

Oil and Natural Gas Industry Guidelines for Greenhouse Gas Reduction Projects

# Part II: Carbon Capture and Geological Storage Emission Reduction Family

June 2007





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<sup>1</sup> International Petroleum Industry Environmental Conservation Association (IPIECA) and American Petroleum Institute (API). *Oil and Natural Gas Industry Guidelines for Greenhouse Gas Reduction Projects*, March 2007.

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The Joint Industry Task Force formed a Drafting Committee to the Carbon Capture and Geological Storage Emission Reduction Project Family. The committee was comprised of:

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## **SECTION 6. CARBON CAPTURE AND GEOLOGICAL STORAGE EMISSION REDUCTION PROJECT FAMILY**

### **6.1 Overview**

This section is a continuation of the *Oil and Natural Gas Industry Guidelines for Greenhouse Gas Reduction Projects* (IPIECA and API, 2007), referred to as the General Project Guidelines.<sup>2</sup> It is the second of five greenhouse gas (GHG) reduction “project families” in an ongoing process of developing guidelines for project activities of interest to the oil and natural gas industry.

Guidelines are provided for carbon dioxide (CO<sub>2</sub>) capture and geological storage (CCS) as an emission reduction option, following the framework presented in Section 2 of the General Project Guidelines (IPIECA and API, 2007).<sup>3</sup> The focus is on specific technical considerations and aspects rather than policy considerations. Case studies of three potential applications are provided in Attachment 1.

### **6.2 Introduction**

CCS refers to the chain of processes to collect or capture a CO<sub>2</sub> gas stream, transport the CO<sub>2</sub> to a storage location, and inject the CO<sub>2</sub> into a geological formation<sup>4</sup> for long-term isolation from the atmosphere (See Figure 6-1). The assessment of project reductions from CCS should address all of these elements.

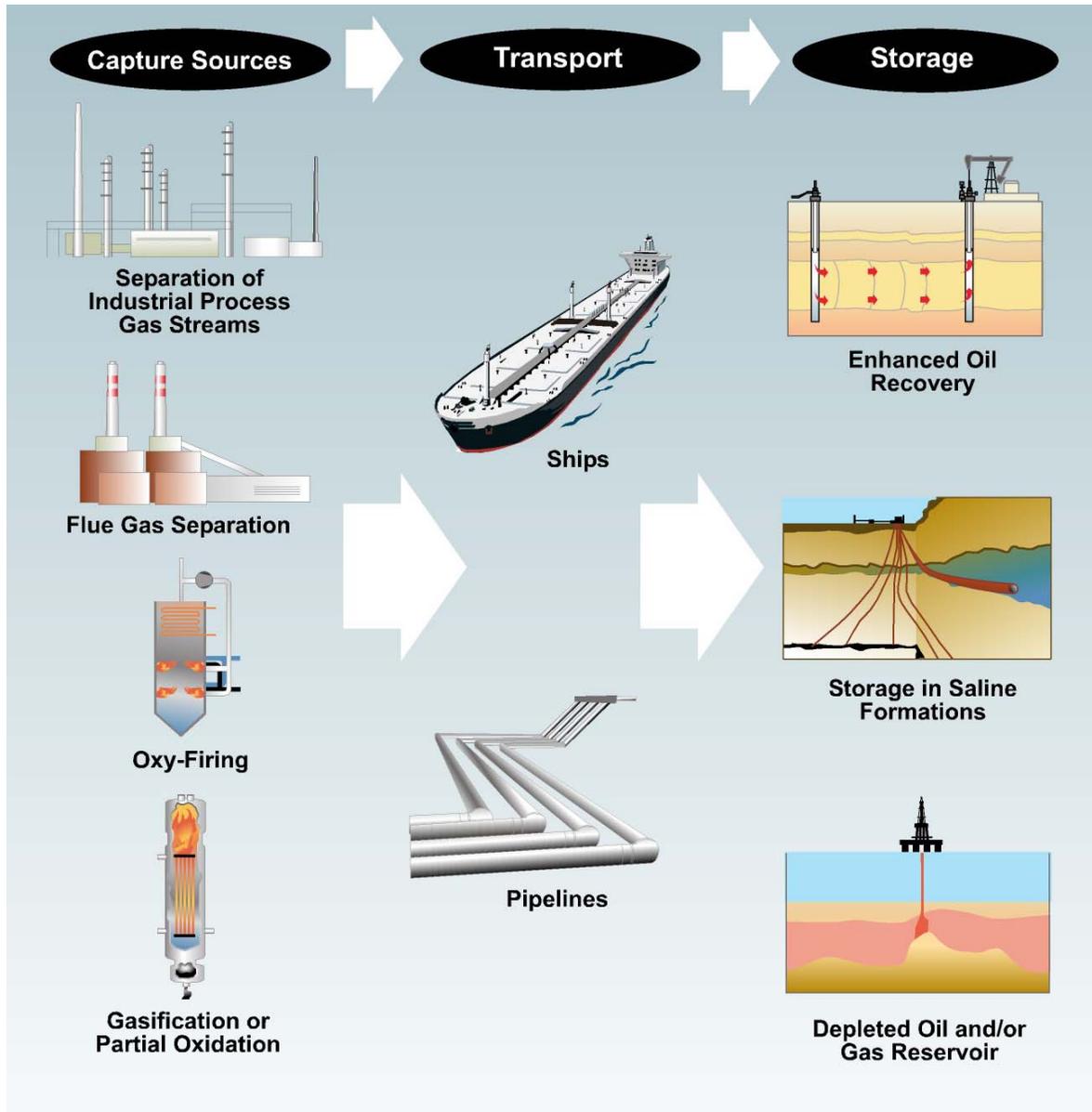
CCS involves avoiding CO<sub>2</sub> emissions to the atmosphere by injecting CO<sub>2</sub> and ultimately storing it in a geological formation. For a CCS project to be regarded as a climate change mitigation activity, the geological formations at the selected site must have the appropriate long-term containment capability. Definition of long-term containment or an insignificant probability of physical leakage is a policy matter.

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<sup>2</sup> This guidance document is not intended to create any requirement or industry standards for GHG reduction projects. Rather it is intended solely for the convenience and voluntary use of oil and natural gas companies that may find it helpful. Nor is this document intended to imply a direct connection between GHG emissions from the oil and natural gas industry and the phenomenon commonly referred to as climate change. To the contrary, this guidance document recognizes that companies may undertake GHG reduction projects for a variety of reasons.

<sup>3</sup> The American Petroleum Institute (API) and the International Petroleum Industry Environmental Conservation Association (IPIECA) make no representation that use of this guidance document would satisfy any legal or technical requirements of standards for creditable GHG reduction projects, or ensure compliance with any other requirements, under any applicable regulatory regime. Any company that uses these Project Guidelines should consult its own legal counsel as to any legal requirements that may apply to a project.

<sup>4</sup> For the purpose of this project family, geological storage reservoirs explicitly exclude ocean sequestration.



**Figure 6-1. CCS Process Chain**

Adapted from IEA, Energy Technology Analysis, Prospects for CO<sub>2</sub> Capture and Storage, 2004

Most experts agree on what makes a geological formation suitable for very long-term storage of CO<sub>2</sub> (addressed further in Section 6.7.4). Application of CCS toward climate change mitigation builds on existing industrial operations, for example in the separation of CO<sub>2</sub> from gas mixtures; in the compression, transport, and injection of CO<sub>2</sub>; and corrosion control, and may be compatible with many current energy infrastructures. Many of the methods and techniques to identify appropriate sites, conduct injection operations, project subsurface performance, manage injected gases and substances, and to avoid or mitigate unwanted developments are well known to the oil and natural gas industry. By 2000, there were 84 CO<sub>2</sub> enhanced oil recovery (EOR)

operations worldwide (*Oil and Gas Journal*, 2001) and about 33 million tonnes (Mt) of CO<sub>2</sub> injected each year, in addition to the volume of CO<sub>2</sub> that were recycled as part of the EOR operations (IPEICA, 2003). One of the largest EOR operations injects nearly 260 MMscf of CO<sub>2</sub> per day (Heinrich, 2003), five times greater than the injection rate of the Sleipner Field. Although the scale of CCS deployment that would be required to make a substantial impact as a global climate change mitigation option is much larger, these operations provide significant experience in the handling of large quantities of CO<sub>2</sub>. Additional significant experience is provided by natural gas storage and acid gas injection operations (IPCC SRCCS, 2005). In addition, a number of pilot- and commercial-scale CO<sub>2</sub> storage projects are underway or planned (see examples provided in Attachment 2).

In principle, the steps for site selection to determine if a geological formation is suitable for long-term containment of CO<sub>2</sub> include:

- Site characterization– confirming that the storage location is appropriate for CO<sub>2</sub> containment based on evaluating
  - surface area land use;
  - the geology and local hydrogeology;
  - its capacity to store the desired amount of CO<sub>2</sub>;
  - its injectivity to receive CO<sub>2</sub> at the rate that it is supplied from the source(s);
  - the presence of a secure structural or stratigraphic trap or other confining unit; and
  - possible physical leakage pathways (site characterization is discussed further in Section 6.7.3); and
- An assessment of the risk of physical leakage from the geological formations – including the use of models that predict movements of CO<sub>2</sub> over time and locations where potential physical leakage might occur.

CCS may play a significant role in mitigating greenhouse gas (GHG) emissions. However, much of this depends on public and policy maker acceptance, which will necessitate demonstrating that potential local risks or other concerns associated with long-term CO<sub>2</sub> storage are managed.

Risk management entails applying a structured process to identify and quantify the risks associated with a given process, to evaluate these, taking into account stakeholder input, to modify the process to remove risks, where possible, and to identify and implement appropriate monitoring and intervention strategies to manage the remaining risks. Careful site selection, monitoring to provide assurance that the CCS project is performing as expected and to provide early warning in the event that it begins to leak, and use of remediation measures to eliminate or limit the causes and impacts of physical leakage are effective ways of managing potential risks associated with CCS. In this project family, pre-operational evaluation as a risk management technique for selecting a geological formation and monitoring to control potential risks during and after injection are described separately from the monitoring and reporting activities to determine GHG emission reductions from a CCS project.

## 6.3 Project Definition

As defined in the General Project Guidelines, a GHG reduction project is a recognizable and distinct activity or set of activities that reduce global GHG emissions, increase the storage of carbon, or enhance GHG removals from the atmosphere. A project activity is a specific action or intervention that changes GHG emissions, removals, or storage. An overview of technologies associated with the three main activities of the CCS process chain—capture, transport, injection, and storage—is provided below.

### 6.3.1 Capture

The capture step involves the separation of CO<sub>2</sub> from other gaseous products, compression to facilitate efficient transportation and injection and, where necessary, conditioning for transport (e.g., dehydration). Figure 6-2 provides a simple illustration of the four primary separation applications for potential CO<sub>2</sub> capture from industrial and power plant operations:

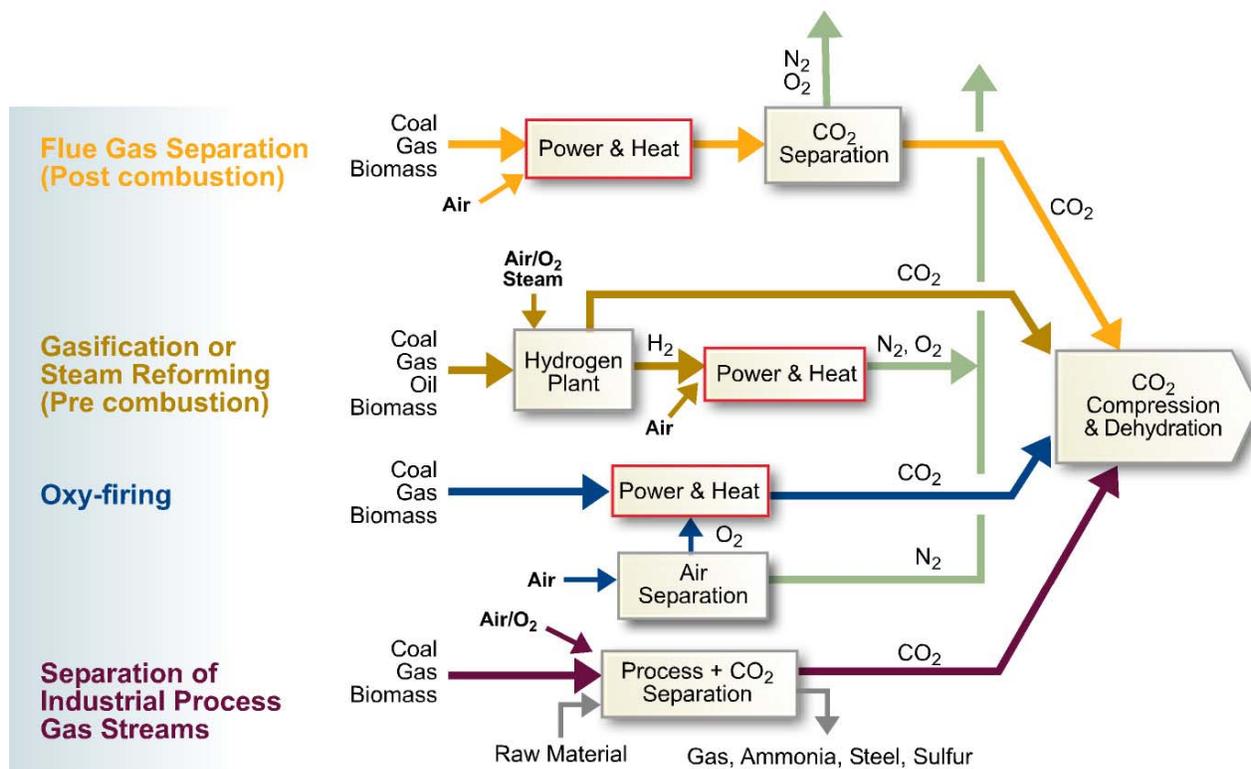
- *Separation of industrial process gas streams.* This includes the separation of CO<sub>2</sub> from natural gas to meet sales gas specifications or to condition the gas for producing liquefied natural gas (LNG). In addition, a number of industrial processes involve chemical reactions that form CO<sub>2</sub> in quantities and concentrations that may allow direct capture or separation of the CO<sub>2</sub>. These include: hydrogen production, ethanol production, ammonia production, cement manufacturing, and iron and steel manufacturing;
- *Flue gas separation* where CO<sub>2</sub> is separated from the flue gases produced by combustion of a primary fuel (coal, natural gas, oil or biomass) in air;
- *Oxy-firing combustion* which uses oxygen instead of air for combustion, producing a flue gas that is mainly H<sub>2</sub>O and CO<sub>2</sub> and which is readily captured. This option is still under development; and
- *Gasification (partial oxidation) or steam reforming* where a gas, liquid, or solid hydrocarbon is reacted to produce separate streams of CO<sub>2</sub> for storage and H<sub>2</sub>.

Additional information on specific technologies and applications are provided in Attachment 3.

### 6.3.2 Transport

Except when an industrial facility is located directly above a geological storage site, captured CO<sub>2</sub> must be transported from the point of capture to the storage site. Pipelines operate as a mature market technology and historically are the most common method for transporting CO<sub>2</sub>. These pipelines operate at ambient temperature and high pressure, with flow driven by pumps. There are currently about 5,000 km of land-based CO<sub>2</sub> pipelines in existence worldwide (IOGCC, 2005), with more expected to be built or begin operation in the near future. For example, a sub-sea pipeline transporting captured CO<sub>2</sub> for storage under the seabed 146 km offshore will come into operation in Norway in 2007.

Bulk transport of CO<sub>2</sub> by ship also takes place, though on a much smaller scale. This occurs in insulated containers at low temperatures and much lower pressures than pipeline transport. Transport by truck and rail occurs for small quantities of CO<sub>2</sub>, but is unlikely to be widely used if large volumes of CO<sub>2</sub> are to be transported for CCS purposes.



**Figure 6-2. CO<sub>2</sub> Capture Processes**

Adapted from IPCC SRCCS, 2005<sup>5</sup>

### 6.3.3 Storage

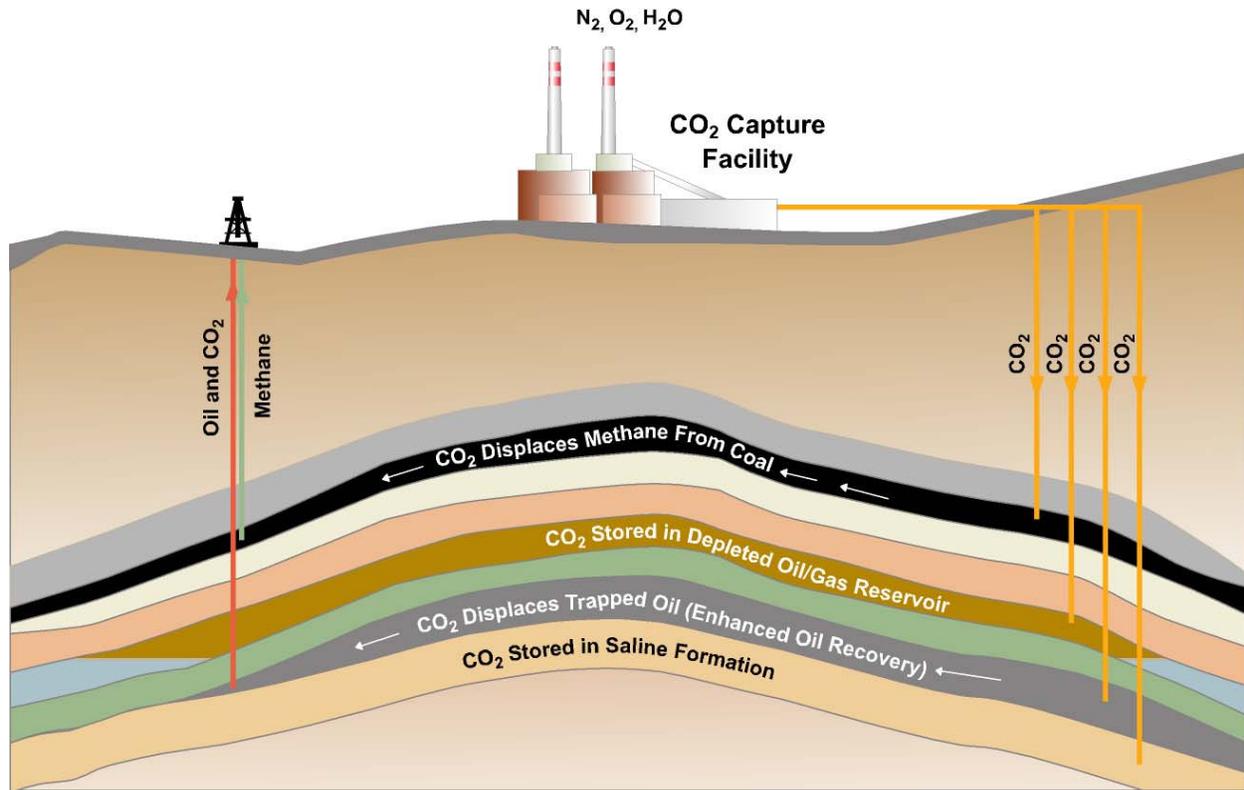
Geological structural and stratigraphic traps have demonstrated the ability of reservoirs to seal and store hydrocarbon liquids and gases for millions of years. Large, long-standing geological occurrences of CO<sub>2</sub> and other non-hydrocarbon gases are also known. The structural and stratigraphic mechanisms that initially trapped these materials typically remain intact as fluids are extracted from or injected into these reservoirs, and continue to support the long-term storage of reservoir fluids.

For the purpose of this project family, ocean storage is not included because this storage option is not generally accepted, nor regarded as ready for industrial operation for the foreseeable future.

As illustrated in Figure 6-3, geological storage venues could include:

- Depleted oil and natural gas reservoirs without enhanced hydrocarbon recovery;

<sup>5</sup> Note that this figure differs slightly from that provided in the IPCC SRCCS (Figure TS.3). For the pre-combustion capture process, the IPCC SRCCS figure incorrectly shows a gasification unit followed by a reformer + CO<sub>2</sub> separation unit in series. In actuality, gasification and steam reforming are two competing processes used to produce hydrogen, and would not be combined in series. For either process, the hydrogen plant includes water-gas shift and CO<sub>2</sub> separation.



**Figure 6-3 Geological Storage Options**

Adapted from CO<sub>2</sub> Capture Project Phase 1 ([http://www.co2captureproject.org/technologies/tech\\_index.htm](http://www.co2captureproject.org/technologies/tech_index.htm))

- Producing oil reservoirs for enhanced oil recovery (EOR) and later final long-term storage;
- Natural gas formations for enhanced gas recovery (EGR) operations and later final long-term storage;
- Unmineable coal seams suitable for enhanced coalbed methane (ECBM) recovery operations; and<sup>6</sup>
- Deep saline formations<sup>7</sup>, where the sole purpose is CO<sub>2</sub> storage.

Prior to injection, CO<sub>2</sub> must be compressed to enable injection at reservoir conditions. At depths below 800-1,000 m, the ambient pressures and temperatures in the reservoir will usually result in CO<sub>2</sub> being in a liquid or supercritical state. Since the liquid or supercritical CO<sub>2</sub> at reservoir conditions occupies a much smaller volume than the gaseous state at atmospheric conditions, this

<sup>6</sup> ECBM and EGR operations are less mature technologies than EOR. There is no widespread practice for EGR and ECBM currently.

<sup>7</sup> Saline formation is the term used in the IPCC SRCCS to refer to saline- or brackish-water-bearing porous and permeable reservoir rocks.

provides the potential for more efficient utilization of underground storage space in the pores of sedimentary rocks, and improves storage security.

CO<sub>2</sub> is retained in geological formations by a combination of physical and geochemical trapping mechanisms, with the proportion of exact mechanism(s) depending on the formation type and fluid properties. These trapping mechanisms include the presence of an impermeable caprock, dissolution in water, trapping by capillary forces in small pores, and long-term mineralization. In oil reservoirs, CO<sub>2</sub> may dissolve in and be produced with oil, but a portion of the CO<sub>2</sub> will remain in the reservoir.

For saline formations with no distinct geological trap, the presence of an impermeable caprock above the reservoir, residual or capillary trapping, and the geochemical mechanisms of solubility and mineral trapping are also very important. For example, solubility trapping involves the dissolution of the CO<sub>2</sub> into the reservoir fluids over hundreds to thousands of years. The formation water saturated with CO<sub>2</sub> is denser than water without the CO<sub>2</sub>; hence the formation water containing CO<sub>2</sub> slowly sinks towards the bottom of the storage formation. Mineral trapping involves the reaction between the dissolved CO<sub>2</sub> and minerals present in the formation to form stable, solid compounds (e.g., carbonates) over thousands to millions of years, permanently trapping the CO<sub>2</sub> in the reservoir.

ECBM through the injection of CO<sub>2</sub> is possible due to the preferential adsorption of CO<sub>2</sub> over methane onto the coal matrix. In the case of ECBM, the CO<sub>2</sub> will remain trapped as long as pressures and temperatures remain stable and the coal is not disturbed by mining or seismic activity.

The injection of CO<sub>2</sub> in deep geological formations involves many of the same technologies that have been developed in the oil and natural gas exploration and production industry for EOR purposes – well drilling, fluid injection, computer simulation of storage reservoir systems, performance monitoring, and well intervention methods.

#### **6.4 Baseline Scenarios**

Potential candidates for the baseline scenario represent situations or conditions that plausibly would have occurred in the absence of the emission reduction project. There is no generic baseline for CCS; baseline scenario candidates must be evaluated for the specific CCS application and should consider all elements of the CCS chain. A listing of potential baseline scenario candidates for the most probable CCS projects is provided in Table 6-1. To the extent possible, project activities and potential baseline candidates associated with each step of the CCS chain are presented separately.

**Table 6-1. Potential Baseline Candidates for Probable CCS Project Elements**

*Bold italic text indicates the project activity*

CCS Chain	Probable Project Elements	Potential Baseline Candidates
Capture	Separation of CO <sub>2</sub> to purify natural gas to sales gas specifications or for producing LNG	<ul style="list-style-type: none"> <li>CO<sub>2</sub> is separated from the Hydrogen sulfide (H<sub>2</sub>S) and CO<sub>2</sub> is vented to the atmosphere</li> <li>CO<sub>2</sub> is vented to the atmosphere when the acid gas is incinerated</li> <li><b><i>CO<sub>2</sub> and H<sub>2</sub>S are separated from the acid gas stream and CO<sub>2</sub> is captured</i></b></li> </ul>
	Separation of CO <sub>2</sub> from industrial process gas streams	<ul style="list-style-type: none"> <li>CO<sub>2</sub> is vented to the atmosphere as a result of one of the industrial processes described in Section 6.3.1</li> <li><b><i>CO<sub>2</sub> is captured</i></b></li> </ul>
	Flue gas CO <sub>2</sub> separation	<ul style="list-style-type: none"> <li>CO<sub>2</sub> from an existing flue gas stream (e.g., power plant exhaust gas) is vented to the atmosphere.</li> <li><b><i>CO<sub>2</sub> is captured</i></b></li> </ul>
	Oxy-firing combustion	
	Gasification (partial oxidation) or steam reforming to produce hydrogen	
Transport	Transport by land or marine pipeline	<ul style="list-style-type: none"> <li>Where CO<sub>2</sub> is vented to the atmosphere in the baseline scenario, transport baseline candidates would not exist</li> <li>Natural-sourced CO<sub>2</sub> is transported by pipeline or ship</li> <li><b><i>Captured CO<sub>2</sub> is transported by pipeline or ship</i></b></li> </ul>
	Transport by ship	
Injection and Storage	Acid gas injection - CO <sub>2</sub> and H <sub>2</sub> S are disposed of through injection into the production reservoir.	<ul style="list-style-type: none"> <li>CO<sub>2</sub> and H<sub>2</sub>S separated from the acid gas stream are stored in another geological formation</li> <li>CO<sub>2</sub> separated from the acid gas stream is sold to the market</li> <li>CO<sub>2</sub> separated from the acid gas stream is used for EOR, EGR, ECBM, or to maintain reservoir pressure</li> <li><b><i>CO<sub>2</sub> and H<sub>2</sub>S separated from the acid gas stream are stored in the production reservoir</i></b></li> </ul>
Injection and Storage	Captured CO <sub>2</sub> is used for EOR or enhanced gas recovery (EGR)	<ul style="list-style-type: none"> <li>CO<sub>2</sub> is purchased from a naturally-occurring underground source for use in EOR or EGR<sup>8</sup></li> <li>CO<sub>2</sub> is purchased from an industrial facility for use in EOR or EGR</li> <li>EOR is achieved by the injection of natural gas, nitrogen (N<sub>2</sub>), or water. EGR is achieved by means other than the injection of CO<sub>2</sub>.</li> <li>Captured CO<sub>2</sub> is reinjected into the same hydrocarbon reservoir (oil or gas) from which it was produced.</li> <li>CO<sub>2</sub> produced from EOR production wells in a CO<sub>2</sub>-flooded field is vented to the atmosphere</li> <li>CO<sub>2</sub> produced from EOR production wells in a CO<sub>2</sub>-flooded field is recycled to EOR operations and sealed for final storage</li> <li><b><i>Captured CO<sub>2</sub> is used for EOR or EGR</i></b></li> </ul>

<sup>8</sup> The use of naturally occurring, underground-sourced CO<sub>2</sub> for enhanced hydrocarbon recovery is not, in and of itself, a GHG emission reduction project.

