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CO_2 Management at ExxonMobil's LaBarge Field, Wyoming, USA

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Abstract

Production of natural gas from the LaBarge field in southwest Wyoming began in 1986. This gas contains high concentrations of carbon dioxide (CO_2), and from the very beginning, ExxonMobil has successfully implemented several technologies and approaches to effectively manage the substantial volumes of CO_2 associated with its production. Many of the technologies and approaches used for managing CO_2 at LaBarge are examples of technologies and approaches being proposed for use in carbon capture and storage (CCS) by other industries.

The Shute Creek Treating Facility (SCTF) processes the gas produced from the LaBarge field. The SCTF handles the lowest hydrocarbon content natural gas commercially produced in the world. The gas composition entering Shute Creek is 65% CO_2, 21% methane, 7% nitrogen, 5% hydrogen sulfide (H_2S) and 0.6% helium. The SCTF separates CO_2, methane, and helium for sale and removes hydrogen sulfide for disposal.

Most of the CO_2 captured at Shute Creek is used for enhanced oil recovery (EOR). EOR is consistently cited as one of the most viable early opportunities for large scale implementation of CCS. ExxonMobil's LaBarge operation is the largest deployment of this approach to CCS in the world today. Currently ExxonMobil provides 4 to 5 million tonnes per year of CO_2 for EOR. Ongoing facility expansion will increase this capacity to over 7 million tonnes per year in 2010.

A concentrated acid gas stream of about 60% hydrogen sulfide and 40% CO_2 is injected into a carefully selected section of the same reservoir from which it was produced, safely disposing of the hydrogen sulfide along with approximately 400,000 tonnes of CO_2 per year. Other technologies and approaches that have reduced CO_2 emissions include the ExxonMobil patented low BTU fuel co-generation system that substantially reduces CO_2 emissions when compared to emissions from purchased power.

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Cumulatively, through the application of these technologies at LaBarge, ExxonMobil will have the capacity to capture and manage over 75% of the CO_2 produced from the LaBarge field.

Additionally, new technologies are being developed that may provide additional reductions in emissions, either at this site or at others with similarly challenged production streams. Construction of a commercial demonstration facility for ExxonMobil's Controlled Freeze Zone™ (CFZ) gas treatment technology has been completed at Shute Creek and operations are about to begin. The CFZ™ technology allows the single step separation of CO_2 and other contaminants from a natural gas stream without the use of solvents or absorbents. Its successful commercial demonstration would enable the development of increasingly sour gas resources around the world by substantially reducing gas treatment and geo-sequestration costs from these sources.

CO_2 Management Challenges

Discovered in 1963, the Madison gas reservoir comprising the LaBarge Field remained undeveloped for more than twenty (20) years due to the technical challenges presented by the composition of the gas (65% carbon dioxide, 21% methane, 7% nitrogen, 5% hydrogen sulfide, and 0.6% helium). After gas processing technology advanced to the point that marketable methane could be efficiently extracted from the Madison reservoir, the problem of what to do with the substantial volumes of non-hydrocarbon by-products that would be produced along with the readily marketable methane still had to be overcome. In 1983, prior to construction, authority to vent unmarketable non-hydrocarbon gases was sought from and granted by the four state and federal agencies having jurisdiction over these mineral resources, which enabled the project to go forward.

The very high CO_2 content, averaging 65%, was one of the most difficult aspects of development of the LaBarge Field, which makes this the highest CO_2 content and lowest BTU content gas commercially produced in the world today. Beginning with the planning stages for the development of this resource, ExxonMobil recognized the potential value in using the produced CO_2 resources for EOR and other industrial applications. Thus, since the start of production operations at LaBarge in 1986, CO_2 has been sold for EOR projects in Rangely, Colorado and Baroil, Wyoming. While all of the marketable CO_2 was contracted for sale at the start of operations, long term sales have averaged about half of this volume until recently.

The EOR market for CO_2 in the Rocky Mountain area developed more slowly than originally anticipated. From the mid-1980's through the mid-2000's, oil and gas prices were weak, making operators reluctant to make the significant investments necessary for CO_2 EOR projects. Operators found it difficult to identify the keystone project or critical mass of smaller projects necessary to justify the investment in infrastructure necessary to enable and maintain the rates of CO_2 sales seen even in the first years after project start-up. In addition, the remote location of the resource relative to potential EOR opportunities and the absence of any CO_2 transportation infrastructure limited the early development of the CO_2 resources at LaBarge.

