and Paaratte saline aquifer was carried out to verify absence of leaks. By comparing the differences between time-lapse 3D seismic surveys over Paaratte interval to the modeling results, it was demonstrated that no significant amount of CO_2 has escaped Waarre C reservoir and migrated up the fault into overlain strata (Urosevic et al., 2010). At Otway, the pressure measurements and fluid samples collected in the observation well provided the best monitoring information on the behavior of the CO_2 in the reservoir.

Results from this research are helpful for assessing and monitoring leakage in order to set up regulatory frameworks of future CO_2 storage facilities (Jenkins et al., 2013).

Japan

In Japan, the one CO_2 injection pilot completed to date was carried out at Nagaoka on the west coast of Honshu, Japan, to the north-west of Tokyo, where 10,400 tonnes of CO_2 was injected into a saline reservoir between 2003 and 2005. The sandstone reservoir was about 60 m thick and at a depth of about 1100 m. Extensive reservoir modeling has been carried out, including reactive chemical

transport, as well as conventional fluid flow simulations (Sato et al., 2006). Using three observation wells, an extensive monitoring program, including time-lapse cross-well seismic tomography, well logging, pressure and temperature measurements, geochemical monitoring, and micro-seismic measurements was carried out (Michael et al., 2010). The arrival of CO_2 at the observation wells was detected by neutron logging, sonic logging, and induction logging. Time-lapse well logging carried out post injection from 2005 to 2009 showed essentially no changes (Mito and Xue, 2009). The interpretation of this result is that the CO_2 did not migrate away, suggesting the action of secondary trapping mechanisms in keeping the CO_2 in place.

Since the nuclear accident at Fukushima in 2011, only about two of the 54 reactors are in operation, which has a major impact on Japan's energy supply since nuclear power accounted for approximately 30 percent of the country's energy supply. Fossil fuel has had to accommodate the shortfall, which in turn has raised the GHG emission significantly (Hong et al., 2013)

Republic of Korea

Korean Electric Power Corporation (KEPCO) is proposing the application of post-combustion capture, either a 300 MW out of 400 MW circulating fluidized bed combustion (CFBC) or 500 MW pulverised coal power plant. Approximately 1.5 Mt of CO_2 would be produced each year. Captured CO_2 is proposed to be transported by a combination of pipeline and ship, for storage in offshore deep saline formations. A pre-feasibility study commenced in 2009 and is scheduled to be completed mid-2014. The Ministry of Knowledge Economy, other ministries and industry are working to survey three or four deep saline formation storage sites, including the Ulleung deep saline formation and the Gorae gas reservoir. Plant operations are expected to continue for 30 years or more to continue to supply power in Korea while abating the majority of its CO_2 emissions.

A broad framework for sustainability policies (The Basic Law on Low-Carbon Green Growth) came into force in South Korea on 14 April 2010. The new legislation will provide a foundation for a system that regulates greenhouse gas emission volumes and trading emission permits. This is a key driver for investigating the application of CCS in Korea

The Ministry of Knowledge Economy announced today that industrial and power sector businesses will be required to cut emissions by three per cent in 2013, compared to the 1.4 percent reduction target for 2012. This is designed to boost competitiveness and help big emitters prepare for the introduction of a carbon trading platform in 2015, which will see South Korea join China and Australia in launching significant new carbon trading platforms. The three per cent target for next year equates to a reduction of 17.2 Mt of CO_2 equivalent, across 377 large businesses and other carbon intensive organizations. Industrial and power entities will account for around 97 percent of the country's total emissions in 2013, which is expected to be around 589.8 Mt of CO_2e.

The Korea Advanced Institute of Science and Technology and Saudi Aramco recently agreed to establish a research center to develop technologies to capture, store and utilize CO_2. They will build a new facility with a total floor space of 16,500 m^2 in in Daejeon that will be financed equally by the two sides. Their collaboration will run initially for six years and could be extended. They will work to develop commercially viable processes for carbon capture and storage as well as utilization. Also, the Edinburgh-based Scottish Carbon Capture and Storage and the Korean Carbon Capture

and Sequestration R and D Center recently signed an MOU to develop cutting-edge technologies for reducing CO_2 emissions from power generation and industry.

China

In 2006, China surpassed the US to become the world's largest emitter of greenhouse gases and while US emissions have been falling for the last few years, China emissions are now on a par with the European Union on a per capita basis. Of China's CO_2 emissions, 80 percent come from burning coal and the country's coal consumption continues to rise rapidly. The extent of China's storage capacity is incompletely known, but preliminary work by Dahowski et al. (2009) point to a capacity of over 3,000 Gt, of which one third is off-shore. This is thought to be geo-sequestration capacity to meet the country's CCS demand for at least 100 years. Furthermore, these natural storage reservoirs already are located near many of China's stationary carbon dioxide-emission sources.

Since 2008, the Asian Development Bank (ADB) has been supporting the government's efforts through capacity development projects, studies, and financial assistance. Incomplete policy and regulatory framework, low fiscal and financial support for CCS demonstration projects, and inadequate international funding mechanisms to support projects have been identified as key barriers to large-scale demonstration of CCS in China. In May 2013 the Chinese government issued a notice of its intent to put CCUS as an important part of its 12th Five Year Plan.

The ADB will assist the People's Republic of China in developing a detailed plan for a staged demonstration and deployment of CCS, which is an essential set of technologies to prevent climate change. Recent dangerously high levels of pollution in northern China as well as data that show China burning almost as much coal as all other countries combined (Washington Post, 2013), there is an urgent need to fast-track the demonstration and deployment of carbon capture and storage in China to cut CO_2 emissions from the energy and industrial sectors and achieve the country's long-term climate change mitigation goals.

A comprehensive government-endorsed road map for CCS is expected to encourage more demonstration projects in China. This project is set to launch at least two large-scale CCS demonstration projects by 2016, with an installed capacity to capture at least 2 Mt of CO_2 per year.

The large-scale demonstration of CCS in China is expected to drive the technology's commercialization globally and help reduce CCS project costs as well as overcome remaining technical challenges.

ADB will also support the assessment of the potential role of oxy-fuel combustion CO_2 capture, one of the three available CO_2 capture technologies, in the PRC's optimal mix of CO_2 capture technologies. To fast-track CCS demonstration, necessary analyses and studies of oxy-fuel combustion CO_2 capture technology will be undertaken in parallel to the formulation of the road map.

ADB is providing $2.2 million, financed on a grant basis by the ADB-administered Carbon Capture and Storage Fund under the Clean Energy Financing Partnership Facility. In 2009, the Global Carbon Capture and Storage Institute contributed to establish the fund. In April 2012, the United Kingdom announced financing for CCS development in developing and emerging countries.

Shenhua is China's first CCS project, where 40,000 tonnes of CO_2 have been sequestered as of August 2012, according to the country's leading coal energy company, the Shenhua Group Corporation. Located in China's Inner Mongolia autonomous region the CCS system has been operating for 15 months taking carbon dioxide from a Shenhua's Direct Coal Liquefaction Megaton commercialized demonstration plant, which produces diesel and naphtha from coal. This project makes China the first country to realize the entire process of capturing carbon dioxide and sequestering it in saline aquifers. This research project expects to seal 300,000 tonnes of CO_2 by June 2014; 46,000 tonnes have been sequestered since 2011. The CO_2 is transported by lorries some 16 km away from the coal processing facility then injected 5,000 m into underground saline aquifers in Ordos Basin,Inner Mongolia. Initial estimates indicate that these formations in the Ordos basin could store tens of billions of tones of CO_2, and that this is one of many such basins in China. China's first CCS project 40,000 tonnes of CO_2 have been sequestered as of August 2012, according to the country's leading coal energy company, the Shenhua Group Corporation.

The US-China Clean Energy Research Center will work on this project that will look at sequestration capacity and near-term opportunities for cooperative research in the Ordos Basin, including stimulation technology for CO_2 storage in saline formations, research and application of monitoring technology of CO_2 storage in saline formation, assessment technology of safety and risk of CO_2 storage in saline formation, geological characterization of CO_2 sequestration in aquifers, and related research. Through the above research and the execution of the Shenhua demonstration project, this effort will improve understanding and provide verification of key technologies for CO_2 storage in saline formations and provide the scientific evidence to implement large scale CCS in China and support for CCS development in the US.