**Table 6-1. Potential Baseline Candidates for Probable CCS Project Elements (Continued)***Bold italic text indicates the project activity*

CCS Chain	Probable Project Elements	Potential Baseline Candidates
Injection and Storage	Captured CO <sub>2</sub> is injected in a geological formation or saline formation for long-term storage	<ul style="list-style-type: none"> <li>• Captured CO<sub>2</sub> is sold to market</li> <li>• Captured CO<sub>2</sub> is reinjected into the same hydrocarbon reservoir (oil or gas) from which it was produced.</li> <li>• Captured CO<sub>2</sub> is used for EOR, EGR, or to maintain pressure in a hydrocarbon reservoir</li> <li>• <b><i>Captured CO<sub>2</sub> is stored</i></b></li> </ul>
Injection and Storage	CO <sub>2</sub> capture for enhanced coal bed methane (ECBM) operations	<ul style="list-style-type: none"> <li>• CO<sub>2</sub> is purchased from a naturally-occurring underground source for use in ECBM</li> <li>• CO<sub>2</sub> is purchased from an industrial facility for use in ECBM</li> <li>• N<sub>2</sub> is used in ECBM operations</li> <li>• <b><i>Captured CO<sub>2</sub> is used for ECBM</i></b></li> </ul>

## 6.5 Emission Sources and Assessment Boundary

As discussed in Section 2.5 of the General Project Guidelines (IPIECA and API, 2007), the assessment boundary encompasses all project and baseline emission sources controlled by the project proponent, related to the CCS project, or affected by the CCS project. Affected emissions are discussed in Section 6.9.1. Emissions discussed below may be controlled or related, depending on which sources the project proponent controls. This can vary from project to project. Different sources of emissions that could occur across the CCS chain are summarized in Table 6-2 and illustrated in Figure 6-4. For a CCS project, the assessment boundary also includes the subsurface.

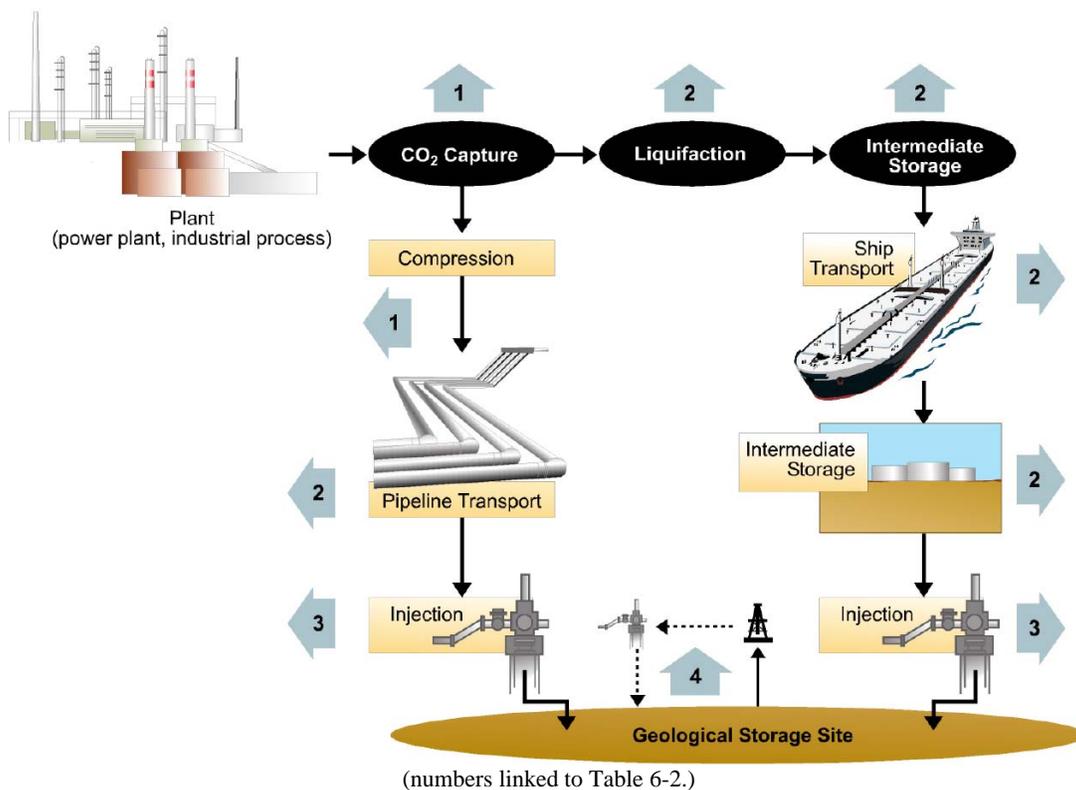
**Table 6-2. Summary of Potential GHG Emission Sources**

	Emission Source	Emission Type*	GHG Species
Baseline	Waste gas stream from an industrial process	Vented	CO <sub>2</sub>
	Flue gas stream from a large stationary source	Vented	CO <sub>2</sub>
	Emissions from stationary combustion sources, flares, and/or incinerated streams (e.g., flared associated gas)	Combustion	Primarily CO <sub>2</sub> ; CH <sub>4</sub> and N <sub>2</sub> O to lesser degree
	Venting of stripped CO <sub>2</sub> from a natural gas stream	Vented	CO <sub>2</sub> and potentially CH <sub>4</sub>
	Naturally occurring emissions originating from a geological CO <sub>2</sub> formation	Vented and fugitive	Primarily CO <sub>2</sub> , may contain some CH <sub>4</sub>

**Table 6-2. Summary of Potential GHG Emission Sources (Continued)**

		<b>Emission Source</b>	<b>Emission Type*</b>	<b>GHG Species</b>	
CCS Chain	1. Capture	Dehydration and other gas treatment equipment to separate the CO <sub>2</sub> from other gas stream components	Combustion	Primarily CO <sub>2</sub> ; CH <sub>4</sub> and N <sub>2</sub> O to lesser degree	
			Vented	CO <sub>2</sub> and CH <sub>4</sub>	
			Fugitive	CO <sub>2</sub> and CH <sub>4</sub>	
			Fuel combustion associated with capture process (Note: compression may occur in the capture step)	Combustion	Primarily CO <sub>2</sub> ; CH <sub>4</sub> and N <sub>2</sub> O to lesser degree
			Purchased electricity associated with capture process	Indirect	Primarily CO <sub>2</sub> ; CH <sub>4</sub> and N <sub>2</sub> O to lesser degree
			Fraction of CO <sub>2</sub> or CH <sub>4</sub> not captured	Vented and fugitive	CO <sub>2</sub> and/or CH <sub>4</sub>
			Use and disposal/incineration of CO <sub>2</sub> removal process/agent	Primarily energy consumption	Primarily CO <sub>2</sub> ; CH <sub>4</sub> and N <sub>2</sub> O to lesser degree
	2. Transport		Gas-fired compressor engines	Combustion	Primarily CO <sub>2</sub> ; CH <sub>4</sub> and N <sub>2</sub> O to lesser degree
			Mobile source energy consumption	Combustion	Primarily CO <sub>2</sub> ; CH <sub>4</sub> and N <sub>2</sub> O to lesser degree
			Purchased electricity	Indirect	Primarily CO <sub>2</sub> ; CH <sub>4</sub> and N <sub>2</sub> O to lesser degree
			Pressurized equipment and pipeline leaks	Fugitive	CO <sub>2</sub> and potentially CH <sub>4</sub>
			Maintenance or emergency releases	Vented	
			Intermediate storage	Vented	
Loading/unloading			Vented		
Losses in transport	Vented				
CCS Chain	3. Injection	Gas-fired compressor engines for injection or recycle	Combustion	Primarily CO <sub>2</sub> ; CH <sub>4</sub> and N <sub>2</sub> O to lesser degree	
			Purchased electricity	Indirect	Primarily CO <sub>2</sub> ; CH <sub>4</sub> and N <sub>2</sub> O to lesser degree
		Pressurized CO <sub>2</sub> injection equipment	Fugitive	CO <sub>2</sub> and potentially CH <sub>4</sub>	
			Maintenance or emergency releases		Vented
			Production and injection wells		Vented
		Dehydration and other gas treatment equipment for recycled gas	Combustion	Primarily CO <sub>2</sub> ; CH <sub>4</sub> and N <sub>2</sub> O to lesser degree	
			Vented	CO <sub>2</sub> and CH <sub>4</sub>	
	Fugitive		CO <sub>2</sub> and CH <sub>4</sub>		
		Purchased electricity	Indirect	Primarily CO <sub>2</sub> ; CH <sub>4</sub> and N <sub>2</sub> O to lesser degree	
	4. Storage	Physical leakage from geological formations, CO <sub>2</sub> leakage from wells, Uncaptured CO <sub>2</sub> co-produced with oil/gas	Fugitive	CO <sub>2</sub> and potentially CH <sub>4</sub>	
			Vented and/or Fugitive		
			Vented		

\* Indirect emissions are “related” emission sources. All others may be “controlled” or “related” depending on which sources the project proponent controls.



**Figure 6-4. Schematic of Potential GHG Emission Sources**

Adapted from 2006 IPCC Guidelines for National Greenhouse Gas Inventories, Volume 2, Chapter 5, Figure 5-1.

Although baseline and project emissions associated with CCS will primarily focus on sources of CO<sub>2</sub> (including CO<sub>2</sub> captured as part of the project or CO<sub>2</sub> emissions resulting from energy requirements to capture, transport and inject CO<sub>2</sub>), methane (CH<sub>4</sub>) and nitrous oxide (N<sub>2</sub>O) emissions sources should also be assessed, as indicated in Table 6-2.

### 6.5.1 Baseline Emission Sources

For the project types identified in Table 6-1, baseline emissions may result from venting a gas stream containing CO<sub>2</sub> or from the exhaust of a combustion source. The baseline emissions are quantified as the amount of CO<sub>2</sub> equivalent from that stream that would have been released to the atmosphere in the absence of the project. Baseline emissions may also include energy consumption from a flare or acid gas incineration, or venting and fugitive emissions from natural sources of CO<sub>2</sub>.

Geological storage sites may have a natural (ecological and/or industrial) background flux of CO<sub>2</sub> emissions prior to injection. Analysis of stable and radiogenic carbon isotope ratios in detected CO<sub>2</sub> can help distinguish between man-made CO<sub>2</sub> sources and natural sources. This background flux should be determined prior to the project and is excluded in the estimate of annual emissions.

### **6.5.2 Capture Emission Sources**

Technologies for capturing CO<sub>2</sub> require the use of energy, with a corresponding increase in fossil fuel consumption and/or purchased electricity. Processes that separate CO<sub>2</sub> from other components in the captured gas, such as dehydration to remove H<sub>2</sub>O, are potential sources of combustion, vented or fugitive emissions. Compression of the captured CO<sub>2</sub> may occur in this step, resulting in combustion or indirect emissions. In addition, the capture processes are less than 100 percent efficient, resulting in a small amount of residual CO<sub>2</sub> emissions.

### **6.5.3 Transport Emission Sources**

In transport, fugitive emissions may result from pressurized equipment leaks. Vented emissions result from equipment maintenance, emergency releases, intermediate storage facilities, loading/offloading, and losses in transport. Combustion emissions result from compressor fuel consumption or mobile source fuel consumption. Indirect emissions from purchased electricity may result from the power requirement for compression at booster stations, pump stations, or cooling of CO<sub>2</sub> for cryogenic ship transport.

### **6.5.4 Storage Emission Sources**

Emissions associated with storage operations include vented, fugitive, and combustion emissions from surface equipment at the injection site. Such equipment may include the distribution manifold at the end of the transport pipeline, distribution pipelines to wells, injection wells, compression equipment, and measurement and control systems. Indirect emissions may result from power requirements at the injection site. Additional energy may also be required for ongoing monitoring and maintenance of the storage reservoir.

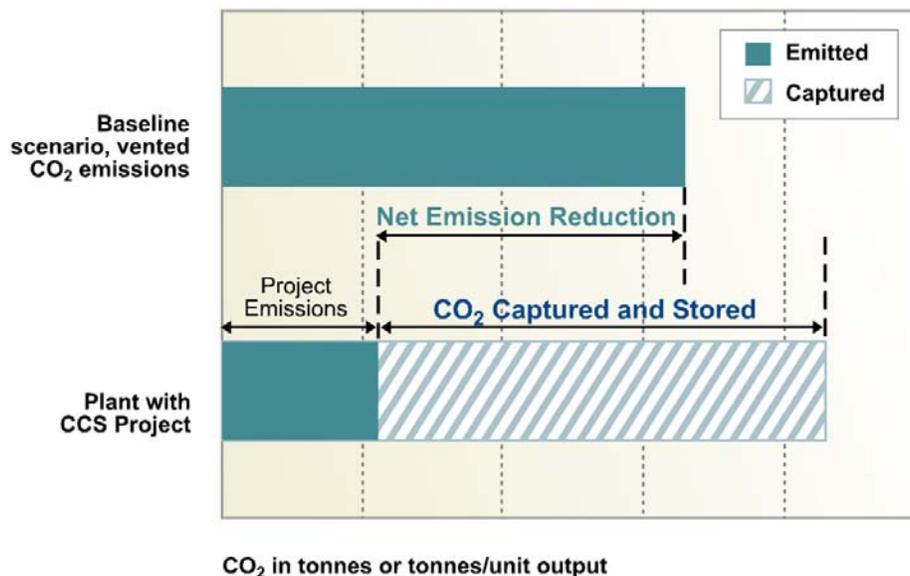
With appropriate site selection and good operating practices, CO<sub>2</sub> emissions from the storage site are likely to be very small, but could include physical leakage from the geological formation and from wells. Site-specific monitoring systems will provide assurance for secure storage.

Emissions associated with CO<sub>2</sub> co-produced with oil and/or gas are another potential emission source within the assessment boundary. ECBM and EGR processes attempt to avoid CO<sub>2</sub> production because it is costly to separate CO<sub>2</sub> from the produced gas mixture, while most EOR projects capture and reinject CO<sub>2</sub> that is produced with the associated gas, due to the cost of purchased CO<sub>2</sub>. For fields that lack adequate gas handling or recompression facilities, the CO<sub>2</sub> associated with oil recovery may be vented to the atmosphere (subject to the EOR operating constraints). If the project activity includes recovery and recycling of this previously vented stream, these emissions would be included in the assessment boundary. Example 1, presented in Attachment 1, addresses considerations for quantifying GHG emission reductions associated with CCS combined with EOR operations.

Fugitive and vented emissions of CH<sub>4</sub> are also associated with enhanced hydrocarbon recovery operations, such as ECBM and EGR. Hydrocarbon gas streams may be processed, used as fuel on site, flared or vented, depending on the hydrocarbon content. These emission sources should be evaluated to determine if there are differences between baseline and project emissions.

## 6.6 Emission Reductions

Emissions reductions are the net difference between the baseline emissions and project emissions, and are primarily attributable to the quantity of CO<sub>2</sub> captured, injected and stored, as illustrated in Figure 6-5. Emissions reductions are typically reported in terms of CO<sub>2</sub> equivalents (CO<sub>2</sub>e), in which all of the GHG species are converted to an equivalent basis relative to their global warming potential (GWP). The calculation of potential emission reductions for various CCS projects is demonstrated through examples in Attachment 1.



**Figure 6-5. Potential Project Emission Reduction Calculated from Reference Baseline Scenario**

Adapted from IPCC Special Report Carbon Dioxide Capture and Storage, Technical Summary, Figure TS.11, 2005

Baseline emissions are emissions that would have occurred from a referenced operation (baseline scenario) without carbon capture but with the same output as the project plant (e.g., similar power output for a power plant, or volume of natural gas processed for a gas processing facility). Baseline emissions should reflect emission sources associated with each step of the CCS chain, but that would have occurred in the absence of the project. This can be expressed by the following general equation:

$$\text{Baseline emissions} = \text{VENT}_1 + \text{CMB}_1 + \text{FUG}_1 + \text{IND}_1 \quad (\text{Equation 1})$$

where,

$\text{VENT}_1$  = Vented CO<sub>2</sub> emissions from baseline operations or equipment that would have occurred in the baseline scenario. (For most petroleum industry CCS projects, the volume of CO<sub>2</sub> captured by the project would be included in this amount.)

- $CMB_1$  = Direct combustion emissions that would have occurred in the baseline scenario. These might include fuel consumed in stationary combustion equipment or emissions from flares or acid gas incineration.
- $FUG_1$  = Fugitive CO<sub>2</sub> emissions from baseline equipment that would have occurred in the baseline scenario.
- $IND_1$  = Indirect emissions that would have occurred from electricity purchased from outside sources in the baseline scenario.

Similarly, project emissions can be expressed as:

$$\text{Project emissions} = VENT_2 + CMB_2 + FUG_2 + IND_2 \quad (\text{Equation 2})$$

where,  $VENT_2$ ,  $CMB_2$ ,  $FUG_2$ , and  $IND_2$  refer to vented, combustion, fugitive, and indirect emissions, respectively, associated with the project.

As presented in Section 6.5, project emissions include the additional energy required for capture, transport, and storage operations, and other emission sources above and beyond the baseline. Project emissions may also include emissions arising from the replacement of lost power due to inefficiencies in the capture process. Thus, while the amount of CO<sub>2</sub> captured and stored can equal the vented CO<sub>2</sub> emissions in the baseline scenario, the net reduction will almost always be a lesser amount.

## **6.7 Monitoring**

### **6.7.1 Definition and Purpose**

Monitoring for CCS has two purposes. The first is from a GHG emissions point of view, to establish the amount of GHG emissions reduction. Here, monitoring refers to the continuous or periodic assessment of GHG emissions and removals with the purpose of determining emissions and emission reductions from the project. The second purpose is for potential risk assessment, avoidance, and mitigation.

Monitoring must be sufficient to allow the transparent quantification of GHG reductions. Methodologies for monitoring can be direct or indirect, and include estimation, modeling, measurements, and/or calculation approaches. Table 6-3 summarizes the breadth and variety of monitoring techniques currently available and applicable to CCS operations, some of which are illustrated in Figure 6-6. The applicability of these techniques is site-specific and selection among these options requires an understanding of the site-specific characteristics and risks, as well as the measurement limitations.

In terms of geological storage of CO<sub>2</sub>, monitoring includes use of methods to assess that the CO<sub>2</sub> in the subsurface is behaving as predicted and according to any permit requirements or regulations. Subsurface monitoring is used to determine that the risk of emissions to the environment is not increasing above accepted levels, usually established by the permit for the storage project. In addition, monitoring should establish that CO<sub>2</sub> does not leak into other energy and mineral resources in the subsurface, shallow potable groundwater, and soils.

**Table 6-3. Summary of Direct and Indirect Techniques that can be used to Monitor CO<sub>2</sub> Storage Projects<sup>9</sup>**

Measurement Technique	Measurement Parameters	Example Applications	Capabilities/Limitations
Introduced and natural tracers	Travel time Partitioning of CO <sub>2</sub> into brine or oil Identification of sources of CO <sub>2</sub>	Tracing movement of CO <sub>2</sub> in the storage formation Quantifying solubility trapping Tracing physical leakage	Ease detection of low levels of CO <sub>2</sub> and are not impacted by background concentrations. Tracers make soil gas or flux measurements more quantitative, eliminating the need to discriminate between sources of CO <sub>2</sub> .
Water composition	CO <sub>2</sub> , HCO <sub>3</sub> <sup>-</sup> , CO <sub>3</sub> <sup>2-</sup> . Major ions Trace elements Salinity pH Isotope analysis	Quantifying solubility and mineral trapping Quantifying CO <sub>2</sub> -water-rock interactions Detecting physical leakage into shallow groundwater aquifers	Compares baseline surveys of water quality and/or isotope composition to differentiate between new (injected) CO <sub>2</sub> and pre-existing CO <sub>2</sub> at that site. CO <sub>2</sub> movement can be detected by monitoring chemical changes in the reservoir fluids, in particular changes in bicarbonate ion levels in the fluid.
Subsurface pressure	Formation pressure Annulus pressure Groundwater aquifer pressure	Controlling formation pressure below fracture gradient Determining wellbore and injection tubing condition Controlling physical leakage out of the storage formation	Injection pressure tests and production tests can be applied in wells to determine permeability, the presence of barriers in reservoir, and assess the ability of caprock to retain fluids.
Well logs	Brine salinity Sonic velocity CO <sub>2</sub> saturation Cement integrity Injection profiles Tracer detection Temperature profiles	Tracking CO <sub>2</sub> movement in and above storage formation Tracking migration of brine into shallow aquifers Calibrating seismic velocities for 3D seismic surveys	Widely used to characterize hydrocarbon reservoirs. Well logs can measure many parameters, including the condition of the well, the identity of pore fluids, estimation of water chemistry based on conductivity measurements, and mineralogy of the formation. Data can be used to track migration of CO <sub>2</sub> and brine in the reservoir and to ensure that the well itself does not provide a physical leakage pathway for CO <sub>2</sub> migration. The resolution of well logs may not be sufficient to detect very small rates of physical leakage through microcracks.

<sup>9</sup> Reference: Table 5.4 of IPCC Special Report on Carbon Dioxide Capture and Storage, 2005.

**Table 6-3. Summary of Direct and Indirect Techniques that can be used to Monitor CO<sub>2</sub> Storage Projects (Continued)**

<b>Measurement Technique</b>	<b>Measurement Parameters</b>	<b>Example Applications</b>	<b>Capabilities/Limitations</b>
Time-lapse 4D seismic imaging	P and S wave velocity Reflection horizons Seismic amplitude attenuation	Tracking CO <sub>2</sub> movement in and above storage formation	Images geological structure of site and surrounding area; structure, distribution and thickness of reservoir rock and caprock, distribution and movement of CO <sub>2</sub> in reservoir. May verify mass of CO <sub>2</sub> in reservoir (within limits). Cannot image dissolved CO <sub>2</sub> or situations where there is little impedance contrast between reservoir fluid and CO <sub>2</sub> -saturated rock. Seismic resolution decreases with depth and certain rock properties; therefore, resolution is site-specific.
Vertical seismic profiling and crosswell seismic imaging	P and S wave velocity Reflection horizons Seismic amplitude attenuation	Detecting detailed distribution of CO <sub>2</sub> in the storage formation Detecting physical leakage through faults and fractures	Images velocity distribution around a well (vertical seismic) and between wells (crosshole seismic). Imaging limitations similar to those of 3D seismic imaging.
Passive seismic monitoring	Location, magnitude and source characteristics of seismic events	Detecting development of microfractures in formation or caprock CO <sub>2</sub> migration pathways	Detects microseismic events in the reservoir and through the use of an array of sensors can locate microfractures in the reservoir rock and surrounding strata. May also be used to track pressure changes and possibly movement of gas in the reservoir or saline formation. Detection limits are site-specific and are affected by background noise.
Electrical and electromagnetic techniques	Formation conductivity Electromagnetic induction	Tracking movement of CO <sub>2</sub> in and above the storage formation Detecting migration of brine into shallow aquifers	May detect changes in resistivity due to replacement of native pore fluid with CO <sub>2</sub> , especially when the CO <sub>2</sub> is supercritical. Could detect changes from displaced brine invading a fresher water aquifer. Could potentially map the spread of CO <sub>2</sub> in a storage reservoir. Currently at research stage and needs development to determine its resolution and overall effectiveness.

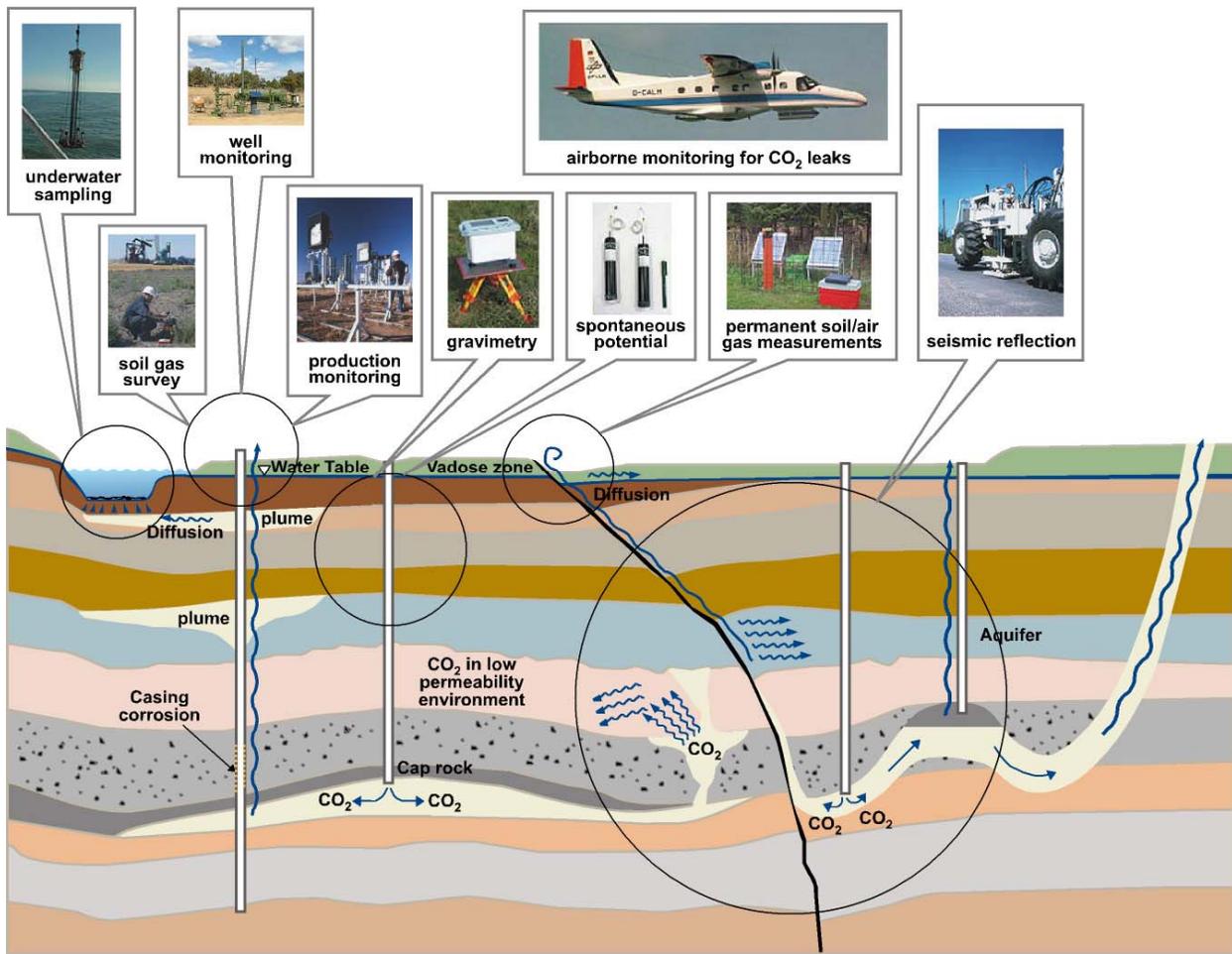
**Table 6-3. Summary of Direct and Indirect Techniques that can be used to Monitor CO<sub>2</sub> Storage Projects (Continued)**

<b>Measurement Technique</b>	<b>Measurement Parameters</b>	<b>Example Applications</b>	<b>Capabilities/Limitations</b>
Time-lapse gravity measurements	Density changes caused by fluid displacement	Detecting CO <sub>2</sub> movement in or above storage formation	Determine mass and approximate distribution of CO <sub>2</sub> injected from minute changes in gravity caused by displacing the original pore fluid from the reservoir. Detection limit is poor (on order of hundreds of thousands to low millions of tonnes) and is site-specific. Cannot image dissolved CO <sub>2</sub> because of insufficient density contrast with native pore fluid.
Land surface deformation	Tilt Vertical and horizontal displacement using interferometry and GPS, or subsurface and/or surface tiltmeter measurements	Detecting geomechanical effects on storage formation and caprock Locating CO <sub>2</sub> migration pathways	Used to assess sub-surface migration of the plume. More applicable in areas where natural variations in the surface such as frost, heave or wetting-drying cycles, do not mask the changes that occur from pressure changes.
Visible and infrared imaging from satellite or planes	Hyperspectral imaging of land surface Hyperspectral imaging of atmospheric CO <sub>2</sub> or CH <sub>4</sub>	Detecting vegetative stress Directing detection of CO <sub>2</sub> or CH <sub>4</sub>	Detects anomalous changes in the health of vegetation that could be due to physical leakage of CO <sub>2</sub> to the ground surface. Research required to determine levels of CO <sub>2</sub> in soil that will produce detectable changes in vegetation health and distribution. Direct detection methods are in the experimental stage.
CO <sub>2</sub> land surface flux monitoring using flux chambers or eddy covariance	CO <sub>2</sub> fluxes between the land surface and atmosphere	Detecting, locating and quantifying CO <sub>2</sub> releases	Measures CO <sub>2</sub> fluxes from regions upwind of the detector. Gas analysis data is integrated with wind speed and direction to define footprint of upwind region and calculate flux. Technology is proven and relatively cheap. For eddy covariance, several instrument towers may be required to cover a large area and flux quantification may be limited to regions of flat terrain

**Table 6-3. Summary of Direct and Indirect Techniques that can be used to Monitor CO<sub>2</sub> Storage Projects (Continued)**

<b>Measurement Technique</b>	<b>Measurement Parameters</b>	<b>Example Applications</b>	<b>Capabilities/Limitations</b>
Soil gas sampling	Soil gas composition Isotopic analysis of CO <sub>2</sub>	Detecting elevated levels of CO <sub>2</sub> Identifying source of elevated soil gas CO <sub>2</sub> Evaluating ecosystem impacts	Measures CO <sub>2</sub> levels and fluxes in soil using probes, commonly hammered in soil to a depth of 50-100 cm. Soil gas is drawn up through probe and analyzed. A range of gases may be measured; ratios of other gases and isotopes can provide clues to origin of CO <sub>2</sub> . Useful for detailed measurements, especially around detected low flux physical leakage points. Accuracy depends on well established levels of background flux and its variation. Surveying large areas may be time consuming and costly.