Throughout this time, the Wyoming Oil and Gas Conservation Commission (WOGCC) encouraged development of the LaBarge CO_2 resources. The WOGCC long recognized the potential benefits to the state from using the CO_2 for EOR to redevelop the state's aging oil resources. Another, more recent motivation for utilizing the LaBarge CO_2 resources are global concerns associated with greenhouse gases (GHG) emissions.

More recently, with improved industry economic conditions and identification of a keystone EOR project (Salt Creek Field, Wyoming), the CO_2 transportation infrastructure has expanded significantly. The pipeline system has been extended into the oil producing regions of central Wyoming and additional compression capacity is being added by ExxonMobil. These improvements will allow even greater utilization of the available CO_2 resources from LaBarge.

Role of CO_2 Enhanced Oil Recovery in CCS

The oil and gas industry has been successfully using CO_2 for EOR for over 35 years. The technologies and operational practices for treating, transporting, and injecting CO_2 for EOR are well developed and are very similar to those technologies anticipated to be necessary for CCS. These technologies are considered readily transferable and applicable to the CCS model suggested for mitigating GHG emissions. Current separation technologies however are relatively energy intensive and offer opportunities for improvement.

The vast majority of CO_2 EOR development has occurred in the Permian Basin of west Texas and southeastern New Mexico. Most of the CO_2 used there is from naturally occurring, nearly pure CO_2 resources. The CO_2 resources accessible to the Permian Basin are for the most part developed. New development of any remaining CO_2 resources is likely to offset production declines from existing fields rather than provide significant opportunities for expanding current capacity. As a result, while additional CO_2 EOR opportunities are recognized in the Permian Basin, further developments are essentially CO_2 supply limited. In most other parts of the US, and the rest of the world, CO_2 EOR development is more dependent on CO_2 that is co-produced with natural gas, or in the future, CO_2 captured from combustion of fossil fuels for power generation or from other industrial processes. CO_2 that is recovered from these types of sources is typically considered anthropogenic CO_2.

Use of anthropogenic CO_2 for EOR has been clearly recognized as an approach to mitigating GHG emissions while offering the important benefit of providing incremental production of oil and gas. Using captured CO_2 for EOR provides an important opportunity for demonstrating all components of the CCS system; capture, transportation, and storage, each of which is demonstrated in ExxonMobil's operations at LaBarge. Additionally, the revenue provided by the incremental oil and gas production provides an important economic basis that may incentivize the early implementation of CCS.

At current levels, the market price of CO_2 ($20-$30/ tonne under the European Trading System) is not considered sufficient to justify commercial scale CCS. Some other form of economic support is necessary. Several options exist, such as dedicated industry and/or government support of enhanced oil and gas recovery or combinations of both. Clearly, the potential economic return associated with CO_2 EOR coupled with CCS has created some significant interest, to the point that the International Panel on Climate Change (IPCC) and the International Energy Agency have identified CO_2 EOR as an "early opportunity" for CCS.

CO_2 EOR provides more than a simple economic incentive to support CCS. There is also a strong technical case that further supports the use of CO_2 EOR as an early opportunity for CCS. Oil and gas fields where the EOR would occur are well understood geologically. The structural or stratagraphic trap has been described in some detail during the development process. Similarly, the physical characteristics of the reservoir are well known, as are the characteristics of the fluids in that reservoir. This combination of technical knowledge and economic support serve to create the potential early opportunity for CCS with CO_2 EOR.

There are several CCS related projects underway involving the oil and gas industry; Sleipner in the North Sea (ExxonMobil interest 34%), In-Salah in Algeria, and LaBarge in the US. Each of these projects utilizes CO_2 produced with natural gas. An important aspect of each of these projects that in order to make the primary product, natural gas, marketable the CO_2 must be removed, regardless of its ultimate disposition. This fact makes the capture component economically justified outside of any consideration related to CCS. CO_2 EOR projects using other forms of anthropogenic CO_2 (captured from combustion sources) will not normally enjoy this advantage.

Looking toward the future, to better facilitate commercial scale CCS (with or without CO_2 EOR) several key challenges must be addressed in an affirmative manner. These challenges include:

- Providing a stable economic basis for CCS
- Developing the legal and regulatory infrastructure necessary to enable CCS
- Providing for the long term stewardship of decommissioned CCS sites.

