STRATUS CONSULTING

Potential Environmental Impacts of the Proposed CIRI Underground Coal Gasification Project, Western Cook Inlet, Alaska

Prepared for:

Center for Science in Public Participation
224 North Church Avenue
Bozeman, MT 59715

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1. Introduction

Cook Inlet Region, Inc. (CIRI) has proposed a combined underground coal gasification (UCG), onsite power generation, and carbon capture and sequestration (CCS) project on CIRI-owned lands on the west side of Cook Inlet, Alaska (the site). Because the project is in an early phase of development, information describing the specifics of the CIRI project is limited at this time. In particular, the site geology has not yet been well characterized; the particular coal seams targeted for gasification have not been described; and the locations of carbon sequestration repositories have not been identified. Despite the lack of specificity surrounding this particular project, there are general environmental risks associated with UCG and CCS, many of which may apply to this site.

Stratus Consulting was retained by the Center for Science in Public Participation to summarize the potential environmental risks associated with UCG and CCS in general, and the CIRI proposed project in particular. This document provides a summary of these general and site-specific issues to the extent possible given currently available site information. Many of the risks and potential adverse impacts discussed herein are common across UCG and CCS. While both technologies are relatively young, there is a greater body of literature on CCS than UCG. We have summarized the risks for each technology here separately, based on the available literature on each technology. Some of the more detailed information currently available in the literature on CCS risks and summarized here, associated for example with wells, faults and fractures, is also likely applicable to UCG operations.

This report is organized as follows:

- The remainder of Section 1 provides an introduction and brief overview of the proposed project, as well as a general summary of the proposed technologies
- Section 2 provides a summary of the potential environmental risks associated with UCG, along with a review of lessons learned from pilot projects around the world
- Section 3 summarizes the potential environmental risks associated with CCS, with examples from pilot projects around the United States and the world
- Section 4 summarizes the limited information available on CIRI's proposed project, as well as an overview of relevant general geologic information about the project area

- Section 5 provides an overview of general environmental monitoring strategies for UCG and CCS implementation
- Section 6 provides a summary of recommendations, including a synthesis of site assessment and environmental monitoring requirements that should be implemented if the project proceeds beyond its current feasibility phase.

1.1 Overview of the Proposed Project

CIRI's proposed project is located within the Susitna lowlands region of Alaska, approximately 60 kilometers west of Anchorage and north of Tyonek (Figure 1). Although details of the project remain limited at this time, the CIRI proposal generally contains three major components:

1. UCG of subsurface coal seams. UCG involves oxidizing coal in place by injecting air or oxygen into the subsurface, which generates a combustible gas product that can extracted and used for power generation.
2. Onsite construction of a 100-MW combined-cycle power plant that will be fueled with the gas product generated by UCG.
3. Capture of a portion of the carbon dioxide (CO_2) generated by the entire process, and sequestration of this CO_2 underground where it will not contribute to global carbon emissions. CIRI has proposed that this carbon would be sequestered via a process referred to as enhanced oil recovery (EOR), in which CO_2 is pumped into declining oil reservoirs to enhance the flow of oil to existing petroleum production wells.[1]

Both UCG and CCS are emerging technologies, and commercial scale implementation of each has occurred at only a small number of sites around the world. The combination of the two technologies at a single commercial-scale site would be the first project of its kind in the world. While the combined approach holds promise as a "green" fossil fuel project, the possibility for success as a commercial venture and the type and extent of environmental impacts are largely unknown.

1. Though their original plan outlined carbon storage via EOR, subsequent communications with CIRI have indicated that they are likely to consider other options for the CCS component of the project, such as injection into deep saline formations (DSFs).

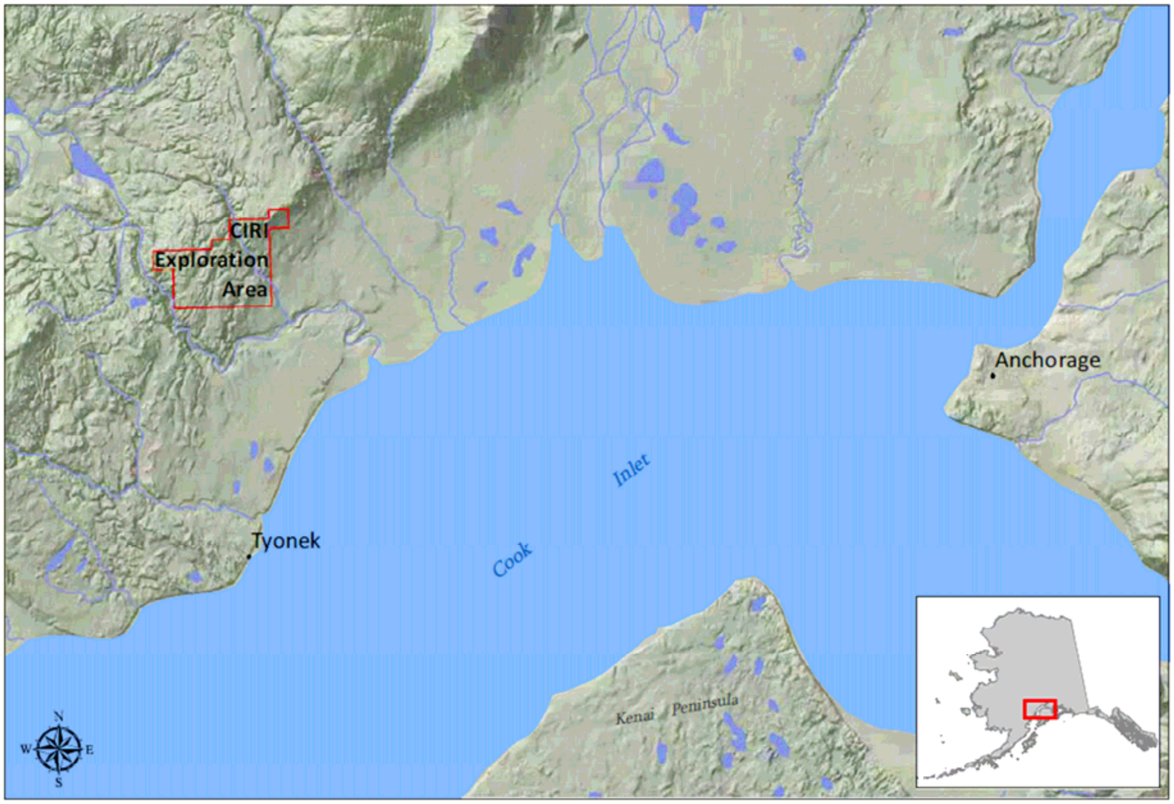

Figure 1. CIRI exploration location map.

2. Environmental Risks of UCG

2.1 The UCG Process and Overview of Environmental Risks

The UCG process involves oxidizing subsurface coal seams, which generates a combination of hydrogen and other gases, referred to as syngas (short for "synthesis gas"). Air or oxygen is pumped into a subsurface coal seam through an injection well. The introduction of an oxidizing gas produces heat, which partially combusts the coal *in-situ* and creates the syngas product (Clean Air Task Force, 2009; Friedmann, 2009). The syngas generated by the UCG process is primarily composed of hydrogen, carbon monoxide, and smaller amounts of CO_2 and methane (e.g., Stephens et al., 1985; Clean Air Task Force, 2009; Friedmann, 2009). The syngas is extracted from the UCG burn cavity by a production well, which brings the gas product to the surface to be burned. CO_2 can be separated from the syngas stream prior to combustion and collected for CCS. A schematic of the UCG process is shown in Figure 2.

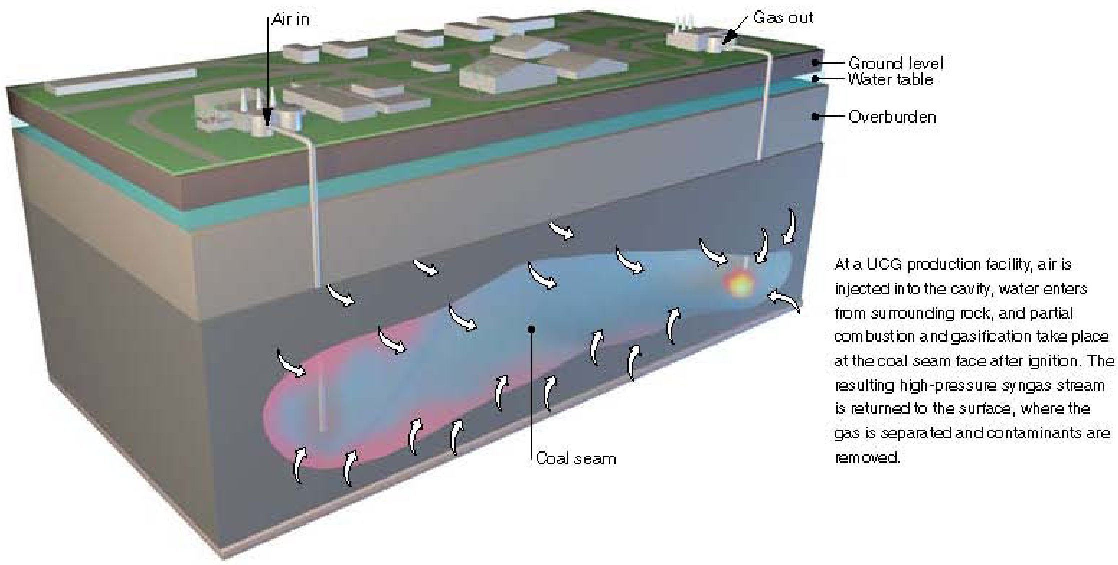

Figure 2. UCG process.