Excerpted from Table A5.1 of the Draft 2006 IPCC Guidelines for National Greenhouse Gas Inventories, Chapter 5, page 5.24.



**Figure 6-6. Illustration of Monitoring Techniques**

Derived from diagrams courtesy of Sally Benson (Stanford University) and the British Geological Service.

Monitoring can be used to:

- Collect relevant data regarding the integrity of the storage formation;
- Determine background CO<sub>2</sub> concentrations and establish baseline conditions;
- Ensure and document effective injection well controls, specifically for monitoring the condition of the injection well and measuring injection rates, wellhead and formation pressures and temperatures, and gas composition;
- Determine the quantity of CO<sub>2</sub> injected and stored;
- Optimize the efficiency of the storage project, including utilization of the storage volume, injection pressures, and drilling of new injection wells;
- Enhance formation simulations;
- Demonstrate with appropriate monitoring techniques that CO<sub>2</sub> remains contained in the target storage formation(s). This is currently the principal method for assuring that the CO<sub>2</sub> remains stored and that performance predictions can be verified;

- Maintain operations, such as injection pressure, at or below any limits imposed by regulatory agencies on the storage of CO<sub>2</sub>, particularly in regard to reservoir and caprock integrity;
- Periodically investigate the entire assessment boundary to confirm the absence of unpredicted leaks;
- Detect physical leakage out of the storage formation and provide an early warning of any physical leakage that might require mitigation; and
- Identify the need for changes in operation or remedial activities to avoid physical leakage out of the storage formation.

The captured stream would include CO<sub>2</sub>, and in addition may include associated substances derived from the process that produced the CO<sub>2</sub> and/or from the separation process. The associated substances may have some impact on monitoring activities to ensure that the captured, transported, injected and stored stream is within limits likely to be set by regulatory agencies.

Section 2 of the Project Guidelines (IPIECA and API, 2007) provides general monitoring guidance for emission reduction projects. For CCS operations, monitoring is an iterative risk-based process, utilizing information from ongoing assessments of characteristics that are specific to a particular CCS project. As a result, monitoring plans should be developed on a case-by-case basis to manage potential risks for the specific CCS application. These may include: Health, Safety, and Environmental (HSE) purposes (worker and public safety; minimization of local environmental impacts to the groundwater and ecosystems; and net isolation from the atmosphere); storage operation performance (in target migration); and physical leakage detection in time to modify the operating parameters. A risk-based monitoring approach applies risk assessment techniques to identify the key potential risks of physical leakage for the specific project. Then appropriate monitoring techniques are identified to manage the risks and demonstrate performance against the monitoring plan. Monitoring should continue to evolve with improved technologies, new information, and ongoing risk management.

### **6.7.2 Monitoring Methods**

As depicted in Figure 6-6, a variety of monitoring methods are available for CCS. Many are well established in the oil and natural gas industry sector from EOR activities, and others are developing to better address CCS. Table 6-3 addresses the capabilities and limitations of the current monitoring methods. The suitability and efficacy of these technologies can be strongly influenced by the geology and potential emission pathways at individual storage sites. Ultimately the monitoring program for CO<sub>2</sub> storage projects should be tailored to the specific conditions and potential risks at the storage site (i.e., fit for purpose), and may include a combination of measurements, modeling, and estimation techniques.

The following subsections address monitoring activities for the complete chain of CCS activities. However, public risk perception and the drivers for a policy framework and regulatory conditions for approving CCS projects rest primarily on demonstrating that the injected CO<sub>2</sub> will be sealed from the atmosphere and will not adversely impact other subsurface resources. Therefore, monitoring techniques associated with storage are discussed in more detail.

### **6.7.3 Emissions Monitoring**

The following subsections describe methods for monitoring the emissions associated with each step of the CCS process chain. In terms of emissions monitoring, many of the methodologies provided in the API Compendium are appropriate for estimating baseline emissions and quantifying project emissions. Where multiple methodologies are available, selection should consider the costs of collecting data or measuring emissions versus the materiality of the emission source and the requirements of the climate change regime or GHG registry.

#### **Capture**

Monitoring emissions associated with CO<sub>2</sub> capture can be accomplished using available technology (e.g., metered fuel or electricity consumption rates, metered gas flow rates). The total CO<sub>2</sub> that could potentially be emitted in the absence of the project can be determined through a carbon balance of the large stationary sources. This quantity establishes the baseline emissions for the capture facility. For the project, the difference between the total CO<sub>2</sub> generated and the quantity captured reflects the performance of the capture technology.

#### **Transport**

Technologies for monitoring the volume of gas transported (by pipeline, marine vessel, railcar or tanker truck) are well established. Losses during pipeline transport can be estimated from the established procedures (e.g., the API Compendium). Key operating parameters for GHG emission sources used during transport (e.g., compressor engines, dehydration equipment) can be monitored using appropriate metering equipment, estimation techniques, and other recognized methods. Transport losses can be quantified from records of maintenance/emergency releases and operational practices that result in releases.

#### **Storage**

For storage, monitoring is conducted both for determining emissions as well as for risk assessment, avoidance and mitigation (discussed in Section 6.7.4). In general, there are three phases for monitoring a geological storage site: pre-operational, operational, and closure monitoring.

##### **Pre-operational Evaluation**

It is essential to have a reasonably detailed understanding of background emissions and conditions at or near the surface prior to injection. Site characterization and monitoring plans should identify possible sources of emissions outside the site including natural (e.g., lateral migration, groundwater) and anthropogenic (industrial and associated facilities) sources. Naturally occurring fluxes of CO<sub>2</sub>, on diurnal, seasonal, and annual cycles must be identified to distinguish naturally occurring CO<sub>2</sub> from what is injected, as well as other background noise around the site that may mask a physical leak or seepage signal. In addition, the pre-operational evaluation should assess the presence and condition of existing and abandoned wells as potential pathways for leakage.

### **Operational Monitoring**

The amount of CO<sub>2</sub> injected into the storage site, the condition of the injection well(s), wellhead pressures, and formation pressures and temperatures are important basic operational parameters to monitor and to control the injection process (e.g., to prevent excess pore fluid pressure building up in the reservoir). Petroleum industry experience suggests that physical leakage from the injection well itself, resulting from improper completion or deterioration of the casing, packers or cement, is one of the most significant areas of potential leakage for injection projects (IPCC, 2005).

Figure 6-6 and Table 6-3 illustrate and summarize a variety of monitoring techniques currently available and applicable to CCS operations. The applicability of these techniques is site-specific and selection among these options requires an understanding of the site-specific characteristics and risks, as well as the measurement limitations.

### **Closure Monitoring**

Closure monitoring refers to the long-term monitoring of the geological storage site after completing CO<sub>2</sub> injection. Many of the measurement techniques shown in Figure 6-6 apply to long-term monitoring, as well as operational monitoring.

#### **6.7.4 Monitoring for Storage Risk Management**

Monitoring to manage the potential risk of leakage involves the use of one or more monitoring techniques and procedures tailored to the storage site and comparison with reservoir simulations to interpret the monitoring results. The three phases for monitoring a geological storage site – pre-operational, operational, and closure monitoring – are discussed separately below.

#### **Pre-operational Evaluation**

Monitoring for risk management begins with characterizing and selecting an appropriate geological formation, and establishing baseline conditions prior to injecting CO<sub>2</sub>. Carbon dioxide can remain trapped under ground by virtue of a number of trapping mechanisms, such as:

- Physical trapping (trapping below an impermeable, confining layer (caprock));
- Capillary trapping (retention in an immobile phase, trapped in the pores spaces of the storage formation);
- Mineralization (precipitation as a carbonate material);
- Solubility trapping (dissolution in fluids already present in the formation); and
- Adsorption onto organic matter in coal and shale.

Various techniques can be used to assess the availability of these trapping mechanisms and the characteristics of the prospective storage site, particularly capacity and injectivity.

Another goal of site characterization is to identify the features, events and processes that could result in physical leakage from the storage reservoir. These include the identification and characterization of potential physical leakage pathways such as faults, fractures, and existing wells (active, inactive, or abandoned), and quantification of hydrogeological properties, particularly with respect to CO<sub>2</sub> migration. Proper site characterization and selection can help

build confidence that there should be minimal risk of physical leakage; improve modeling capabilities, results, and accuracy; and ultimately reduce the level of monitoring needed.

Techniques developed for the exploration, development, production, and management of oil and natural gas reservoirs, natural gas storage sites, acid gas injection locations, and liquid waste disposal sites are potentially suitable for characterizing geological storage sites for CO<sub>2</sub>. Before selecting a site, the subsurface conditions must be characterized to predict the following to a satisfactory level:

- The overlying caprock will provide an effective seal;
- Faults contacted are unlikely to reactivate;
- Existing fractures will not re-open;
- Storage capacity is sufficient;
- Permeable distribution is suitable for both injection and in-target migration;
- Trapping mechanisms (capillary, solubility and mineralization) are effective; and
- New and existing wells will not compromise the integrity of the seal.

Many of the parameters that can be used to monitor a storage project do not directly indicate the presence of CO<sub>2</sub>. Instead it is the changes in these parameters over time that can be used to detect and track migration of CO<sub>2</sub> and its reaction products. For these reasons, it is important to have a well-defined baseline that includes not only the average value of these parameters, but also how they vary in space and time before the project begins. Precise determination of proportions of CO<sub>2</sub> stored by various mechanisms or lost from the target zone may not be achievable, but the principal objective of monitoring should be to detect anomalies in time for intervention.

Baseline determination methods that may provide useful risk management data include the following:

- Any seismic testing that provides information on the size and acoustic properties of the reservoir;
- Any geophysical or geochemical testing that may have been performed on the reservoir and that may help in establishing its mechanical and chemical integrity;
- Any history in the number and types of wells that have penetrated the target reservoir, including their status (e.g., active, suspended, abandoned), well condition, and the abandonment technique used;
- Geological mapping and interpretation based on well logs for wells that have penetrated the target reservoir;
- Gas composition and isotopic analysis of any background fluxes of CO<sub>2</sub>, which is useful for distinguishing between natural (biogenic or thermogenic), anthropogenic and injected CO<sub>2</sub>; and
- Sampling and analysis of in-situ fluids (oil, gas, brine).

Some of these methods are also useful for gathering emissions data.

### **Operational Monitoring**

Periodically monitoring the distribution of CO<sub>2</sub> in the subsurface, whether directly (e.g., logging of, or sampling and analysis from observation wells), indirectly (e.g., seismic or using other compounds in the gas as tracers for monitoring the CO<sub>2</sub>) or remotely (e.g., aerial or satellite anomalies), provides valuable information on reservoir characteristics and the fate of the CO<sub>2</sub> in the near and longer term. Monitoring data also provide information needed to update the modeling/simulation and risk assessment processes by providing calibration points for predictions in the early and interim years, which can help build confidence in the longer-term predictions. A successful history match, or agreement between reservoir simulations and monitoring data, may be used to validate the project and justify monitoring program scale-back and eventual field decommissioning.

Computer programs that model underground CO<sub>2</sub> movement are useful for supporting site characterization and selection activities, as well as operational and long-term monitoring. Many of the physicochemical factors involved (changes in temperature and pressure, mixing of the injected gas with the fluids initially present in the reservoir, the type and rate of CO<sub>2</sub> immobilization mechanisms, and fluid flow through the geological environment) can be modeled successfully with numerical modeling tools generally known as reservoir simulators. These programs are widely used in the oil and natural gas industry, and have proven effective in predicting the movement of gases and liquids, including CO<sub>2</sub>, through geological formations. Reservoir simulations can be useful tools in identifying or predicting potential pathways for physical leakage and are continuing to evolve for CCS applications. Their application, coupled with risk management and other operational data, can be used to focus both operational and long-term monitoring.

Computer models need to be updated and new simulations should be run based on new monitoring data as a project proceeds. Experience from the monitoring exercise and availability of new monitoring techniques may result in the need to modify the monitoring methods during the course of the project. As a result, monitoring methods cannot be pre-defined for the life span of the project, and are best developed for specific applications by operators with knowledge of the geological formation's characteristics and experience in the applicability and limitations of the techniques available. How to examine and determine monitoring techniques and methodologies would be described in the monitoring plan.

### **Closure Monitoring**

Determining, on a long-term basis, how the injected CO<sub>2</sub> is performing and interacting with the subsurface containment is an important aspect of risk management for a CCS project. A closure monitoring program should be based on information collected and modeling conducted during the project period. Modeling coupled with risk assessment studies can predict the long-term fate of the injected CO<sub>2</sub> and help assure that the storage containment capability conforms to the acceptance criteria. This information then can be used to select and implement appropriate closure monitoring methods at high-risk locations.

The operator's responsibilities for reporting, and if needed, remediation activities will normally be defined on the basis of the permit or other authorization needed to inject CO<sub>2</sub> for storage purposes. It may be appropriate to decrease the frequency of (or discontinue) monitoring post-injection based on demonstrating that monitoring data are consistent with reservoir simulations. There are continuing discussions about the extent to which liabilities for the project could potentially be transferred to the public (as represented by national authorities) after the abandonment and the post-injection monitoring period.

### **6.7.5 Remediation**

Although CCS projects will be selected and operated to avoid physical leakage, there exists a small possibility that physical leakage with risk of adverse consequences may occur and remediation methods will be needed, either to stop the leak or to prevent/minimize impacts. As with risk management, remediation planning is another element that contributes to assurance of long-term CO<sub>2</sub> storage.

Physical leakage scenarios and applicable remediation options have been identified based on surveys of practices used to remediate natural gas storage projects, groundwater and soil contamination, and disposal of liquid wastes in deep geological formations. Additional details on potential physical leakage scenarios and the available remediation options are provided in the IPCC Special Report on Carbon Capture and Storage (IPCC, 2005).

Should physical leakage occur, net emission reductions should account for these emissions. The monitoring techniques presented in Table 6-3 and Figure 6-6 address the advantages and complexities of different methods available to detect physical leakage and determine the extent of emissions associated with such leakage.

## **6.8 Reporting and Documentation**

Section 2 of the General Project Guidelines provides the following high-level objectives for emission reduction reporting and documentation:

- Provide sufficient transparency to enable the intended audience to make an informed decision on the credibility of the emission reduction;
- Provide a plausible and transparent account of the project, decisions, and assumptions; and
- Maintain supporting documentation.

These general principles also apply to reporting for CCS projects.

Additional reporting requirements may be specified for a particular climate change regime or GHG registry. IPCC's 2006 guidelines for national inventories (IPCC, 2006) suggests documenting and reporting the following:

### **Reporting Prior to Starting Geological Storage**

- Methods and results of the site characterization
- Methods and results of modeling
- Description of proposed monitoring
- The year in which CO<sub>2</sub> storage began or will begin
- Proposed sources of the CO<sub>2</sub> and the infrastructure involved in the whole CCS chain between source and storage reservoir

### **Annual Reporting**

- Mass of CO<sub>2</sub> injected during the reporting year
- Mass of CO<sub>2</sub> stored during the reporting year and cumulative mass of CO<sub>2</sub> stored at the site
- Source (s) of the CO<sub>2</sub> and the infrastructure involved in the whole CCS chain between source and storage reservoir
- Rationale, methodology, monitoring frequency and results of monitoring
- Additional modeling or adjustments (if any) to the modeling based on monitoring results
- Emissions of CO<sub>2</sub> and any other GHGs from the storage site
- Results of third party verification

## **6.9 Verification/Assurance**

Verification involves an assessment that the project is not materially misrepresented. This entails evaluating the implementation of the approved monitoring methodology against reported project and baseline emissions, and, on the basis of the verification activities, determining whether the data in the emissions report contain any omissions, misrepresentation, or errors that would lead to a misstatement of the reported information. As stated in Section 2 of the General Project Guidelines (IPIECA and API, 2007), verification should focus on quality assurance with the objective of improving the overall reliability of the reported emission reduction. Verification should provide the user with assurance that the reported emissions reduction is credible. For CCS, verification refers to activities used for assessing:

- The inclusion and correct quantification of emissions associated with capture and transport activities;
- The integrity of the geological reservoir for long-term storage;
- The amount of CO<sub>2</sub> that is stored underground; and
- How much, if any, CO<sub>2</sub> is leaking back into the atmosphere.

CCS relies on models for predicting gas migration in the storage formation. According to the WRI/WBCSD Protocol for Project Accounting, modeling is an acceptable means of monitoring and verifying GHG emission reductions, as long as any uncertainties or assumptions in the modeling are transparent. Ultimately the approval criteria and process for assurance will be guided by the requirements of the particular climate change regime, if applicable.

## **6.10 Policy Considerations**

### **6.10.1 Assessment Boundary**

Section 2.5 of the General Project Guidelines (IPIECA and API, 2007) defines GHG emission sources affected by the GHG reduction project as increases or decreases in emissions resulting

from changes in market demand or supply for associated products or services, or through physical displacement of products or services. Other climate change regimes may refer to these as “leakage”<sup>10</sup> or “secondary effects.”

Where CO<sub>2</sub> capture and storage is associated with EOR, ECBM, or EGR operations, the reduction of CO<sub>2</sub> emissions through long-term storage in geological reservoirs occurs in conjunction with increased oil or natural gas production. The increased production resulting from EOR provides an economic incentive for early action to reduce GHG emissions by offsetting a portion of the costs required to capture, transport, inject, and monitor the CO<sub>2</sub>. Additional GHG emissions that result from the combustion of oil or natural gas produced from EOR, ECBM, and/or EGR operations occur outside the direct control of the project proponent. The extent and detail to which these emissions are included in the assessment boundary are policy decisions of the GHG registries and climate change regimes, and their treatment is beyond the scope of these guidelines.

### **6.10.2 Eligibility**

In some regimes, CCS projects may not be eligible as candidate emissions reduction projects. Also in some regimes, the eligibility of a project as a candidate for emissions reduction credits may depend on the financial viability of the project without the revenues from the sale of Certified Emission Reductions (CERs). This may be the situation for a new EOR or ECBM project. However, for an existing EOR or ECBM project, the project developer may need to demonstrate that the project is not a financially attractive investment even with the increased oil production or methane production.

### **6.10.3 Ownership**

Because CCS involves the physical transport of CO<sub>2</sub>, ownership of the CO<sub>2</sub> can change and multiple parties may be involved in the operation or control of the different elements of the CCS chain. Several parties may use the same geological structure/formation for storing their individual streams of CO<sub>2</sub> or for hydrocarbon production, and all the parties may face joint and separate responsibilities. These situations complicate the allocation of benefits (i.e., GHG reductions) and responsibilities, as well as the assignment of potential liability for possible emissions from the formation. Ultimately, discussions and agreements related to responsibilities, liability, contractual obligations, etc., between the parties would be described in agreements between the parties or as part of the conditions for permit decisions.

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<sup>10</sup> It should be noted here that the term “leakage” in this context refers to “secondary” emissions that are accounted as part of a climate change regime or GHG registry requirements, as opposed to physical leakage (escape) of CO<sub>2</sub> from a geologic storage site that is considered in a risk assessment framework (Bachu and Celia, 2006). To clearly differentiate between the two, the term “physical leakage” is used throughout this document to refer to the escape of CO<sub>2</sub> from the storage formation to the atmosphere.

## 6.11 Project Examples

Attachment 1 provides three examples of CCS projects to illustrate the steps of project definition, baseline scenario determination, project assessment boundary and emission source determination, emission reduction calculation, and assessment of monitoring methods. These hypothetical examples are developed from the types of CCS activities that petroleum companies are conducting to demonstrate the application of guidelines for quantifying GHG reductions. The approaches, emission factors, and assumptions used in these examples reflect the decision process by a fictional project proponent based on the defined conditions, and do not universally apply in all situations.

## 6.12 Conclusions

Key messages related to CCS for reducing GHG emissions are:

- CO<sub>2</sub> capture and storage (CCS) offers significant potential for reducing GHG emissions. Through new technologies for capturing CO<sub>2</sub> from exhaust streams, CCS could play a key role in providing affordable energy while minimizing CO<sub>2</sub> emissions to the atmosphere.
- The entire CCS chain – capture, transport, injection and storage – must be considered in assessing and ensuring the integrity of GHG emission reductions associated with CCS project.
- Existing oil and natural gas industry experience and expertise provide a basis for and confidence in CCS. This experience and further demonstrations of CCS projects will highlight best practices, increase alignment among experts, and assist in building broad understanding and public acceptance.
- Growing industry experience with CCS can be used to develop an overall approach to managing geological storage and reducing the risk of unintended physical leakage or other failures. Appropriate site selection, operation, and monitoring are all components of a risk management approach.
- Good practices in monitoring are especially important for CCS to be a safe and secure GHG emission reduction option. Monitoring should be based on a site-specific risk assessment, with monitoring methods appropriate to the identified potential risks.

## 6.13 References

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## **6.14 Glossary**

### **CCS Process Chain**

Refers to the series of processes to collect a CO<sub>2</sub> gas stream, transport the CO<sub>2</sub> to a storage location, and inject the CO<sub>2</sub> into a geological formation for long-term isolation from the atmosphere.

### **Capillary trapping**

Water preferentially adheres to the surface of the reservoir rocks over CO<sub>2</sub>. If there is enough saline water within a pore (75-90% of the pore volume), it will form a capillary plug that traps the CO<sub>2</sub> within the pore space.

**Leakage**

In the context of GHG reduction projects, leakage is used to describe the displacement of GHG emissions beyond the assessment boundary of the project.

**Physical Leakage**

Refers to the flow of CO<sub>2</sub> from the storage site to other places in the ground or to the atmosphere or ocean.

**Migration**

The movement of CO<sub>2</sub> out of the geological storage site while remaining in the same geological formation.

## **Attachments to Section 6: Carbon Capture and Geological Storage Emission Reduction Project Family<sup>9</sup>**

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<sup>9</sup> All of the project case studies in this attachment are hypothetical examples developed from the types of CCS activities that petroleum companies are conducting for the purpose of demonstrating the application of guidelines for quantifying GHG reductions. The approaches, emission factors, and assumptions used in these examples reflect the decision process by a fictional project proponent based on the defined conditions, and do not universally apply in all situations.

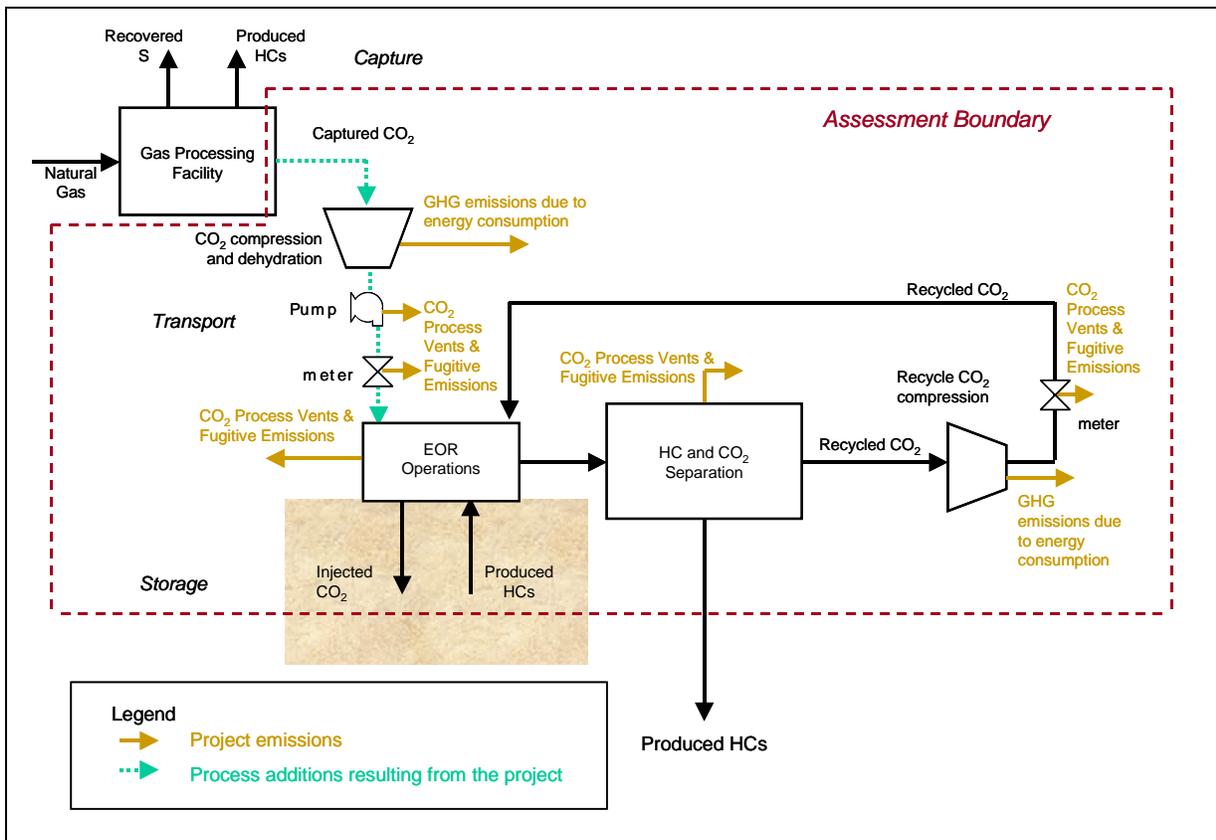
# ATTACHMENT 1

## CCS PROJECT CASE STUDY #1: CARBON CAPTURE AND STORAGE FOR ENHANCED OIL RECOVERY

### Project Definition

#### Description of the Project Activity

The purpose of this project is to recover carbon dioxide (CO<sub>2</sub>) emitted from a natural gas processing facility and inject it into an oil production field for enhanced oil recovery (EOR). The project proponent is a Joint Venture Partner in the EOR operations, but does not own or operate the gas processing facility or the CO<sub>2</sub> transport operations. A schematic diagram of the project activity is shown in Figure 6-7.