The magnitude of investment necessary to capture, transport, and inject commercial scale volumes of CO_2 will be substantial. To encourage this scale of investment, a stable economic foundation will be necessary. A system that allows extreme volatility in the valuation of CO_2 will make investment at the scale thought to be necessary for commercial scale CCS much more difficult to justify, and could delay its implementation.

A legal and regulatory system that balances safe and environmentally sound implementation of CCS with practical consideration of operational controls will be critical to allowing commercial scale CCS to occur at the pace currently thought to be necessary to meet current global GHG emission targets. The system should be geared towards enabling environmentally sound solutions without excessive burdens or unrealistic requirements.

Finally, the ability to transfer long term stewardship responsibility for decommissioned storage sites to a government entity will be vital for commercial entities. Considering the longevity of a governmental entity versus most business entities it is unreasonable for a business to retain stewardship responsibility for such sites in perpetuity. Many workable models exist to support development of workable and sound approaches to facilitate transfer of such responsibility.

As mentioned already, the current development of CO_2 EOR is limited by the availability of CO_2, either due to production capacity limits or the lack of infrastructure. If additional supplies of CO_2 become available, substantial opportunities for CO_2 EOR exist in many oil and gas producing regions around the world. Industry operations like ExxonMobil's LaBarge field provide significant sources of technology and operational experience that the emerging CCS industry can draw upon.

Initial Technical Solutions for CO_2 Management at LaBarge

The initial design and installation of production facilities for the LaBarge Field presented major challenges to the Exxon LaBarge project team. The SCTF was designed to process a very low hydrocarbon content, sour gas. The large production capacity, 480 MCFD (13.6 MNm^3/day), required two parallel processing trains in which CO_2, methane, and helium are separated as products for sale, while hydrogen sulfide is removed for disposal.

In addition to the low 21% hydrocarbon content of the raw gas, the location in Southwest Wyoming, United States presented significant challenges as well. It is remote, and subject to temperature extremes: as low as -40°F (-40°C) in the winter, and as high as 100°F (38°C) in the summer. Furthermore, the plant is located at an elevation of about 6497' (1980m), so atmospheric pressure and liquid boiling points are depressed enough to require some process modifications.

The 17 production wells of the LaBarge field are sited in the high country of the Rocky Mountains, and are deep and expensive to drill. The gas from each well flows to one of three manifolds as depicted in Figure 1. Gas collected at the manifolds then flows to the glycol-based primary treatment facility at Black Canyon. A review of this facility and its own challenges has been presented elsewhere [1]. After the initial treatment, the gas is exported 46 miles (74 km) to the SCTF via a 28" (71 cm) trunk line for final treatment.