Source: Walter, 2007, p. 15.

When compared to conventional coal mining, UCG has a number of potential environmental benefits. In particular, surface disturbance is minimized relative to the disturbance caused by conventional mining, and the *in situ* gasification of coal allows many of coal's potentially hazardous combustion products and leachable contaminants to remain in the ground. Despite these potential benefits, however, the process still creates environmental risks. Based on a limited number of pilot projects in the United States and a small number of full-scale operations worldwide, two main environmental risks have thus far been associated with the UCG process. First is the risk of groundwater contamination. Organic contaminants such as polycyclic aromatic hydrocarbons (PAHs) may be generated during combustion of coal, and trace metals in the coal may be released through geochemical reactions induced by the UCG process. Contaminants may also be released from adjacent geologic units. These organic and metal contaminants could migrate and contaminate groundwater aquifers. Second, because the *in situ* burning of coal creates cavities in the subsurface, there is a risk of ground subsidence, whereby the overlying rock layers partially collapse into the newly created void space. Subsidence creates a hazard for any surface infrastructure that might be present above the UCG zone, and may create detrimental changes in surface or groundwater hydrology above the cavity.

In addition, there are other potential adverse impacts to human health and the environment associated with UCG. For example, uncontrolled migration and leakage of syngas to the surface could result in adverse impacts to local ecosystems and human settlements. Contaminants released from the coal and adjacent geologic units during the UCG process could also be released at the surface, contaminating surface water and/or air. Finally, because all of the combustion occurs in the subsurface where it is difficult to monitor, there is the potential for the oxidation reaction to migrate beyond the target zone or become uncontrolled.

Evaluating each of these risks requires an understanding of the subsurface geology, including the structural integrity, geochemical, and hydrologic properties of the targeted coal seam and rock units surrounding the targeted coal seam. Evaluating risk also requires characterization of potential subsurface and surface receptors, such as groundwater and surface water resources, sensitive ecosystems or species, and human health and infrastructure.

2.2 Groundwater Contamination

One of the most important potential adverse environmental effects related to UCG is groundwater contamination. Here we describe the potential sources of contamination, the geologic factors that will influence the migration of any contaminants generated, and how these risks can be mitigated.

2.2.1 Potential sources and types of contaminants

There are different sources and types of contaminants that may be associated with UCG operations. Uncontrolled migration and leakage of the syngas itself could result in contamination of overlying aquifers. In addition, by-products may be inadvertently generated from the coal during the UCG process. These products may include organic contaminants such as PAHs, phenols, and benzene, as well as inorganics including sulphate, boron, and metals and metalloids such as mercury, arsenic, and selenium, which may be present as metal sulfide impurities in the coal (e.g., Sury et al., 2004; Skousen et al., 2000). Mercury, arsenic, and selenium are volatile metals/metalloids, and they can also be released as gases during the coal gasification process (Liu et al., 2006). Their release could adversely affect water quality and air quality in the underground and on the surface depending on the temperature of the reaction, the type of geochemical reactions occurring during the gasification process, and the presence of pathways from the coal to the surface.

The geologic units surrounding the seam may also be sources of contaminants. Rock units immediately adjacent to the targeted coal seam will also likely be influenced by UCG operations, and thus, oxidation and other geochemical processes in the surrounding rock could also result in the release of contaminants. The types of contaminants potentially released as a result will depend upon the mineralogy and trace impurities of the surrounding rock.

2.2.2 Factors that may influence the potential for groundwater contamination

Fully characterizing the groundwater systems surrounding the targeted coal seam is crucial for evaluating the potential for groundwater contamination from UCG activities. Key hydrogeologic factors that will determine whether or not groundwater becomes contaminated include the hydraulic conductivity (permeability), thickness, and lateral continuity of surrounding rock units that separate the coal seam from any nearby aquifers, and the presence of fractures or faults that may create conduits for fluid migration out of the reactor zone.

Sury et al. (2004) present a flow chart for evaluating the hydrogeologic setting of a proposed UCG project (Figure 3). Note that in addition to pre-existing hydrogeologic conditions such as the permeability and lateral continuity of confining layers, there are a number of factors related to the UCG process itself that can influence the migration of contaminants from the reactor zone. In particular, since the partial combustion of coal creates a cavity in the subsurface (see Section 2.3), the process can create fractures, partings between geologic strata, or induced faults that can create new conduits for fluid flow. Physical properties of the rock, as well as pressure changes induced by UCG operations, will influence the potential for induced fracturing. The potential for these induced fluid migration pathways to allow contaminant migration out of the UCG zone must be evaluated based on available geologic information.

Note that fault and fracture zones are complex, and their behavior under the conditions imposed by UCG operations may be difficult to predict. Faults and fractures may be transmissive or sealed. Transmissive faults and fractures are capable of transmitting gases and/or fluids, and thus may act as direct contaminant pathways to groundwater aquifers from the UCG zone. Sealed faults and fractures may be re-opened as a result of UCG operations, and thus may also act as contaminant pathways. Fractures may also be re-opened by the pressure created as a result of the injected air/oxygen and the formed syngas, or by the dissolution of minerals along fracture zones due to the geochemical conditions created by the UCG operations.

UCG injection and capture wells, if not properly completed, may also act as conduits for contaminants (Sury et al., 2004). In order to maintain well integrity, well materials must be resistant to the potentially corrosive conditions created in the subsurface during operations. If present, existing wells and boreholes associated with previous exploration, and oil and gas operations, may also act as contaminant pathways to groundwater aquifers if they are not properly plugged and sealed, or if the well materials have degraded over time.