**Figure 6-7. Project Illustration of CO<sub>2</sub> Capture, Transport and Injection for Enhanced Oil Recovery Operations**

This project involves the following:

- The CO<sub>2</sub> stream separated from the natural gas and hydrogen sulfide (H<sub>2</sub>S) is captured and routed to compression/dehydration units. These activities and the increased energy requirements associated with them are shown within the assessment boundary, but may physically be located within the gas processing facility.
- Composition of the captured gas is 98.4 percent CO<sub>2</sub>, and 1.6 percent methane (CH<sub>4</sub>) by volume.
- The recovered CO<sub>2</sub> is compressed using multiple engine-driven compressors and electric-driven pumps to transport the CO<sub>2</sub> stream 32 km (20 miles) to the oil production field and inject it into the reservoir for EOR. Facility fuel and electricity usage records, and CO<sub>2</sub> metering records indicate that, on an annual basis,  $31.7 \times 10^6 \text{ m}^3$  ( $1.12 \times 10^9$  scf) of fuel gas and  $17.35 \times 10^{12}$  J (4.82 GW-hr) of electricity are consumed at the compression/pump and metering facilities to compress  $510 \times 10^6 \text{ m}^3$  (18 Bscf) CO<sub>2</sub> that is captured from the gas plant.
- Crude and associated gas produced from the EOR operations are sent to a central processing facility. CO<sub>2</sub> contained in the associated gas is separated through an amine unit, compressed, and re-injected into the EOR process, thereby recycling the CO<sub>2</sub> back into the reservoir.
- The captured, anthropogenic CO<sub>2</sub> from the gas processing facility replaces underground-sourced CO<sub>2</sub> used for tertiary oil recovery.

Assumptions for this example include the following:

- The injection of CO<sub>2</sub> for EOR is planned for the foreseeable future of the reservoir.
- Common practice in the area is to purchase the underground-sourced CO<sub>2</sub> for EOR operations.
- For the gas processing facility, venting the exhaust from the amine unit is common practice, as allowed under the terms of existing regulations in the facility location.
- Common practice for the EOR operation is to capture and recycle the CO<sub>2</sub> produced from the EOR production wells.

### **Reservoir Background**

The geological formation for this project is not prone to significant tectonic activity, earthquakes or proximity to active volcanism, which could pose the potential for accidental, rapid escape of stored CO<sub>2</sub> to the atmosphere. Through petroleum exploration and production operations, the geology and hydrogeology of the reservoir are well understood and documented. These properties make storage of CO<sub>2</sub> in this reservoir a viable long-term option and minimize the potential of an accidental release as a result of natural occurrences.

### **Baseline Scenario Selection**

#### **Baseline Candidates Considered**

The baseline scenario represents the situation or conditions that plausibly would have occurred in the absence of the project. For this example, there are three aspects to the baseline scenario:

- 1) The disposition of the CO<sub>2</sub> associated with the gas processing facility;
- 2) The source of the CO<sub>2</sub> used for EOR; and

- 3) The disposition of the CO<sub>2</sub> produced from the EOR production wells in the CO<sub>2</sub>-flooded field.

Plausible candidates for each of these aspects of the baseline scenario are identified in Table 6-4 below.

**Table 6-4. Case Study #1 Baseline Candidates**

<b>Potential Baseline Candidates for the Disposition of the CO<sub>2</sub> from the Gas Processing Facility</b>	<b>Potential Baseline Candidates Associated with the CO<sub>2</sub> used for EOR</b>	<b>Potential Baseline Candidates for the Disposition of the CO<sub>2</sub> from the EOR wells</b>
<p><b>Candidate 1:</b> Continuation of the current situation, where the natural gas plant receives gas produced from surrounding fields and processes it to remove and separate H<sub>2</sub>S and CO<sub>2</sub>. The removed CO<sub>2</sub> is released to the atmosphere.</p> <p><b>Candidate 2:</b> <i>The project activity</i>, CO<sub>2</sub> is separated from the acid gas stream, captured, and utilized for EOR, EGR, ECBM, or to maintain reservoir pressure in another formation.</p> <p><b>Candidate 3:</b> CO<sub>2</sub> is separated from the acid gas stream, captured, and utilized in another capacity, for example soft drink production or chemical manufacturing.</p> <p><b>Candidate 4:</b> CO<sub>2</sub> is separated from the acid gas stream, captured, and reinjected into the same hydrocarbon reservoir (oil or gas) from which it was produced.</p> <p><b>Candidate 5:</b> CO<sub>2</sub> is separated from the acid gas stream, captured, and injected into a saline aquifer.</p>	<p><b>Candidate A:</b> Continuation of the current situation, where underground-sourced CO<sub>2</sub> is produced with necessary processing to result in a pipeline quality CO<sub>2</sub> stream, and transported for EOR operations.<sup>10</sup></p> <p><b>Candidate B:</b> <i>The project activity</i>, where captured CO<sub>2</sub> replaces the underground-sourced CO<sub>2</sub>. This candidate requires the installation of compression and pipeline facilities to transport the captured CO<sub>2</sub> from the natural gas plant to the EOR location.</p> <p><b>Candidate C:</b> The EOR operations locate another source of anthropogenic CO<sub>2</sub>, such as combustion exhaust streams or industrial processes</p> <p><b>Candidate D:</b> EOR is achieved by the injection of natural gas, N<sub>2</sub>, or water.</p>	<p><b>Candidate I:</b> CO<sub>2</sub> produced from EOR production wells in a CO<sub>2</sub>-flooded field is vented to the atmosphere.</p> <p><b>Candidate II:</b> <i>The project activity</i>, CO<sub>2</sub> produced from EOR production wells in a CO<sub>2</sub>-flooded field is recycled to EOR operations.</p>

All candidates comply with applicable regulations. In addition, the baseline candidates reflect due consideration of the time frame and geological criteria discussed in Section 2.4 of the General Project Guidelines.

**Baseline Scenario**

Table 6-5 applies some common tests or screening procedures to assist in assessing the baseline candidates.

<sup>10</sup> The use of naturally occurring, underground-sourced CO<sub>2</sub> for enhanced hydrocarbon recovery is not, in and of itself, a GHG emission reduction project.

**Table 6-5. Case Study #1 Baseline Scenario Assessment**

	<b>Baseline Scenario Alternatives</b>	<b>Investment Ranking</b>	<b>Technology</b>	<b>Policy/Regulatory</b>	<b>Benchmarking</b>
<b>Disposition of the CO<sub>2</sub> from the Gas Processing Facility</b>	<b>Candidate 1:</b> Current situation - CO <sub>2</sub> removed from the acid gas is released to the atmosphere	No additional costs	No additional technology requirements	Consistent with current, applicable laws or regulations	Common practice in region <sup>11</sup>
	<b>Candidate 2:</b> CO <sub>2</sub> is separated from the acid gas stream, captured, and utilized for EOR, EGR, ECBM, or to maintain reservoir pressure in a hydrocarbon formation	Moderate costs for capture infrastructure; Moderate to high costs for transport	Existing technologies		Commercial in some regions
	<b>Candidate 3:</b> CO <sub>2</sub> is separated from the acid gas stream, captured, and utilized in another capacity	Moderate costs for capture infrastructure; Moderate to high costs for transport. Uncertain market for CO <sub>2</sub>	Existing technologies		Commercial in some regions
	<b>Candidate 4:</b> CO <sub>2</sub> is separated from the acid gas stream, captured, and reinjected into the same hydrocarbon reservoir from which it was produced	Moderate costs for capture infrastructure; Lower transport costs than candidates 2 and 3	Existing technologies		Commercial in some regions
	<b>Candidate 5:</b> CO <sub>2</sub> is separated from the acid gas stream, captured, and injected into a saline aquifer.	Moderate costs for capture infrastructure; Moderate to high costs for transport	Existing technologies		Commercial in some regions
<b>CO<sub>2</sub> used for EOR</b>	<b>Candidate A:</b> Current situation - underground-sourced CO <sub>2</sub> is produced and transported for EOR operations	No additional costs	No additional technology requirements	Consistent with current, applicable laws or regulations	Common practice in region
	<b>Candidate B:</b> <i>The project activity</i> - captured CO <sub>2</sub> replaces underground-sourced CO <sub>2</sub>	Moderate to high costs for capture and transport infrastructure	Existing technologies		Commercial in some regions
	<b>Candidate C:</b> The EOR operations locate another source of anthropogenic CO <sub>2</sub> , such as combustion exhaust streams or industrial processes	Moderate to very high costs for capture infrastructure; Moderate to high costs for transport	Existing technologies for some applications		Commercial in some regions, though applications capturing CO <sub>2</sub> from exhaust streams are limited

<sup>11</sup> Depending on the circumstances of the project, the region or geographic area may be narrow (e.g., an area within a nation or state), or broad (e.g., an international region or global area).

**Table 6-5. Case Study #1 Baseline Scenario Assessment (Continued)**

Baseline Scenario Alternatives		Investment Ranking	Technology	Policy/Regulatory	Benchmarking
CO <sub>2</sub> used for EOR	<b>Candidate D:</b> EOR is achieved by the injection of natural gas, N <sub>2</sub> , or water	Moderate to high costs for purchase and transport of natural gas, N <sub>2</sub> , or water		Consistent with current, applicable laws or regulations	Commercial in some regions
	Disposition of the CO <sub>2</sub> from the EOR wells	<b>Candidate I:</b> CO <sub>2</sub> produced from EOR production wells in a CO <sub>2</sub> -flooded field is vented to the atmosphere	No additional costs		No additional technology requirements
<b>Candidate II:</b> CO <sub>2</sub> produced from EOR production wells in a CO <sub>2</sub> -flooded field is recycled to EOR operations		Additional costs for CO <sub>2</sub> capture; Reduces the amount of additional CO <sub>2</sub> needed for EOR operations.	Existing technologies		Common practice in some regions

Based on comparing the baseline candidates presented above:

- Candidates 2 (*the project activity*), 3, and 5 are comparable in terms of additional costs for capture and transport infrastructure, and the availability of existing commercial technology. EGR and ECBM have limited commercial applications.
- For Candidate 3, CO<sub>2</sub> can be used for other industrial or manufacturing purposes, but would require additional processing. However, it is assumed for this example that there is no current demand near the project. This scenario may incur additional financial risk due to uncertainty in the market for CO<sub>2</sub> in a particular region. The ultimate disposition of the CO<sub>2</sub> may be vented or stored, depending on the end use application.
- Candidates 4 and 5 are assumed not to be feasible for this example.
- Candidates B (*the project activity*) and C are comparable in terms of potential transport costs and the CCS application. However, where Candidate C utilizes CO<sub>2</sub> from an exhaust stream, multiple smaller volume combustion exhaust streams may need to be combined to reach an equivalent mass of CO<sub>2</sub> as the amine unit exhaust.
- Candidate B (*the project activity*) requires that the reservoir is suitable for EOR using CO<sub>2</sub>, and suitable for long-term storage of the CO<sub>2</sub>.
- Candidate D requires a supply of water, N<sub>2</sub>, or natural gas, and that the reservoir's characteristics are suitable for one of these EOR activities.
- For Candidate I, under some circumstances it may not be feasible to capture and recycle the CO<sub>2</sub> produced from the EOR production wells.

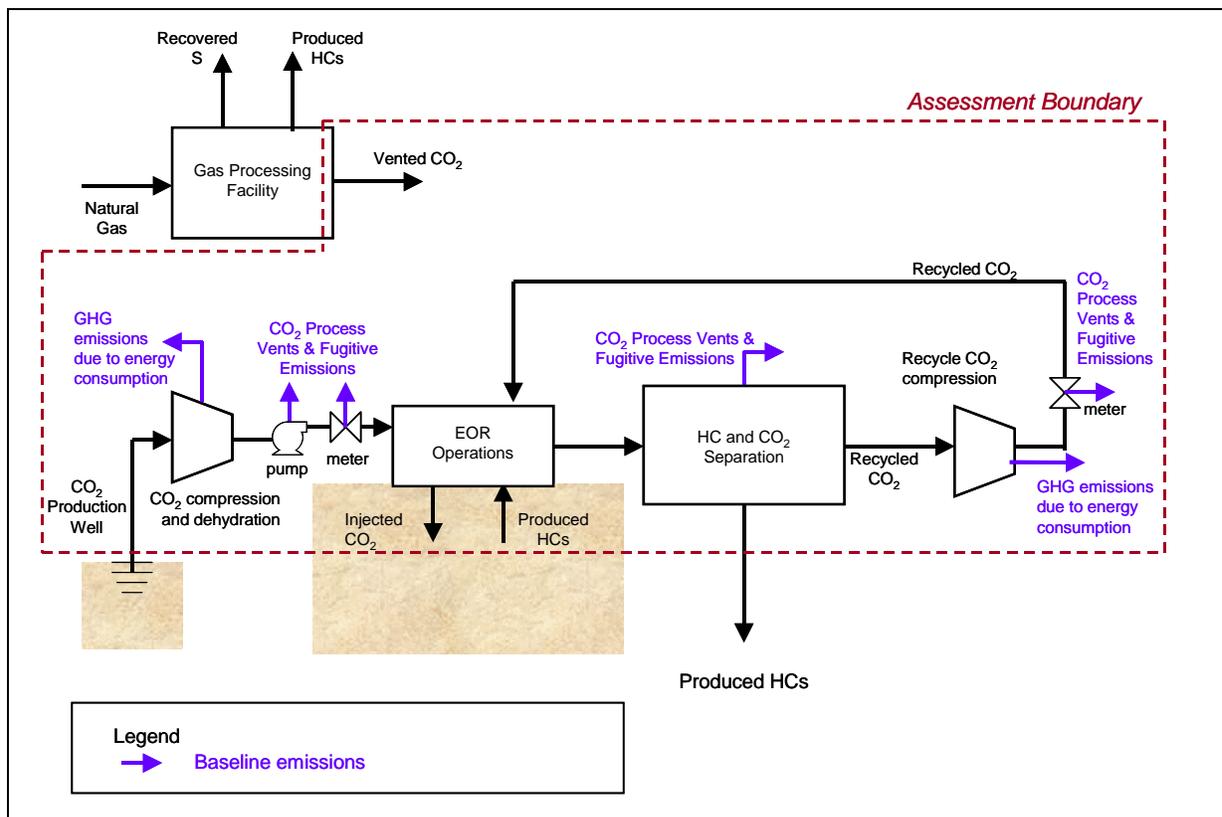
As a result of this analysis, Candidates 1, A, and II, each representing the continuation of current activities, comprise the most probable baseline scenario.<sup>12</sup>

Carbon dioxide is vented in the baseline scenario for the gas processing portion of the project. For this example, the disposition of H<sub>2</sub>S in the produced natural gas does not matter because it is unchanged between the project and the baseline.

The baseline scenario for the EOR operation portion of the project consists of the project proponent purchasing equivalent volumes (equal to metered volumes of captured vent-stack CO<sub>2</sub> supplied for EOR purposes) from natural, underground-sourced CO<sub>2</sub> sources, which are located approximately 80.5 km (50 miles) from the EOR operations. This natural CO<sub>2</sub> is dehydrated and compressed using electric-driven compressors requiring  $1.02 \times 10^5$  J/m<sup>3</sup> (802 kW-hr/MMscf) of compressed CO<sub>2</sub> for pipeline transport to the EOR operations for this example.

Crude and associated gas produced from the EOR operations are sent to a central processing facility. CO<sub>2</sub> contained in the associated gas is separated through an amine unit, compressed, and combined with natural-sourced CO<sub>2</sub> for re-injection into the EOR process.

The baseline operations are illustrated in Figure 6-8.



**Figure 6-8. Baseline Illustration of CO<sub>2</sub> Capture, Transport and Injection for Enhanced Oil Recovery Operations**

<sup>12</sup> Baseline candidates and the analysis presented here are for illustrative purposes only. Actual project activities will require an assessment of the candidates and characteristics specific to the project application. Specific climate change regimes may require additional details and justification for baseline scenario determination.

## Project Assessment Boundary

After defining the project and identifying the baseline scenario, the next step is to determine the assessment boundary. The assessment boundary encompasses GHG emission sources, sinks, and reservoirs controlled by the project proponent that are related to the GHG reduction project, affected by the GHG reduction project, and relevant to the baseline scenario. Figures 6-7 and 6-8 illustrate the processes and operations within the assessment boundary for both the project activity and the baseline scenario, respectively.

Table 6-6 examines potential emission sources within the assessment boundary and compares the baseline scenario to the project activity.

**Table 6-6. Case Study #1 Assessment Boundary Determination**

Potential Emission Sources		Relation to the Project Proponent	Considerations
<b>Baseline Scenario</b>			
<b>Capture</b>	<ul style="list-style-type: none"> <li>✓ CO<sub>2</sub> and, to a lesser extent, CH<sub>4</sub> emissions from the amine unit exhaust at the gas plant</li> <li>✓ Vented and fugitive CO<sub>2</sub> emissions associated with recovering CO<sub>2</sub> from the underground-sourced source</li> </ul>	Related	
<b>Transport</b>	<ul style="list-style-type: none"> <li>✓ CO<sub>2</sub>, CH<sub>4</sub>, and N<sub>2</sub>O emissions from offsite electricity generation used to operate transport equipment</li> <li>✓ CO<sub>2</sub>, CH<sub>4</sub>, and N<sub>2</sub>O emissions from fuel combustion associated with transport equipment</li> <li>✓ Vented and fugitive CO<sub>2</sub> emissions, associated with transport operations and equipment</li> </ul>	Related	Baseline scenario transport emissions are similar to the project activity and may cancel out depending on the difference in distance transported.
<b>Storage</b>	<ul style="list-style-type: none"> <li>✓ CO<sub>2</sub>, CH<sub>4</sub>, and N<sub>2</sub>O emissions from offsite electricity generation used for storage operations and equipment, including the recycle of CO<sub>2</sub> from the associated gas.</li> <li>✓ CO<sub>2</sub>, CH<sub>4</sub>, and N<sub>2</sub>O emissions from fuel combustion associated with storage operations and equipment, including the recycle of CO<sub>2</sub> from the associated gas.</li> <li>✓ Vented and fugitive CO<sub>2</sub> emissions, associated with storage operations and equipment, including the recycle of CO<sub>2</sub> from the associated gas.</li> </ul>	<p>Related</p> <p>Controlled</p> <p>Controlled</p>	Baseline scenario storage and recycle emissions will likely cancel out the project-based emissions.

**Table 6-6. Case Study #1 Assessment Boundary Determination (Continued)**

Potential Emission Sources		Relation to the Project Proponent	Considerations
<b>Project Activity</b>			
<b>Capture</b>	<ul style="list-style-type: none"> <li>✓ CO<sub>2</sub> and, to a lesser extent, CH<sub>4</sub> emissions from the dehydration of the capture gas stream</li> <li>✓ CO<sub>2</sub>, CH<sub>4</sub>, and N<sub>2</sub>O emissions from fuel combustion associated with compressing the capture gas stream</li> <li>✓ CO<sub>2</sub>, CH<sub>4</sub>, and N<sub>2</sub>O emissions from offsite electricity used to operate capture equipment</li> </ul>	Related	
<b>Transport</b>	<ul style="list-style-type: none"> <li>✓ CO<sub>2</sub>, CH<sub>4</sub>, and N<sub>2</sub>O emissions from offsite electricity used to operate transport equipment</li> </ul>	Related	Project-based transport emissions are similar to the baseline scenario and may cancel out depending on the difference in distance transported.
	<ul style="list-style-type: none"> <li>✓ CO<sub>2</sub>, CH<sub>4</sub>, and N<sub>2</sub>O emissions from fuel combustion associated with transport equipment</li> <li>✓ Vented and fugitive CO<sub>2</sub> emissions, associated with transport operations and equipment</li> </ul>	Related	
<b>Storage</b>	<ul style="list-style-type: none"> <li>✓ CO<sub>2</sub>, CH<sub>4</sub>, and N<sub>2</sub>O emissions from offsite electricity generation used for storage operations and equipment</li> <li>✓ CO<sub>2</sub>, CH<sub>4</sub>, and N<sub>2</sub>O emissions from fuel combustion associated with storage operations and equipment, including the recycle of CO<sub>2</sub> from the associated gas</li> <li>✓ Vented and fugitive CO<sub>2</sub> emissions, associated with storage operations and equipment, including the recycle of CO<sub>2</sub> from the associated gas.</li> </ul>	Related  Controlled  Controlled	Project-based storage and recycle emissions will likely cancel out the baseline scenario emissions.

**Quantifying Emission Reductions**

The following exhibit demonstrates the emission estimation for the baseline scenario and project activity. Emission reductions are quantified as the difference between the baseline and project emissions.

**EXHIBIT 6.1: Capture and Storage of Vent-Sourced CO<sub>2</sub>**

Known Information (based on hypothetical, measured data)

- Process: 510×10<sup>6</sup> m<sup>3</sup> (18 ×10<sup>9</sup> scf) CO<sub>2</sub> is captured from the gas plant for the year
- Captured Gas Composition: 98.4 % CO<sub>2</sub>, 1.6 % CH<sub>4</sub> by volume

Energy Requirements: 31.7×10<sup>6</sup> m<sup>3</sup> (1,120 MMscf) of natural gas and 17.35×10<sup>12</sup> J (4.82 GW-hr) of electricity are consumed at the compression/pump and metering facilities to transport the capture gas 32 km (20 miles) to the EOR facility and inject it into the formation.

**EXHIBIT 6.1 Continued**

- CO<sub>2</sub> Emission Factor: Based on natural gas composition, the CO<sub>2</sub> emission factor is 49.95 tonnes/10<sup>12</sup> J (0.0527 tonnes CO<sub>2</sub>/10<sup>6</sup> BTU), assuming all of the C is converted to CO<sub>2</sub>, and heating value is 37.7×10<sup>6</sup> J/m<sup>3</sup> (1012 Btu HHV/scf).
- Transport: For the baseline scenario, underground-sourced CO<sub>2</sub> was transported 80.5 km (50 miles) using electric-driven compressors requiring 1.02×10<sup>5</sup> J/m<sup>3</sup> (802 kW-hr/MMscf) of compressed gas.

In addition, monitoring of potential CO<sub>2</sub> escape routes during the year did not detect any CO<sub>2</sub> losses.

**Baseline Emissions**

Baseline emissions = VENT<sub>1</sub> + CMB<sub>1</sub> + FUG<sub>1</sub> + IND<sub>1</sub>  
where,

- VENT<sub>1</sub> = Vented CO<sub>2</sub> that would have occurred as a result of transporting the underground-sourced CO<sub>2</sub> to the EOR site. For the baseline scenario, emissions from the dehydrator and recycle operations also occur in the project activity and therefore cancel out the baseline emissions. Pipeline venting and blowdown emissions would apply to the baseline scenario.
- CMB<sub>1</sub> = Combustion emission associated with the recycle CO<sub>2</sub>. These emissions also occur in the project activity, and therefore cancel out the baseline emissions.
- FUG<sub>1</sub> = Fugitive CO<sub>2</sub> emissions that would have occurred as a result of transporting the underground-sourced CO<sub>2</sub> to the EOR site. For the baseline scenario, fugitive emissions from the compressor, dehydrator, and recycle operations also occur in the project activity and therefore cancel out the baseline emissions. Pipeline fugitive emissions would apply to the baseline scenario.
- IND<sub>1</sub> = Indirect emissions that would have occurred from electricity usage to transport the underground-sourced CO<sub>2</sub> to the EOR site. Indirect emissions associated with the recycle operations also occur in the project activity and therefore cancel out the baseline.

**Baseline Emissions Estimate**

**Vented Emissions (VENT<sub>1</sub>):**

Vented emissions for the baseline scenario include the gas volume that would have been vented to the atmosphere in the absence of the project. This gas volume is estimated based on the volume of gas captured (510×10<sup>6</sup> m<sup>3</sup>) and the CO<sub>2</sub> and CH<sub>4</sub> concentrations in the gas (98.4 and 1.6 % by volume, respectively). A global warming potential (GWP) of 21 is used for CH<sub>4</sub> to convert emissions to CO<sub>2</sub> equivalent (CO<sub>2</sub> Eq.).

**EXHIBIT 6.1 Continued**

$$\begin{aligned}
 \text{VENT}_1 &= (\text{Metered volume}) \times [\text{CO}_2 \text{ fraction} + 21 \times (\text{CH}_4 \text{ fraction})] \\
 &= 510 \times 10^6 \text{ m}^3 \text{ gas} \times \\
 &\quad \left( 0.984 \frac{\text{m}^3 \text{ CO}_2}{\text{m}^3 \text{ gas}} \times \frac{\text{kg mole CO}_2}{23.685 \text{ m}^3 \text{ CO}_2} \times 44 \frac{\text{kg CO}_2}{\text{kg mole CO}_2} \times \frac{\text{tonne}}{1000 \text{ kg}} \right. \\
 &\quad \left. + 21 \times 0.016 \frac{\text{m}^3 \text{ CH}_4}{\text{m}^3 \text{ gas}} \times \frac{\text{kg mole CH}_4}{23.685 \text{ m}^3 \text{ CH}_4} \times 16 \frac{\text{kg CH}_4}{\text{kg mole CH}_4} \times \frac{\text{tonne}}{1000 \text{ kg}} \right) \\
 &= 1,048,035 \text{ tonnes CO}_2 \text{ Eq.}
 \end{aligned}$$

Vented emissions associated with the baseline scenario would also include pipeline vents during normal operations and maintenance/upset conditions. API Compendium Table 5-24 provides an emission factor for transmission pipeline venting/blowdowns that can be converted from a CH<sub>4</sub> basis (for natural gas pipelines) to a CO<sub>2</sub> basis for this analysis.

$$\begin{aligned}
 \text{VENT}_1 &= 80.5 \text{ km} \times \frac{0.4881 \text{ tonnes CH}_4}{\text{km - yr}} \times \frac{\text{tonne mole CH}_4}{16 \text{ tonne CH}_4} \times \frac{\text{tonne mole gas}}{0.934 \text{ tonne mole CH}_4} \\
 &\quad \times \frac{0.984 \text{ tonne mole CO}_2}{\text{tonne mole gas}} \times \frac{44 \text{ tonne CO}_2}{\text{tonne mole CO}_2} \\
 &= 113.8 \text{ tonnes CO}_2
 \end{aligned}$$

**Combustion Emissions (CMB<sub>1</sub>):**

Combustion sources associated with capture, transport, and storage (including CO<sub>2</sub> recycle) in the baseline scenario also occur in the project, and therefore cancel out.