At Dongying, Shandong Province, People's Republic of China, the China Datang Corporation and Alstom propose to capture 1 Mt year CO_2 at a new power generation facility that would be captured at the plant and transported by pipeline for enhanced oil recovery. The project is at the very early stages of development with a feasibility study completed by 2015. The project intends to build a 1,000 MW power plant in Dongying, Shandong province, and capture 1 Mtpa CO_2 from 2020 using oxy-firing or PCC (chilled ammonia or advanced amine) technologies.

At Songyuan, Jilin Province, People's Republic of China, the Jilin Oil Field, China National Petroleum Company has established a pilot plant that is the first commercial CO_2 enhanced oil recovery operation in China. After the successful injection of around 200,000 tonnes per year of CO_2 from a natural gas processing plant in the first phase, the China National Petroleum Company is planning to expand capacity to 800,000-1,000,000 tonnes per year by 2015.

International Policy

In many parts of the developed and developing world there is a recognition that because of the urgency to reduce GHG emissions, it is not sufficient to rely on carbon pricing mechanisms to establish CCUS projects around the globe in order to meet the emission goals. CCUS-friendly policy packages are also required to assure appropriate levels of investment.

CCS secured a major step forward two years ago after the technology was officially approved as an eligible clean energy option under the Clean Development Mechanism (CDM), which was cemented in the Durban, South Africa meeting in 2011, Formal rules were established for its inclusion into the mechanism, ending years of debate on the issue. The mechanism does this by giving credits to developers building projects in industrializing countries, which rich nations can then purchase to ultimately apply toward their binding targets.

At the December 2012 Conference of the Parties Climate Change Summit meeting in Doha, Qatar, Climate, there was some progress on clarifying the details of CCS' role within the Clean Development Mechanism, but delegates ultimately agreed to postpone the consideration for at least four years, allowing developers to gain more on-the-ground experience related to CCS projects. This delay is a not entirely unforseen delay, but frustrating for many in the field.

CCS advocates underscored that the most important issue discussed at Doha regarding CCS' future centered on negotiations for a comprehensive international emissions reduction scheme, whether through an extension of the Kyoto Protocol, further development of a plan around the structure agreed to at Durban, or an entirely new agreement. Ultimately the main policy driver for CCS deployment on an international basis will be the requirement to manage or limit CO_2 emissions, presumably through an agreement that puts a price on carbon and creates a demand for CCS.

A report released by a recently-created group of international environmental NGOs (ENGO) recommended that CCS' inclusion in the CDM should not lose focus on environmental integrity and sound project planning. "It will be paramount for expertise that resides mostly in industrialized countries to be transferred to host [developing] countries in order to ensure sound site selection, operation, monitoring, accounting and project closure" (ENGO, 2012).

ENGO also proposed that a new CCS-specific mechanism should be created beyond the CDM that could ultimately help further accelerate the deployment of CCS technology in developing nations with the help of industrialized countries. The CDM currently could give rise to some projects and select applications, but it will not cause broad power sector deployment of CCS.

With the exception of the United Kingdom, CCUS policies are primarily focused on first demonstration or early mover projects that can be tailored at later stages of the industry's evolution. The UK alone is putting into place a comprehensive policy suite to guide deployment beyond initial demonstration sites. The principal driver for the UK policy on GHG emission reduction is the European Union's emissions trading scheme. But because low carbon prices have been insufficient to attract private investment, the UK government introduced three incentive mechanisms for low-carbon technologies: (1) a carbon floor price, (2) an Emission Performance Standard, and (3) a Feed-in-Tariff. In addition, the government introduced a commercialization program to produce capital for initial commercial-scale CCUS projects and to fund technical and policy-related R and D. The government goal is to provide market stability for this nascent industry that will attract industry leadership, although recent tension within the coalition government over its broader energy policy is showing signs of undermining this stability.

For the European Union, the EU Storage Directive establishes a comprehensive legal and regulatory framework, which removes CO_2 storage from waste legislation; requires captured CO_2 to be permanently stored; establishes a regulatory regime for long-term liability and stewardship; and

creates pipeline access and capacity expansion rules designed to ensure access, while protecting service to existing shippers. It also accepts the principle of combining CCS storage with EOR, but requires storage to be under the Directive. Carbon dioxide stored at an EOR facility that is permitted under the CCS Directive counts as abated for EU Emission Trading System.

Australia has established one of the most developed regulatory regimes in the world for CCUS projects that matches the country's heavy investment in a number of projects around the country. The core policy is the Clean Energy Legislation that established the carbon pricing mechanism - an "emission liability" - on facilities that emit over 25,000 tonnes CO_2/year, which currently is about $24/tonne. More recently Australia launched its intention to connect with the European emission trading scheme starting in 2015 with a full connection in 2018. The Australian CCS Working Group, under the auspice of the Council of Australian Governments, have been trying to harmonize regulations in order to establish a national approach to long-term liability, CO_2 storage issues including EOR, and identifying pipeline corridors.

Discussion

Europe forged an early start to CCS projects with Norway's well-documented Sleipner and Snøhvit fields, both products from a need to purify natural gas from those fields, which lie offshore. Extensive geological data and careful injection and subsequent monitoring has ensured that these projects have operationally successful as well as demonstrating that over a significant period, the technology is viable. The geological environment of these two sites is tectonically stable, though structurally complex, and work there has shown that such environments, which are common in the western USA, can accommodate large volumes of CO_2. It is noteworthy that Scandinavia is attempting a similar GHG mitigation target as California despite the lack of convenient geological storage or EOR prospects, and that such sequestration in North Sea fields will require expensive pipeline infrastructure to be put in place.

The German experience with CCS has been quite different. Potential projects were all onshore and while the geology is promising, the public opposition, and thence the political opposition, has been strong. The government has allowed a compromise that permits low volume pilot sites for CCS, but only one such project has proceeded. The strong anti-nuclear policies coupled with a policy of total reliance on renewable technologies, has now been forced to realize that economic strength needs more energy than the renewable industry can provide. Accordingly, the government has approved a major reinvestment in coal-based power generation to maintain its European economic prominence. But without CCS, it is difficult to foresee how the GHG emissions targets will be met. Elsewhere in this report, we attempt to make the case for CCS as a necessary bridging low carbon mechanism to sustain economic well-being and a non-fossil fuel based energy regime at some future period. A prudent path from California's current energy structure to a viable structure that meets its GHG emissions goals, is the focus of the state's energy debate, and the example of Germany's rather headlong, albeit well meant, policies underscores the need for considered analysis for California.

Creating a national energy framework that is consistent with reducing GHG has been the approach taken by the United Kingdom. The desire is strong to invoke a complete renewable energy basis for the UK, but the government has chosen a balanced portfolio in which CCS plays a prominent role.

Public acceptance, economic need, and future energy prospects are factors that require careful handling, which for a coalition government is not unchallenging. With the expectation of significant government funding, several industry led coalitions have formed to implement CCS in the UK, taking advantage of abundant CO_2 and relatively benign offshore sequestration and EOR. The UK example is a good demonstration of creating a supportive policy framework, some economic incentive, and letting interested parties move ahead.

The Netherlands have a concentrated region around Rotterdam of CO_2 emissions that, for a small country, require sequestration in order to meet their GHG reduction targets. This country has numerous depleted gas fields offshore that provide suitable sites for sequestration. Earlier attempts at onshore sequestration faced unanticipated hostility from the local communities, which led to The Netherlands becoming a global center for public acceptance research, only some which is reported here. As the discussion to implement CCS proceeds in California, the Dutch research will be valuable for assessing engagement with potential communities impacted by such projects.

Europe implemented a regional carbon trading scheme that generated during the summer of 2012, approximately $2 billion for research and demonstrations in CCS and related energy development projects. The amount raised was less than hoped because of the depressed natural gas prices, but it is expected that this amount will enable Europe to retain a viable position as a global leader in CCS development of deployment.

The CCS commercial project deep in the Algerian desert at In Salah is one that lacks comparisons with California's more regulated social and political environment. Even the geology is different. The value of a study of this project to California is that it is a large scale injection, it has been intensively monitored (by, amongst others, researchers from LBNL funded by DOE), and it leaked small amounts of CO_2. From this natural laboratory, numerous innovative monitoring techniques emerged and are being modified and applied elsewhere in the world. The leakage occurred due to a local, more flexible regulatory regime that was not designed to accommodate this technology. The lesson from this example has been rigorous modeling of subsurface CO_2 behavior as well as important monitoring techniques. Satellite measurements that detected vertical topographic changes due to CO_2 injection, spectacular enough in deserts conditions, are now being applied successfully in southern England with all its rich, pastoral foliage.