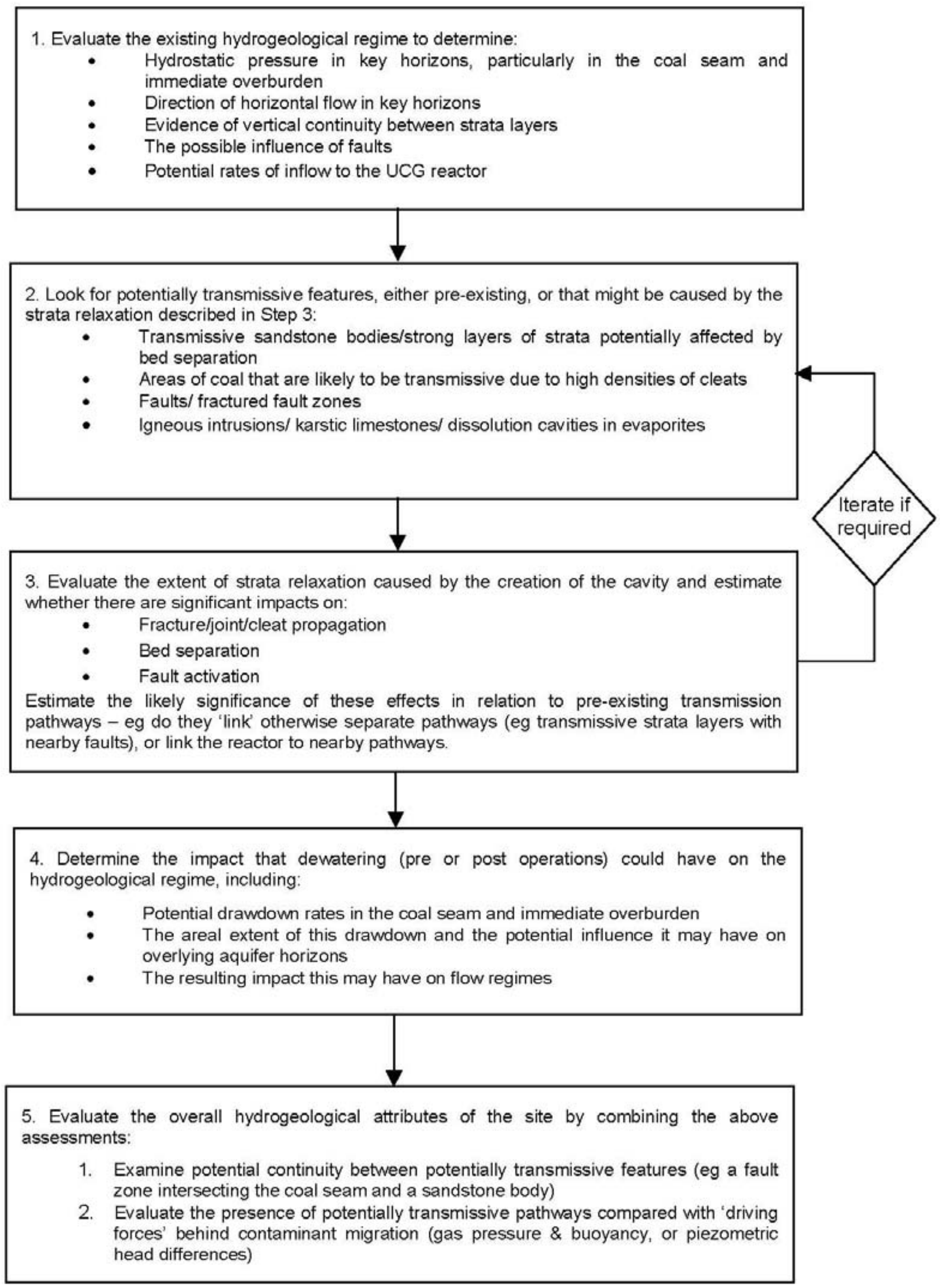

Figure 3. Concept for the general hydrogeological evaluation process.

Source: Sury et al., 2004, Figure 4.1.

Finally, conditions created by the burn itself may influence the potential for the spread of contaminated groundwater. Groundwater models have been developed which suggest that heating in the reactor zone can create convection cells in overlying units, which can generate rising plumes of potentially contaminated groundwater (Walter, 2007). Combined with the potential for fractures created by the collapse of the UCG burn cavity, these induced groundwater circulations can help to spread contaminants from the burn zone into overlying aquifers.

2.2.3 Mitigating groundwater contamination risks

Recommendations for groundwater protection have included ensuring that drinking water aquifers are at a distance of more than 25 times the seam height from the reactor (e.g., Shafirovich et al., 2008). In practice, detailed characterization of the hydraulic properties of the geologic units surrounding the reactor zone and an understanding of the hydrogeology of potential drinking water aquifers in the region, are likely to be more appropriate technical considerations.

In addition to geological controls, engineering controls are also important in limiting migration of contaminated groundwater from the reactor zone. In particular, ensuring that the UCG reactor zone pressure is lower than the ambient (hydrostatic) pressure should create inward hydraulic gradients, so that groundwater is flushed into the reactor rather than out of it. Experience suggests that maintaining a reactor pressure lower than hydrostatic pressure may be one effective means of avoiding groundwater contamination issues (e.g., Walter, 2007). For example, the Chinchilla project in Australia, where reactor pressure has been controlled to be lower than ambient pressure, appears to have had no escape of contaminated groundwater to its surroundings. In contrast, UCG pilot projects in shallow seams and without careful reactor pressure control such as at Hoe Creek, Wyoming, were plagued with significant groundwater contamination issues (e.g., Burton et al., 2007).

One potential problem with maintaining low reactor pressures is that higher pressures and temperatures create a higher methane content in the gas and therefore a more energy-rich product (e.g., Shafirovich et al., 2008). Thus, there may be conflicts between controlling gradients to minimize risk of groundwater contamination versus producing a more energy-rich product.

In summary, groundwater contamination is likely to be one of the most significant environmental concerns related to the UCG process. A combination of careful site selection and proper engineering controls is essential to limiting groundwater contamination from UCG sites.

2.3 Subsidence

Combustion of underground coal seams and removal of the resulting syngas creates void space in the subsurface. These voids can result in subsidence of the land surface above the UCG reactor zone. The problem of surface subsidence related to UCG projects is analogous to subsidence related to subsurface coal mining operations; as a result, there is a well-developed literature on the physical parameters controlling the magnitude of subsidence that might be created by UCG projects (e.g., Gregg, 1977; Shu and Bhattacharyya, 1993; Burton et al., 2007).

In practice, there may be no way to prevent collapse of the burn cavity itself during UCG operations. However, physical properties of the overlying rock column can mitigate the effects of cavity collapse at the land surface. The factors controlling the amount of subsidence generated by the collapse of subsurface cavities include the depth and width of the subsurface cavity; the geotechnical properties of the overlying rocks (overburden); and the degree of fracturing of the overburden. An analytical model by Shu and Bhattacharyya (1993) suggests that the primary control on surface subsidence is the ratio of cavity width to depth. Thus wide and/or shallow cavities are the most likely to induce significant subsidence at the surface. Other modeling frameworks have been developed to evaluate the potential for induced subsidence from evacuation of subsurface cavities (e.g., Creedy and Garner, 2004); some commercially available software packages can also be adapted to evaluate subsidence risks for particular settings (e.g., Burton et al., 2007).

In addition to the width and depth of the cavity, the physical properties of the overburden and the coal seam will also be important in controlling the degree of subsidence at the surface. A modeling study by Dr. T.X. Ren (Appendix E of Creedy and Garner, 2004) indicates that while the mechanical properties of the overburden are important in controlling collapse and subsidence, the thermal and mechanical properties of the coal seam itself also play an important role in controlling cavity growth. Laboratory analysis of the geotechnical and thermal properties of the overburden and the coal are required to characterize the risk of surface subsidence.

To minimize the risk of subsidence, Burton et al. (2007) suggest that coal seams targeted for UCG should be deeper than 200 meters (m). This recommendation appears to be based on a combination of experience from pilot studies and modeling constraints. For example, subsidence occurred at the Hoe Creek pilot study, where the target coal seam was approximately 10-m thick and only 40–50-m deep; deeper UCG projects in the United States and elsewhere have had fewer problems with surface subsidence (Burton et al., 2007). Modeling studies also indicate that deeper coal seams will result in lower surface subsidence: as the depth of the cavity increases, the overlying rock column is more likely to accommodate some of the resulting strain, resulting in a broad warping of the ground surface that will be more subdued for deeper UCG cavities (e.g., Shu and Bhattacharyya, 1993).

If the UCG zone underlies any significant infrastructure such as roads, buildings, or power generating facilities, subsidence will clearly present an engineering concern. Subsidence can also have detrimental ecological effects, such as creating depressions that may collect water, capturing flow from rivers and streams, or altering groundwater recharge, discharge, and flow patterns in the subsurface. The impacts of subsidence will depend on site-specific attributes, which must be evaluated prior to initiation of a UCG project.

2.4 Other Environmental Risks

Although groundwater contamination and subsidence are most often cited as the primary environmental risks associated with UCG, there are additional environmental concerns that should be addressed when designing a UCG project. Of these, gas leakage to the surface and the potential for uncontrolled reaction rates appear to be the most significant concerns.

Gas leaks to the surface may occur through pre-existing faults or fractures, or they could occur as a result of induced fractures created by subsidence (Gregg, 1977). The potential environmental risks associated with a gas release will depend on the nature of the gas and the ecological resources present at the surface, but could include asphyxiation, vegetative die-off, or acidification of surface waters. Volatilization of metals and metalloids such as arsenic, mercury, or selenium, if they occur, could also create toxic conditions if these volatile compounds migrate to the surface.

Another potential environmental concern related to UCG is the relative lack of control on reaction rates in the subsurface. As noted by Friedmann et al. (2009), the only engineering control on reaction rate is the rate of gas injection. Parameters such as the rate of cavity growth or water influx to the burn zone cannot be controlled with existing technology. Furthermore, to the extent that UCG induced fracturing could provide pathways for increased air intrusion to the reactor zone, it is possible that even the rate of gas injection could become difficult to control. As a result, there is the potential for the generation of uncontrolled burns in the subsurface.

2.5 Site Characterization and Monitoring Needs for UCG Projects

Although many authors have proposed "rules of thumb" for the proper siting of UCG projects (e.g., more than 200-m deep, more than 25 times the seam thickness from the nearest drinking water aquifer), there is no substitute for site-specific geological information. At a minimum, proper siting of a UCG project to minimize risk of contaminant releases or subsidence requires the following information:

- Characterization of the geologic units above and below the target coal seam, including a consideration of the lateral continuity, heterogeneity, porosity, permeability, and continuity of confining layers and overburden

- Characterization of the physical nature of the coal seam, including depth, width, thickness, and permeability, with particular attention paid to the potential size and spatial extent of the burnout area from UCG

- Geochemical and mineralogic characterization of the coal seam and host rock to evaluate potential contaminants of concern, such as sulfides, metals, metalloids, or other trace impurities

- A pilot burn test of samples from the target coal seams that would identify the gases produced by UCG

- Identification and characterization of groundwater aquifers in the subsurface, including their chemistry (e.g., major, minor, and trace), groundwater flow directions, and horizontal and vertical hydraulic conductivity

- Laboratory analysis of the thermal and mechanical properties of the target coal seams and overlying stratigraphy, to enable an evaluation of the potential risk of subsidence resulting from UCG burnout

- Evaluation of existing and potential faulting in the area, with particular attention paid to whether faults/fractures are sealed or transmissive

- Evaluation of existing wells and boreholes, their location, depth, and the integrity of well construction and sealing/plugging materials, and stability under UCG-imposed conditions.