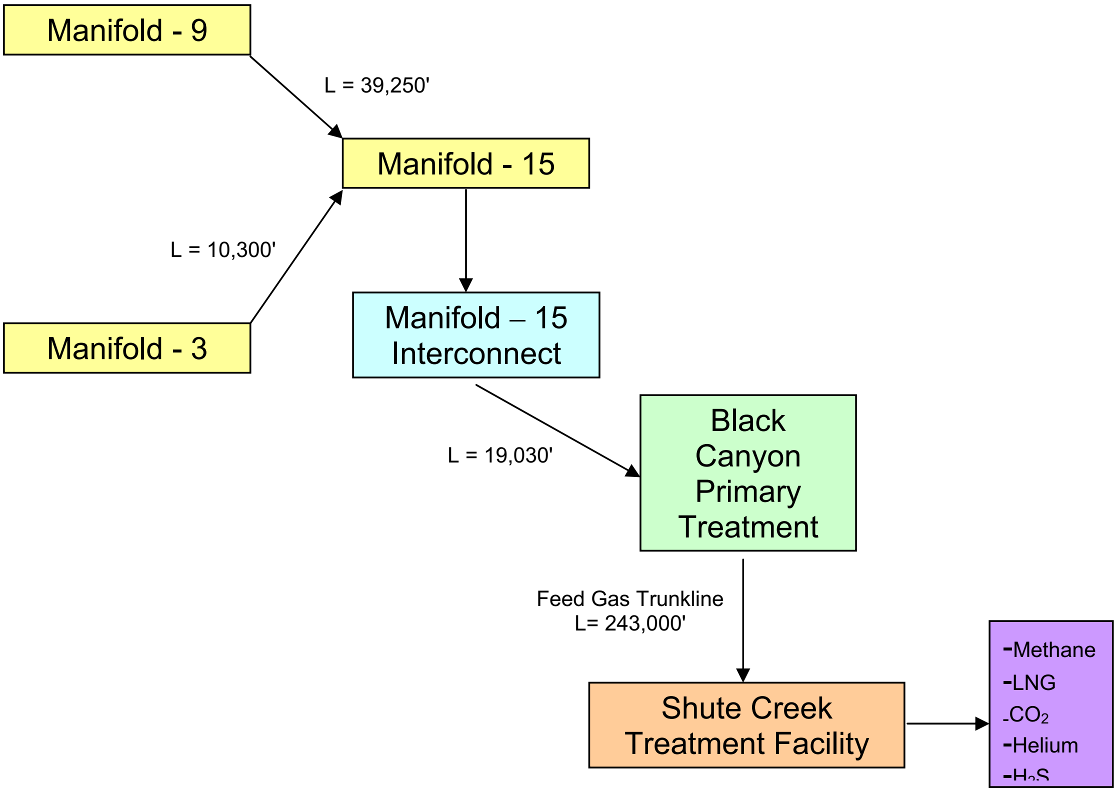

Figure 1. Schematic of the LaBarge field gas production operation.

Each SCTF train utilizes two Selexol™ physical solvent units in series to sweeten the gas, as shown in the block flow diagram in Figure 2. The first unit operates in an "H_2S-selective" mode to remove the H_2S to ppm levels while passing a majority of the CO_2 (and virtually all of the methane and nitrogen) to the second unit. The second unit removes the remaining CO_2 to very low levels. The H_2S removal process shown in Figure 3 was designed to minimize the removal of CO_2 in this step, and allow the subsequent CO_2 removal process to maximize the capture of CO_2 for sales in the CO_2 removal process. Two important design features were applied to achieve this objective. Prior to entering the H_2S Absorber tower, the lean Selexol is pre-saturated with CO_2 by contacting it with the sweetened gas from the overhead of the absorber tower. Pre-saturated with CO_2, the Selexol absorbs less CO_2 in the H_2S Absorber tower, which minimizes heating of the Selexol from the high heat of absorption of carbon dioxide. This improves the efficiency of absorption of H_2S, reducing Selexol circulation rates and improving the selectivity of the process for H_2S. To further improve H_2S selectivity, an intermediate recycle flash vessel is replaced by an enricher tower. This tower uses nitrogen that is captured from the back end of the process to reject a greater percentage of CO_2 to recycle. The enricher tower reduces CO_2 that must be handled by the acid gas (CO_2 and H_2S) disposal system and increases CO_2 for sales.

From the low pressure flash vessel and H_2S stripper, a combined waste stream of approximately 40 MCFD of H_2S and 25 MCFD of CO_2 must be disposed. The plant was originally outfitted with a Sulfur Recovery Unit (SRU) for the conversion of the H_2S to elemental sulfur. In 2005, Acid Gas Injection (AGI) facilities were started up for the sequestration of this waste gas in the water leg of the Madison reservoir.