Australia, with its coal-based energy structure, moved to reduce its carbon footprint by investing heavily in CCS, which included ambitions to solidify its bid to be the world's go-to country for technologies that will allow continued use of fossil fuels while minimizing their impact on the global climate. The Global Carbon Capture and Storage Institute in Canberra was created in 2008 and funded to accelerate the worldwide commercial deployment of sequestration technologies. Recognizing the contribution carbon capture and storage can make in mitigating climate change, the government of former Prime Minister Kevin Rudd committed $100 million in annual funding for the Global CCS Institute (to be re-assessed). Australia's ambitious projects in Otway and Gorgon reveal the seriousness with which the government is tackling Australia's GHG contributions despite significant political skepticism.

South Korea is a small country with high CO_2 emissions and limited geological potential for sequestration. The government has agreed to invest heavily in CCS deployment and has a created a

national structure involving relevant ministries to develop and deploy CCS to reduce CO_2 emissions I accordance with its commitment to the Kyoto Protocol. With a focused approach the Koreans have identified the problem and the contribution its emissions have on global GHGs, and are planning its solution. The cost will be significant and there are few opportunities for economic compensation through, for example, EOR.

China acknowledges that it has an enormous pollution problem that derives in large part from its CO_2 emissions, but it also recognizes its need to energy to maintain economic growth that is largely derived from coal burning. It also recognizes that CCS is at least a temporary solution to this conundrum and has therefore proceeded to create a roadmap, with funding from the ADB, and establish pilot projects, some in collaboration with the DOE. The scale of the undertaking is enormous from which numerous lessons will undoubtedly emerge, and the California research community will be following the Chinese venture closely. The scale of China's emissions and storage potential has been found comparable with the U.S. situation (Dahowski et al., 2011), the political and regulatory differences notwithstanding.

Saudi Arabia's official strategy of de-carbonizing its energy provision through energy efficiencies and enhanced renewable technologies conforms to most other national strategies. But their investment in nuclear power to provide zero emission generation is a departure from many other countries, and is a pathway not open to the California.

The oil company Occidental Petroleum owns and operates the Lost Hills oil field in Kern County, and is also a principal in the Bahrain oilfield development. Their experience in sequestration and EOR operations in California and the Middle East plays out for mutual benefit.

The projects discussed represent the major CO_2 storage efforts, worldwide, and in aggregate, represent the storage of more than 31 Mt of CO_2, of which more than 16Mt have been stored in saline formations, with 15.8 Mt being stored in the three commercial storage projects, Sleipner, In Salah, and Snøhvit. All of the projects have been the focus of intense scientific study and public scrutiny and none, except In Salah, has experienced any leakage to the near-surface environment. While the leak from an abandoned well at In Salah was unfortunate, it was very small, and was discovered and mitigated without causing any adverse impacts to the environment or the public, illustrating both the need, and success, of an effective monitoring program.

The results of these field projects have clearly yielded many advances in geologic storage through validation of existing tools, and demonstration and testing of new ones. The accuracy of the geologic model was paramount, and permeability is the most frequently identified physical characteristic as the most important variable. Accurate pre-injection geologic models and hydrologic properties of the storage formation remains a challenge and should be given high priority in planning of projects.

A diverse set of technologies for measurements at the surface and in the subsurface have been field tested, and technologies conventionally used by the oil and gas industry have been validated for application to monitoring of CO_2. Unique new technologies have been demonstrated, such as the successful application of seismic techniques for monitoring the movement of CO_2 in the reservoir. However, active seismic methods will probably not be useful for monitoring of storage in depleted gas reservoirs. Though seismic methods have the highest resolution of the geophysical monitoring

methods, it is clear that there are some circumstances where their applicability is limited, and the field studies also showed that other methods can provide complimentary information to improve understanding of plume behavior. Based on field performance in major pilots and some modeling, a comparative assessment of seismic, electrical, and gravimetric techniques is given in Myers (2011).

In addition to geophysical monitoring, the field tests have also demonstrated the value of other types of monitoring measurements, including pressure and temperature, tracers, fluid sampling for geochemical analyses, and well logs of many kinds. Geophysical monitoring is generally considered to be the most expensive type of monitoring, and it is noted that cost effective technologies such as wellhead and annulus monitoring were also proven to be useful.

Experience strongly underscores that monitoring programs need to be developed to accommodate the unique geology, and risks, associated with each site. Furthermore, injection strategies and monitoring plans should be expected to evolve as experience and monitoring data becomes available during operation of the project.

The overall experience represented by the reviewed projects shows that geologic storage of CO_2 is technologically feasible in a diverse, though not comprehensive, set of geologic environments. Insufficient data has been developed about the post-injection behavior of CO_2 in the reservoir. The same simulation and monitoring tools used during the operational phase of storage are applicable to post-injection phase, but field demonstrations of the processes that lead to plume stabilization and long-term trapping are needed.

Significant progress has been made over the past decade, but there remain a number of challenges to the broad global deployment of CCS that do not involve major technical or knowledge barriers to the adoption of geological storage of captured CO_2. Extensive experience with technologies for the capture of CO_2 in hydrogen production and CO_2 separation for natural gas processing as well as technologies encompassing EOR using CO_2, acid gas disposal, and natural gas storage, provide substantial knowledge basis for transport and storage of CO_2. However, an integrated system linking permanent geological storage with power plants and industrial facilities involves several key technology gaps where additional work would reduce uncertainty and facilitate decision making about large-scale deployment. In their 2005 report (Metz et al., 2005), the IPCC identified a need for:

- Integration of capture, transport, and storage in full-scale projects.
- Demonstration of CO_2 capture on coal-based and natural gas plants at the several hundred megawatts (or several $MtCO_2$) scale to establish the reliability and environmental performance of CCS on different types of power systems, to reduce the costs of CCS, and to improve confidence in cost estimates.
- Large-scale implementation in industrial processes such as the cement and steel industries that have little or no experience with CO_2 capture.
- An improved picture of the proximity of major CO_2 sources to suitable storage sites to evaluate how well large CO_2 emission sources (both current and future) match suitable storage options that can store the volumes required.
- More pilot and demonstration storage projects in a range of geological and economic settings to gain a better understanding of long-term storage, migration, and leakage processes.

- An enhanced ability to monitor and verify the behavior of geologically stored CO_2.
- R and D for emerging concepts and enabling technologies for CO_2 capture that have the potential to significantly reduce the costs of capture for new and existing facilities.

Beyond the technical issues, The World Resources Institute (WRI 2007) focused on policy issues that they considered major challenges to broad global deployment of CCS. These are:

- the need for policy drivers to incentivize deployment;
- the need to further refine a flexible and adaptable regulatory framework which addresses capture; transport; site characterization and permitting; operating standards, including monitoring, measurement, and verification and remediation plans; crediting of mitigated CO_2; and measures to deal with long-term stewardship;
- the need for consistent funding for large-scale demonstration projects to test and better understand the cost and performance of capture technologies and storage reservoirs, with specific focus on reducing capture costs, achieving a better understanding of the behavior of injected CO_2 in deep saline reservoirs, advancing monitoring and verification technologies, and integrating the various components of the entire system; and
- the need to continue to address public acceptability.

In order to gain public acceptance of CCS, the potential risks to the environment and the general population must be deemed reasonable. On the issue of risk, the IPCC 2005 *Special Report* concluded:

> "With appropriate site selection informed by available subsurface information, a monitoring program to detect problems, a regulatory system, and the appropriate use of remediation methods to stop or control CO_2 releases if they arise, the local health, safety, and environment risks of geological storage would be comparable to risks of current activities such as natural gas storage, EOR, and deep underground disposal of acid gas." The U.S. DOE/NETL has similarly concluded (www.netl.doe.gov/technologies/carbon_seq/index.html): "With proper site selection based on available subsurface information, a monitoring and verification program, regulatory system, and appropriate mitigation to stop or control CO_2 releases should they arise, environmental and safety concerns are minimal. Local health, safety, and environmental risks of geological storage would be less than the risks of current activities such as natural gas storage and enhanced oil recovery due to the fact that CO_2 is not toxic, flammable, or explosive."