**Fugitive Emissions (FUG<sub>1</sub>):**

Similarly, fugitive emissions associated with the baseline scenario would include pipeline leaks. API Compendium Table 6-1 provides a fugitive pipeline emission factor for transmission pipelines that can be converted from the default API Compendium CH<sub>4</sub> basis to a CO<sub>2</sub> basis for this analysis. For this conversion, the Draft 2006 IPCC Guidelines for National Greenhouse Gas Inventories Chapter 5 derives a CO<sub>2</sub> emission factor based on the CH<sub>4</sub> mass-based emission rate, where CO<sub>2</sub> emission rate = 1.66 times the CH<sub>4</sub> emission rate.

$$\begin{aligned}
 \text{FUG}_1 &= 80.5 \text{ km} \times \frac{2.233 \text{ tonne CH}_4}{\text{km - yr}} \times \frac{1.66 \text{ tonnes CO}_2}{\text{tonnes CH}_4} \\
 &= 298 \text{ tonnes CO}_2
 \end{aligned}$$

**EXHIBIT 6.1 Continued****Indirect Emissions (IND<sub>1</sub>):**

Emissions associated with the electricity used to transport the underground-sourced CO<sub>2</sub> to the EOR facility are estimated based on the electricity demand for the volume of gas transported and regional electric generation emission factors. For the purpose of this example, the electricity emission factors for the (hypothetical, undefined) region associated with the underground-sourced CO<sub>2</sub> are: 0.2425 tonnes CO<sub>2</sub>/10<sup>9</sup> J, 0.0016 tonnes CH<sub>4</sub>/10<sup>12</sup> J, and 0.0036 tonnes N<sub>2</sub>O/10<sup>12</sup> J. The total CO<sub>2</sub> Eq. emissions are calculated using a GWP of 21 for CH<sub>4</sub> and 310 for N<sub>2</sub>O.

$$\text{IND}_1(\text{energy}) = 510 \times 10^6 \text{ m}^3 \text{ gas} \times \frac{1.02 \times 10^5 \text{ J}}{\text{m}^3 \text{ gas}} = 52.02 \times 10^{12} \text{ J}$$

$$\text{CO}_2 \text{ emissions} = 0.2425 \frac{\text{tonnes}}{10^9 \text{ J}} \times 52.02 \times 10^{12} \text{ J} = 12,615 \text{ tonnes CO}_2$$

$$\text{CH}_4 \text{ emissions} = 0.0016 \frac{\text{tonnes}}{10^{12} \text{ J}} \times 52.02 \times 10^{12} \text{ J} = 0.0832 \text{ tonnes CH}_4$$

$$\text{N}_2\text{O emissions} = 0.0036 \frac{\text{tonnes}}{10^{12} \text{ J}} \times 52.02 \times 10^{12} \text{ J} = 0.187 \text{ tonnes N}_2\text{O}$$

$$\begin{aligned} \text{IND}_1 &= 12,615 \text{ tonnes CO}_2 + (21 \times 0.0832 \text{ tonnes CH}_4) \\ &\quad + (310 \times 0.187 \text{ tonnes N}_2\text{O}) \\ &= 12,675 \text{ tonnes CO}_2 \text{ Eq.} \end{aligned}$$

$$\begin{aligned} \text{Baseline emissions} &= 1,048,035 + 113.8 + 298 + 12,675 \\ &= 1,061,122 \text{ tonnes CO}_2 \text{ Eq.} \end{aligned}$$

**Project Emissions Calculations**

$$\text{Project emissions} = \text{VENT}_2 + \text{CMB}_2 + \text{FUG}_2 + \text{IND}_2$$

where,

VENT<sub>2</sub> = Pipeline venting and blowdown emissions from transporting the CO<sub>2</sub> to the EOR site. Note that dehydrator emissions also occur in the baseline scenario and therefore cancel out. Vented emissions associated with the recycle CO<sub>2</sub> also occur in the baseline scenario, and therefore cancel out.

CMB<sub>2</sub> = Combustion emissions from gas-fired compressors at the gas plant. Note that fuel usage to inject the CO<sub>2</sub> into the EOR reservoir would also occur for the baseline scenario and therefore cancel out. Combustion emissions associated with the recycle CO<sub>2</sub> also occur in the baseline scenario, and therefore cancel out.

**EXHIBIT 6.1 Continued**

- FUG<sub>2</sub> = Pipeline fugitive CO<sub>2</sub> emissions from transporting the CO<sub>2</sub> to the EOR site. Note that fugitive emissions from the compressor, dehydrator, and CO<sub>2</sub> recycle operations also occur in the baseline scenario and therefore cancel out.
- IND<sub>2</sub> = Indirect emissions for electric-driven pumps used to transport the CO<sub>2</sub> to the EOR site. Indirect emissions associated with the recycle CO<sub>2</sub> also occur in the baseline scenario, and therefore cancel out.

**Vented Emissions (VENT<sub>2</sub>):**

Vented emissions associated with the project include pipeline vents during normal operations and maintenance/upset conditions. API Compendium Table 5-24 provides an emission factor for transmission pipeline venting/blowdowns that can be converted from a CH<sub>4</sub> basis (for natural gas pipelines) to a CO<sub>2</sub> basis for this analysis. Note that the gas transported in the project contains a small amount of CH<sub>4</sub>.

$$\text{CO}_2 \text{ Emissions} = 32 \text{ km} \times \frac{0.4881 \text{ tonne CH}_4}{\text{km}} \times \frac{\text{tonne mole CH}_4}{16 \text{ tonne CH}_4} \times \frac{\text{tonne mole gas}}{0.934 \text{ tonne mole CH}_4} \\ \times \frac{0.984 \text{ tonne mole CO}_2}{\text{tonne mole gas}} \times \frac{44 \text{ tonne CO}_2}{\text{tonne mole CO}_2} = 45.3 \text{ tonnes CO}_2$$

$$\text{CH}_4 \text{ Emissions} = 45.3 \text{ tonnes CO}_2 \times \frac{\text{tonne mole CO}_2}{44 \text{ tonnes CO}_2} \times \frac{\text{tonne mole gas}}{0.984 \text{ tonne mole CO}_2} \\ \times \frac{0.016 \text{ tonne mole CH}_4}{\text{tonne mole gas}} \times \frac{16 \text{ tonne CH}_4}{\text{tonne mole CH}_4} \\ = 0.27 \text{ tonnes CH}_4$$

$$\text{VENT}_2 = 45.3 \text{ tonnes CO}_2 + (21 \times 0.27 \text{ tonnes CH}_4) \\ = 51.0 \text{ tonnes CO}_2 \text{ Eq.}$$

**Combustion emissions (CMB<sub>2</sub>):**

Project combustion emissions are calculated based on measured fuel consumption rates and fuel analysis data. Based on fuel analysis data, the CO<sub>2</sub> emission factor in terms of thermal energy input is 49.95 tonnes/10<sup>12</sup> J (0.0527 tonnes CO<sub>2</sub>/10<sup>6</sup> Btu) and the fuel heating value is 37.7×10<sup>6</sup> J/m<sup>3</sup> (1012.4 Btu/scf). The emission factor was conservatively estimated by assuming all the carbon in the fuel is converted to CO<sub>2</sub> during the combustion process and discharged to the atmosphere, consistent with the API Compendium's preferred approach.

Using this emission factor and the fuel usage, the annual CO<sub>2</sub> emissions are calculated as:

$$\text{CO}_2 \text{ emissions} = 31.7 \times 10^6 \text{ m}^3 \times 37.7 \times 10^6 \frac{\text{J}}{\text{m}^3} \times 49.95 \frac{\text{tonne CO}_2}{10^{12} \text{ J}} = 59,695 \text{ tonnes CO}_2$$

**EXHIBIT 6.1 Continued**

To calculate CH<sub>4</sub> and N<sub>2</sub>O emissions from fuel combustion, compressor engine emission factors for 2-stroke gas-fired engines are applied (API Compendium, Table 4-5).

CH<sub>4</sub> Emissions = (fuel usage) × (emission factor)

$$= 31.7 \times 10^6 \text{ m}^3 \times 37.7 \times 10^6 \frac{\text{J}}{\text{m}^3} \times 0.623 \frac{\text{tonne CH}_4}{10^{12} \text{ J}} = 745 \text{ tonnes CH}_4$$

$$\text{N}_2\text{O Emissions} = 31.7 \times 10^6 \text{ m}^3 \times 37.7 \times 10^6 \frac{\text{J}}{\text{m}^3} \times 0.0021 \frac{\text{tonne N}_2\text{O}}{10^{12} \text{ J}} = 2.51 \text{ tonnes N}_2\text{O}$$

The direct CO<sub>2</sub> equivalent (CO<sub>2</sub> Eq.) emissions for combustion sources is calculated using a GWP of 21 for CH<sub>4</sub> and 310 for N<sub>2</sub>O.

$$\begin{aligned} \text{CMB}_2 &= \text{CO}_2 + (21 \times \text{CH}_4) + (310 \times \text{N}_2\text{O}) \\ &= 59,695 + (21 \times 745) + (310 \times 2.51) = 76,118 \text{ tonnes CO}_2 \text{ Eq.} \end{aligned}$$

**Fugitive Emissions (FUG<sub>2</sub>):**

Similarly, fugitive emissions for the project include pipeline leaks. API Compendium Table 6-1 provides a transmission fugitive pipeline emission factor that can be converted from a CH<sub>4</sub> basis (for natural gas pipelines) to a CH<sub>4</sub> and CO<sub>2</sub> basis for this analysis, where the CO<sub>2</sub> emission rate = 1.66 times the CH<sub>4</sub> emission rate (IPCC Inventory Guidelines, Chapter 5). Note that the gas transported in the project contains a small amount of CH<sub>4</sub>, in which case both a leak and oxidation emission factor apply.

$$\begin{aligned} \text{CH}_4 \text{ Emissions} &= 32 \text{ km} \times \frac{2.233 \text{ tonnes CH}_4}{\text{km}} \times \frac{0.016 \text{ mole CH}_4 \text{ (project)}}{0.984 \text{ mole CH}_4 \text{ (default)}} \\ &= 1.16 \text{ tonnes CH}_4 \end{aligned}$$

$$\begin{aligned} \text{CO}_2 \text{ Emissions} &= 32 \text{ km} \times \frac{2.233 \text{ tonnes CH}_4}{\text{km}} \times \frac{1.66 \text{ tonnes CO}_2}{\text{tonnes CH}_4} \\ &= 119 \text{ tonnes CO}_2 \end{aligned}$$

CO<sub>2</sub> emissions from the oxidation of CH<sub>4</sub> in the soil:

$$\begin{aligned} \text{CO}_2 \text{ Emissions} &= 32 \text{ km} \times \frac{2.139 \times 10^{-3} \text{ tonnes CO}_2}{\text{km}} \times \frac{0.016 \text{ tonne mole CH}_4 \text{ project}}{0.934 \text{ tonne mole CH}_4 \text{ EF basis}} \\ &= 0.0012 \text{ tonnes CO}_2 \end{aligned}$$

$$\begin{aligned} \text{FUG}_2 &= (119 + 0.0012) \text{ tonnes CO}_2 + (21 \times 1.16 \text{ tonnes CH}_4) \\ &= 143.4 \text{ tonnes CO}_2 \text{ Eq.} \end{aligned}$$

**EXHIBIT 6.1 Continued****Indirect emissions (IND<sub>2</sub>)**

Indirect emissions (IND<sub>2</sub>) are calculated from regional emission factors [for the purpose of this example, the electricity emission factors for the (hypothetical, undefined) region associated with the underground-sourced CO<sub>2</sub> are: 0.2425 tonnes CO<sub>2</sub>/10<sup>9</sup> J (0.873 tonnes CO<sub>2</sub>/MW-hr), 0.0016 tonnes CH<sub>4</sub>/10<sup>12</sup> J (5.76E-6 tonnes CH<sub>4</sub>/MW-hr), and 0.0036 tonnes N<sub>2</sub>O/10<sup>12</sup> J (1.311E-5 tonnes N<sub>2</sub>O/MW-hr)]. The indirect emissions represent the emissions due to the generation of electricity required to operate the pumping equipment and facilities associated with transporting the captured CO<sub>2</sub> from the gas plant to the EOR site. These emissions are calculated from actual electricity usage data as reflected in the electric utility bills. The total CO<sub>2</sub> Eq. emissions are calculated using a GWP of 21 for CH<sub>4</sub> and 310 for N<sub>2</sub>O.

Emissions = (emission factor) × (electrical usage)

$$\text{CO}_2 \text{ Emissions} = 0.2425 \frac{\text{tonne CO}_2}{10^9 \text{ J}} \times 17.35 \times 10^{12} \text{ J} = 4,207 \text{ tonnes CO}_2$$

$$\text{CH}_4 \text{ Emissions} = 0.0016 \frac{\text{tonnes CH}_4}{10^9 \text{ J}} \times 17.35 \times 10^{12} \text{ J} = 0.028 \text{ tonne CH}_4$$

$$\text{N}_2\text{O Emissions} = 0.0036 \frac{\text{tonnes N}_2\text{O}}{10^9 \text{ J}} \times 17.35 \times 10^{12} \text{ J} = 0.063 \text{ tonne N}_2\text{O}$$

$$\begin{aligned} \text{IND}_2 &= 4,207 \text{ tonnes CO}_2 + (21 \times 0.028 \text{ tonnes CH}_4) + (310 \times 0.063 \text{ tonnes N}_2\text{O}) \\ &= 4,227 \text{ tonnes CO}_2 \text{ Eq.} \end{aligned}$$

$$\begin{aligned} \text{Project emissions} &= \text{VENT}_2 + \text{CMB}_2 + \text{FUG}_2 + \text{IND}_2 \\ &= 51.0 + 76,118 + 143.4 + 4,227 \\ &= 80,539 \text{ tonnes CO}_2 \text{ Eq. per year} \end{aligned}$$

$$\begin{aligned} \text{Emission Reductions} &= \text{Baseline Emissions} - \text{Project Emissions} \\ &= 1,061,122 - 80,539 \\ &= \mathbf{980,583 \text{ tonnes CO}_2 \text{ Eq. per year}} \end{aligned}$$

**Monitoring**

As discussed in Section 6.7, monitoring for CCS is an iterative, risk-based process, utilizing information from ongoing assessments of characteristics that are specific to a particular CCS project. As a result, monitoring plans should be fit-for-purpose to manage potential risks for the specific CCS application.

The following outlines some potential monitoring activities that might be implemented for this type of GHG reduction project. These are provided for illustrative purposes for this example. Actual monitoring requirements depend on the specific project characteristics. In addition, particular climate change regimes may specify monitoring requirements.

### **Baseline Monitoring**

For the baseline scenario, CO<sub>2</sub> injection was already occurring for EOR. In addition, the reservoir was well characterized before and during the stages of oil production. Baseline monitoring information may include the following:

- Characterization of sub-surface conditions to determine the effectiveness of the trapping mechanisms and of the caprock to serve as a seal;
- Determination of storage capacity;
- Characterization of permeable distribution for CO<sub>2</sub> injection (not necessary for long-term monitoring of CO<sub>2</sub>) and in targeted areas for migration for EOR;
- Integrity of existing wells (active wells and abandoned wells); and
- Identification of any other potential escape mechanisms.

In assessing the reservoir's ability to store CO<sub>2</sub>, seismic monitoring and simulation results were used to determine potential pathways for CO<sub>2</sub> to escape and estimate the amount of CO<sub>2</sub> that could escape from any identified routes.

### **Operational (Project) Monitoring**

Monitoring methods were established to detect anomalies from any areas identified during the baseline period that indicated a risk for loss of containment. During the project's operational phase, three types of monitoring are used:

- 1) Monitoring to determine the project activities emissions,
- 2) Monitoring of the movement of CO<sub>2</sub> within the reservoir; and
- 3) Monitoring of areas of potential escape to demonstrate containment.

The example above demonstrates the type of measurement data needed to quantify the project activity's emissions and reductions. The temperature and pressure of the reservoir are obtained through downhole monitoring, and are used to support reservoir simulations, as well as to ensure that the reservoir pressure does not adversely impact the caprock and that injection does not induce fractures in the reservoir formation. The amount of CO<sub>2</sub> injected into the reservoir, the condition of the injection well(s), and wellhead pressures are additional monitoring data.

The movement of the CO<sub>2</sub> within the reservoir is monitored through sampling and analysis from observation wells. Since the reservoir contains some natural CO<sub>2</sub> that is produced with the crude, a tracer gas can be added to the injected CO<sub>2</sub> to distinguish it from the underground-sourced CO<sub>2</sub>.

The containment of CO<sub>2</sub> depends on the migration rate, path, and extent of the caprock. Baseline data established the areas of potential leaks. Monitoring methods specific to those areas are used to determine the ongoing containment of the reservoir. Here also, tracers may be used to distinguish the injected CO<sub>2</sub> from underground-sourced CO<sub>2</sub>.

3D seismic surveys can be used to confirm that the injected CO<sub>2</sub> behaves as expected, and/or can be conducted if/when the escape of CO<sub>2</sub> is detected. Seismic survey data also support reservoir modeling, which can be used to examine the potential for CO<sub>2</sub> leaks and to estimate the volume of any CO<sub>2</sub> leaks.

### **Post-Injection Monitoring**

Emission reductions are not quantified after injection has ceased; however, adjustments and emissions will continue to be assessed and thus ongoing monitoring may be needed post-injection. Data collected during the injection phase will be used to determine the type and extent of monitoring after the production lifetime of the reservoir.

# ATTACHMENT 1

## CCS PROJECT CASE STUDY #2: GEOLOGICAL STORAGE OF ACID GAS

### Project Definition

#### Description of the Project Activity

This project example is based on capture of acid gas from sour gas production (including sour associated gas during oil production), separation of the acid gas components ( $H_2S$  and  $CO_2$ ) in a conventional acid gas removal process, and transport and re-injection of the acid gas in an abandoned reservoir. As a result, this project avoids  $CO_2$  emissions, as well as the need for sulfur recovery operations. A schematic diagram of the project activity is shown in Figure 6-9.

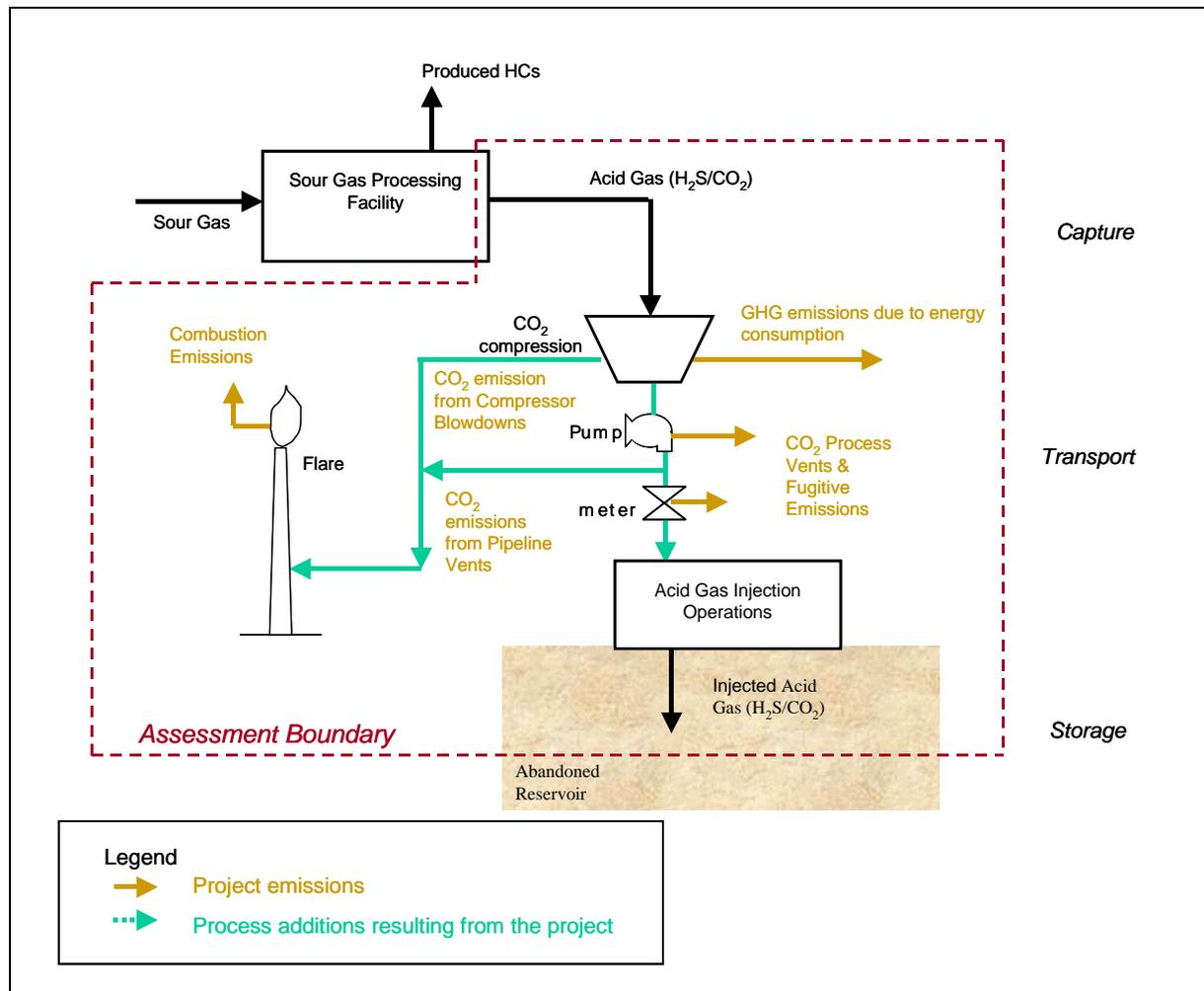


Figure 6-9. Project Illustration of Acid Gas Storage Operations

This project involves the following:

- Capture of the exhaust stream from the sour gas processing unit regenerator. The composition of the captured gas in this example is taken to be 50% H<sub>2</sub>S, 45% CO<sub>2</sub>, 4% moisture, and 1% CH<sub>4</sub> by volume, but is expected to vary from project to project. (Note that the separation of the acid gases [H<sub>2</sub>S and CO<sub>2</sub>] from the hydrocarbons in the produced gas occurs in the absence of the project.)
- Compression using multiple electric-driven compressors and pumps to transport the acid gases 16 km (10 miles) by pipeline.
- Injection of the acid gases into an abandoned reservoir.
- Facility electricity usage and CO<sub>2</sub> metering records indicate that, on an annual basis, 308×10<sup>12</sup> J (85.6 GW-hr) of electricity is consumed at the compression/pump and metering facilities to compress 362×10<sup>6</sup> m<sup>3</sup> (12.8 ×10<sup>9</sup> scf) gas captured from the sour gas processing plant.

### Reservoir Background

The geological formation for this project is suitable for storage. It is not prone to significant tectonic activity, earthquakes, or proximity to active volcanism, or other types of potential leaks of the stored gas. Since this reservoir formerly contained hydrocarbons that have been recovered, the geology and hydrogeology of the reservoir are well understood and documented. These properties make injection and storage of the acid gas in this reservoir a viable long-term option and minimize the potential of an accidental release as a result of natural occurrences.

### Baseline Scenario Selection

For this example, common practice for gas processing operations is assumed to consist of processing the H<sub>2</sub>S in the gas by conversion to elemental sulfur (Claus process) and venting the exhaust, mainly products of combustion, including CO<sub>2</sub>, to the atmosphere. Alternatively, the acid gas may be incinerated, which also results in venting the CO<sub>2</sub> to the atmosphere.

### Baseline Candidates Considered

The baseline scenario represents the situation or conditions that plausibly would have occurred in the absence of the project. Plausible candidates for the baseline scenario are presented in Table 6-7. To the extent possible, elements of the baseline candidates are aligned with corresponding aspects of the CCS chain.

**Table 6-7. Case Study #2 Baseline Candidates**

<b>Potential Baseline Candidates for the Disposition of the CO<sub>2</sub> from the Gas Processing Facility (Capture)</b>	<b>Potential Baseline Candidates Associated with Transport</b>	<b>Potential Baseline Candidates Associated with the Ultimate Disposition of the CO<sub>2</sub> (Storage)</b>
<b>Candidate 1:</b> Further processing of the acid gas stream in a sulfur plant to separate out the sulfur using a suitable process (e.g., Claus units).	<b>Candidate 1:</b> The sulfur separated from the acid gas stream would either be sold or transported offsite for disposal in the absence of a market for the product.	<b>Candidate 1:</b> The CO <sub>2</sub> in the acid gas and additional CO <sub>2</sub> generated from the process would be emitted to the atmosphere.

**Table 6-7. Case Study #2 Baseline Candidates (Continued)**

<b>Potential Baseline Candidates for the Disposition of the CO<sub>2</sub> from the Gas Processing Facility (Capture)</b>	<b>Potential Baseline Candidates Associated with Transport</b>	<b>Potential Baseline Candidates Associated with the Ultimate Disposition of the CO<sub>2</sub> (Storage)</b>
<b>Candidate 2:</b> The acid gas stream is combusted in incinerators. Some further processing may be required prior to incineration.	<b>Candidate 2:</b> There is no transport component for this baseline candidate.	<b>Candidate 2:</b> The products of combustion including SO <sub>2</sub> and CO <sub>2</sub> would be released to the atmosphere. Depending on regional SO <sub>2</sub> regulations, a flue gas desulfurization (FGD) unit may be required to reduce SO <sub>2</sub> emissions.
<b>Candidate 3:</b> <i>The project activity</i> , which includes capture of the exhaust stream from the sour gas processing unit regenerator.	<b>Candidate 3:</b> <i>The project activity</i> , Installation of compression equipment and pipeline infrastructure to transport the CO <sub>2</sub> to the geological storage formation.	<b>Candidate 3:</b> <i>The project activity</i> , Installation of injection facilities for long-term storage of the acid gas stream (H <sub>2</sub> S and CO <sub>2</sub> ) in an abandoned underground reservoir, deep saline formation, or other geological formation.
<b>Candidate 4:</b> Similar to Candidate 3, CO <sub>2</sub> and H <sub>2</sub> S are removed from the natural gas stream.	<b>Candidate 4:</b> As with Candidate 3, this requires the installation of compression equipment and pipeline infrastructure to transport the CO <sub>2</sub> . The transport requirements and costs would likely be less than Candidate 3.	<b>Candidate 4:</b> Installation of injection facilities for long-term storage of the acid gas stream (H <sub>2</sub> S and CO <sub>2</sub> ) in the same production reservoir from which they originated.
<b>Candidate 5:</b> CO <sub>2</sub> is separated from the sour gas.	<b>Candidate 5:</b> May require compression, dehydration, and/or pipeline to deliver the CO <sub>2</sub> to custody transfer.	<b>Candidate 5:</b> CO <sub>2</sub> is utilized in another capacity, for example soft drink production or chemical manufacturing.
<b>Candidate 6:</b> CO <sub>2</sub> is separated from the sour gas.	<b>Candidate 6:</b> Installation of compression equipment and pipeline infrastructure to transport the CO <sub>2</sub> to the EOR, EGR, ECBM, or reservoir location.	<b>Candidate 6:</b> CO <sub>2</sub> is used for EOR, EGR, ECBM, or to maintain reservoir pressure.

All of the baseline candidates comply with applicable regulations for this example.<sup>13</sup>

**Baseline Scenario**

Table 6-8 applies some common tests or screening procedures to assist in evaluating the baseline candidates.