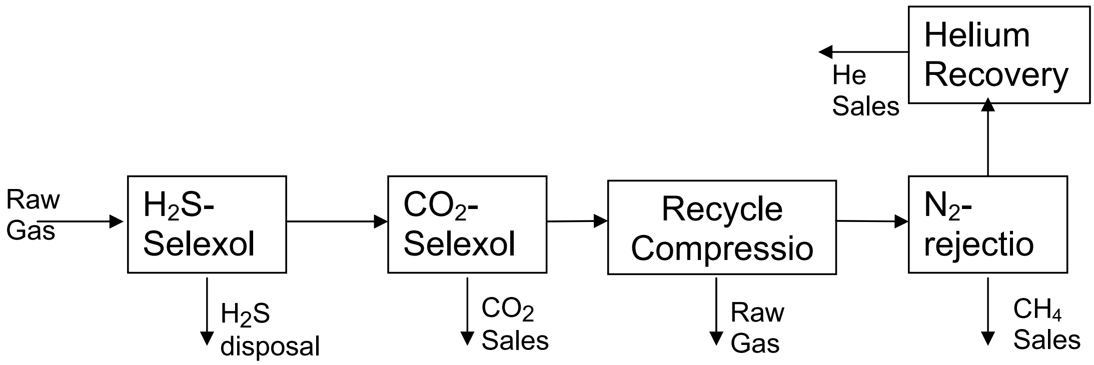

Figure 2: Shute Creek Treating Facility block diagram

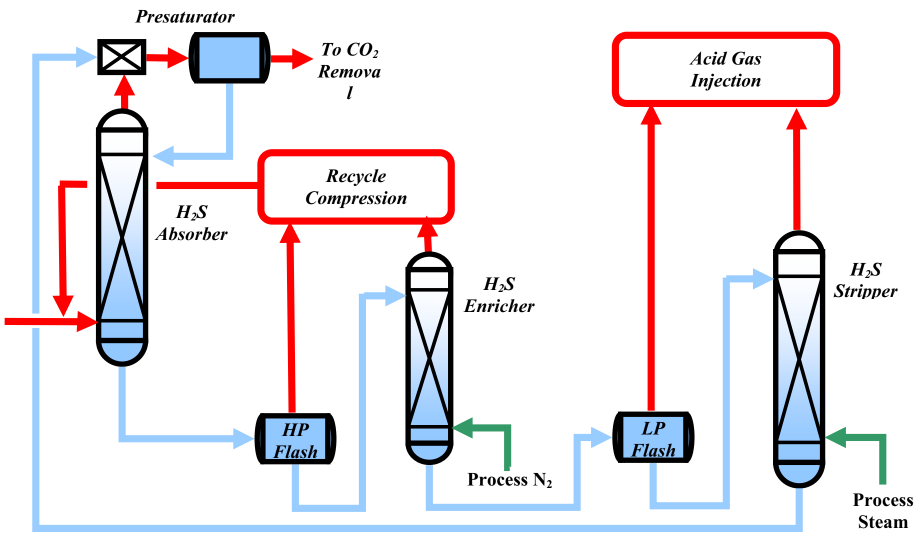

Figure 3: Schematic of H_2S removal system

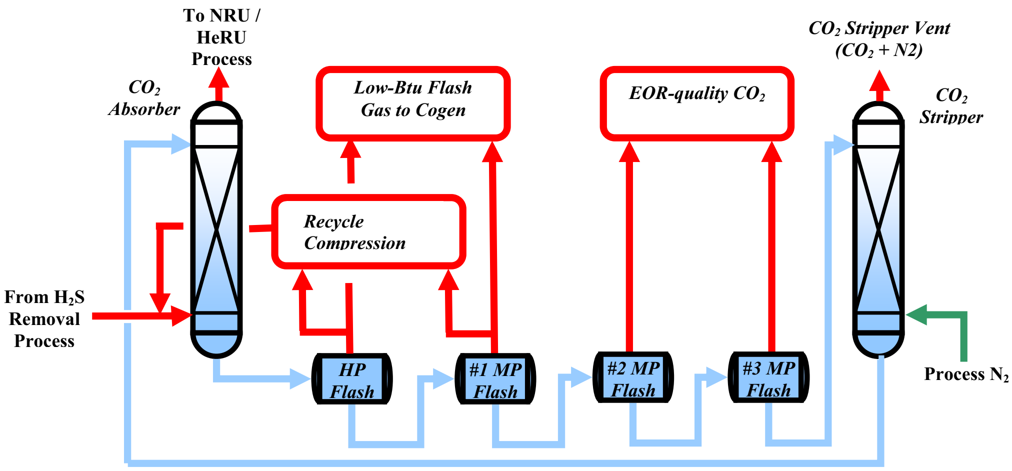

Figure 4: Schematic of CO_2 Removal system

As shown in Figure 4, the sweetened gas stream from the H_2S removal system is sent to a second Selexol process for removal of carbon dioxide, shown in Figure 4. CO_2 is absorbed into the Selexol solvent in the high pressure CO_2 Absorber tower. Downstream of the absorption section, a series of four flash vessels release CO_2 with varying levels of purity. The flash gases from the first two flash vessels, primarily CO_2 and methane, are recycled in to the absorber or used as fuel for plant power generation. The CO_2 flash streams from the two lowest pressure vessels, with a total flow of approximately 340 MCFD (9.6 MNm^3/day), are of greater than 95% purity, making them suitable for enhanced oil recovery. Clean CO_2 is gathered from the flash stages in the second Selexol® train, and is compressed and sold for enhanced oil recovery. Because the CO_2 in the stripper overhead vent is mixed with nitrogen in the treatment process, this stream is not marketable and is vented to the atmosphere.