APPENDIX C:
LBNL White Paper on the Role of Life Cycle Assessment in CCUS Implementation

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Introduction

A decision to develop and deploy CCUS technology at large-scale should be guided by its overall costs and benefits. Life cycle assessment (LCA) is a framework for holistic analysis of a technology system, and can provide crucial information regarding environmental, social, and economic tradeoffs to policy-makers and other stakeholders as they consider CCUS options. Credible LCA contributes to informed decision-making by providing a broad system-wide perspective, and it allows the practice of calculated caution in the context of uncertainty. Appropriate LCA methodology that is specific to CCUS systems is currently under development to ensure that conclusions and recommendations from CCUS LCA are robust. Beyond simple analyses of immediate technological effectiveness, prospective LCA can also help guide decision-making toward a long-term transition to a low-carbon economy, considering issues of competing technologies and technological lock-in.

An LCA strives to characterize the environmental burdens posed by mass and energy flows across the entire life cycle of a product or process, including its raw material extraction, manufacture, use, and disposal phases. To conduct an LCA, the goal and scope must be defined describing the purpose of the study, the system boundaries of the analysis, and the functional unit used for assessment and comparison. Then, an inventory assessment quantifies the inputs and outputs of mass and energy attributable to processes occurring within the system boundaries. An impact assessment characterizes the effects of these inputs and outputs considering resource depletion, human health, ecosystem quality, and climate change. Finally, the inventory and impact assessment results are interpreted to identify significant conclusions, recommendations, and implications for decision-making.

Spatial and temporal boundaries

Accounting methodologies must have effective and workable system boundaries in terms of temporal and spatial characteristics. System boundaries delineate what is included in the analysis and what is disregarded. Boundaries should be established broadly enough to capture the significant impacts of interest, but not so broadly as to make the analysis too unwieldy; in practice this is rarely straightforward. Geographic specificity is important, especially for CCUS, and can be captured with spatially explicit modeling and databases. For example, variation in state regulations, infrastructure, demographics, and geology will likely affect the performance and potential of CCUS

technologies. Incorporating time dynamics is challenging but important, and is relevant to power plant fleet turnover, technology advancement, resource depletion, behavior of CO_2 in geological storage, and cumulative radiative forcing from greenhouse gas (GHG) emissions.

Methods of comparison

The results of an LCA can be used to compare the environmental performance of different (and often competing) technology options for meeting a given societal service if they are expressed in terms of consistent functional units. A functional unit should be selected to facilitate and inform the decision-making process; different functional units may be appropriate for different uses. For example, most CCUS LCAs have analyzed electric power plants and have quantified results on a "per kWh of deliverable electricity" basis. While useful for understanding the differences in technologies at a power plant, this functional unit does not consider technologies that do not produce electricity (e.g. cement plants, oil refineries), and is not indicative of the valued output of those systems. In these situations, it may be appropriate for a CCUS LCA to express results in more than one functional unit. For example, using captured CO_2 for enhanced oil recovery (EOR) serves to both sequester CO_2 and allow the recovery of additional quantities of oil, so calculating CO_2 sequestered per barrel of oil produced might be an appropriate additional metric. However, the method used to allocate CO_2 storage benefits among multiple products (e.g. electricity generation and oil production) is not always straightforward and can significantly affect the calculated emissions of the products.

Conventional areas of evaluation

Although CCUS technologies are intended for carbon mitigation, accounting methodologies must evaluate performance metrics beyond carbon-capture compliance. To produce LCA results that contribute to robust policy decisions, LCA practitioners should endeavor to quantify all relevant environmental benefits and costs of CCUS systems, including non-climate aspects. A CCUS system should avoid regrettable substitutions such as trading a reduction in CO_2 for an increase in impacts from another pollutant. A recent meta-analysis of CCUS LCA studies found that decreased GHG emissions are typically accompanied by increased human health and environmental impacts, though the limited number of studies and large variation in outcomes prevent definitive conclusions. In particular, the results of an LCA can reveal "hotspots," or aspects of a technology's life cycle that produce major non-climate stressors. This information allows for targeted redesign and/or remediation, increasing the overall performance of CCUS systems. The combined evaluation of GHG and non-GHG effects of CCUS encourages the development of strategies that lead to optimal reductions across multiple societal, resource, and environmental impacts.

Several areas of evaluation are considered by the LCA community as critical to the assessment and comparison of diverse technologies: natural environment, human health, natural resources, and the man-made environment. We discuss each one briefly in turn below:

Natural environment

CCUS is considered a promising environmental technology because it reduces anthropogenic GHG emissions. The potential for CCUS technologies to mitigate climate change can be determined by quantifying the resulting avoided cumulative radiative forcing. CCUS LCA can help establish realistic expectations of the climate-mitigation effectiveness of CCUS implemented at scale. Popular claims of "zero-carbon" electricity from CCUS systems are refuted by LCA studies that consider system-wide emissions. The percentage of CO_2 removed from power plant flue gas is typically modeled at 90%, and the additional fuel extracted to meet the energy demand of CO_2-capture technologies leads to increased upstream emissions, including releases of high global warming potential (GWP) methane from coal mines as well as natural gas networks. Including emissions system-wide, the net GHG reductions is only 60% to 85%.

CCUS technologies are energy intensive, and ecological damage may occur with increased fuel extraction and combustion. The ultimate impact of ecological damage, loss of biodiversity, is estimated by aggregating the losses attributed to disparate environmental impacts. Regional acidification, local eutrophication, and the release of toxic compounds like monoethanoamine (MEA), a solvent used in post-combustion capture technologies, are expected to increase unless CCUS project develop abatement strategies. Aside from GHG emissions, conventional LCA impact categories include fresh- and saltwater acidification, eutrophication, ozone depletion, and terrestrial and aquatic ecotoxicity.

Human Health

The damage that a CCUS technology may have on human health will vary depending on its location and emissions. The mass of harmful emissions to land, air, and soil systems can be quantified using characterization factors that convert the LCA inventory to damage equivalents. Particulate matter, ozone, radiation, and toxic emissions can all lead to human health damage. The total loss of life, or disability-adjusted life years (DALY), associated with a CCUS project may be more relevant to compliance accounting, but it requires extensive research, monitoring, and uncertainty management.

Natural resources

CCUS technologies consume limited resources like land, minerals, fossil fuels, and water. Cumulative resource demand of life cycle stages, such as materials manufacturing, is a useful indicator of the sustainability of a technology. It also reveals the impact that a technology may have on local, regional, and national markets. LCA impact categories include cumulative energy demand, and cumulative consumption and degradation of materials (both renewable and non-renewable), land, and water.

Man-made environment

The man-made environment accounts for damage to buildings and other assets that hold cultural, historical, or economic value. Methods are being developed so that previously intangible impacts, such as noise pollution, monument deterioration, land use change, and traffic density, can be accounted for as man-made environmental impacts.

Emerging areas of evaluation

The scope of LCA is expanding to address several additional areas of evaluation that are necessary for supporting sustainable decision-making, including life cycle costing, investment risks, equity, national security, risk of catastrophic failure, and uncertainty and variability. A summary of each area is given below.

Life cycle costing

Life cycle costing seeks to determine the total economic cost of a CCUS technology's life cycle stages. This analysis is useful for calculating the cost effectiveness of different CCUS options, often measured using "cost per unit of avoided CO_2 emissions" as a functional unit. The results of CCUS LCA can also be monetized to arrive at estimates of indirect costs; for example, the health care costs associated with air pollution attributable to the life cycle energy use of the technology. This information can be included for estimation of full societal costs (i.e., direct plus indirect costs), which can aid in assessing the likely net economic impacts of technology deployment.

Investment risks

The first large-scale CCUS projects may face unique legal and regulatory investment risks. Permit processes can delay or even freeze projects. Public knowledge and acceptance of CCUS projects by all stakeholders are also important considerations. The simultaneous development of competing technologies may serve to undermine (or enhance) the economic viability of CCUS technologies.

Equity

Environmental justice implies equal protection from environmental and human health hazards for all individuals, regardless of their race, economic status, gender, or age. It also means that all individuals have a voice in the decision-making process. When used in conjunction with geospatial mapping tools, LCA can identify where environmental impacts are likely to occur. This information can provide decision-makers with the foresight to achieve equitable distribution of environmental, human health and economic cost burdens.

National security

The United States' dependency on foreign fossil fuels is an issue of national security. LCA databases will allow LCA to quantify the source and quantity of fuels and energy consumed. A life cycle inventory and assessment can highlight stages in a technology's life cycle where cumulative energy demand is high. Once identified, these stages may be targeted for improvement. Carbon utilization technologies that are used for domestic EOR may reduce our dependency on foreign oil. The caveat to this is that available renewable energy sources may lose a financial competitive edge if domestic oil becomes cheaper.