**Table 6-8. Case Study #2 Baseline Scenario Assessment**

<b>Baseline Scenario Alternatives</b>	<b>Investment Ranking</b>	<b>Technology</b>	<b>Policy/Regulatory</b>	<b>Benchmarking</b>
Candidate 1: Further processing in a sulfur plant	Moderate costs	Existing technologies	Consistent with current, applicable laws or regulations in most regions. Sulfur disposition may be regulated.	Common practice in region

<sup>13</sup> Note, acid gas injection is illegal in Australia.

**Table 6-8. Case Study #2 Baseline Scenario Assessment (Continued)**

<b>Baseline Scenario Alternatives</b>	<b>Investment Ranking</b>	<b>Technology</b>	<b>Policy/Regulatory</b>	<b>Benchmarking</b>
Candidate 2: Combust gas stream in an incinerator	Moderate to high costs depending upon required exhaust controls to limit SO <sub>2</sub> emissions. Additional fuel costs.	Existing technologies	May require significant SO <sub>2</sub> reductions to meet applicable environmental regulations	Some commercial projects
Candidate 3: <i>The project activity</i> - Store the acid gas in an abandoned underground reservoir	Moderate costs for capture, transport, and injection infrastructure	Existing technologies	Acid gas injection may be regulated in some areas.	Commercial in some regions <sup>14</sup>
Candidate 4: CO <sub>2</sub> and H <sub>2</sub> S are removed from the natural gas and injected back into the same production reservoir from which they originated.	Moderate costs for capture and injection infrastructure. Costs for transport would likely be less than for Candidate 3.	Existing technologies	Consistent with current, applicable laws or regulations	Commercial in some regions
Candidate 5: CO <sub>2</sub> is separated from the sour gas and is utilized in another capacity.	Requires additional processing to separate the CO <sub>2</sub> from the H <sub>2</sub> S. Moderate to high costs for transport infrastructure, depending on the distance. Uncertain market for CO <sub>2</sub> .	Existing technologies	Consistent with current, applicable laws or regulations	Commercial in some regions
Candidate 6: CO <sub>2</sub> is separated from the sour gas and is used for EOR, EGR, ECBM, or to maintain reservoir pressure.	Moderate to high costs for capture and transport infrastructure, depending on the distance. Requires a need for CO <sub>2</sub> in a suitable geological formation.	Existing technologies		Some commercial projects

Evaluating the baseline candidates presented above:

- Candidate 1 incurs moderate costs, meets applicable regulations for this example, and is the common practice in the region. Candidate 1 has potential environmental and liability impacts because it converts the H<sub>2</sub>S to sulfur rather than SO<sub>2</sub>.
- Candidate 2 may require significant control of SO<sub>2</sub> emissions to meet regulations, which will result in significant additional costs. Candidate 2 also incurs additional costs for natural gas to fuel the incinerator and results in additional GHG emissions.
- Candidate 3, *the project activity*, incurs costs for transport and injection infrastructure (including an adequate number of injection and monitoring wells). Although applied in some regions, it is not the common practice in the project's geographical area. The project proponent has to overcome several regional barriers to the implementation of the project.

<sup>14</sup> Depending on the circumstances of the project, the region or geographic area may be narrow (e.g., an area within a nation or state), or broad (e.g., an international region or global area).

- Similar to the project activity, Candidate 4 incurs costs for injection, though costs for transport are likely to be less than those for Candidate 3. In certain locations, injecting the acid gas into the production formation may be preferred over transporting and injecting it in another geological formation. It is assumed that this option is not viable for this example.
- For Candidate 5, CO<sub>2</sub> can be used for other industrial or manufacturing purposes, but would require additional processing and potentially installation of compression and pipeline infrastructure to transport the CO<sub>2</sub> to the end user. The ultimate disposition of the CO<sub>2</sub> may be vented or stored depending on the end use. In addition, this option would likely require further processing of the sour gas to separate the CO<sub>2</sub> and H<sub>2</sub>S. As with Candidate 1, there may be potential environmental and liability issues associated with the disposition of the H<sub>2</sub>S or sulfur.

For this example it is assumed that there is no current demand near the project and it is not economical to transport and sell the CO<sub>2</sub> to manufacturing and processing industries located a significant distance from the gas processing facility.

- Similar to Candidate 5, Candidate 6 incurs costs for injection and transport. Additional processing is also likely to be required to separate the CO<sub>2</sub> from the H<sub>2</sub>S, potentially resulting in environmental and liability issues associated with the disposition of the H<sub>2</sub>S or sulfur. It is assumed that this option is not viable for this example.

As a result of this analysis, Candidate 1, the further processing of the acid gas stream in a sulfur plant, is the most probable baseline scenario.<sup>15</sup>

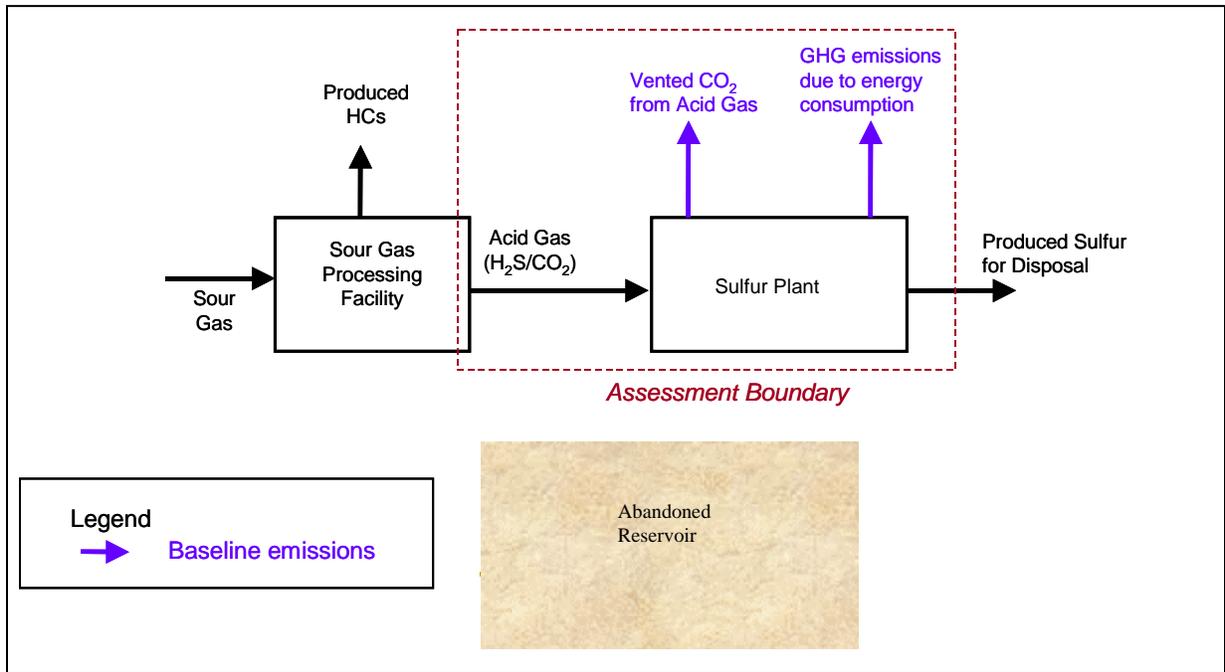
The baseline scenario is shown in Figure 6-10. In this scenario, the acid gas would be further processed in a sulfur plant to convert the H<sub>2</sub>S in the gas stream to elemental sulfur. Energy in the form of gas fuel and electricity would be required at the sulfur plant. Based on the utility requirements at other sulfur plants operating in the region and processing similar acid gas streams, energy required for the baseline scenario is estimated to be  $1.87 \times 10^{15}$  J (1772 MMBtu) of natural gas and  $136.8 \times 10^{12}$  J (38,000 MW-hr) of electricity. The produced sulfur would be disposed of or sent to market (if available).

### **Project Assessment Boundary**

After defining the project and selecting the baseline scenario, the next step is to determine the assessment boundary. The assessment boundary encompasses GHG emission sources, sinks, and reservoirs controlled by the project proponent, related to the GHG reduction project, affected by the GHG reduction project, and relevant to the selected baseline scenario. Figures 6-9 and 6-10 illustrate the processes and operations within the assessment boundary for both the project activity and the baseline scenario, respectively. In this example, the assessment boundary excludes the sour gas processing facility since its operations are similar in both the baseline and project scenarios, and remain unaffected by the project. Therefore, GHG emissions related to the processing and separation of hydrocarbons in this facility are not explicitly evaluated.

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<sup>15</sup> Baseline candidates and the analysis presented here are for illustrative purposes only. Actual project activities will require an assessment of candidates and characteristics specific to the project application. Specific climate change regimes may require additional details and justification for baseline scenario determination.



**Figure 6-10. Baseline Illustration of Acid Gas Storage Project**

Table 6-9 examines potential emission sources within the assessment boundary and compares the baseline scenario to the project activity.

**Table 6-9. Case Study #2 Assessment Boundary Determination**

	Potential Emission Sources	Relation to the Project Proponent	Considerations
<b>Baseline Scenario</b>			
✓ Emissions of the CO <sub>2</sub> contained in the acid gas stream ✓ CO <sub>2</sub> , CH <sub>4</sub> and N <sub>2</sub> O emissions from fuel combustion associated with sulfur plant		Controlled	Venting and fugitive emissions that occur in the sulfur plant are included in the metered volumes leaving the sour gas processing facility.
✓ CO <sub>2</sub> , CH <sub>4</sub> and N <sub>2</sub> O emissions from offsite electricity used during sulfur plant operations		Related	
<b>Project Activity</b>			
<b>Capture</b>	✓ CO <sub>2</sub> and, to a lesser extent, CH <sub>4</sub> emissions from the dehydration of the capture gas stream ✓ CO <sub>2</sub> , CH <sub>4</sub> , and N <sub>2</sub> O emissions from fuel combustion associated with compressing the capture gas stream ✓ CO <sub>2</sub> , CH <sub>4</sub> , and N <sub>2</sub> O emissions from offsite electricity used to operate capture equipment	Controlled  Related	A dehydrator was not included in this project example because the acid gas was assumed to be naturally de-watered during compression.

**Table 6-9. Case Study #2 Assessment Boundary Determination (Continued)**

	Potential Emission Sources	Relation to the Project Proponent	Considerations
<b>Project Activity (Continued)</b>			
<b>Transport</b>	<ul style="list-style-type: none"> <li>✓ CO<sub>2</sub>, CH<sub>4</sub>, and N<sub>2</sub>O emissions from fuel combustion associated with transport equipment</li> <li>✓ Vented and fugitive CO<sub>2</sub> emissions, associated with transport operations and equipment</li> <li>✓ CO<sub>2</sub>, CH<sub>4</sub>, and N<sub>2</sub>O emissions from offsite electricity used to operate transport equipment</li> </ul>	Controlled  Related	.
<b>Storage</b>	<ul style="list-style-type: none"> <li>✓ CO<sub>2</sub>, CH<sub>4</sub>, and N<sub>2</sub>O emissions from fuel combustion associated with storage operations and equipment</li> <li>✓ CO<sub>2</sub>, CH<sub>4</sub>, and N<sub>2</sub>O emissions from offsite electricity generation used for storage operations and equipment</li> </ul>	Controlled  Related	

### Quantifying Emission Reductions

The following exhibit demonstrates the emission estimation for the baseline scenario and project activity. Emission reductions are quantified as the difference between the baseline and project emissions.

#### **EXHIBIT 6.2: Storage of Acid Gas (H<sub>2</sub>S/CO<sub>2</sub>) in an Abandoned Reservoir**

##### **Known Information (based on measured data)**

- Process:  $362 \times 10^6 \text{ m}^3$  ( $12.8 \times 10^9 \text{ scf}$ ) of H<sub>2</sub>S/CO<sub>2</sub> gas mixture is captured from the sour gas plant for the year.
- Captured Gas Composition: 50% H<sub>2</sub>S, 45% CO<sub>2</sub>, and 1% CH<sub>4</sub> by volume
- Sulfur Unit: In the baseline scenario, the energy required to remove sulfur from the H<sub>2</sub>S and vent the CO<sub>2</sub> is  $1.87 \times 10^{15} \text{ J}$  ( $1.77 \times 10^6 \text{ MMBtu}$ ) of natural gas for the heaters and  $136.8 \times 10^{12} \text{ J}$  (38,000 MW-hr) electricity.
- Transport:  $308 \times 10^{12} \text{ J}$  (85.76 GW-hr) of electricity is consumed at the compression/pump and metering facilities to transport the captured gas 16 km (10 miles) to the injection wells.
- CO<sub>2</sub> Emission Factor: Based on natural gas composition, the CO<sub>2</sub> emission factor is 49.95 tonnes CO<sub>2</sub>/10<sup>12</sup> J (0.0527 tonnes CO<sub>2</sub>/10<sup>6</sup> BTU), assuming all or the C is converted to CO<sub>2</sub> and heating value is  $37.7 \times 10^6 \text{ J/m}^3$  (1012 Btu [HHV]/scf).
- Pilot gas fuel rate for the flare is assumed at 0.028 m<sup>3</sup>/min (1 scf/min) or about 14,866 m<sup>3</sup>/yr (525,000 scf/yr). Based on a natural gas hydrocarbon composition of 95% CH<sub>4</sub>, and 2.5% C<sub>2</sub>H<sub>6</sub>, and a flare combustion efficiency of 98%, the CO<sub>2</sub> emission factor for the flare pilot gas was calculated as  $1.82 \times 10^{-3} \text{ tonne/m}^3$  ( $5.16 \times 10^{-5} \text{ tonne CO}_2/\text{scf}$ ) fuel gas using procedures shown in Exhibit 4.8 of the API Compendium.

**EXHIBIT 6.2 Continued**

In addition, monitoring of potential escape routes during the year did not detect any CO<sub>2</sub> losses.

**Baseline Emissions**

$$\text{Baseline emissions} = \text{VENT}_1 + \text{CMB}_1 + \text{FUG}_1 + \text{IND}_1$$

where,

VENT<sub>1</sub> = Volume of CO<sub>2</sub> (and CH<sub>4</sub>) separated from the sour gas in the gas processing facility, captured and injected in the reservoir (converted to tonnes of CO<sub>2</sub> Eq. per year). This volume is released to the atmosphere in the baseline scenario. Vented emissions also include process and equipment vents of CO<sub>2</sub> and CH<sub>4</sub> emissions at the sulfur plant. However, these emissions also occur in the project activity and therefore cancel out the baseline emissions.

CMB<sub>1</sub> = Direct emissions from combustion of natural gas in heaters at the sulfur plant.

FUG<sub>1</sub> = Fugitive emissions of CO<sub>2</sub> and CH<sub>4</sub> at the sulfur plant. These emissions also occur in the project activity and therefore cancel out the baseline emissions.

IND<sub>1</sub> = Indirect emissions from electricity usage at the sulfur plant in the baseline scenario.

**Baseline Emissions Estimate**

**Vented Emissions (VENT<sub>1</sub>):**

Emissions associated with the baseline vented gas volume are estimated based on the volume of gas captured (362×10<sup>6</sup> m<sup>3</sup> [12.8 Bscf/yr]) and the CO<sub>2</sub> and CH<sub>4</sub> concentrations in the gas (45 and 1 % by volume, respectively). A global warming potential (GWP) of 21 is used for CH<sub>4</sub> to convert emissions to CO<sub>2</sub> equivalent (CO<sub>2</sub> Eq.).

$$\begin{aligned} \text{VENT}_1 &= (\text{Metered volume}) \times [\text{CO}_2 \text{ fraction} + 21 \times (\text{CH}_4 \text{ fraction})] \\ &= 362 \times 10^6 \text{ m}^3 \text{ gas} \times \\ &\quad \left( 0.45 \frac{\text{m}^3 \text{ CO}_2}{\text{m}^3 \text{ gas}} \times \frac{\text{kg mole CO}_2}{23.685 \text{ m}^3 \text{ CO}_2} \times 44 \frac{\text{kg CO}_2}{\text{kg mole CO}_2} \times \frac{\text{tonne}}{1000 \text{ kg}} \right. \\ &\quad \left. + 21 \times 0.01 \frac{\text{m}^3 \text{ CH}_4}{\text{m}^3 \text{ gas}} \times \frac{\text{kg mole CH}_4}{23.685 \text{ m}^3 \text{ CH}_4} \times 16 \frac{\text{kg CH}_4}{\text{kg mole CH}_4} \times \frac{\text{tonne}}{1000 \text{ kg}} \right) \\ &= 353,976 \text{ tonnes CO}_2 \text{ Eq.} \end{aligned}$$

**Combustion Emissions (CMB<sub>1</sub>):**

Combustion emissions result from fuel that would have been used in gas-fired heaters at the sulfur plant. Fuel usage was estimated as 1.87×10<sup>15</sup> J. Using this fuel usage and emission factor for natural gas and the fuel usage, the annual CO<sub>2</sub> emissions are calculated as:

$$\text{CO}_2 \text{ emissions} = 49.95 \frac{\text{tonne CO}_2}{10^{12} \text{ J}} \times 1.87 \times 10^{15} \text{ J} = 93,406 \text{ tonnes CO}_2$$

**EXHIBIT 6.2 Continued**

To calculate CH<sub>4</sub> and N<sub>2</sub>O emissions from fuel combustion, emission factors for boilers/heaters are applied (API Compendium, Table 4-4).

$$\begin{aligned} \text{CH}_4 \text{ Emissions} &= (\text{emission factor}) \times (\text{fuel usage}) \\ &= 9.7 \times 10^{-4} \frac{\text{tonne CH}_4}{10^{12} \text{ J}} \times 1.87 \times 10^{15} \text{ J} = 1.81 \text{ tonnes CH}_4 \end{aligned}$$

$$\text{N}_2\text{O Emissions} = 2.7 \times 10^{-4} \frac{\text{tonne N}_2\text{O}}{10^{12} \text{ J}} \times 1.87 \times 10^{15} \text{ J} = 0.50 \text{ tonnes N}_2\text{O}$$

The direct CO<sub>2</sub> equivalent (CO<sub>2</sub> Eq.) emissions for combustion sources are calculated using a GWP of 21 for CH<sub>4</sub> and 310 for N<sub>2</sub>O.

$$\begin{aligned} \text{CMB}_1 &= \text{CO}_2 + (21 \times \text{CH}_4) + (310 \times \text{N}_2\text{O}) \\ &= 94,905 + (21 \times 1.84) + (310 \times 0.51) = 95,102 \text{ tonnes CO}_2 \text{ Eq.} \end{aligned}$$

**Fugitive Emissions (FUG<sub>1</sub>):**

Both the project and the baseline involve separating the acid gas stream from the natural gas. Fugitive emissions of CO<sub>2</sub> and CH<sub>4</sub> are associated with pressurized equipment at the sulfur plant. These emissions also occur in the project activity and therefore cancel out the baseline emissions.

**Indirect Emissions (IND<sub>1</sub>):**

Emissions associated with the electricity that would have been used at the sulfur plant are based on the electricity demand for sulfur removal processes and regional electric generation emission factors. The electricity demand was estimated as 136.8 × 10<sup>12</sup> J (38,000 MW-hr). For the purpose of this example, the electricity emission factors for the (hypothetical, undefined) region are: 0.2425 tonnes CO<sub>2</sub>/10<sup>9</sup> J (0.873 tonnes CO<sub>2</sub>/MW-hr), 0.0016 tonnes CH<sub>4</sub>/10<sup>12</sup> J (5.76E-6 tonnes CH<sub>4</sub>/MW-hr), and 0.0036 tonnes N<sub>2</sub>O/10<sup>12</sup> J (1.296E-5 tonnes N<sub>2</sub>O/MW-hr). The total CO<sub>2</sub> Eq. emissions are calculated using a GWP of 21 for CH<sub>4</sub> and 310 for N<sub>2</sub>O.

$$\text{CO}_2 \text{ emissions} = 0.2425 \frac{\text{tonnes}}{10^9 \text{ J}} \times 136.8 \times 10^{12} \text{ J} = 33,174 \text{ tonnes CO}_2$$

$$\text{CH}_4 \text{ emissions} = 0.0016 \frac{\text{tonnes}}{10^{12} \text{ J}} \times 136.8 \times 10^{12} \text{ J} = 0.22 \text{ tonnes CH}_4$$

$$\text{N}_2\text{O emissions} = 0.0036 \frac{\text{tonnes}}{10^{12} \text{ J}} \times 136.8 \times 10^{12} \text{ J} = 0.49 \text{ tonnes N}_2\text{O}$$

**EXHIBIT 6.2 Continued**

$$\begin{aligned} \text{IND}_1 &= 33,174 \text{ tonnes CO}_2 + (21 \times 0.22 \text{ tonnes CH}_4) \\ &\quad + (310 \times 0.49 \text{ tonnes N}_2\text{O}) \\ &= 33,330 \text{ tonnes CO}_2 \text{ Eq.} \end{aligned}$$

$$\begin{aligned} \text{Baseline emissions} &= 353,976 + 93,599 + 33,330 \\ &= 480,905 \text{ tonnes CO}_2 \text{ Eq.} \end{aligned}$$

**Project Emissions Calculations**

$$\text{Project emissions} = \text{VENT}_2 + \text{CMB}_2 + \text{FUG}_2 + \text{IND}_2$$

where,

$\text{VENT}_2$  = Pipeline venting and compressor blowdown emissions from transporting the  $\text{CO}_2$  to the injection site.

$\text{CMB}_2$  = Combustion emissions from flare pilot gas usage, and pipeline venting and compressor blowdown emissions routed to the flare. Note that the gas stream is naturally dewatered during compression and a dehydrator is not necessary to reduce moisture concentrations to levels required to prevent pipeline corrosion. If a dehydrator is required, combustion emissions due to fuel usage by the dehydrator reboiler and vented  $\text{CH}_4$  emissions from regenerating the glycol should be included.

$\text{FUG}_2$  = Pipeline fugitive  $\text{CO}_2$  emissions from transporting the gas stream to the reservoir site.

$\text{IND}_2$  = Indirect emissions for electric-driven compressors and pumps used to transport and inject the acid gas stream in the reservoir.

Since the acid gas stream contains significant concentrations of  $\text{H}_2\text{S}$ , piping venting and compressor blowdown emissions will be routed to a flare equipped with a natural gas pilot. Additionally pipeline connections are expected to be tight and well maintained to minimize fugitive emissions.

**Vented Emissions ( $\text{VENT}_2$ ):**

Vented emissions associated with the project include pipeline vents during normal operations and maintenance/upset conditions. API Compendium Table 5-24 provides an emission factor for pipeline venting/blowdowns that can be converted from a  $\text{CH}_4$  basis (for natural gas pipelines) to a  $\text{CO}_2$  basis for this analysis. For conservatism, the transmission pipeline factor is applied. Note that the gas transported in the project contains a small amount of  $\text{CH}_4$ .

**EXHIBIT 6.2 Continued**

$$\begin{aligned} \text{CO}_2 \text{ Emissions} &= 16 \text{ km} \times \frac{0.4881 \text{ tonne CH}_4}{\text{km}} \times \frac{\text{tonne mole CH}_4}{16 \text{ tonne CH}_4} \times \frac{\text{tonne mole gas}}{0.934 \text{ tonne mole CH}_4} \\ &\times \frac{0.45 \text{ tonne mole CO}_2}{\text{tonne mole gas}} \times \frac{44 \text{ tonne CO}_2}{\text{tonne mole CO}_2} = 10.3 \text{ tonnes CO}_2 \end{aligned}$$

Since this stream is routed to the flare to prevent the release of H<sub>2</sub>S, additional CO<sub>2</sub> and unburned CH<sub>4</sub> emissions that occur during flare combustion are accounted for in the calculation of flare emissions under CMB<sub>2</sub>.

Vented emissions also include compressor blowdown emissions. API Compendium Table 5-21 provides an emission factor for compressor blowdowns that can be converted from a CH<sub>4</sub> basis to a CO<sub>2</sub> basis for this analysis. Note that the gas transported in the project contains a small amount of CH<sub>4</sub>.

Assuming one blowdown event per year from each of the eight compressors used for transport and injection, CO<sub>2</sub> emissions are calculated as:

$$\begin{aligned} \text{CO}_2 \text{ Emissions} &= 8 \text{ compressors} \times \frac{0.07239 \text{ tonnes CH}_4}{\text{compressor}} \times \frac{\text{tonne mole CH}_4}{16 \text{ tonnes CH}_4} \\ &\times \frac{\text{tonne mole gas}}{0.788 \text{ tonne mole CH}_4} \times \frac{0.45 \text{ tonne mole CO}_2}{\text{tonne mole gas}} \times \frac{44 \text{ tonne CO}_2}{\text{tonne mole CO}_2} \\ &= 0.91 \text{ tonne CO}_2 \end{aligned}$$

Since this stream is routed to the flare, additional CO<sub>2</sub> and unburned CH<sub>4</sub> emissions that occur during flare combustion are accounted for in the calculation of flare emissions under CMB<sub>2</sub>.

Vented emissions are calculated as:

$$\begin{aligned} \text{VENT}_2 &= 10.3 \text{ tonnes CO}_2 + 0.91 \text{ tonnes CO}_2 \\ &= 11.2 \text{ tonnes CO}_2 \text{ Eq.} \end{aligned}$$

**Combustion Emissions (CMB<sub>2</sub>)**

Combustion emissions CMB<sub>2</sub> result from combustion of flare pilot gas, and pipeline venting and blowdown emissions that are routed to the flare. Using the emission factor provided in the known information for this example project (based on the combustion of CH<sub>4</sub> and C<sub>2</sub>H<sub>6</sub> in the gas), CO<sub>2</sub> emissions from the combustion of flare pilot gas is calculated as,

$$\text{CO}_2 \text{ Emissions} = 1.82 \times 10^{-3} \frac{\text{tonnes CO}_2}{\text{m}^3 \text{ gas}} \times 14,866 \text{ m}^3 = 27.1 \text{ tonne CO}_2$$

**EXHIBIT 6.2 Continued**

In addition to the flare pilot, CO<sub>2</sub> emissions also result from burning process vents that are sent to the flare. These include pipeline and compressor blowdowns that are routed to the flare.