The remaining hydrocarbon gas must be polished with a regenerable, solid adsorbent to drop the CO_2 concentration low enough so that it does not freeze out in the subsequent cryogenic nitrogen rejection unit (NRU). The NRU separates the nitrogen and helium from the methane, which is then sold. Finally, valuable helium is separated and liquefied in a helium recovery plant.

Subsequent CO_2 Management Enhancements at LaBarge

The SCTF was originally designed for a total inlet rate of 480 MCFD (13.6 MNm^3/day) between the two trains. Constant efforts to debottleneck the facilities resulted in processing capacity increasing to 650 MCFD (18.4 MNm^3/day) in 2004. Installation of the AGI facilities, described in detail below, further increased the plant processing capacity to 720 MCFD (20.4 MNm^3/day) in the summer of 2005.

While great efforts have been made to maximize efficiency in the design of the H_2S and CO_2 removal systems, they are still power intensive processes. Between Selexol pumping and recycle compression, over 55 MW of power is consumed in the SCTF gas treatment process. Further, the acid gas injection system consumes over 15 MW of power for compression and pumping, and the CO_2 sales system consumes over 30 MW of power for compression. This huge electrical load was a major driver of the installation of a combined heat and power generation (CoGen) system composed of three General Electric Frame 6B CoGen turbines, which supply the stream required for operation of the Shute Creek facilities.

CO_2 Management Efforts and Initiatives

With approximately 465 MCFD (13.2 MNm^3/day) of produced CO_2, representing about two thirds of the well field production volume, effective CO_2 management has been critical to the continued development of the LaBarge Field. In addition to multiple debottlenecking efforts which have ultimately resulted in the increase of inlet capacity from 480 MCFD (13.6 MNm^3/day) to 720 MCFD (20.4 MNm^3/day), several projects have been undertaken that have had a significant impact on how CO_2 is handled.

Acid Gas Injection

Faced with declining trends in the long term sulfur market, in 2005 ExxonMobil mothballed the Sulfur Recovery Unit (SRU) and installed one of the world's largest AGI facilities. The AGI system was designed to inject 65 MCFD (1.8 MNm^3/day) of acid gas at pressures of up to 3100 psig (214 bar). The waste gas from the H_2S removal process is a mixture of approximately 40 MCFD (1.1 MNm^3/day) of H_2S and 25 MCFD (0.7 MNm^3/day) of CO_2 and is saturated with water. This gas is compressed by three - fifty percent capacity, four-stage compressors to approximately 1150 psig (79 bar). At the fourth stage of compression the gas becomes under-saturated with water. The acid gas stream is then condensed and pumped up to injection pressure by two - one hundred percent capacity pumps. Since start-up, the AGI system safety and operational performance has been excellent. There has been no unscheduled downtime to LaBarge operations associated with the AGI system as a result of the robust design and backup capacity built into all critical rotating machinery.

The acid gas is injected into two injection wells where it is sequestered below the gas/water contact in the same Madison reservoir from which the natural gas is produced. Far from the production zone, this injection location ensures that the vast Madison gas field is not contaminated by the injected fluids.

The hydrogen sulfide in the acid gas can cause respiratory irritation at low levels of exposure and fatalities at higher levels of exposure. The large flow rates of concentrated liquid H_2S in the AGI system heavily influenced operating practices for safe operations at the Shute Creek Facility. Extensive dispersion modelling was performed to evaluate the radius of exposure from potential releases. Based on these results, the area surrounding the AGI facility was designated to require stringent work rules. The AGI area of the plant requires special entry procedures including control room notification, identified observers and the carrying of emergency air and 10-minute escape packs. During start-up of the AGI facilities, it was recognized that tiny leaks might not disperse adequately to alarm a gas detector. To mitigate this potential risk, breathing air rules were modified to require that personnel within 20 ft (6.1m) of process piping in the AGI area must be under contained air. Initial start-ups are performed on CO_2 only as a further risk reduction measure.

One of the largest acid gas injection facilities in the world, the AGI system also represents one of the largest examples of carbon capture and sequestration facilities currently in operation, sequestering approximately 450 ktonnes of CO_2 per year.

CO_2 Sales Expansion

At the start of production, the SCTF has had the capacity to capture, compress and distribute 230 MCFD (6.5 MNm^3/day) of sales quality CO_2. ExxonMobil has maintained an active CO_2 marketing program to maximize sales of existing capacity, seek new markets for additional CO_2 sale and reduce CO_2 venting. In fact, the full capacity of sales quality CO_2 from the SCTF has been under contract since the start of production, however actual takes of contacted CO_2 have been sensitive to oil prices as shown in Figure 5. As a result of market sensitivities, annual CO_2 deliveries since start-up, through the early 2000s, averaged less than half of the contacted volumes.