Risk of catastrophic failure

The risk of catastrophic failure should be a determinant of a technology's adoption. Geologic carbon sequestration sites may be at risk of failure if they are sited near fault lines. The contamination of a precious freshwater source due to leaking CO_2 may be considered a catastrophic risk and weighed appropriately. The modeling and interpretation of low-probability, high-impact events is challenging with conventional LCA methodologies. However, an LCA approach may be useful to identify sources of risk throughout the system.

Uncertainty and variability

To effectively guide decision-making, LCAs must credibly model the potential system-wide effects of CCUS technologies implemented at large scale. Uncertainty and variability must be managed to reduce the risk of policy failure, or the implementation of policy that generates counterproductive results. When analyzing CCUS systems, uncertainty exists at many levels, including measurement uncertainty and variability, structural uncertainty due to the complexity of models and their validation, temporal uncertainty regarding past and future events, and translational uncertainty in interpreting results. A comprehensive uncertainty analysis should evaluate uncertainties derived from parameters, models, and scenarios.

Conclusions

Initial efforts have been made within the LCA research community to project and estimate the life cycle environmental, social, and economic performance of emerging CCUS technologies when deployed on a large scale. Such timely projections can provide critical feedback to the policy-making and R&D processes, and help steer material, design, and operational specifications towards the most environmentally-, socially-, and economically-robust development pathways. Accounting and regulatory structures should be based on a holistic evaluation of options, which requires a system-wide analysis in a life cycle perspective. Once embodied in policy and standards development, LCA can play an important role in determining appropriate roles for CCUS in future energy systems.

APPENDIX D:
LBNL White Paper on Induced Seismicity

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The risk of induced seismicity from injecting large quantities of CO_2 deep underground is one of various risks associated with CCS that must be assessed for each geologic storage site.

Since the 1920s, it has been recognized that some earthquakes can be associated with human activities such as impounding water behind dams, controlled explosions related to mining and construction, injecting fluids deep into the Earth, or withdrawing fluids from deep in the Earth. The number of these human-induced earthquakes is small compared to the thousands of earthquakes that occur naturally around the world every day. As seismic monitoring technology has improved, scientists have observed that the vast majority of natural and induced earthquakes (frequently called *seismic events* among earth scientists) are of such low magnitude that they are not felt by people.

However, the relatively rare induced seismic events that are *felt* can alarm and/or annoy people, raise public concerns about safety, and occasionally cause property damage. In 2006, an enhanced geothermal energy project in Basel, Switzerland, involved pumping cold water into hot basement rock at a depth of 4.8 km (3 miles). It induced a magnitude 3.4 earthquake that cracked house walls and collapsed part of an unreinforced masonry church. Public outcry stopped injection and the project was terminated by authorities in 2009 after completion of a seismic hazard[1] study that found significant risk of induced seismicity that could result in costly damage to structures. It is unlikely that the project would ever have been approved if the study had been completed as part of initial site characterization. Basel is known to sit atop an active fault that produced an earthquake with an estimated magnitude of 6.0-6.9 that destroyed most of the city in 1356.

[1] The *hazard* of induced seismicity is a description or calculation of the probability of occurrence of an earthquake with a specified minimum magnitude, or specified minimum severity of ground shaking. The *risk* of induced seismicity is the probability of hazard times the consequence, i.e., the damage or injury that could occur to structures or people as a result of the human activity that produces a seismic event (NRC, 2012). For additional information, see the section below, "3. Hazard and risk assessment."

An earthquake is the result of slippage on a fault when shear stress exceeds frictional force along the fault. This can occur from an increase in pore pressure[2] that reduces normal stress across the fault and/or reduces cohesion of the fault[3], or from tectonic or thermal stress changes. Thus, the important criteria for predicting the likelihood of induced seismic events from fluid injection or withdrawal "include the amplitude and direction of the state of stress in the Earth's crust in the vicinity of the fluid injection or withdrawal area; the presence, orientation, and physical properties of nearby faults; pore fluid pressure … ; pore pressure change; the rates and volumes of fluid being injected or withdrawn; and the rock properties in the subsurface" (NRC, 2012). The critical stress necessary to trigger slippage on a particular fault is difficult to assess, however, in part because frequently the fault plane is not a simple flat frictional surface, but a curving feature with varying surface properties.

The moment magnitude "**M**" of an earthquake is related to the total energy released at the source (hypocenter) of a seismic event. The total energy released is related to the surface area that slips and the amount of slippage on the fault. Large magnitude earthquakes necessarily have fault rupture that extends to great depth because the movement of a large fault surface is required to release a high level of accumulated stored energy. Another earthquake gauge is "intensity," often measured on the Modified Mercalli scale, which is a qualitative measure of the ground motion, or shaking, at a particular location. Intensity is a measure of whether and how an earthquake will be felt by people and whether and how it will damage structures. The intensity is determined by many factors, including the magnitude **M**, location and depth of the source, distance and direction with respect to the orientation of fault rupture, and subsurface structure and physical properties of the rocks between the hypocenter and the location of interest. Most events with **M**<2 are not felt by people unless the hypocenter is shallow and directly below them, whereas higher magnitude events may be more widely felt and may damage property.

Recognizing the ever expanding need for energy resource development, in June 2010, U.S. Senator Jeff Bingaman, Chairman of the Senate Committee on Energy and Natural Resources, asked the Department of Energy (DOE) to initiate a National Academy of Sciences and National Academy of Engineering study of the scale, scope, and potential consequences of seismicity induced by energy technologies – geothermal energy production, hydraulic fracturing to extract shale gas, enhanced oil recovery (including underground wastewater disposal), and geologic carbon storage. These energy

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[2] Many types of rock contain pore space, "empty" space among the mineral grains or within the solid rock mass. Sandstone, a common reservoir rock for oil and gas, and a likely candidate for CO_2 storage, can have up to about 40% open pore space. Volcanic rocks may contain voids created by gas bubbles. Denser metamorphic rocks such as granite may contain little or no native pore space, but all rock types may be fractured at various scales, providing void space and permeability. Except at shallow depths, this pore space will be filled with water (usually salty at depths below drinking water aquifers), or other fluids, such as oil, natural gas, CO_2, nitrous oxides, and radon. Pore pressure is the pressure of these fluids in the pore space of the rock. On average, pore pressure increases about 0.46 pound per square inch (psi) per foot of depth (~10.4 kPa/m), but can vary significantly depending on geologic and hydrologic conditions, and from human injection or withdrawal of fluids.

[3] In the earth science literature, these conditions for sliding on a fault are characterized by the Mohr-Coulomb failure criterion. See, for example, Nicholson and Wesson (1990), an excellent source of information about induced seismicity.

technologies all involve the injection or withdrawal of fluids, which can change the pressure in the pore space between the mineral grains or solid matrix of the rock. In June 2012, the National Research Council (NRC) of the National Academies released a prepublication report, *Induced Seismicity Potential in Energy Technologies* (NRC, 2012). It is instructive to review some of the conclusions and data comparing induced seismicity in the United States for the energy technologies discussed in the NRC report, paraphrased below:

- Shale gas recovery
- ~35,000 wells in the US; one felt induced event (in OK); **M** 2.1 [4]
- The process of hydraulic fracturing ("fracking") of a shale formation as presently performed for shale gas recovery involves injection of a relatively small volume of fluid over a short time. Once the formation is fractured, pressure is reduced to promote the flow of gas into the well. This process does not pose a high risk for inducing felt seismic events.
- Secondary oil and gas recovery (waterflooding)
- ~108,000 wells in the US; one or more felt events at 18 sites (in AL, CA, CO, MS, OK, TX); maximum **M** 4.9
- Pore pressure increase is the likely mechanism for the induced events, but reservoir pressure is generally balanced by fluid withdrawal while water is injected. Considering the large number of wells and fields where secondary recovery is used, the incidence of felt events is relatively low.
- Tertiary oil and gas recovery / enhanced oil recovery (EOR) [5]
- ~13,000 wells in the US; no known felt events
- EOR projects involve the injection of steam, chemicals, or gases (including supercritical[6] CO_2) while producing fluids at other wells, thus minimizing pressure changes in the reservoir. Projects designed to maintain a balance between the amount of fluid injected and withdrawn, such as most oil and gas development projects, generally produce fewer seismic events than projects that do not maintain fluid balance.
- Oil and gas withdrawal

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[4] Hydraulic fracturing for shale gas production in northeastern British Columbia, Canada, in 2011 induced events with magnitudes between 2.2 and 3.8 (BC Oil and Gas Comm., 2012).