Based on a CH<sub>4</sub> concentration of 1% in the acid gas stream, the CH<sub>4</sub> flow rate to the flare from pipeline blowdowns is calculated as:

$$\begin{aligned} \text{CH}_4 \text{ from pipeline vents} &= 16 \text{ km} \times \frac{0.4881 \text{ tonne CH}_4}{\text{km}} \times \frac{0.01 \text{ tonne mole CH}_4}{0.934 \text{ tonne mole CH}_4} \\ &= 0.0836 \text{ tonnes CH}_4 \end{aligned}$$

Similarly CH<sub>4</sub> from compressor blowdowns routed to the flare are calculated as:

$$\begin{aligned} \text{CH}_4 \text{ from compressor blowdowns} &= 8 \text{ compressors} \times \frac{0.07239 \text{ tonnes CH}_4}{\text{compressor}} \times \frac{0.01 \text{ tonne mole CH}_4}{0.788 \text{ tonne mole CH}_4} \\ &= 0.00735 \text{ tonnes CH}_4 \end{aligned}$$

CO<sub>2</sub> flare emissions from pipeline venting and compressor blowdowns are then calculated based on a 98% efficiency in converting hydrocarbons in the flared gas to CO<sub>2</sub> (from the API Compendium):

$$\begin{aligned} \text{CO}_2 \text{ Emissions} &= (0.0836 + 0.00735) \text{ tonnes CH}_4 \times \frac{\text{tonne mole CH}_4}{16 \text{ tonne CH}_4} \\ &\times \frac{0.98 \text{ tonne mole CO}_2}{\text{tonne mole CH}_4} \times \frac{44 \text{ kg CO}_2}{\text{kg mole CO}_2} \times \frac{\text{tonne CO}_2}{1000 \text{ kg CO}_2} \\ &= 0.24 \text{ tonnes CO}_2 \end{aligned}$$

There is also a small amount of CH<sub>4</sub> that is not combusted in the flare (0.5% of the CH<sub>4</sub> in the flared gas, based on the API Compendium).

$$\begin{aligned} \text{CH}_4 \text{ Emissions} &= (0.0836 + 0.00735) \text{ tonnes CH}_4 \times \frac{0.005 \text{ tonne CH}_4 \text{ uncombusted}}{\text{tonne CH}_4 \text{ total}} \\ &= 0.00045 \text{ tonnes CH}_4 \end{aligned}$$

$$\begin{aligned} \text{CMB}_2 &= (27.1 + 0.24) \text{ tonnes CO}_2 + (21 \times 0.00045 \text{ tonnes CH}_4) \\ &= 27.3 \text{ tonnes CO}_2 \text{ Eq} \end{aligned}$$

**EXHIBIT 6.2 Continued****Fugitive Emissions (FUG<sub>2</sub>):**

Fugitive emissions for the project include pipeline leaks. API Compendium Table 6-1 provides fugitive pipeline emission factors that can be converted from the default API Compendium CH<sub>4</sub> basis to the CH<sub>4</sub> content for this analysis. (Note: Due to the H<sub>2</sub>S content of the acid gas stream, fugitive components would likely be well maintained, thus minimizing or eliminating any emissions.

$$\begin{aligned} \text{CH}_4 \text{ Emissions} &= 16 \text{ km} \times \frac{2.233 \text{ tonne CH}_4}{\text{km}} \times \frac{0.01 \text{ mole CH}_4 \text{ (project)}}{0.934 \text{ mole CH}_4 \text{ (default)}} \\ &= 0.38 \text{ tonnes CH}_4 \end{aligned}$$

For CO<sub>2</sub>, the Draft 2006 IPCC Guidelines for National Greenhouse Gas Inventories Chapter 5 derives a CO<sub>2</sub> emission factor based on the CH<sub>4</sub> mass-based emission rate, where CO<sub>2</sub> emission rate = 1.66 times the CH<sub>4</sub> emission rate.

$$\begin{aligned} \text{CO}_2 \text{ Emissions} &= 16 \text{ km} \times \frac{2.233 \text{ tonne CH}_4}{\text{km}} \times \frac{1.66 \text{ tonne CO}_2}{\text{tonne CH}_4} \\ &= 59.3 \text{ tonnes CO}_2 \end{aligned}$$

$$\begin{aligned} \text{FUG}_2 &= (59.3) \text{ tonnes CO}_2 + (21 \times 0.38 \text{ tonnes CH}_4) \\ &= 67.3 \text{ tonnes CO}_2 \text{ Eq.} \end{aligned}$$

**Indirect Emissions (IND<sub>2</sub>):**

The indirect emissions represent the emissions resulting from the generation of electricity required to operate the compression and pump facilities associated with transporting the captured gas stream from the gas plant to the injection site. These emissions are calculated from actual electricity usage data as reflected in the electric utility bills and regional emission factors. For the purpose of this example, the electricity emission factors for the region are:

0.2425 tonnes CO<sub>2</sub>/10<sup>9</sup> J (0.873 tonnes CO<sub>2</sub>/MW-hr), 0.0016 tonnes CH<sub>4</sub>/10<sup>12</sup> J (5.76E-6 tonnes CH<sub>4</sub>/MW-hr), and 0.0036 tonnes N<sub>2</sub>O/10<sup>12</sup> J (1.296E-5 tonnes N<sub>2</sub>O/MW-hr) (the same values as used for the baseline scenario). The total CO<sub>2</sub> Eq. emissions are calculated using a GWP of 21 for CH<sub>4</sub> and 310 for N<sub>2</sub>O.

Emissions = (emission factor) × (electrical usage)

$$\text{CO}_2 \text{ Emissions} = 0.2425 \frac{\text{tonne CO}_2}{10^9 \text{ J}} \times 308 \times 10^{12} \text{ J} = 74,690 \text{ tonnes CO}_2$$

$$\text{CH}_4 \text{ Emissions} = 0.0016 \frac{\text{tonnes CH}_4}{10^{12} \text{ J}} \times 308 \times 10^{12} \text{ J} = 0.49 \text{ tonne CH}_4$$

**EXHIBIT 6.2 Continued**

$$\text{N}_2\text{O Emissions} = 0.0036 \frac{\text{tonnes N}_2\text{O}}{10^{12} \text{ J}} \times 308 \times 10^{12} \text{ J} = 1.11 \text{ tonne N}_2\text{O}$$

$$\begin{aligned} \text{IND}_2 &= 74,690 \text{ tonnes CO}_2 + (21 \times 0.49 \text{ tonnes CH}_4) + (310 \times 1.11 \text{ tonnes N}_2\text{O}) \\ &= 75,044 \text{ tonnes CO}_2 \text{ Eq.} \end{aligned}$$

$$\begin{aligned} \text{Project emissions} &= \text{VENT}_2 + \text{CMB}_2 + \text{FUG}_2 + \text{IND}_2 \\ &= 11.2 + 27.3 + 67.3 + 75,044 \\ &= 75,150 \text{ tonnes CO}_2 \text{ Eq. per year} \end{aligned}$$

$$\begin{aligned} \text{Emission Reductions} &= \text{Baseline Emissions} - \text{Project Emissions} \\ &= 482,408 - 75,150 = \mathbf{407,258 \text{ tonnes CO}_2 \text{ Eq. per year}} \end{aligned}$$

### **Monitoring**

Guidelines on monitoring CCS projects are provided in Section 6.7 with some potential activities addressed in CCS Project Case Study #1. The key messages are that monitoring for CCS is an iterative, risk-based process and monitoring plans should be fit-for purpose.

For acid gas injection, the quantities injected are generally small in relation to the amount of oil and/or gas produced. The general principles for risk-based monitoring of the geological storage of acid gases apply, although specific climate change regimes may require additional activities.

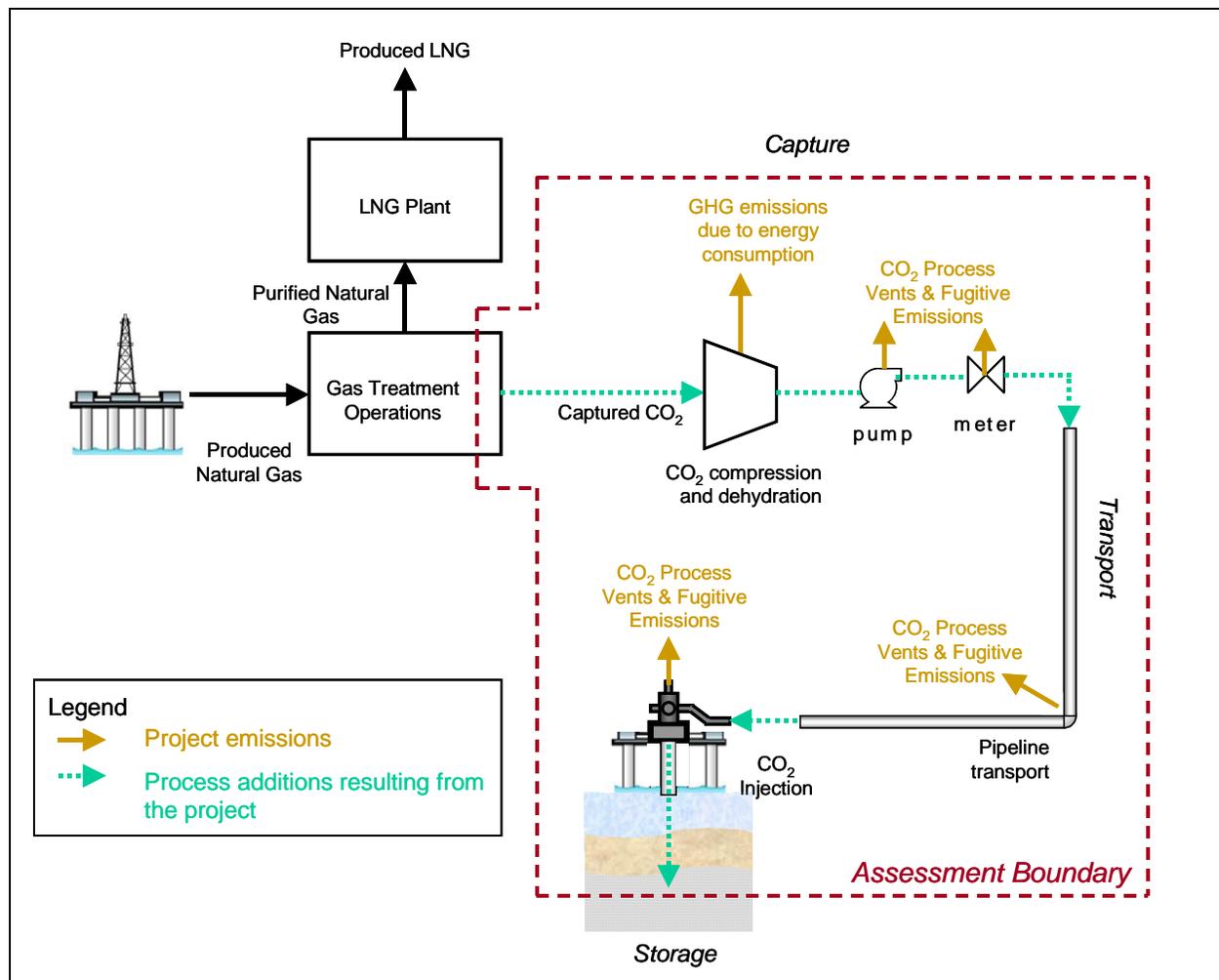
# ATTACHMENT 1

## CCS PROJECT CASE STUDY #3: CARBON CAPTURE AND STORAGE IN A DEEP SANDSTONE RESERVOIR FILLED WITH SALINE FORMATION WATER

### Project Definition

#### Description of the Project Activity

The purpose of this project is to recover CO<sub>2</sub> emitted from the gas treatment operations associated with a newly constructed liquefied natural gas (LNG) facility and inject it into a deep saline formation. A schematic diagram of the project activity is shown in Figure 6-11.



**Figure 6-11. Project Illustration of CO<sub>2</sub> Capture, Transport and Injection in a Saline Formation**

This project involves the following:

- $20.8 \times 10^6 \text{ Sm}^3/\text{day}$  ( $734 \times 10^6 \text{ scf/day}$ ) of natural gas is produced from 9 offshore wells and is piped to an onshore LNG facility. The produced natural gas contains 3.9 to 5.4 mol%  $\text{CO}_2$ , 0-2 mol%  $\text{H}_2\text{S}$ , and 81-83 mol%  $\text{CH}_4$ . (The remaining gas constituents are inconsequential to this example.)
- $\text{CO}_2$  is separated from the natural gas using an amine unit and amine regeneration prior to cooling the produced gas to form LNG containing 99%  $\text{CH}_4$ .
- Captured  $\text{CO}_2$  is compressed using multiple engine-driven compressors and electric-driven pumps to transport the  $\text{CO}_2$  stream 152 km (94 miles) to an offshore  $\text{CO}_2$  injection well and inject the  $\text{CO}_2$  into the deep saline formation. Facility fuel and electricity usage records, and  $\text{CO}_2$  metering records indicate that, on an annual basis,  $35.9 \times 10^6 \text{ Sm}^3$  ( $1.27 \times 10^9 \text{ scf}$ ) of fuel gas and  $1.27 \times 10^{13} \text{ J}$  (3,528 MW-hr) of electricity are consumed at the compression/pump and metering facilities to compress  $700 \times 10^3$  tonnes  $\text{CO}_2$  per year that is captured from the LNG plant.
- The  $\text{CO}_2$  is injected into a deep saline formation, separated from the ocean floor by a gas bearing formation, an oil bearing formation, and a thick shale formation.

### Reservoir Background

Extensive reservoir studies associated with the gas production activities provide significant information on the geology and hydrogeology of the reservoir. Figure 6-12 provides a schematic cross-sectional view of the  $\text{CO}_2$  injection location.  $\text{CO}_2$  is injected into a deep saline formation. A thick shale layer separates the injection location from the gas production formation. These properties make storage of the  $\text{CO}_2$  in this reservoir a viable, long-term option and minimize the potential for an accidental release as a result of natural occurrences.

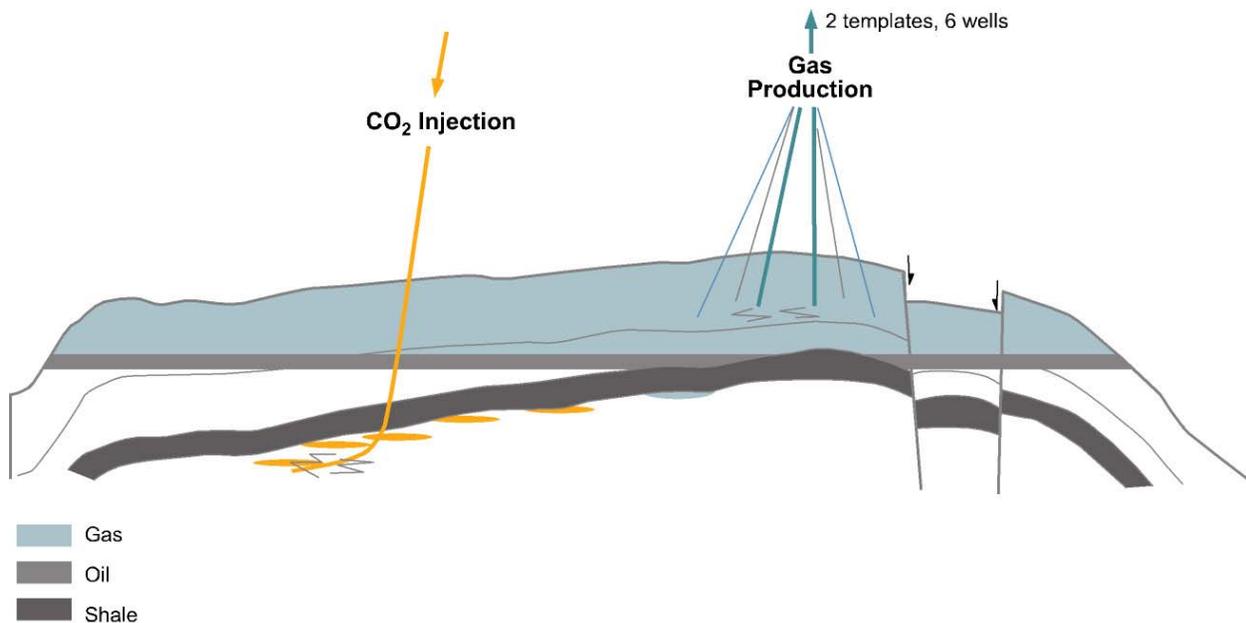


Figure 6-12.  $\text{CO}_2$  Storage Formation

## Baseline Scenario Selection

### Baseline Candidates Considered

The baseline scenario represents the situation or conditions that plausibly would have occurred in the absence of the project. Plausible candidates for the baseline scenario are presented in Table 6-10. To the extent possible, elements of the baseline candidates are aligned with corresponding aspects of the CCS chain. All of the proposed baseline candidates comply with applicable regulations.

**Table 6-10. Case Study #3 Baseline Candidates**

<b>Potential Baseline Candidates for the Disposition of the CO<sub>2</sub> from the Gas Processing Facility (Capture)</b>	<b>Potential Baseline Candidates Associated with Transport</b>	<b>Potential Baseline Candidates Associated with the Ultimate Disposition of the CO<sub>2</sub> (Storage)</b>
<b>Candidate 1:</b> Natural gas is processed to meet sales specifications. This includes the removal of CO <sub>2</sub> .	<b>Candidate 1:</b> There is no transport component for this baseline candidate.	<b>Candidate 1:</b> The CO <sub>2</sub> removed from the natural gas is vented to the atmosphere.
<b>Candidate 2:</b> <i>The project activity</i> , which includes capture of the CO <sub>2</sub> from the natural gas treatment operations.	<b>Candidate 2:</b> <i>The project activity</i> , which includes installation of compression and dehydration equipment, and pipeline infrastructure to transport the CO <sub>2</sub> to the geological storage formation.	<b>Candidate 2:</b> <i>The project activity</i> , which includes installation of injection facilities for long-term storage of the CO <sub>2</sub> in a deep saline formation.
<b>Candidate 3:</b> Includes capture of the CO <sub>2</sub> from the natural gas treatment operations. The CO <sub>2</sub> may require additional processing depending on the end use.	<b>Candidate 3:</b> May require compression, dehydration, and/or pipeline to deliver the CO <sub>2</sub> to custody transfer	<b>Candidate 3:</b> CO <sub>2</sub> is sold for use for industrial or manufacturing purposes.
<b>Candidate 4:</b> Includes capture of the CO <sub>2</sub> from the natural gas treatment operations.	<b>Candidate 4:</b> Installation of compression and dehydration equipment, and pipeline infrastructure to transport the CO <sub>2</sub> to the EOR, EGR, ECBM, or reservoir location.	<b>Candidate 4:</b> CO <sub>2</sub> is used for EOR, EGR, ECBM, or to maintain reservoir pressure.
<b>Candidate 5:</b> Includes capture of the CO <sub>2</sub> from the natural gas treatment operations.	<b>Candidate 5:</b> Installation of compression and dehydration equipment, and pipeline infrastructure to transport the CO <sub>2</sub> . The transport requirements and costs would likely be less than that of candidates 2, 3, or 4.	<b>Candidate 4:</b> Installation of injection facilities for long-term storage of the CO <sub>2</sub> into a geological formation beneath the gas treatment/LNG facility.

### Baseline Scenario

Table 6-11 applies some common tests or screening procedures to assist in assessing the baseline candidates.

**Table 6-11 Case Study #3 Baseline Scenario Assessment**

<b>Baseline Scenario Alternatives</b>	<b>Investment Ranking</b>	<b>Technology</b>	<b>Policy/Regulatory</b>	<b>Benchmarking</b>
Candidate 1: Vent the CO <sub>2</sub>	No additional costs	No additional technology requirements	Consistent with current, applicable laws or regulations	Common practice in most regions <sup>16</sup>
Candidate 2 ( <i>Project activity</i> ): Separate and capture the CO <sub>2</sub> , transport offshore, and inject into the deep saline formation	Moderate to high costs for capture and transport infrastructure	Existing technologies		Some commercial projects
Candidate 3: Separate and capture the CO <sub>2</sub> , transport for sale for industrial use	Moderate to high costs for capture and transport infrastructure, depending on the distance. Uncertain market for CO <sub>2</sub> .	Existing technologies		Commercial in some regions
Candidate 4: Separate and capture the CO <sub>2</sub> , transport for use in EOR, EGR, or formation pressure maintenance	Moderate to high costs for capture and transport infrastructure, depending on the distance. Requires a need for CO <sub>2</sub> in a suitable geologic formation.	Existing technologies	Consistent with current, applicable laws or regulations	Commercial in some regions
Candidate 5: Separate and capture the CO <sub>2</sub> , inject the CO <sub>2</sub> beneath the separation facility	Moderate costs for capture, minimal costs for transport. Requires a suitable geologic formation.	Existing technologies		Some commercial projects

Based on comparing the baseline candidates presented above:

- Candidate 1 requires no additional gas processing and no additional costs. For this example, it is assumed that venting the CO<sub>2</sub> meets applicable regulations and is the common practice in the region.
- Candidate 2, *the project activity*, requires additional processing of the produced gas to separate and capture the CO<sub>2</sub>. Pipeline and an offshore injection well are required to transport and inject the gas into the deep saline formation.
- Similar to the project activity, Candidate 3 requires additional processing to separate and capture the CO<sub>2</sub>, as well as pipeline infrastructure to transport the CO<sub>2</sub> to the end user. This scenario may incur additional financial risk due to uncertainty in the market for CO<sub>2</sub> in a particular region. The ultimate disposition of the CO<sub>2</sub> may be vented or stored, depending on the end use application.
- Similar to the project activity, Candidate 4 requires additional processing to separate and capture the CO<sub>2</sub>, as well as pipeline infrastructure to transport the CO<sub>2</sub> to the end user. In certain locations, using the CO<sub>2</sub> for enhanced hydrocarbon recovery may be preferred over injecting it into a saline formation. Candidate 4 requires a hydrocarbon reservoir suitable for enhanced hydrocarbon recovery or a formation

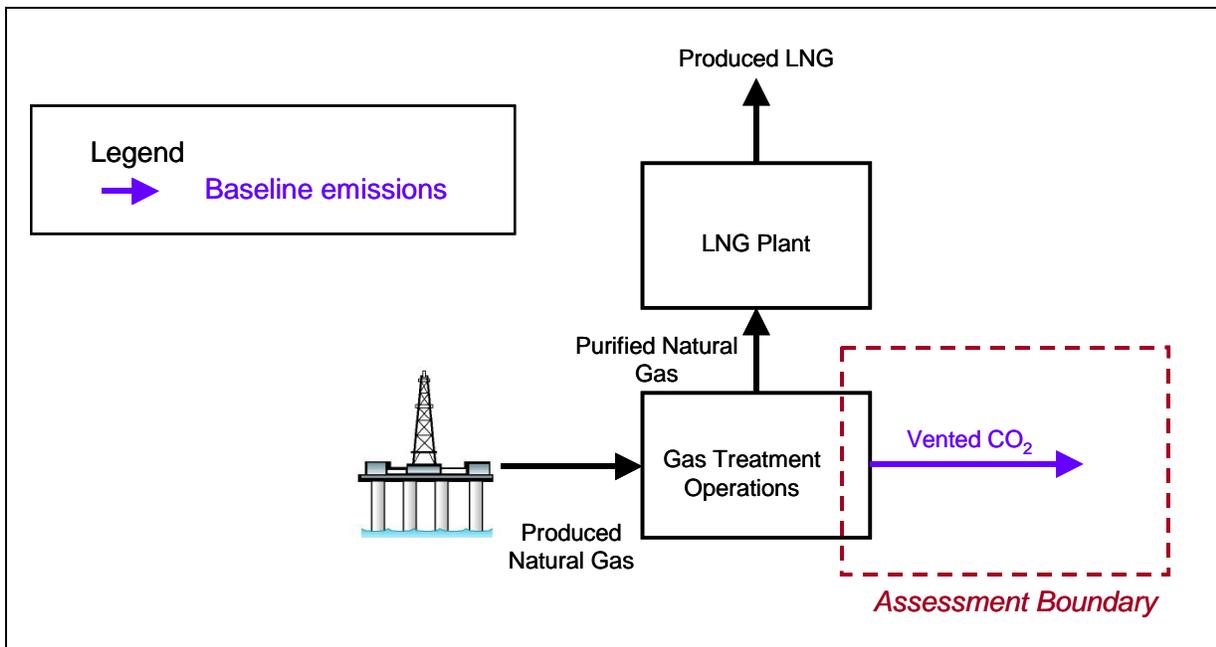
<sup>16</sup> Depending on the circumstances of the project, the region or geographic area may be narrow (e.g., an area within a nation or state), or broad (e.g., an international region or global area).

with declining pressure. It is assumed that these options are not available for this example.

- Similar to the project activity, Candidate 5 requires additional processing to separate and capture the CO<sub>2</sub>. Transport requirements are less than the project activity. Candidate 5 requires a suitable geologic formation located near the CO<sub>2</sub> capture process. It is assumed that such a formation is not available for this example.

As a result of this analysis, Candidate 1, venting of the CO<sub>2</sub> removed from the natural gas, is the most probable baseline scenario.<sup>17</sup>

The baseline scenario is shown in Figure 6-13. In this scenario, CO<sub>2</sub> is separated from the produced natural gas and vented to the atmosphere. Similar to the project activity, an amine unit is required to treat the natural gas and the amine is regenerated. However, for the baseline scenario, the CO<sub>2</sub> is vented during the regeneration process. No additional energy or treatment is required.



**Figure 6-13. Baseline Illustration of CO<sub>2</sub> Capture, Transport and Injection in a Saline Formation**

### ***Project Assessment Boundary***

After defining the project and selecting the baseline scenario, the next step is to determine the assessment boundary. The assessment boundary encompasses GHG emission sources, sinks, and reservoirs that are controlled by the project proponent, related to the GHG reduction project,

<sup>17</sup> Baseline candidates and the analysis presented here are for illustrative purposes only. Actual project activities will require an assessment of candidates and characteristics specific to the project application. Specific climate change regimes may require additional details and justification for baseline scenario selection.

affected by the GHG reduction project, and relevant to the selected baseline scenario. Figures 6-11 and 6-13 illustrate the processes and operations within the assessment boundary for both the project activity and the baseline scenario, respectively.

For this example, the assessment boundary excludes the gas treatment operations and LNG facility since these operations are similar in both the baseline and project scenarios, and remain unaffected by the project. Therefore, GHG emissions related to gas processing and hydrocarbon production operations are not explicitly evaluated. If the emissions from the gas processing operations or LNG facility were impacted by the CO<sub>2</sub> capture, they would need to be included in the assessment boundary.

Table 6-12 examines potential emission sources within the assessment boundary and compares the baseline scenario to the project activity.

**Table 6-12. Case Study #3 Assessment Boundary Determination**

Potential Emission Sources		Relation to the Project Proponent	Considerations
<b>Baseline Scenario</b>			
✓ Emissions of the CO <sub>2</sub> removed from the produced natural gas as part of the gas treatment operations		Controlled	These emissions are assumed to be equivalent to the amount of CO <sub>2</sub> captured from the project activity.
<b>Project Activity</b>			
<b>Capture</b>	✓ CO <sub>2</sub> and to a lesser extent, CH <sub>4</sub> emissions from the dehydration of the capture gas stream	Controlled	A dehydrator is not included in this project example because the CO <sub>2</sub> stream is assumed to be naturally de-watered during compression.
	✓ CO <sub>2</sub> , CH <sub>4</sub> , and N <sub>2</sub> O emissions from fuel combustion associated with compressing the captured CO <sub>2</sub> stream	Controlled	
	✓ CO <sub>2</sub> , CH <sub>4</sub> , and N <sub>2</sub> O emissions from offsite electricity used to operate capture equipment	Related	
<b>Transport and Storage</b>	✓ CO <sub>2</sub> , CH <sub>4</sub> , and N <sub>2</sub> O emissions from fuel combustion associated with the compression/pump, metering and injection operations required to transport and inject the CO <sub>2</sub> stream.	Controlled	Energy consumption required to transport and inject the CO <sub>2</sub> occurs onshore at the gas processing facility. Therefore emissions from the transport and storage activities are evaluated together.
	✓ CO <sub>2</sub> , CH <sub>4</sub> , and N <sub>2</sub> O emissions from offsite electricity used at the compression/pump, metering and injection operations required to transport and inject the CO <sub>2</sub> stream.	Related	
	✓ Vented and fugitive CO <sub>2</sub> emissions, associated with the compression/pump, metering and injection operations.	Controlled	

### **Quantifying Emission Reductions**

The following Exhibit demonstrates the emission estimation for the baseline scenario and project activity. Emission reductions are quantified as the difference between the baseline and project emissions.