In order to properly characterize the subsurface stratigraphy, exploratory boreholes and downhole geophysical measurements should be tied to seismic lines to enable a complete characterization of the lateral continuity of coal seams and surrounding aquifers and aquitards. Burton et al. (2007) also stress the importance of understanding the depositional context of coal beds targeted for UCG, because this basic geologic framework can be used to evaluate the lateral extent of coal seams and their connection to surrounding permeable units. For example, coal seams deposited in tidal environments may be more laterally continuous than coals deposited along floodplains, and the overlying stratigraphy may also be more predictable based on basic principles of sequence stratigraphy. Empirical data from seismic lines and boreholes should therefore be coupled with an understanding of the depositional environment of the target coal seams, so that their lateral continuity and relationship to overlying materials can be inferred based on geological constraints.

If site characterization data demonstrate that the environmental risks of the project can be managed and the project proceeds, the following monitoring requirements should be considered:

- The pressure in the burn cavity should be monitored and managed to ensure that hydraulic gradients are directed inward, to minimize groundwater flow out of the cavity
- Groundwater in surrounding aquifers should be sampled and monitored regularly, to detect any contaminant migration from the burn cavity
- Tiltmeters, radar interferometry, and/or high-resolution differential global positioning system (GPS) should be used to monitor for subsidence at the surface
- Gas detection monitoring should be implemented to detect any surface leakage of syngas that may occur.

3. Environmental Risks of CCS

Conceptually, UCG may be well-suited to CCS, since (1) coal seams are commonly located in the types of sedimentary environments where formations suitable for CCS are found; and (2) CO_2 can be relatively easily and economically separated from the pre-combustion gas stream, compared to post-combustion separation (Friedmann et al., 2009). The combination of UCG and CCS technology may therefore become common. Like UCG, however, CCS also has a number of technological challenges and environmental risks that need to be carefully addressed.

The primary risks of CCS relate to unanticipated or uncontrolled releases of CO_2 from the sequestration zone. The environmental risks associated with such releases range from acidification of groundwater aquifers to asphyxiation of biota, including humans, at the land surface. In addition, since CCS is designed to mitigate climate change risk, loss of CO_2 from the sequestration zone also negates the intended environmental benefits of the process.

3.1 Geologic Sequestration Systems

According to U.S. EPA (2008), geologic sequestration (GS) systems for CCS consist of an injection zone and an overlying confining system. The injection zone is a geologic formation or group of formations that are targeted for CO_2 injection. Formations with relatively high porosity and high permeability, such as sandstones, allow for greater storage of CO_2 and are preferred injection zone materials. To maximize storage capacity, the CO_2 is compressed and injected as a supercritical fluid. These artificially high pressures create a tendency for the injected CO_2 to diffuse out of the injection zone. In addition, the injected CO_2 will have a tendency to rise due to the relative buoyancy of supercritical CO_2 compared to the native fluids (e.g., brine or saline water) present within the injection zone. The role of the confining system, also sometimes referred to as a caprock, is to prevent the upward migration of the injected CO_2. Thus, low-permeability geologic formations such as siltstones or mudstones that are thick and laterally continuous are preferred formations for confining systems (IPCC, 2005; U.S. EPA, 2008).

In this section, we describe the mechanisms at play to keep CO_2 sequestered in the subsurface, the types of geologic settings being considered for CCS, a brief summary of current CCS operations, regulatory considerations, and potential risks and adverse impacts associated with CCS.

3.1.1 GS CO_2 trapping mechanisms

The CO_2 is retained in the injection zone through a combination of different trapping mechanisms. The confining system, a physical stratigraphic trap that inhibits the upward migration of CO_2, provides one of the most important trapping mechanisms.

Within the injection zone, additional trapping mechanisms can occur to sequester the CO_2. These include residual CO_2 trapping, dissolution trapping, preferential adsorption trapping, and mineral trapping. Residual CO_2 trapping occurs when the CO_2 is retained by capillary forces in some of the pores of the injection zone geologic formation(s). Solubility trapping can occur as a result of the dissolution of CO_2 into the fluid inhabiting the pore space of the geologic formations (e.g., saline water). The fluids become denser as a result of CO_2 dissolution, and will tend to sink, thus further entraining the CO_2 in the subsurface. CO_2 trapping through preferential adsorption occurs when CO_2 adsorbs to certain geologic materials such as coal and shale that have a high affinity for CO_2. Mineral trapping occurs when the CO_2 reacts with the injection zone rock and/or fluids to form solid minerals. Although mineralization is the most permanent trapping mechanism in GS systems, it occurs relatively slowly compared to the other mechanisms [see IPCC (2005) and U.S. EPA (2008) and references therein for more detailed descriptions of these trapping mechanisms].

3.1.2 Geologic settings under consideration for GS

There are a number of different types of geologic settings under consideration for sequestration. These include deep saline formations (DSFs), oil and gas reservoirs (both depleted formations, and formations targeted for enhanced oil and gas recovery), and coal seams.

DSFs are sedimentary geologic units in which the pore space between the formation rock is filled with saline (salty) water. These formations are found in subsurface sedimentary basins and are deep enough (800–1,000 m) to achieve pressures that will keep the CO_2 in its compressed, supercritical phase. There are many very large sedimentary basins across the United States, and DSFs are believed to have the greatest capacity for sequestration, compared to the other settings under consideration (Dooley et al., 2006; NETL, 2007). The National Energy Technology Laboratory (NETL) has estimated that DSFs may have the capacity to store between 1,000 and 3,700 billion tons of CO_2 (NETL, 2007). However, they are typically less well characterized than other settings, such as oil and gas fields, and thus storage capacities are somewhat uncertain, and may be overly optimistic.

Oil and gas fields have stored oil and natural gas for hundreds of thousands to millions of years prior to resource extraction, and are thus believed to be good potential candidates to store CO_2 for long periods of time (Benson et al., 2002; IPCC, 2005). CO_2 is currently injected into some reservoirs to enhance the extraction of oil, in a process called EOR. Similarly, CO_2 is also used in some reservoirs to enhance the extraction of natural gas. Both depleted oil and gas fields, and EOR sites, could potentially be transitioned to GS. These reservoirs are typically very well characterized, which is advantageous for their use to store CO_2. However, as a result of extraction activities, these formations are typically penetrated by many wells and boreholes, which is disadvantageous to GS, because the penetrations could be conduits for CO_2 leakage (Celia et al., 2004; Heller, 2005). According to NETL, the estimated CO_2 storage capacity associated with EOR sites is 90 billion tons (NETL, 2007). This is much smaller than the estimated capacity of DSFs. However, these settings may be attractive candidates for immediate implementation of CCS, because much of the needed infrastructure and CO_2 injection technology is already in place.

Coal seams have also been suggested for GS. Because of coal's high affinity for CO_2, CO_2 may be stored in coal beds through adsorption to the coal surface. CO_2 may also enhance the extraction of methane from coal beds (enhanced coalbed methane), because coal's high affinity for CO_2 may displace methane present in the coal beds, which could then be captured for extraction. However, the small-scale fractures (cleats) that allow fluid flow through coal seams can become plugged as a result of CO_2 adsorption, and thus restrict further CO_2 storage (Haszeldine, 2006). Thus, the sequestration of CO_2 in coal beds may be challenging.

Other geologic settings, such as volcanically deposited basalts, oil or gas-rich shale, geologic repositories such as salt caverns, and abandoned mines may also be considered for GS, but are not currently major focuses (see IPCC, 2005, for further discussion of these other settings).