[5] For more than 40 years, oil companies have been injecting large quantities of CO_2 for EOR in the Permian Basin of western Texas and eastern New Mexico. At more than 72 U.S. oil fields, a total of about of 50 million tons per year of new CO_2 is currently being injected, plus half again as much recycled CO_2 that comes up with the oil. There is no incidence of felt induced seismicity.

[6] Many fluids, including water and CO_2, have a certain pressure and temperature called the *critical point*, above which they become *supercritical*. In the supercritical state, a fluid does not have distinct liquid and gas phases. It will have the high density of a liquid and the low viscosity of a gas. CO_2 becomes supercritical at 1,071 psi, 88°F (7.4 MPa, 31.1°C). These conditions exist in the Earth below a depth of about 2,400 feet (730 meters).

- ~6,000 fields; felt events at 20 sites (in CA, IL, NB, OK, TX); maximum **M** 4.6 [7]
- Pore pressure decrease has been responsible for stress changes from reservoir volume contraction or weight reduction, initiating slippage on pre-existing faults.
- Wastewater disposal
- ~30,000 wells in the US; eight felt events (in AR, CO, OH); maximum **M** 4.8 [8]
- The **M** 4.8 event noted above occurred in 1967 near Denver following 1,500 lower magnitude events resulting from five years of wastewater injection into relatively impermeable crystalline rocks beneath the Rocky Mountain Arsenal. But most wastewater disposal wells reinject water produced with oil and gas (including shale gas), and typically this wastewater is injected at relatively low pressures into large porous aquifers that are selected to accommodate large volumes of fluid, or back into the production reservoir to maintain pressure. Considering the large number of wells and large quantities of wastewater injected, only a small fraction of these wells have been linked to felt events. However, the incidence of induced seismicity that does occur appears to be higher for injection into basement rocks or other hard lithologies. There have been few felt events for several decades, but the effects of continued injection over longer periods are unknown.
- Geothermal
- Liquid-dominated: 23 projects (in CA); 10-40 felt events/year; maximum **M** 4.1
- Vapor-dominated: The Geysers, CA; 300-400 felt events/year; maximum **M** 4.6
- Enhanced geothermal system (EGS): 8 pilot projects (in CA, NV); 2-10 felt events/year; max. **M** 2.6 [9]
- Induced seismicity in conventional liquid-dominated geothermal projects has been relatively infrequent, likely the result of maintaining a moderate level of fluid balance with reinjected

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[7] Large seismic events from oil and gas withdrawal occurred in the 1930s and 1940s, before oil producers learned to avoid reservoir collapse. In 1938, oil production at the Wilmington oil field in the Los Angeles Basin reached an ongoing rate of ~100,000 barrels per day. The land surface subsided as much as 29 feet (8.8 m), which produced several damaging earthquakes between 1947 and 1961. The most severe, in 1949, had an estimated magnitude of 5.1. In 1958, water injection began and soon exceeded the rate of oil production. Subsidence and major earthquakes stopped (Nicholson and Wesson, 1990). This would not happen today because oil producers inject water as oil is withdrawn to maintain pore pressure in the reservoir.

[8] Nicholson and Wesson (1990) report that three events in 1967 linked to wastewater injection at Rocky Mountain Arsenal had magnitudes of 5.0-5.5.

[9] EGS projects in Europe have sometimes produced high levels of induced seismicity when high-pressure hydraulic fracturing was used to stimulate fluid flow in deep basement rock. At Soultz-sous-Forêts in the Upper Rhine Graben, after hydraulic fracking of crystalline rock at a depth of 16,000 feet (4.9 km), there were many felt events as large as **M** 2.9. Plans for increased energy production were scaled back. In Basel, Switzerland, which sits atop an active fault, a hot dry rock EGS project induced thousands of seismic events, with 200 in the range of **M** 0.7-3.4. There was moderate structural damage and the project was shut down in 2009.

water. For the vapor-dominated field at The Geysers, high levels of induced seismicity may be the result of large volumes of cold make-up water being injected into hot reservoir rocks, making them contract. At some EGS sites in the U.S., low levels of induced seismicity have been felt.

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While the rare high magnitude seismic events cited above can be problematic, the much more frequent microseismic events (not felt) can provide valuable information to guide field operations. At The Geysers geothermal area, where large quantities of water are injected to sustain reservoir pressure and fluid content, microseismicity has been useful for tracking fluid flow in the subsurface (Majer *et al*., 2012) and for managing the field (i.e., selecting among the array of wells, those to be used for production and injection, and the flow rates, at a particular time). Induced microseismicity has also proven to be beneficial for tracking fluid flow and reservoir management at other geothermal areas, as well as at secondary and tertiary oil production sites, and CCS sites.

Regarding geologic CO_2 storage, the NRC (2012) report points out that the risk of induced seismicity is difficult to assess because there are only a few projects worldwide and these have injected small quantities of CO_2 relative to the large quantities that would be required to have an impact on climate change. The report states, "Given that the potential magnitude of an induced seismic event correlates strongly with the fault rupture area, which in turn relates to the magnitude of pore pressure change and the rock volume in which it exists, large-scale CCS may have the potential for causing significant induced seismicity. CCS projects that do not cause a significant increase in pore pressure above its original value will likely minimize the potential for inducing seismic events." The report concludes that more research is needed.

To have a significant impact on mitigating climate change with CCS, the quantity of CO_2 that would need to be stored is immense, and injection would need to continue for decades. Estimates of global geologic CO_2 storage capacity vary widely, with many estimates suggesting a minimum of about 300 Gt (billion metric tonnes) and a maximum of 10,000 Gt or more (IEA, 2008). In 2011, global CO_2 emissions from all sources were 34 Gt (Oliver *et al*., 2012). At that rate, global storage capacity could accommodate approximately 9-300 years of emissions if all could be captured.

California has the geologic resources to store its CO_2 emissions for many decades. The state's potential on-shore CO_2 storage capacity is estimated to be 30-417 Gt in saline formations (primarily in the Central Valley), plus 3.0-5.2 Gt in depleted gas reservoirs, and 0.3-1.1 Gt in oil reservoirs and for EOR (DOE, 2012) for a total of 33-423 Gt. Estimates have not yet been completed for all potential offshore storage reservoirs. In 2010, California's CO_2 emissions from stationary sources of fossil fuel combustion were approximately 140 million tonnes (0.14 Gt). Vehicle emissions contributed approximately 180 million tonnes (0.18 Gt) (CARB, 2013).

Of the few CO_2 storage projects worldwide to-date, some, but not all, have experienced low levels of induced seismicity, as anticipated. But these projects are too small to provide a basis for long term projections of seismicity. The vast majority of all injection wells worldwide do not produce earthquakes that are felt by the public. But for those that do, studies by McGarr (2012) suggest that the *maximum* magnitudes of induced earthquakes that *do* occur are frequently related to the total quantity of fluid injected at a site, so with continued injection over long periods of time, the seismic

hazard would be expected to increase. However, it is unknown how this relationship scales with increasing volumes that would be required for CCS, and for the reservoir formations that would be selected. The largest magnitude events identified in the McGarr study (**M** 4.0-5.7) were for wells injecting wastewater into crystalline basement rocks and/or the aquifer immediately above basement.

The induced seismicity mechanism of primary concern is pore pressure increase. For CO_2 injection, particularly into saline reservoirs, low-amplitude pore pressure increases will be found at lateral distances far exceeding the extent of the CO_2 plume as brine is displaced by the expanding CO_2 front (Zhou and Birkholzer, 2011). For potential CO_2 storage reservoirs that are geologically confined (surrounded on all sides by low permeability rocks), brine withdrawal has been proposed to limit pressure increase. Hence, pressure monitoring and pressure control are essential.

While increased pore pressure will reduce the confining force normal to a fault and/or reduce the fault frictional resistance, the component of stress parallel to the fault needs to exceed the frictional force before there will be a seismic event. Thus, the existing state of stress acting on a fault and the frictional force inhibiting slippage play critical roles in the safety of large scale projects involving the injection or withdrawal of fluids. Both of these are areas of active research. It is understood that regional stress in the Earth's crust is dominated by forces at tectonic plate boundaries and in other tectonically active areas. But it is not usually known how regional stress is accommodated locally and how it affects the stress on a particular fault at a particular time. The release of stress from an earthquake on one fault will change the stress field affecting other faults in the area. However, at a specific location and depth, the magnitude and orientation of the stress field can be measured with tests performed in a deep well.