Recently, higher oil prices have led to new EOR projects and increased demand for CO_2 in the Wyoming region. This, in turn, has made an ExxonMobil project to capture and compress the remaining 110 MCFD (3.1 MNm^3/day) of sales quality CO_2 that is currently vented, economically viable, thus increasing CO_2 sales capacity by almost 50%. The CO_2 Sales Expansion Project will add an additional 20,000 hp (14.9 MW) compressor at Shute Creek's CO_2 sales facility. Additionally, a 3000 hp (2.2 MW) low pressure compressor will be installed at Shute Creek to boost the pressure of CO_2 flashed from the lowest pressure flash vessel up to the 220 psig (15.2 bar) pressure of the higher pressure vessel that currently supplies CO_2 sales. In order to deliver the full 340 MCFD (9.6 MNm^3/day) through the existing CO_2 sales pipeline, discharge pressure of the CO_2 sales compressors will be increased from 2150 psig (148 bar) to 2450 psig (169 bar). These additional CO_2 sales volumes will then maximize the capacity of the existing CO_2 sales pipeline, based on the pipeline's maximum allowable operating pressure and the required discharge pressure at the downstream sales point.

Scheduled to start-up in the second quarter of 2010, this project will potentially reduce CO_2 emissions by up to 50%, eliminating up to 2 Mtonnes per annum of CO_2 emissions from Shute Creek.

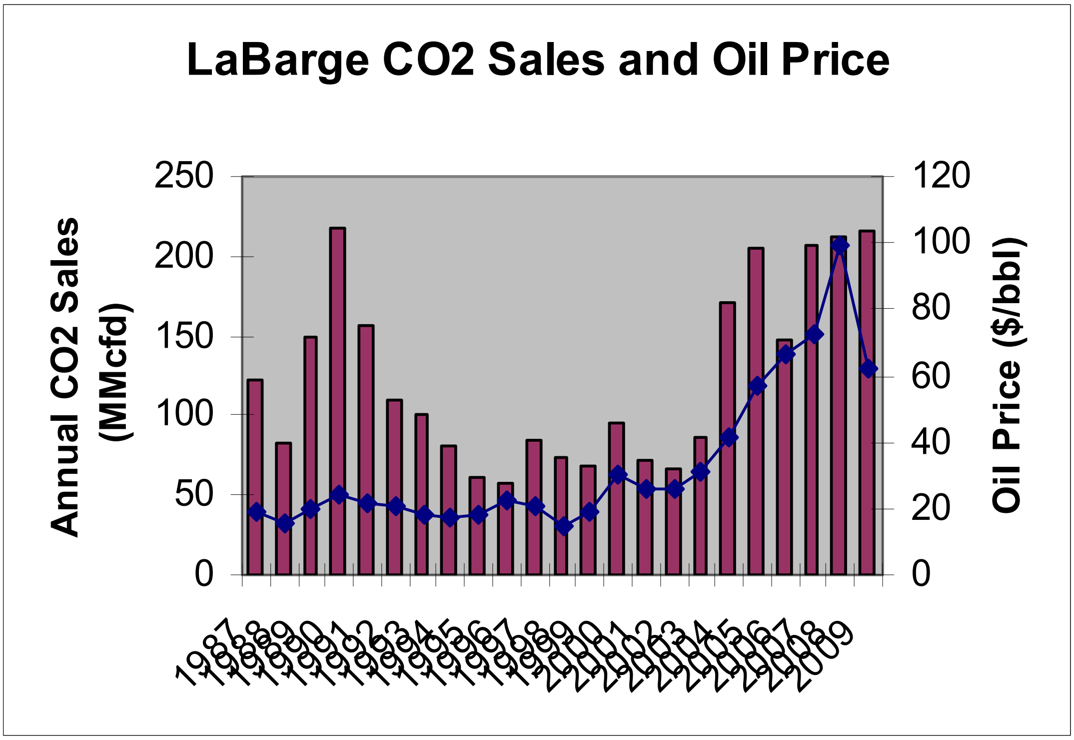

Figure 5: CO_2 sales volumes at the Shute Creek Treating Facility

New Promising Technologies - Controlled Freeze Zone™

Controlled Freeze Zone™ (CFZ) is a cryogenic process for the single step separation of CO_2 and H_2S from natural gas involving the controlled freezing and melting of CO_2. ExxonMobil is working on this technology to enable the development of increasingly sour gas reserves around the world to meet the growing global demand for clean burning natural gas. At the same time CFZ™ contributes to the protection of the environment by greatly facilitating the geosequestration of acid gas components present in the natural gas and the use of CO_2 for enhanced oil recovery (EOR).