3.1.3 Natural and industrial analogs and existing CCS operations

Natural and industrial systems that have stored CO_2 and other fluids (e.g., gases such as natural gas) may provide analogs for GS, demonstrating the potential ability to store CO_2 and other fluids in the subsurface. CO_2 accumulates underground naturally in a variety of geologic settings, and there are numerous natural analogs that demonstrate the long-term trapping of CO_2 in the subsurface. For example, 200 million metric tons of naturally occurring CO_2 have remained trapped in the Pisgah Anticline in central Mississippi, northeast of the Jackson Dome, for more than 65 million years with no evidence of leakage (IPCC, 2005). Industrial analogs include the practice of injecting and temporarily storing natural gas in underground reservoirs. The oil and gas industry has engaged in this practice for nearly 100 years (IPCC, 2005). Experience from these natural gas storage operations is mixed. While these operations demonstrate that fluids and gases can be stored in the subsurface, there have been several instances of documented leakage of natural gas to the surface, either due to induced fracturing caused by application of excessive pressures to the formations, pre-existing leakage pathways through the confining system, or leakage at improperly sealed or plugged wells (Perry, 2005). Furthermore, these sites are generally used for temporary storage and hence do not provide insight into the long-term feasibility of underground storage of fluids and gases. These sites do provide some evidence that with careful management, confining systems can be exposed to repeated stress cycling (i.e., depressurizing and pressurizing) without adverse effects on seal integrity, which may support the use of depleted oil and gas reservoirs for CO_2 storage.

As mentioned above, the oil and gas industry also has experience in the injection of CO_2 through enhanced product recovery projects. EOR has been practiced for over 35 years, and these projects contribute substantial knowledge about the design of CO_2 injection wells and technologies for handling, injecting, and monitoring injected supercritical CO_2 (Benson et al., 2002; Heinrich et al., 2003; IPIECA, 2007). However, such projects are designed to maximize oil production, and thus provide rather limited insight into the long-term storage of CO_2 in the subsurface.

While few in number, currently operating pilot and commercial CCS projects have thus far demonstrated that CCS can be successfully implemented. Currently operating commercial projects include the Sleipner project in the North Sea (Norway), the Weyburn EOR project (Canada), and the In Salah Gas Formation project (Algeria). Additional commercial GS projects that are in the planning stages and are anticipated to be underway in the near future include the Gorgon Joint Venture (Barrow Island, Australia) and other potential sites in Europe and the United States. There are also a number of smaller-scale research field experiments that have recently been conducted or are underway at sites in the United States and internationally. Examples include the CO_2 SINK Ketzin site in Germany, the U.S. Frio Brine Experiment (Texas), and the currently underway regional projects supported by the U.S. Department of Energy's (DOE's) Regional Carbon Sequestration Partnerships Program [see U.S. DOE (2010) for a summary of this program]. For a more comprehensive list of current and planned GS projects in the United States and around the world, see NETL's CO_2 Storage website (http://www.netl.doe.gov/technologies/carbon_seq/core_rd/world_projects.html) and the Scottish Centre for Carbon Storage website (http://www.geos.ed.ac.uk/ccsmap).

Operating commercial and experimental projects have demonstrated thus far that CO_2 can be injected and sequestered in geologic formations. However, these sites have been operating for only a relatively short period of time (Sleipner is the longest running operation, and began in 1996), and hence do not yet demonstrate the long-term storage of CO_2 in the subsurface over required storage time periods of hundreds to thousands of years. Full commercial-scale deployment of GS will also involve injecting much larger volumes of CO_2 than currently operating projects. Because of their smaller scale, current projects likely do not demonstrate the full range of scenarios that may be encountered in commercial-scale deployment. For example, commercial-scale GS projects will encompass areas that may be miles in diameter (as opposed to for example the small fraction of a mile encompassed by most DOE pilot projects), and thus may be more likely to:

- Encounter geologic heterogeneities that may serve as CO_2 leakage pathways, including faults and fractures, or potential anthropogenic pathways such as unplugged wells and boreholes

- Face challenges regulating pressure, and thus experience adverse pressure effects that can cause fracturing or other adverse impacts, such as the displacement of brine into overlying aquifers, or regional effects on groundwater flow

- Encounter basin-wide effects, and influences of neighboring projects.

However, pilot projects can nevertheless provide useful information, particularly if multiple projects are implemented and evaluated across a variety of geologic settings.

3.1.4 Regulatory framework for CCS

Federal and State regulations address the injection of fluids into the subsurface for the protection of underground sources of drinking water (USDWs), under the Safe Drinking Water Act (SDWA). Specifically, the U.S. Environmental Protection Agency (U.S. EPA) Underground Injection Control (UIC) program regulates the injection of fluids into the subsurface (including liquids, gases, and semisolids), and the regulations are designed to ensure that injected fluids do not endanger USDWs.

According to the U.S. EPA (2010), GS of CO_2 through well injection meets the definition of "underground injection" in Section 1421(d)(1) of the SDWA, and the U.S. EPA has authority for underground injection under the SDWA UIC program. The U.S. EPA, states, territories, and tribes that have primacy for UIC programs ("Primacy States") act as co-regulators to protect USDWs from any potential endangerment from underground injection of CO_2.

In July 2008, the U.S. EPA published a Proposed Rule for Federal Requirements for CO_2 GS wells under the UIC program. The Proposed Rule describes a new class of wells for the regulation of CO_2 injection, and addresses issues related to siting, well construction, monitoring, and site closure. See U.S. EPA's website (http://www.epa.gov/safewater/uic/wells_sequestration.html) for the history and current status of the Proposed Rule.

3.2 Potential Risks and Adverse Impacts Associated with CCS

The main environmental risks associated with CCS are related to the potential for leakage from the GS formation, and the potential for adverse impacts in the subsurface associated with the applied injection pressures. Key attributes of GS systems that have been identified as particularly important when evaluating the potential risk of leakage of CO_2 from the injection zone include wells, faults, and fracture zones. The applied injection pressures may also induce fracturing or reactivate faults, and may have other adverse impacts to the subsurface, such as displacing large volumes of brine, or potentially causing changes in groundwater flow directions.

Wells (and other artificial penetrations such as boreholes) have been identified as one of the most probable conduits for the escape of CO_2 from GS systems (Gasda et al., 2004; Benson, 2005; IPCC, 2005; Carey et al., 2007). If not properly sealed and plugged, wells and boreholes that were previously installed during exploration and resource extraction can be a direct conduit for CO_2 to escape from depth to the surface. Such wells may also act as pathways for brines to contaminate overlying freshwater aquifers. Even properly completed wells may pose a risk of leakage, as the acid generated when CO_2 contacts water may degrade well construction materials over time (Scherer et al., 2005). Identifying and evaluating abandoned wells may be particularly challenging in some geologic settings, such as depleted oil and gas fields. Furthermore, the GS injection and monitoring wells themselves need to be properly constructed and operated in order to avoid leakage of CO_2, and other fluids such as brine. Experience from other analogous injection projects (such as those used in oil and gas operations) has shown that leakage from the injection well itself, as a result of improper completion or deterioration of the casings, packing, or cement well materials, is one of the most significant well failure modes (Benson et al., 2002; IPCC, 2005).

The potential for existing faults and fractures to act as fluid pathways in GS systems is a function of numerous factors, comparable to those described above for UCG. These include the level of applied pressure, whether they are sealed or transmissive; their stratigraphic position with respect to the confining system, their orientation, and their geometry with respect to the applied pressures. Tectonically active settings, such as the proposed CIRI site and southern Alaska in general, may be more likely to have transmissive faults and/or fracture zones, and may be unsuitable for GS. Faults and fractures may also be induced if the GS system is overpressurized during injection of CO_2. The risk of injection pressure exceeding fracture pressure can be reduced through understanding the relevant geologic attributes, careful site characterization, careful operation of GS systems, and monitoring (IPCC, 2005). The potential for existing and induced fractures and faults to result in adverse impacts will depend on numerous additional factors, including whether the faults are connected to an overlying receptor, whether they may be connected to other fluid-conducting pathways (such as wells), and whether or not they may be resealed by geochemical processes associated with GS (U.S. EPA, 2008).

Additional factors that will influence the risk of CO_2 leakage include the lateral extent, thickness, and permeability of the confining system. Furthermore, the physical capacity, injectivity and geochemical and geomechanical properties of the injection zone may also influence the likelihood of leakage.

There are numerous potential adverse impacts resulting from the leakage of CO_2 (as well as other fluids, such as brine) and changes in subsurface pressure caused by CO_2 injection. According to U.S. EPA (2008), categories of receptors that could potentially be adversely impacted by CCS include human health and welfare, the atmosphere, ecosystems, groundwater and surface water, and the geosphere. The vulnerability of a GS system to these adverse impacts is a function of both the presence of the key receptors in the impact categories, and the levels of exposure. A number of factors affect exposure, including but not limited to the concentration and volume of the release, the rate of release (i.e., slow vs. sudden), the proximity of the release to the receptor, and wind or wave dispersion. Impacts are also affected by whether the release is acute but limited (in time or spatial extent) or chronic. The potential impact categories are briefly summarized below; for a more detailed discussion, see U.S. EPA (2008):

- *Human health and welfare*: Adverse health effects caused by CO_2 can range from minor, reversible effects to mortality, depending on the concentration of CO_2 and the length of the exposure (Benson et al., 2002; CEC, 2007). Release of CO_2 may also adversely impact recreational and economic resources by restricting access or use or by changing the quantity and quality of the resource. Resources that could potentially be impacted by CO_2 leakage include mineral extraction, forestry, fisheries, or other harvested natural resources, which could in turn result in adverse economic impacts to humans

- *Atmospheric impacts*: In some cases, small releases of CO_2 from GS may not adversely impact local environmental receptors (e.g., ecological receptors, groundwater and surface water, humans). However, such releases do reduce the climate benefits of capturing CO_2, thus decreasing the overall effectiveness of GS as a climate change mitigation strategy.