In two "opinion piece" articles by geophysicists Zoback and Gorelick (2012a, 2012b), they assert that in the upper brittle part of the Earth's crust, faults in active tectonic areas and in the interior of the continent are critically stressed and ready to fail, so large-scale CO_2 injection, whether in seismically active areas or not, could trigger earthquakes that might fracture overlying caprocks and allow the CO_2 to escape. Hence, they conclude, CCS at a scale to mitigate climate change will be unsuccessful because of "triggered fault slip" on unidentified and/or ancient faults.

These assertions are mentioned here only because the articles were picked up and broadcast by the public media, in spite of the fact that the articles were not peer-reviewed. Zoback was a contributor to, and reviewer of, the NRC (2012) report, yet the NRC report, which *was* peer-reviewed, did *not* concur with these opinions. It states, "Determination of the in-situ state of stresses in the subsurface is both complex and often expensive. Consequently, the information on the in situ stress in the Earth is usually too fragmentary to allow confident estimates of the actual stresses acting on a fault."

Furthermore, the Zoback and Gorelick (2012a, 2012b) articles unleashed an avalanche of criticism from other earth scientist experts stating that their conclusions are unfounded. For example, Juanes *et al.* (2012) noted that 1) most earthquake hypocenters in the continental crust are in brittle basement rock at a depth of 8-16 km (5-10 miles), whereas shallower sedimentary rocks at depths less than 3 km (1.9 miles) where CO_2 would be stored can sustain considerable deformation before fracturing; and 2) other buoyant fluids – oil and natural gas – have remained contained in geologic reservoirs for millions of years in areas with intense faulting and earthquakes, such as in southern

California. Hill (2012) responded with comments intended for a national audience, but particularly relevant for California with its many depleted oil and gas reservoirs and long coastline:

… injection of CO_2 into depleted petroleum reservoirs, with known capacities, injectivity and infrastructure could accommodate many decades of captured CO_2. According to [the NRC (2012)] report, there have been no cases of observed humanly perceptible induced seismicity from CO_2 injections associated with enhanced oil recovery–which has successfully taken place in Texas and elsewhere for four decades. Moreover, widely associated with these depleted oil fields are brine formations that offer large volume "stacked storage"–managed CO_2 injection and storage in sandstones or carbonate rocks above or below the producing intervals in oil fields. Other storage options include offshore reservoirs … Furthermore, specific EPA geologic sequestration rules require that operators inject CO_2 at pressures that would not induce rock failure. All told, while regulators should take care to ensure that significant induced seismicity does not occur, there is a substantial body of evidence, beyond the geophysics, that North America's ample geologic resources can accommodate many decades of captured CO_2.

The Intergovernmental Panel on Climate Change issued a report on CCS (IPCC, 2005) in which an international group of 37 earth scientists wrote a consensus section on induced seismicity. They recognize that injecting large quantities of fluid in deep wells at pressures substantially above background pressure can induce fracturing and fault slippage, with potential risks of 1) increasing fracture permeability that can allow the fluids to flow into unwanted locations, and 2) producing earthquakes that may be large enough to be felt and do damage. They also recognize that there is extensive experience throughout the world with deep-well injection of very large quantities of fluids: CO_2 for EOR, brines from oil and gas production, aquifer wastewater, hazardous waste, and natural gas. With the exception of natural gas injection, which is for temporary seasonal storage, the cumulative quantities of these injected fluids rival the quantities needed for effective CO_2 storage, and these injections have resulted in an exceptionally low frequency of felt and damaging seismic events. They conclude that this empirical evidence suggests that regulatory limits on injection pressure are effective and the seismic risk from CCS is expected to be low. They acknowledge that some aspects of CO_2 storage differ from the other deep-well injection practices, so commercial-scale CO_2 projects will be needed to quantify risk levels.

When evaluating a possible site for CO_2 storage, the potential for induced seismicity needs to be addressed, then managed if the site is selected. Best practice approaches for assessing the potential for, and management of, induced seismicity have been grouped into the following, often overlapping, six categories by Myer (2012).

- **Site selection and characterization:** For a preliminary screening evaluation of a possible CO_2 storage site, including public outreach discussed below, see Majer *et al.* (2012, Step 1). The potential for induced seismicity is one of many aspects of site selection and characterization that must be considered. It begins with the collection of existing data: geologic structure based on well logs and seismic surveys; mapping of fault locations; historical seismicity (location, magnitude and frequency of earthquakes); and if available, regional hydrologic boundary conditions, and in-situ fluid pressures and stress state. From this information a 3D geologic model is developed, and augmented as more data become available. Of course, it would be wise to avoid establishing large CO_2 storage sites near known faults that may be large enough to cause felt events, especially in an area where previous seismicity has

occurred. Existing 2D and 3D active-source seismic surveys, as well as a pre-injection baseline 3D survey, can help to locate hidden faults and estimate fault dimensions.

- The magnitude and orientation of in-situ stress can be correlated with the orientation and frequency of seismic activity on known faults to help estimate seismic hazard potential. So determining the in-situ stress state is important, but it is also expensive because it requires data, testing, and sample acquisition from deep wells (e.g., density well log, minifrac or step-rate injection test, well bore imaging, dipole sonic log, and triaxial strength tests on oriented cores).

- **Public outreach:** Of equal importance with geologic assessment of a potential CO_2 storage site is early and ongoing public outreach and engagement. The attitudes of local people need to be assessed on topics such as well drilling, infrastructure construction, jobs, fear of CO_2 leakage, and induced seismicity. To some extent, people who have grown up with the oil and gas industry operating around them have a better understanding of, and comfort level with, these types of issues. Also, states with long-standing oil and gas operations tend to have effective regulations and regulatory agencies. Nonetheless, NIMBYism and fears – sometimes based on emotions rather than technical evidence – have stopped some proposed CCS projects in the U.S. and Europe. So public outreach starting early in the characterization phase is essential – and dealing with the potential for induced seismicity is part of the public outreach process.

- In public meetings about the project, an open and straightforward discussion (in layman's terms) of natural and induced seismicity, monitoring activities, and mitigation plans is important. No one (except perhaps a geophysicist) will welcome the prospect of felt seismic events, but attitudes can differ from one area to another, so it is good to understand what they are.

- The Geysers Geothermal Area in northern California provides an interesting example. The area is rural, but there are small communities that, for many years, have regularly experienced felt microseismicity, induced by the injection of cold make-up water into the hot rocks at depth. An extensive seismic monitoring network provides information about the location, depth, and magnitude of seismic events and puts the information on a publically available website. Local residents have access to the website on a real-time basis. Also, the operators have an insurance fund to repair the occasional low level damage, such as a crack in a wall (Majer *et al*., 2012).

- **Hazard and risk assessment:** For the public, seismic risk is of more concern than seismic hazard. That is to say, ground shaking intensity is more important than earthquake magnitude **M**. Ground shaking depends, not only on earthquake magnitude, but also on regional geologic conditions and the distance between the hypocenter and the location of people and structures. It is ground shaking that is felt by people and can damage structures or cause public concern. A risk assessment includes the likelihood of injury to people and damage to property, and the value of that damage. The concept of risk can also include an evaluation of low levels of induced seismic activity that annoy and anger people, potentially to the point of terminating a project.

- The traditional approach to estimating potential seismic hazard from *natural* earthquakes is a Probabilistic Seismic Hazard Analysis (PSHA), which is based on 1) an historical record of earthquake frequencies and magnitudes in an area, 2) an earthquake rupture forecast to evaluate the probability of all possible earthquake ruptures (fault offsets) throughout the region and over a specified time span, and 3) an earthquake shaking model to estimate the probability that an intensity-measure type will exceed some level of concern for a given earthquake rupture (Myer and Daley, 2010). Geologic characterization data mentioned below are used for a PSHA for natural earthquakes. However, extending the analysis to an estimate of potential risk from induced events requires other data and approaches because there is often no historical record of past injection-induced seismicity. (See Majer *et al*., 2013, Section 5.)

- **Passive seismic monitoring:** Another aspect of site characterization is establishing an array of microseismic monitoring stations in the vicinity of the proposed injection site to assess the level of natural background seismic activity. When characterization wells are drilled, downhole seismic sensors can be emplaced for higher levels of sensitivity and more accurate hypocenter location. Monitoring for at least a year before injection begins, while exceptionally short in geologic terms, can still be useful for seeing current activity on known faults or identifying unknown faults.