**EXHIBIT 6.3: Capture and Storage of CO<sub>2</sub> in a Deep Saline Formation**

Known Information (based on hypothetical data for this example):

- 700×10<sup>3</sup> tonnes/yr CO<sub>2</sub> is captured from the LNG plant, transported offshore, and injected in the deep saline formation.
- Captured Gas Composition: 99 mol% CO<sub>2</sub>, 1 mol% other non-GHG constituents.
- Energy Requirements: 35.9×10<sup>6</sup> m<sup>3</sup> (1.27×10<sup>9</sup> scf) of fuel gas and 1.27×10<sup>13</sup> J (3527 MW-hr) of electricity are consumed at the compression/pump and metering facilities to transport the capture gas 152 km (94 miles) offshore and inject it into the deep saline formation.
- CO<sub>2</sub> Emission Factor: Based on fuel gas composition: the CO<sub>2</sub> emission factor is 49.95 tonnes/10<sup>12</sup> J (0.0527 tonnes CO<sub>2</sub>/10<sup>6</sup> BTU), assuming all of the C is converted to CO<sub>2</sub>, and heating value is 37.7×10<sup>6</sup> J/m<sup>3</sup> (1012 Btu HHV/scf).
- As mentioned previously, the assessment boundary excludes emission sources associated with the gas processing operations and LNG facility. Therefore vented and fugitive emissions for the project activity focus on the transport and injection operations.
- Maintenance activities and upset conditions associated with the transport and injection operations for the project activity include pipeline blowdowns, injection well workovers, compressor blowdowns and starts, and pressure relief valve releases. For this example, it is assumed that one well workover occurred during the course of the year. Vented emissions also include two pressure relief valves (PRVs) and blowdowns and starts for one large compressor.
- Fugitive emission sources for the project activity include the compressor, one meter and associated piping, the pipeline to the injection well, and the injection wellhead.
- The facility operated 8,640 hours during the past year.

In addition, monitoring of potential CO<sub>2</sub> escape routes during the year did not detect any CO<sub>2</sub> losses.

**Baseline Emissions:**

$$\text{Baseline emissions} = \text{VENT}_1 + \text{CMB}_1 + \text{FUG}_1 + \text{IND}_1$$

where,

VENT<sub>1</sub> = Vented CO<sub>2</sub> emissions from baseline operations or equipment that would have occurred in the baseline scenario. For this example, this includes the volume of CO<sub>2</sub> captured as a result of treating the produced natural gas that would have been released to the atmosphere in the baseline scenario.

CMB<sub>1</sub> = Direct combustion emissions that would have occurred in the baseline scenario.

FUG<sub>1</sub> = Fugitive CO<sub>2</sub> emissions from baseline equipment that would have occurred in the baseline scenario.

IND<sub>1</sub> = Indirect emissions that would have occurred from electricity purchased from outside sources in the baseline scenario.

**EXHIBIT 6.3 Continued**

The gas treatment and LNG operations are similar in both the baseline and project scenarios, and remain unaffected by the project. Other than the VENT<sub>1</sub> emissions described above, the assessment boundary does not include combustion, fugitive, and indirect emission sources for the baseline scenario. Therefore, GHG emissions related to gas processing and hydrocarbon production operations are not explicitly evaluated.

**Baseline Emissions Estimate**

$$\text{VENT}_1 = 700 \times 10^3 \text{ tonnes/yr CO}_2$$

**Project Emissions Calculations**

$$\text{Project emissions} = \text{VENT}_2 + \text{CMB}_2 + \text{FUG}_2 + \text{IND}_2$$

where,

VENT<sub>2</sub> = Process and maintenance vents from equipment associated with the capture and transport of the CO<sub>2</sub>.

CMB<sub>2</sub> = Combustion emissions from gas-fired equipment at the LNG plant.

FUG<sub>2</sub> = Fugitive emissions associated with the capture and transport of the CO<sub>2</sub>.

IND<sub>2</sub> = Indirect emissions for electric-driven pumps used to transport the CO<sub>2</sub> to the offshore injection well.

**Vented Emissions (VENT<sub>2</sub>):**

Vented activities defined for this example consist of one well workover and emissions associated with 2 PRVs, one dehydrator, and one compressor. API Compendium Tables 5-21, 5-1, and 5-22, respectively, provide emission factors for these sources that can be converted from a CH<sub>4</sub> basis (for natural gas pipelines) to a CO<sub>2</sub> basis for this analysis.

For the well workover:

$$\begin{aligned} \text{CO}_2 \text{ Emissions} &= 1 \text{ workover} \times \frac{0.04707 \text{ tonne CH}_4}{\text{workover}} \times \frac{\text{tonne mole CH}_4}{16 \text{ tonne CH}_4} \times \frac{\text{tonne mole gas}}{0.788 \text{ tonne mole CH}_4} \\ &\times \frac{0.99 \text{ tonne mole CO}_2}{\text{tonne mole gas}} \times \frac{44 \text{ tonne CO}_2}{\text{tonne mole CO}_2} = 0.16 \text{ tonnes CO}_2 \end{aligned}$$

For the PRVs:

$$\begin{aligned} \text{CO}_2 \text{ Emissions} &= 2 \text{ PRVs} \times \frac{0.00065 \text{ tonne CH}_4}{\text{PRV}} \times \frac{\text{tonne mole CH}_4}{16 \text{ tonne CH}_4} \times \frac{\text{tonne mole gas}}{0.788 \text{ tonne mole CH}_4} \\ &\times \frac{0.99 \text{ tonne mole CO}_2}{\text{tonne mole gas}} \times \frac{44 \text{ tonne CO}_2}{\text{tonne mole CO}_2} = 0.0045 \text{ tonnes CO}_2 \end{aligned}$$

**EXHIBIT 6.3 Continued**

For the dehydrator (Note: the dehydrator for this hypothetical example uses an electric pump to circulate the glycol. These emissions are estimated as part of the total indirects.):

$$\begin{aligned} \text{CO}_2 \text{ Emissions} &= 700,000 \text{ tonne CO}_2 \times \frac{1000 \text{ kg CO}_2}{\text{tonne CO}_2} \times \frac{\text{kg mole CO}_2}{44 \text{ kg CO}_2} \times \frac{23.685 \text{ m}^3}{\text{kg mole CO}_2} \\ &\times \frac{0.18667 \text{ tonne CH}_4}{10^6 \text{ m}^3 \text{ processed}} \times \frac{\text{tonne mole CH}_4}{16 \text{ tonne CH}_4} \times \frac{\text{tonne mole gas}}{0.788 \text{ tonne mole CH}_4} \\ &\times \frac{0.99 \text{ tonne mole CO}_2}{\text{tonne mole gas}} \times \frac{44 \text{ tonne CO}_2}{\text{tonne mole CO}_2} = 243 \text{ tonnes CO}_2 \end{aligned}$$

For the compressor blowdowns and starts:

$$\begin{aligned} \text{CO}_2 \text{ Emissions} &= 1 \text{ compressor} \times \left( \frac{0.1620 \text{ tonne CH}_4}{\text{compressor}} \begin{matrix} \text{Starts} \\ + \end{matrix} \frac{0.07239 \text{ tonne CH}_4}{\text{compressor}} \begin{matrix} \text{Blowdowns} \end{matrix} \right) \\ &\times \frac{\text{tonne mole CH}_4}{16 \text{ tonne CH}_4} \times \frac{\text{tonne mole gas}}{0.788 \text{ tonne mole CH}_4} \times \frac{0.99 \text{ tonne mole CO}_2}{\text{tonne mole gas}} \\ &\times \frac{44 \text{ tonne CO}_2}{\text{tonne mole CO}_2} = 0.81 \text{ tonnes CO}_2 \end{aligned}$$

For pipeline venting/blowdowns, the emission factor for production gathering pipelines is applied:

$$\begin{aligned} \text{CO}_2 \text{ Emissions} &= 152 \text{ km} \times \frac{0.00368 \text{ tonne CH}_4}{\text{km}} \times \frac{\text{tonne mole CH}_4}{16 \text{ tonne CH}_4} \times \frac{\text{tonne mole gas}}{0.788 \text{ tonne mole CH}_4} \\ &\times \frac{0.99 \text{ tonne mole CO}_2}{\text{tonne mole gas}} \times \frac{44 \text{ tonne CO}_2}{\text{tonne mole CO}_2} = 1.93 \text{ tonnes CO}_2 \end{aligned}$$

$\text{VENT}_2 = \text{Well workover emissions} + \text{PVR emissions} + \text{Dehydrator emissions} + \text{Compressor emissions} + \text{Pipeline emissions.}$

$$\text{VENT}_2 = (0.16 + 0.0045 + 243 + 0.81 + 1.93) \text{ tonnes CO}_2 = 246 \text{ tonnes CO}_2$$

**Combustion emissions (CMB<sub>2</sub>):**

Project combustion emissions are calculated based on measured fuel consumption rates and fuel analysis data. Based on the fuel gas analysis data, the CO<sub>2</sub> emission factor in terms of thermal energy input is 49.95 tonnes/10<sup>12</sup> J (0.0527 tonnes CO<sub>2</sub>/10<sup>6</sup> Btu) and the fuel heating value is 37.7×10<sup>6</sup> J/m<sup>3</sup> (1012.4 Btu/scf). The emission factor was conservatively estimated by assuming all the carbon in the fuel is converted to CO<sub>2</sub> during the combustion process and discharged to the atmosphere, consistent with the API Compendium's preferred approach.

**EXHIBIT 6.3 Continued**

Using this emission factor and the fuel usage, the annual CO<sub>2</sub> emissions are calculated as:

$$\begin{aligned}\text{CO}_2 \text{ emissions} &= 35.9 \times 10^6 \text{ m}^3 \times 37.7 \frac{10^6 \text{ J}}{\text{m}^3} \times 49.95 \frac{\text{tonne CO}_2}{10^{12} \text{ J}} \\ &= 67,604 \text{ tonnes CO}_2\end{aligned}$$

To calculate CH<sub>4</sub> and N<sub>2</sub>O emissions from fuel combustion, compressor engine emission factors for 2-stroke gas-fired engines are applied (API Compendium, Table 4-5).

$$\begin{aligned}\text{CH}_4 \text{ Emissions} &= (\text{fuel usage}) \times (\text{emission factor}) \\ &= 35.9 \times 10^6 \text{ m}^3 \times 37.7 \frac{10^6 \text{ J}}{\text{m}^3} \times 0.623 \frac{\text{tonne CH}_4}{10^{12} \text{ J}} \\ &= 843 \text{ tonnes CH}_4 \\ \text{N}_2\text{O Emissions} &= 35.9 \times 10^6 \text{ m}^3 \times 37.7 \frac{10^6 \text{ J}}{\text{m}^3} \times 0.0021 \frac{\text{tonne N}_2\text{O}}{10^{12} \text{ J}} \\ &= 2.84 \text{ tonnes N}_2\text{O}\end{aligned}$$

The direct CO<sub>2</sub> equivalent (CO<sub>2</sub> Eq.) emissions for combustion sources are calculated using a GWP of 21 for CH<sub>4</sub> and 310 for N<sub>2</sub>O.

$$\begin{aligned}\text{CMB}_2 &= \text{CO}_2 + (21 \times \text{CH}_4) + (310 \times \text{N}_2\text{O}) \\ &= 67,604 + (21 \times 843) + (310 \times 2.84) \\ &= 86,187 \text{ tonnes CO}_2 \text{ Eq.}\end{aligned}$$

**Fugitive Emissions (FUG<sub>2</sub>):**

Similarly, fugitive emissions for the project include pipeline leaks and other pressurized equipment handling the CO<sub>2</sub> stream. API Compendium Table 6-3 provides fugitive emission factors for the specified equipment. Each of the CH<sub>4</sub>-based emission factors can be converted from a CH<sub>4</sub> basis to a CO<sub>2</sub> basis for this analysis. For fugitive pipeline emissions the 2006 IPCC Guidelines for National Greenhouse Gas Inventories Chapter 5 derives a CO<sub>2</sub> emission factor based on the CH<sub>4</sub> mass-based emission rate, where CO<sub>2</sub> emission rate = 1.66 times the CH<sub>4</sub> emission rate.

Compressor emissions:

$$\begin{aligned}\text{CO}_2 \text{ Emissions} &= 1 \text{ compressor} \times \frac{0.0122 \text{ tonne CH}_4}{\text{compressor - hr}} \times 8,640 \text{ hours} \times \frac{\text{tonne mole CH}_4}{16 \text{ tonne CH}_4} \\ &\quad \times \frac{\text{tonne mole gas}}{0.788 \text{ tonne mole CH}_4} \times \frac{0.99 \text{ tonne mole CO}_2}{\text{tonne mole gas}} \times \frac{44 \text{ tonne CO}_2}{\text{tonne mole CO}_2} \\ &= 364 \text{ tonnes CO}_2\end{aligned}$$

**EXHIBIT 6.3 Continued**

**Dehydrator emissions:**

$$\begin{aligned} \text{CO}_2 \text{ Emissions} &= 1 \text{ dehydrator} \times \frac{4.42 \times 10^{-5} \text{ tonne CH}_4}{\text{dehydrator - hr}} \times 8,640 \text{ hours} \times \frac{\text{tonne mole CH}_4}{16 \text{ tonne CH}_4} \\ &\times \frac{\text{tonne mole gas}}{0.788 \text{ tonne mole CH}_4} \times \frac{0.99 \text{ tonne mole CO}_2}{\text{tonne mole gas}} \times \frac{44 \text{ tonne CO}_2}{\text{tonne mole CO}_2} \\ &= 1.32 \text{ tonnes CO}_2 \end{aligned}$$

**Meter/piping emissions:**

$$\begin{aligned} \text{CO}_2 \text{ Emissions} &= 1 \text{ meter} \times \frac{3.52 \times 10^{-5} \text{ tonne CH}_4}{\text{meter - hr}} \times 8,640 \text{ hours} \times \frac{\text{tonne mole CH}_4}{16 \text{ tonne CH}_4} \\ &\times \frac{\text{tonne mole gas}}{0.788 \text{ tonne mole CH}_4} \times \frac{0.99 \text{ tonne mole CO}_2}{\text{tonne mole gas}} \times \frac{44 \text{ tonne CO}_2}{\text{tonne mole CO}_2} \\ &= 1.05 \text{ tonnes CO}_2 \end{aligned}$$

**Pipeline emissions:**

$$\begin{aligned} \text{CO}_2 \text{ Emissions} &= 152 \text{ km} \times \frac{2.65 \times 10^{-5} \text{ tonne CH}_4}{\text{km - hr}} \times 8,640 \text{ hr} \times \frac{1.66 \text{ tonnes CO}_2}{\text{tonnes CH}_4} \\ &= 57.8 \text{ tonnes CO}_2 \end{aligned}$$

**Wellhead emissions:**

$$\begin{aligned} \text{CO}_2 \text{ Emissions} &= 1 \text{ well} \times \frac{1.80 \times 10^{-5} \text{ tonne CH}_4}{\text{well - hr}} \times 8,640 \text{ hours} \times \frac{\text{tonne mole CH}_4}{16 \text{ tonne CH}_4} \\ &\times \frac{\text{tonne mole gas}}{0.788 \text{ tonne mole CH}_4} \times \frac{0.99 \text{ tonne mole CO}_2}{\text{tonne mole gas}} \times \frac{44 \text{ tonne CO}_2}{\text{tonne mole CO}_2} \\ &= 0.54 \text{ tonnes CO}_2 \end{aligned}$$

FUG<sub>2</sub> = Compressor emissions + Dehydrator emissions + Meter/piping emissions + Pipeline emissions + Wellhead emissions

$$\text{FUG}_2 = (364 + 1.32 + 1.05 + 57.8 + 0.54) \text{ tonnes CO}_2 = 425 \text{ tonnes CO}_2$$

**EXHIBIT 6.3 Continued****Indirect Emissions (IND<sub>2</sub>):**

Indirect emissions (IND<sub>2</sub>) are calculated from regional emission factors (for the purpose of this example, the electricity emission factors for the (hypothetical, undefined) region associated with the underground-sourced CO<sub>2</sub> are: 0.2425 tonnes CO<sub>2</sub>/10<sup>9</sup> J (0.873 tonnes CO<sub>2</sub>/MW-hr), 0.0016 tonnes CH<sub>4</sub>/10<sup>12</sup> J (5.76E-6 tonnes CH<sub>4</sub>/MW-hr), and 0.0036 tonnes N<sub>2</sub>O/10<sup>12</sup> J (1.296E-5 tonnes N<sub>2</sub>O/MW-hr).

The indirect emissions represent the emissions resulting from the generation of electricity required to operate the pumping equipment and facilities associated with transporting and injecting the captured CO<sub>2</sub> into the deep saline formation. These emissions are calculated from actual electricity usage data as reflected in the electric utility bills. The total CO<sub>2</sub> Eq. emissions are calculated using a GWP of 21 for CH<sub>4</sub> and 310 for N<sub>2</sub>O.

Emissions = (emission factor) × (electrical usage)

$$\text{CO}_2 \text{ Emissions} = 0.2425 \frac{\text{tonne CO}_2}{10^9 \text{ J}} \times 1.27 \times 10^{13} \text{ J} = 3,080 \text{ tonnes CO}_2$$

$$\text{CH}_4 \text{ Emissions} = 0.0016 \frac{\text{tonnes CH}_4}{10^{12} \text{ J}} \times 1.27 \times 10^{13} \text{ J} = 0.0203 \text{ tonne CH}_4$$

$$\text{N}_2\text{O Emissions} = 0.0036 \frac{\text{tonnes N}_2\text{O}}{10^{12} \text{ J}} \times 1.27 \times 10^{13} \text{ J} = 0.0457 \text{ tonne N}_2\text{O}$$

$$\begin{aligned} \text{IND}_2 &= 3,080 \text{ tonnes CO}_2 + (21 \times 0.0203 \text{ tonnes CH}_4) + (310 \times 0.0457 \text{ tonnes N}_2\text{O}) \\ &= 3,095 \text{ tonnes CO}_2 \text{ Eq.} \end{aligned}$$

$$\begin{aligned} \text{Project emissions} &= \text{VENT}_2 + \text{CMB}_2 + \text{FUG}_2 + \text{IND}_2 \\ &= 246 + 86,187 + 425 + 3,095 \\ &= 89,953 \text{ tonnes CO}_2 \text{ Eq. per year} \end{aligned}$$

$$\begin{aligned} \text{Emission Reductions} &= \text{Baseline Emissions} - \text{Project Emissions} \\ &= 700,000 - 89,953 \\ &= \mathbf{610,047 \text{ tonnes CO}_2 \text{ Eq. per year}} \end{aligned}$$

**Monitoring**

Historical information is not available for this project since the LNG operations and project activity of capturing and injecting the CO<sub>2</sub> are new.

Baseline, project, and post injection monitoring are discussed in the following sections as illustrations of potential monitoring methods for this hypothetical CCS project. Actual

monitoring requirements depend on the specific project characteristics. In addition, particular climate change regimes may specify monitoring requirements.

For injection into a saline formation, there are generally fewer pre-existing wells than with injection into an active or abandoned hydrocarbon reservoirs. As a result, the risk of leakage through wells is reduced. Storage in a saline aquifer also provides additional trapping mechanisms, such as residual or capillary trapping, and geochemical mechanisms of solubility and mineral trapping. Therefore, monitoring for this example might focus on the risk of migration.

### **Baseline Monitoring**

#### **Baseline Emissions Monitoring**

In the baseline scenario, CO<sub>2</sub> emissions are equivalent to the quantity of CO<sub>2</sub> captured by the project activity. Therefore, baseline emissions monitoring consists of measuring the quantity of CO<sub>2</sub> captured.

#### **Pre-operational Evaluation**

Monitoring associated with the pre-operational evaluation of storage reservoir includes the following activities:

- Characterization of sub-surface conditions to determine the effectiveness of the trapping mechanisms and of the shale formation to serve as a seal (illustrated in Figure 6-12);
- Determination of storage capacity;
- Characterization of permeable distribution for CO<sub>2</sub> injection (not necessary for long-term monitoring of CO<sub>2</sub>) and in targeted areas for migration; and
- Identification of any other potential escape mechanisms.

In assessing the reservoir's ability to store CO<sub>2</sub>, seismic monitoring and simulation results were used determine potential pathways for CO<sub>2</sub> to escape and estimate the amount of CO<sub>2</sub> that could escape from any identified routes.

#### **Operational (Project) Monitoring**

Monitoring methods are established to detect anomalies from any areas identified during the baseline period that indicated a risk for loss of containment. During the project's operational phase, three types of monitoring are used:

- 1) Monitoring to determine the project activities emissions;
- 2) Monitoring of the movement of CO<sub>2</sub> within the storage formation; and
- 3) Monitoring of areas of potential escape to demonstrate containment.

#### **Emissions Monitoring**

The example above demonstrates the type of measurement data needed to quantify the project activity's emissions and reductions. Temperature and pressure sensors located at the injection well and close to the formation are used to support geological simulations, as well as to ensure that the pressure does not adversely impact the shale layer above the deep saline formation and that injection does not induce fractures in the reservoir formation above the storage location.

The amount of CO<sub>2</sub> injected into the formation and the condition of the injection well are additional monitoring data.

**Risk Management Monitoring**

The containment of CO<sub>2</sub> depends on the migration rate, path, and extent of the shale layer. Baseline data established the areas of potential leaks. Monitoring methods specific to those areas are used to determine the ongoing containment of the formation. The extension of the injected CO<sub>2</sub> within the formation is monitored through 2D seismic imaging conducted at the start of injection and repeated periodically.

**Post-Injection Monitoring**

Emission reductions are not quantified after injection has ceased. Data collected during the injection phase will be used to determine the type and extent of monitoring after the production lifetime of the reservoir.

## ATTACHMENT 2 – EXAMPLE CCS PROJECTS AND RESEARCH, CURRENT AND PLANNED

Project	Country	Scale of Project	Lead Organization	Injection Start Date	Approximate average daily injection rate, tonne/day	Total Storage	Storage Type
Sleipner	Norway	Industrial	Statoil, IEA	1996	3000	20 Mt planned	Saline formation
Weyburn	Canada	Industrial	EnCana, IEA	May 2000	3000-5000	20 Mt planned	EOR
In Salah	Algeria	Industrial	Sonatrach, BP, Statoil	2004	3000 -4000	17 Mt planned	Depleted HC reservoirs
Salt Creek	USA	Industrial	Anadarko	2004	5000-6000	27 Mt	EOR
Minami-Nagoaka	Japan	Demo	Research Institute of Innovative Technology for Earth	2002	Max 40	10,000 tonne planned	Saline formation
Yubari	Japan	Demo	Japanese Ministry of Economy, Trade and Industry	2004	10	200 tonne planned	ECBM
Frio	USA	Pilot	Bureau of Economic Geology of the University of Texas	4-13 Oct. 2004	177 (for 9 days)	1600 tonnes	Saline formation
K12B	Netherlands	Demo	Gaz de France	2004	100 - 1000	~ 8Mt	EGR
K14B			Gas de France	2004-2005	(22,000 tCO <sub>2</sub> total)		
Fenn Big Valley	Canada	Pilot	Alberta Research Council	1998	50	200 tonnes	ECBM
Recopol	Poland	Pilot	TNO-NITG	2003	1	10 tonnes	ECBM
Qinshui Basin	China	Pilot	Alberta Research Council	2003	30	150 tonnes	ECBM
Snohvit (Snow White)	Norway	Industrial	Statoil	2006	2,000		Saline formation
Gorgon	Australia	Planned Industrial	Chevron	Planned 2009	10,000		Saline formation
Ketzin	Germany	Demo	GFZ Potsdam	2006	100	60 kt	Saline formation
Otway	Australia	Pilot	CO <sub>2</sub> CRC	2007	150 for 2 years	100 kt	Saline and depleted gas

**Example CCS Projects And Research, Current And Planned (Continued)**

<b>Project</b>	<b>Country</b>	<b>Scale of Project</b>	<b>Lead Organization</b>	<b>Injection Start Date</b>	<b>Approximate average daily injection rate, tonne/day</b>	<b>Total Storage</b>	<b>Storage Type</b>
Teapot Dome	USA	Demo	RMOTC	2006	170 for 3 months	10 kt	Saline and – EOR
CSEMP	Canada	Pilot	Suncor Energy	2005	50	10 kt	ECBM
Pembina	Canada	Pilot	Penn West	2005	50	50 kt	EOR
JODCO	Japan	Demo	Mitsubishi Heavy Industries	2004-2005			EOR
Lacq Oxyfuel	France	Pilot	Total	2008		150 kt	Depleted gas field
Sour Gas Injection	Abu Dhabi	Demo	Abu Dhabi Oil Company	2000			
Draugen and Heidrun	Norway		Shell and Statoil		5500		
DF1 Miller	North Sea	Demo	BP, Scottish & Southern Energy, Shell, ConocoPhillips			1.3 Mt	
DF2 Carson	California	Demo	BP, Edison Mission Group	2011	11 kt		EOR
Vattenfall	Germany	Planned		2008			Coal seam
ZeroGen	Australia	Feasibility	EPRI, Shell, Stanwell Energy		1150		Sandstone reservoir with saline formation
Aracas and Rio Pojuca	Brazil	Pilot			300		
Miranga Field	Brazil			2008	370		
Carmito Artesa	Mexico				40 Mcfd		
Sitio Grande	Mexico			2005	51 Mcfd		

Adapted from Table 5.1 of the IPCC SRCCS, with additional projects added.

This table provides a summary of numerous CCS projects and research activities, both planned and current. It is not inclusive of all CCS activities.

## ATTACHMENT 3 – APPLICATIONS AND TECHNOLOGIES FOR CO<sub>2</sub> CAPTURE

Current and emerging technologies, categorized into four general types, target the separation of CO<sub>2</sub> from gas mixtures containing N<sub>2</sub>, H<sub>2</sub>, H<sub>2</sub>O and CH<sub>4</sub> associated with the different applications. The following table demonstrates how these overlap and lists some of the technologies. The choice of a specific capture technology is determined largely by the process conditions under which it operates.

### Current and Emerging Capture Applications and Technologies

Capture Technologies	Capture Applications			
	Process Streams	Flue gas Separation	Oxy-fuel Combustion	Gasification
<b>Solvents</b>	Current – Chemical and physical solvents; Emerging – improved solvents, contacting equipment and process designs	Current – Chemical solvents; Emerging – improved solvents, contacting equipment and process designs	Emerging – Biomimetic solvents	Current – Chemical and physical solvents; Emerging – improved solvents, contacting equipment and process designs
<b>Membranes</b>	Current – Polymeric; Emerging – Ceramic, Facilitated transport, and Carbon Contactors			
<b>Sorbents</b>	Current – Zeolites and Activated carbon			
		Emerging – carbonates, and carbon-based sorbents	Emerging – Adsorbents for O <sub>2</sub> /N <sub>2</sub> separation, Perovskites, and Oxygen chemical looping	
<b>Cryogenic distillation</b>	Current – Ryan-Holmes process	Current – Liquefaction; Emerging - Hybrid processes	Current – Distillation; Emerging – Improved distillation	Current – Liquefaction; Emerging -Hybrid processes

Reference: IPCC SRCCS, Table 3.1





*energy* **API** American Petroleum Institute

 **IPIECA** International Petroleum Industry Environmental Conservation Association