- *Ecosystem impacts*: Leakage of CO_2 could have adverse impacts on soil-dwelling animals and microbes (Sustr and Siemk, 1996; Benson et al., 2002), plants (MeGee and Gerlach, 1998; Saripalli et al., 2002), surface-dwelling animals (Benson et al., 2002), and aquatic organisms, particularly calcifying organisms (Turley et al., 2004; Miles et al., 2007; Spicer et al., 2007). Particular attention may be required to address protected or endangered species if present.

- *Groundwater and surface water quality and quantity*: Leakage of CO_2 into aquifers can have detrimental impacts on water quality. For example, the dissolution of CO_2 in the water can create acidity which can in turn dissolve metal-bearing minerals, or result in the desorption of metal and organic contaminants adsorbed to geologic formations (Jaffe and Wang, 2003; Wang and Jaffe, 2004). The pressure-induced displacement of brine or salty waters into overlying aquifers can also negatively impact water quality, and can potentially result in the loss of USDWs. Pressure changes associated with injection of CO_2 may also cause changes in flow directions in groundwater and surface water bodies and points of recharge and discharge (Nicot et al., 2006; Tsang et al., 2007). This may in turn negatively impact municipal water supplies, and the water balance of local ecosystems. The spatial area affected by pressure changes associated with injection will typically be significantly larger than the injected CO_2 plume itself, and thus, adverse impacts associated with pressure changes could potentially be experienced over very large spatial areas.

- *Geosphere*: Changes in subsurface pressure from GS can have direct impacts on the local landmass itself. Subsurface pressure changes that exceed the subsurface geologic formation's geomechanical strength could cause fracturing or reopening of faults and fracture zones (Quintessa, 2004; IPCC, 2005). Impacts could also include induced seismic activity, including earthquakes in the extreme case (Healey et al., 1968) and land deformation through uplift (Quintessa, 2004; Birkholzer et al., 2007).

In general, the overall likelihood of adverse impacts is expected to decline over time at GS sites. This assumption is based on a number of factors, including the greater permanence of secondary trapping mechanisms, such as dissolution, which decreases buoyancy, and mineralization; the anticipated return to pre-injection pressure conditions once injection stops in most cases; and improved characterization and modeling of the GS system over time (U.S. EPA, 2008).

3.3 Site Characterization and Monitoring Needs for CCS Systems

While experience from existing projects and natural and industrial analogs to GS demonstrates that CO_2 can be safely sequestered in geologic formations, there is the potential for unanticipated migration and leakage of injected CO_2 and other fluids such as brine, as well as the potential for adverse impacts caused by excessive pressure. As a result, site characterization and monitoring to evaluate potential risks are necessary components of GS projects. Specific purposes for site characterization, monitoring, and applicable technologies at CCS sites include:

- *Establishing baseline conditions*. CO_2 is ubiquitous in the environment, and concentrations vary diurnally, seasonally, and annually, and spatially. Determining background levels of CO_2 and understanding natural fluctuations is necessary to discern whether detected CO_2 is attributable to leakage from the GS site, or to other sources. In addition, many technologies, such as seismic profiling, identify CO_2 on a comparative basis, and thus measurements need to be taken prior to injection. The techniques selected to establish a baseline will be dependent upon site-specific conditions, and anticipated monitoring needs during injection. Examples of technologies that may be applied include seismic imaging; wellhead and formation pressure monitoring techniques; temperature and fluid composition measurement techniques; electrical measurements of subsurface conductivity/resistance; atmospheric and soil gas monitoring technologies; and land surface deformation monitoring technologies (Benson et al., 2004; WRI, 2008; Bacon et al., 2009; Johnson, 2009).

- *Identifying and providing oversight of targeted locations and site features*. Specific locations and site features should be identified and targeted for monitoring if they are known or suspected to have elevated risk of CO_2 leakage and adverse impacts. For example, existing wells and faults should be targeted for characterization and monitoring because of their elevated potential to act as CO_2 conduits, which can result in leakage. During site characterization, monitoring techniques can be tested and selected to target site-specific attributes (Benson et al., 2004). During injection and site closure, monitoring can help identify existing or newly developed risks and inform the application of additional, targeted monitoring techniques if needed. The specific type of monitoring technique to be used will depend upon the specific site characteristic that is being assessed, and could include seismic surveys, tracers, borehole logs, pressure measurements at the wellhead and in the formation, formation fluid sampling, surface water sampling, and air and soil gas sampling.

- *Ensuring injection controls*. Monitoring the condition of the injection well, the injection rate, and wellhead and formation pressure are important to verify the amount of CO_2 injected and to avoid leakage. Available technologies to monitor that injection controls are handled appropriately include wellhead and formation pressure gauges, core logging, and wellbore annulus pressure measurements (Benson et al., 2004; IPCC, 2005; Benson, 2007; Freifeld et al., 2009; NETL, 2009).

- *Confirming the quantity and location of injected CO_2, and detecting unanticipated leakage:* The movement and fate of injected CO_2 are influenced by injection-related factors, properties of the CO_2, and properties of the GS formations. As a result, many different subsurface parameters may need to be measured to assess the location and quantity of the injected CO_2. Existing pressure gradients and gradients induced by injection can influence CO_2 movement, and so techniques that measure the injection rate and formation pressure gradients can help monitor CO_2 in the subsurface. Other examples of techniques that may be used to confirm the location and quantity of injected CO_2 include seismic surveys; electrical and electromagnetic methods, such as electrical resistance tomography; gamma ray, resistivity and other types of logging; and fluid and mineral sampling methods (Benson et al., 2004; Benson, 2007; Bachu and Bennion, 2009; Bachu et al., 2009; NETL, 2009). Several monitoring techniques may be used to detect surface leakage, including sampling air using eddy covariance, infrared and other techniques; sampling soil gas with soil gas probes; using tracers (small quantities of a chemical compound or isotope added to trace flow patterns); monitoring for land surface deformation; measuring productivity of local flora and fauna; and sampling overlying hydrologic systems (Chabora and Benson, 2009; Darby et al., 2009; Jones et al., 2009; Schwarz et al., 2009).

- *Assessing environmental and human health impacts of leakage if they occur*. If CO_2 leaks from the targeted injection zone, adverse impacts to the environment and human health can occur. Monitoring techniques can help assess the severity of adverse impacts by providing information on the amount of leaked CO_2. Site-specific receptors may also be targeted for monitoring, such as sensitive or endangered species, or USDWs, to ensure that they are not adversely impacted by unanticipated CO_2 migration and leakage.

- *Detecting induced microseismicity*. Microseismic activity may be induced by CO_2 injection if pressures within the target zone are high enough to cause a release of accumulated strain on fault zones. Monitoring can help recognize induced microseismicity, so that mitigative actions, such as reducing the injection pressure, can be implemented.

- *Resolving liability/legal disputes*. Monitoring could potentially be used to help resolve disputes arising from unanticipated leakage of CO_2. For example, liability disputes could arise if other underground natural resources, such as minerals or oil and gas reserves, were adversely impacted by injected CO_2 that has migrated outside the target formation. Damages could be sought by parties that have an interest in the impacted resources from the legally responsible injector of the CO_2. Monitoring can assist with determining which injector is liable in the event that multiple injectors are in proximity to the damaged resources. Liability disputes could be complicated by the additional factor that projects can be in injection and post-injection site care phases at varying times; if leakage occurs while one project is operational and a nearby project is in post-injection site care phase, the leaking CO_2 could be emanating from either the closed or the currently operational project (Wilson et al., 2007; GAO, 2008; CCSReg, 2009). There may also be questions about the long-term liability and legal responsibility of leakage from sites after closure of operations.

4. CIRI Proposal and Study Site

4.1 Information on CIRI Proposal

Although the details of CIRI's proposed project are limited, we have obtained general information about their plans from the website that they have set up for this project (http://www.cirienergy.com/) and from the coastal management and exploration permit applications they submitted in late 2009 (Belowich, 2009). This section contains a brief description of their plans based on this information, recognizing that the details of their plans are not likely to emerge until after their exploratory drilling has been completed.