- Once injection is underway, ongoing seismic monitoring is essential for assessing whether the level of microseismic activity is growing, both in terms of frequency and magnitude of events. If increased seismic activity is observed, it will provide the basis for stopping or slowing injection according to pre-established criteria. The monitoring array may also identify regions of subsurface fluid flow, identify activity on faults, and help to identify events that are natural rather than induced. For example, seismic monitoring data might show that a felt event, attributed by the public to fluid injection, is actually located far from any injection well and on the opposite side of an impermeable fault, and therefore most likely a natural event.

- **Managing reservoir pressure:** To protect Underground Sources of Drinking Water (USDWs), EPA's regulations for CO_2 injection wells (Class VI) require a pre-injection step-rate injection test[10] to the determine the pressure that will fracture the reservoir rock at the injection point. Then EPA stipulates a maximum permissible downhole CO_2 injection pressure that is significantly below the fracture pressure, and requires continuous monitoring and recording of the injection pressure. In this regard, CO_2 injection wells, which seek to avoid fracturing the reservoir rock and the caprock (commonly shale), are fundamentally different from shale gas production wells, which deliberately use high pressure for a short time to fracture the formation. However, this constraint on CO_2 injection

[10] A step-rate test is performed by injecting water at a constant rate for a period of time, then increasing the injection rate for the same time interval, all the while measuring pressure at the injection point. The injection rate is increased in step-wise fashion until there is a pressure drop, indicating that small fractures have been created near the injection point. The maximum pressure reached before the drop is the formation fracture pressure.

pressure does not preclude seismicity on critically stressed faults induced by pore pressure changes from injected CO_2 or displaced brine.

- The geologic model developed during characterization includes hydrologic modeling using the best available permeability and porosity data. As wells are drilled before and during injection, the model is updated based on new permeability and porosity data from in-situ and laboratory measurements and observed pressure measurements in the storage reservoir. Pressure measurements in the aquifer overlying the caprock are also important to monitor for leakage. As the number of injection wells increases, the hydrologic model will help to assess cumulative pressure effects in different parts of the reservoir and guide the management of injection rates at different wells.
- Seismic monitoring data may reveal areas of increased microseismic frequency and/or magnitude. If seismic activity exceeds a pre-established threshold, injection pressure and injection rate should be reduced at one or more wells. If a high magnitude (perhaps **M**>4), or alternatively, a high intensity event occurs, injection can be stopped to reassess the injection program. In large reservoirs with open lateral boundaries and water drives, pressure will usually drop quickly once injection is stopped. However, brine extraction is an option for reducing pressure (although it may present disposal challenges), and may be necessary for CO_2 storage in small, closed basins or other confined geologic structures where pressure cannot dissipate rapidly.
- A conservative approach for CO_2 storage in depleted oil or gas reservoirs may be to limit reservoir pressure to the pressure that existed before the hydrocarbons were produced.
- **Seismic event response procedures / Mitigation:** CO_2 storage field operators will need to work with regional and local regulators and authorities to agree on specific procedures and actions to be taken if earthquakes of a specified magnitude or shaking intensity occur, for example, no action for **M**<2, reduced injection pressure for **M** 2-4, and suspend injection for **M**>4 to evaluate the situation. Injection rates and locations may need to be adjusted, or data may suggest that the event was natural. If ground motion is a more appropriate concern, accelerometers could be placed in buildings closest to the storage site to monitor vibration or swaying.

Protocol for mitigating and managing induced seismicity

Recognizing the need to address induced seismicity related to energy production technologies, DOE has started by supporting the development of a "Protocol" document for enhanced geothermal system (EGS) projects, with the objective of providing "a guidance document for geothermal developers, public officials, regulators and the general public that provides a set of general guidelines detailing useful steps to evaluate and manage the effects of induced seismicity related to EGS projects. This Protocol puts high importance on safety while allowing geothermal technology to move forward in a cost effective manner" (Majer *et al*., 2012). The Protocol is based on empirical evidence that EGS induced events have, in nearly all cases, been an "annoyance," which is defined as a threshold of ground shaking that does not compromise the physical integrity of structures. Damage such as a cracked wall would be handled with regulations or codes similar to those currently used for ground shaking caused by construction projects or mine blasting, which specify that damage will be repaired. The Protocol is being followed by a "Best Practices" document, intended to be a living document for geothermal operators, to supplement the Protocol and "be kept up-to-date with state-of-the-art knowledge and practices, both technical and non-technical" (Majer *et al*., 2013).

These EGS guidance documents provide a template for developing similar documents for CO_2 storage projects, recognizing that there are some differences between the two types of project. An important difference may be that most EGS projects rely on fracturing hard rocks to develop confined a flow path between injection and production wells, whereas CO_2 storage projects inject into relatively porous, permeable rocks that are usually less brittle, and at pressures low enough to avoid fracturing. The Protocol and Best Practices documents provide detailed descriptions of the six numbered topics above. They provide guidance without being prescriptive, recognizing that for each project site there will be a unique set of circumstances – geologic conditions, prior seismicity, locations of faults, proximity of people and diverse structures, planned depth and quantity of fluid injection, etc. This will also be the case for potential CO_2 storage sites.

The DOE/NETL Carbon Storage Program has published a set of Best Practice Manuals for CCS, which provide lessons learned from the research carried out by the Program and guidance to future operators on the topics of site selection and characterization, drilling and well management, monitoring, simulation and risk assessment, and public outreach. A recently released revised edition of the Best Practice Manual on monitoring for geologic CO_2 storage (NETL, 2012) specifically addresses the NRC (2012) recommendations on induced seismicity. Future updated versions of the other Best Practice Manuals will also address the NRC recommendations.

Induced seismicity and the future of CCS

There are only a few CCS projects around the world, and none injecting CO_2 at a scale sufficient to assess induced seismic hazard for effective climate change mitigation. Furthermore, there are many avenues of research related to natural and induced seismicity that could provide insight into the potential for induced seismicity from geologic CO_2 storage. A short list of topics and questions could include:

- Development of computer simulation codes that link reservoir fluid flow, geomechanics, and geochemistry
- Development of cost-effective methods for determining the stress state of the Earth's crust, in sufficient detail for regional and site assessment
- Conducting rock mechanics research related to the strength of faults and fault triggering
- For induced seismicity risk assessments, development of an approach analogous to the Probabilistic Seismic Hazard Analysis for natural seismicity risk assessments
- Undertaking research to understand why some large events induced by EGS and wastewater injections have occurred days or weeks after injection stopped
- What is the seismicity risk associated with small pore pressure increases at great distances from the area directly impacted by fluid injection?
- Are porous, permeable reservoir formations significantly less prone to induced seismicity than hard, less permeable formations?
- Can injection (and small induced or natural seismic events) at the relatively shallow depths of interest for CO_2 storage trigger larger earthquakes at greater depths? (Large earthquakes necessarily occur at great depth where tectonic forces can move large masses of rock.)

While research in these and related areas is critical for understanding the relationship between fluid injection and induced seismicity, there is a large body of existing literature, research results, and empirical data. There is much that the earth science community does understand. As part of site characterization, informative tests and measurements can be performed to assess the risk and hazard of induced seismicity. There are permitting requirements and operational prescriptions for different types of deep injection wells, enforced by the EPA or state oil and gas agencies, designed to protect underground sources of drinking water. However, the Earth is large, complex, and dynamic. No tests and surveys that scientists can perform – even if we could afford the cost – will provide comprehensive and definitive answers.

All scientific organizations and individuals assessing the array of technologies necessary to mitigate climate change regard CCS as an *essential* bridging technology, until fossil fuel combustion can be replaced by carbon-free energy generation throughout the world. And CCS will be necessary for California to meet greenhouse emissions reduction goals for 2050 established by Assembly Bill 32, the Global Warming Solutions Act (Greenblatt and Long, 2012). Induced seismicity is one of various risks that must be assessed for CO_2 storage sites. As stated by Majer *et al.* (2007), "induced seismicity is not new, it has successfully been dealt with in many different environments ranging from a variety of injection and engineering applications …"

Regarding CCS, research needs to continue, along with commercial-scale CCS projects with careful site characterization and screening, effective seismic monitoring, mitigation plans, and transparent public engagement. For the other energy technologies discussed in the NRC (2012) report, only a few projects have been problematic while the vast majority operate within acceptable seismic limits. Similarly, it may turn out that at some CCS sites, CO_2 injection will need to be curtailed, while at many other sites, injection will proceed to meet project objectives. Greenhouse gas emissions

reductions demand continued geologic CO_2 storage technology development and commercial-scale project implementation.