CIRI's presentation of their proposed project indicates that the target coal seams for UCG will be more than 650 feet (ft) deep and will be isolated from freshwater aquifers by "strong and impermeable overlying rock layers" (CIRI, 2009). Beyond these generalities, however, there have been no details provided about the thickness of the coal seams targeted; the stratigraphy of the overlying geologic units; or the quality and character of the coal beds themselves.

CIRI also indicates that they will be capturing CO_2 from their syngas stream using existing technologies. Again, however, no details have been given as to the mechanisms of capturing or sequestering the CO_2. The CIRI proposal indicated that CO_2 would be sequestered via EOR. However, for EOR to occur, CIRI would need to partner with Cook Inlet oil producers to supply their carbon stream to existing oil infrastructure. At least one of the Cook Inlet producers, Chevron, has apparently already indicated that they are not interested in this project (AlaskaCoal.org, 2009), and CIRI has since indicated that EOR may not be a viable alternative. In such case, CCS could possibly be accomplished by GS into DSFs or other geologic settings, or by re-injecting CO_2 into the burn cavities left behind by UCG. Either of these alternatives would require significant additional investigation into the geology of the targeted sequestration zones.

CIRI's exploration permit indicates that they plan to drill two deep boreholes to 2,500 ft, three boreholes to 2,000 ft, and one to 1,250 ft (Belowich, 2009). The stated goal of these boreholes is to enable stratigraphic correlation across major faults and with stratigraphic information from an existing borehole on the site. Results from deep borehole exploration could also enable identification of potential CCS targets.

4.2 Site Geology

Although information about the specific coal beds that CIRI is targeting for UCG remains limited, this section describes the general geologic setting of the proposed project, with particular attention paid to the tectonics, stratigraphy, and characteristics of coal seams that will be relevant to evaluating environmental risks of the project.

4.2.1 Coal bearing units

The Susitna lowlands region is well known for its coal resources. Barnes (1966) estimated the coal reserves in the region at 2.4 billion tons based on field mapping and aerial reconnaissance surveys. Subsequent studies have improved understanding of the depositional environment, thickness, and distribution of coal beds throughout the region (e.g., Merritt, 1990; Flores et al., 1997), as well as the role of faults in exposing different packages of coal-bearing units at the surface.

As suggested by Burton et al. (2007), a general understanding of the depositional environments of the coal beds targeted for UCG is one means of assessing their lateral continuity, their general geochemistry, and their connection to surrounding aquifers. A brief description of available geologic information is included here.

There are two major coal-bearing units present in the study area: the Beluga Formation, and the underlying Tyonek Formation. Both of these Miocene (5–23 million year) units belong to the Tertiary-aged Kenai Group, which includes interbedded clays, silts, sands, and conglomerates of a generally nonmarine origin (Barnes, 1966). Merritt (1990) describes the Tyonek Formation as the result of channel and floodplain sedimentation, and the Beluga Formation as a set of coalescing alluvial fans. More recent stratigraphic work by Flores et al. (1997) indicates that some of the beds within the Tyonek Formation may also have been tidally influenced, suggesting a fluvial-estuarine depositional environment. Flores et al. (1997) also suggest that much of the Tyonek Formation was laid down while the Castle Mountain Fault (CMF) was active; thus the courses of the rivers in which the coal beds were formed are likely to have been controlled by motion on this fault.

The coal beds in the Tyonek Formation are typically thicker than those in the Beluga Formation: Some of the Tyonek Formation coals are as much as 50–70 ft thick, while the Beluga Formation coals are typically less than 8 ft (Belowich, 2009). Given the complex geological and structural setting of the proposed exploration area, boring logs and more detailed development plans from CIRI will be necessary before the relationships between coal beds, permeable units, and faults can be evaluated.

4.2.2 Structural geology and tectonics

The Beluga and Tyonek formations are typically flat to shallowly dipping (< 15 degrees), except where locally influenced by motion along the CMF and Moquawkie (Bruin Bay) fault zone. Where these faults are present, the stratigraphic package is tilted or gently folded so that dips can be up to 35−50 degrees (Barnes, 1966). In the southwestern corner of the CIRI exploration block, the Tyonek and Beluga formations are warped by an east-northeast trending syncline, which plunges shallowly to the east (Belowich, 2009).[2] It is not clear from CIRI's plans whether the coal beds involved in this structure may be the target of their exploration further to the northeast.

The CIRI exploration block is crossed by the CMF along its northern edge, and is nearly bisected by the northeast-trending Moquawkie/Bruin Bay Fault (Figure 4). Both of these faults are high-angle, and both have accommodated significant displacement. The CMF offsets the Tyonek Formation by as much as 4,000 ft, with the northern block upthrown relative to the southern block. The Moquawkie/Bruin Bay Fault offsets the stratigraphy by an additional 2,000 ft, with the western block displaced upwards relative to the eastern block. Although the stratigraphy is generally shallowly dipping throughout the study area, motion along these faults is likely to have caused local warping and fracturing near these faults. The influence of these major faults and associated fractures on fluid migration warrants further investigation.

The entire Cook Inlet region is very active seismically (Figure 5). Recent work on portions of the CMF indicates that it is active, with the most recent dated surface rupture occurring approximately 670 years ago, and an average recurrence interval of approximately 700 years (e.g., Willis et al., 2007). Moderate earthquakes of magnitude 5.7 and 4.5 occurred along the eastern portions of the CMF in 1984 and 1996, respectively (e.g., Haeussler et al., 2002). The Moquawkie/Bruin Bay Fault has received relatively less attention in the literature; however, aligned and offset river drainages along its course in the vicinity of the exploration block are consistent with recent motion along this fault as well. These faults and fractures are potential pathways for fluid migration to the surface. The influence of seismicity on fracture generation and fluid migration at the proposed site also warrants further investigation once more detailed site plans have been released.

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2. A syncline is a "U" shaped warping of geologic layers. The plunge is the direction and angle that the axis of this "U" is tilted. The 30-ft thick Beluga coal bed crops out in a "U" shape along the Beluga River canyon, and the attitude of these beds indicates that the axis of this "U" becomes deeper to the east.

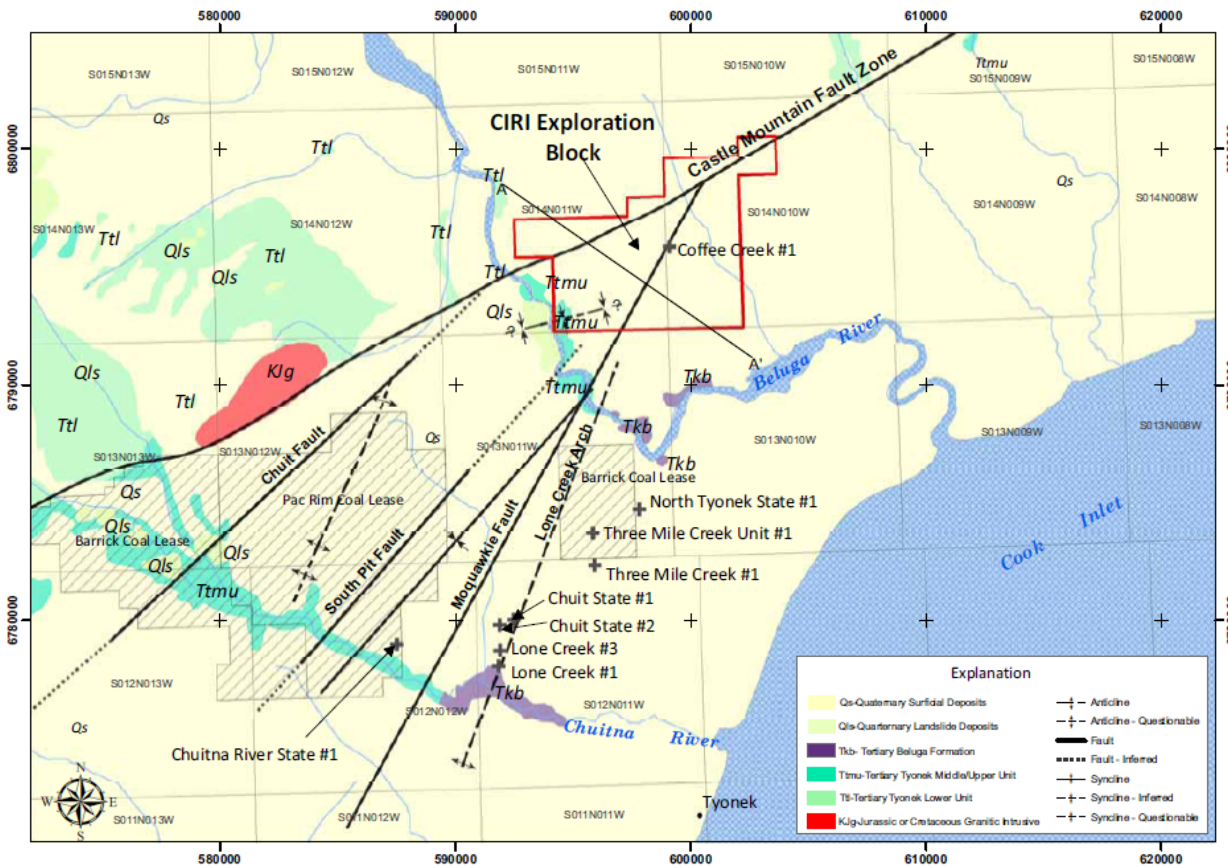

Figure 4. CIRI exploration area generalized geology.

Source: Belowich, 2009, Figure 3.

5. Environmental Monitoring for UCG and CCS

It is difficult at this stage to provide detailed comments on environmental monitoring needs at the CIRI site due to the lack of site-specific information. However, this section provides some general comments on the needs and importance of site characterization and environmental monitoring at UCG and CCS sites

The need for flexibility and responsiveness in site characterization and monitoring cannot be overemphasized for a project such as the proposal from CIRI. Geologic systems are inherently heterogeneous and complex, and their properties can be highly variable over a variety of spatial scales. As a result, environmental monitoring will likely need to be an iterative process, with data

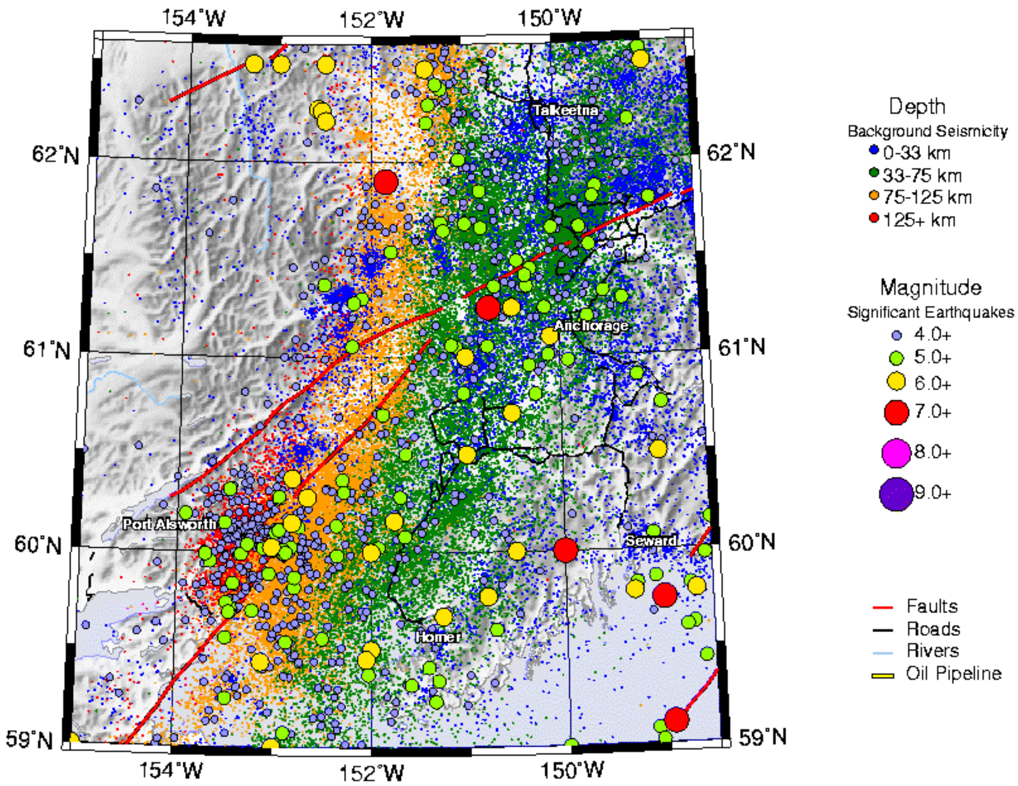

Figure 5. Cook inlet seismicity. The location of the CIRI site is approximately at the intersection of the two faults located west of Anchorage.

Source: AEIC, 2006.

gathered during initial site characterization and monitoring likely used as initial inputs for a flexible set of models (Bacon et al., 2009). Monitoring data gathered during the initial UCG burnout phase and the early CO_2 injection phase can then be used to refine models, if needed. If unanticipated conditions are detected, the location and frequency of monitoring, and employed technologies can then be altered so that monitoring occurs where the produced or injected fluids have come to be located.

Overall, the frequency of measurements may be greatest during the early part of the project, when the least is known about the site, and data are needed for model and instrument calibration. Longer time intervals between measurements may be sufficient during later phases of syngas generation and CO_2 injection. The initial start-up of both phases of the project is likely to be the most intensive period for modeling activities, including model calibration and refinement, and for verification as initial field data are collected. The intensity of modeling activities may also slow with time, once models are refined and are able to adequately predict subsurface fluid movement, location, and quantity.

The need for careful site characterization and monitoring is illustrated by experience at well-characterized GS sites such as Sleipner (North Sea), Frio (Texas), and Weyburn (Saskatchewan). At these sites, model simulations based on initially gathered site characterization data did not accurately predict the migration and location of the injected CO_2. For example, at Sleipner, the lateral dimensions of the CO_2 plume were much smaller than predicted by pre-injection model simulations. Compared to predictions, the plume spread out less laterally and more vertically. Unrecognized discontinuous silt layers within the injection zone were responsible for the unanticipated distribution of CO_2 (Johnson and Nitao, 2003). Unpredicted CO_2 migration was also observed at Frio, where the CO_2 migrated much more quickly than anticipated (Doughty et al., 2001; Hovorka et al., 2005; Kharaka et al., 2009). At Weyburn, modeled predictions of the location and shape of the CO_2 plume were partially incorrect. A series of faults at the site that were not included in the model simulations were believed to be responsible for the unanticipated results (Friedmann, 2003). At each of these sites, none of the unanticipated migration resulted in leakage, and the CO_2 remained sequestered in the intended injection zone, thus demonstrating the potential for successful storage of CO_2 in the subsurface. All of these examples, however, reinforce the need for careful, iterative site characterization; flexibility and responsiveness in monitoring activities; and the need for dynamic monitoring plans so that the location, frequency, and types of field measurements can be adjusted as needs and conditions change.

6. Conclusions and Recommendations

The project proposed by CIRI has a number of potential environmental benefits when compared to conventional coal mining. As described above, however, there remain a number of environmental risks associated with both UCG and CCS. Some of the most important of these risks are:

- The risk of groundwater contamination as a result of UCG and/or CCS
- The risk of subsidence resulting from cavity formation in the UCG burn-out zone
- The risk of syngas and/or CO_2 releases to the surface, and associated impacts on surface water resources, ecosystems, or human health
- The risk of induced microseismicity as a result of overpressurizing CCS target zones.

As it currently stands, the CIRI proposal is far too general to enable a reasoned evaluation of the environmental risks of the project. Sections 2.5 and 3.3 describe the minimum environmental characterization data that are required for such a reasoned evaluation to occur. To summarize, the data requirements for environmental characterization follow:

- Detailed stratigraphic information compiled from borehole and seismic data, including the depth, thickness, and geotechnical properties of coal seams and overlying stratigraphic units
- Geochemical and mineralogical characterization of the target coal seams for UCG, the target GS sites, and surrounding rocks, to evaluate the potential for groundwater contamination from the proposed project
- Baseline characterization of groundwater conditions, including the depth, thickness, hydraulic conductivity, and groundwater flow directions in subsurface aquifers
- Detailed geologic mapping of active and fossil fault zones in the areas proposed for UCG and CCS, along with a characterization of their hydraulic properties.

If the project proceeds, further risks to the environment can be mitigated through comprehensive site monitoring. As described in Section 5, environmental monitoring is likely to be an iterative process; however, minimum requirements for monitoring follow:

- Pressure monitoring, including monitoring of hydrostatic pressure in the UCG burnout zone to ensure inward hydraulic gradients, and monitoring of injection pressures for CCS.
- Groundwater monitoring in the areas surrounding UCG and CCS injection zones, to detect the potential for escape of contaminated groundwater.
- Air monitoring to detect potential escapes of syngas and/or CO_2 to the surface. Both of these air monitoring campaigns would require establishment of baseline conditions prior to project initiation.
- Monitoring of induced surface motions, including the potential for subsidence induced by UCG cavity formation and the potential for induced microseismicity induced by increased pressures in GS formations.

While the CIRI proposal holds some promise as a marriage of new technologies for energy exploitation, these data requirements still need to be met. Only when all of these additional data needs have been met can an informed permitting and regulation process proceed.

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