Concept Development

Very low temperature, cryogenic processes are often the most efficient for the separation of gases containing light components such as oxygen, nitrogen, and methane. The presence of CO_2 in natural gas, however, precludes the use of conventional cryogenic distillation to separate CO_2 from methane. At the low temperatures needed to purify methane to saleable specifications, CO_2 solidifies if present in concentrations exceeding a few mole per cent. This limitation led, over the past decades, to the development of CO_2 removal technologies based on principles that did not involve cryogenic temperatures. Most of them are solvent based, using chemical, physical or hybrid solvents to capture the CO_2, followed by a solvent regeneration step where the process is reversed and the CO_2 is released by the solvent. Solvent regeneration is typically accomplished by addition of heat or lowering of pressure or both, and it is very energy intensive. Regeneration energy requirements and the amount of solvent used are directly proportional to the amount of CO_2 present. Thus while these processes are well suited to remove impurity levels of contaminants, their applicability is severely taxed when high concentrations of CO_2 are present in natural gas. In addition the CO_2 stream removed by these processes is normally a low pressure vapor stream that must undergo very costly recompression for EOR or geosequestration.

A number of schemes have been proposed or employed to circumvent the CO_2 freezing problem, most notably the Ryan-Holmes process which suppresses the solidification of CO_2 by the addition of heavier hydrocarbons as solubilizing agents. The Ryan-Holmes process has been used in a number of gas processing facilities [2]. While this process brings back some of the benefits of distillation processes, the recovery and regeneration of the solubilizing agents does involve additional separation steps.

In the mid-1980's, Exxon developed a process that addressed the CO_2 freezing problem without the use of additives in the cryogenic distillation. It became known as the Controlled Freeze Zone™ (CFZ) process. The idea behind the CFZ™ technology is not to suppress or avoid CO_2 freezing, but rather to induce it and confine it to a specific section of an otherwise conventional distillation column that has been specially designed to handle solidification and remelting of CO_2 [3]. A simplified process diagram, including a sketch of such a column is shown in Figure 6.

The CFZ process has been previously described in detail (4). Briefly, feed gas is dehydrated, chilled and/or expanded, and fed in to the middle portion of the column. Liquid from the upper conventional distillation section, that is about to enter solidification conditions, is sprayed into the CFZ section, which is very open and unobstructed. As the liquid droplets fall, they encounter warmer temperatures. Methane and any lighter components such as nitrogen, if present, vaporize. The residual concentration of CO_2 in the droplets increases, leading to solidification. The solids that form fall onto a liquid layer at the bottom of this chamber that is maintained above solidification temperatures. A liquid, beyond solidification conditions, emerges from the bottom of the CFZ chamber and is directed to the stripper section to recover valuable methane. Similarly, vapors from the bottom conventional distillation (stripper) section, rise through the CFZ section and encounter colder temperatures. CO_2 condenses or frosts onto the falling spray droplets or solid crystals, further contributing to the solidification process. The solids formed in the CFZ section are pure CO_2, thus providing greater separation factors and high efficiency for this section. Their removal from the vapor stream results in a product exiting the top of the CFZ chamber that is significantly depleted in CO_2. Above the CFZ section, the CO_2 content is further reduced, if necessary, to meet pipeline or LNG feed quality, via conventional distillation in a rectifying section.

Two very important characteristics of the CFZ process are that it imposes no limitations on how high the CO_2 or H_2S content can be in the feed stream, and that the captured CO_2 is discharged as a high pressure liquid stream that can be readily boosted to injection pressure. Another related advantage of the CFZ process is that essentially all sulfur-containing compounds (H_2S, COS, mercaptans, etc.) end up with the CO_2 in this easily-pumped liquid discharge. Further, this stream contains only traces of dissolved water, and is easier to handle than the low-pressure (and likely water-saturated) acid gas coming off of the regenerator of a solvent process.

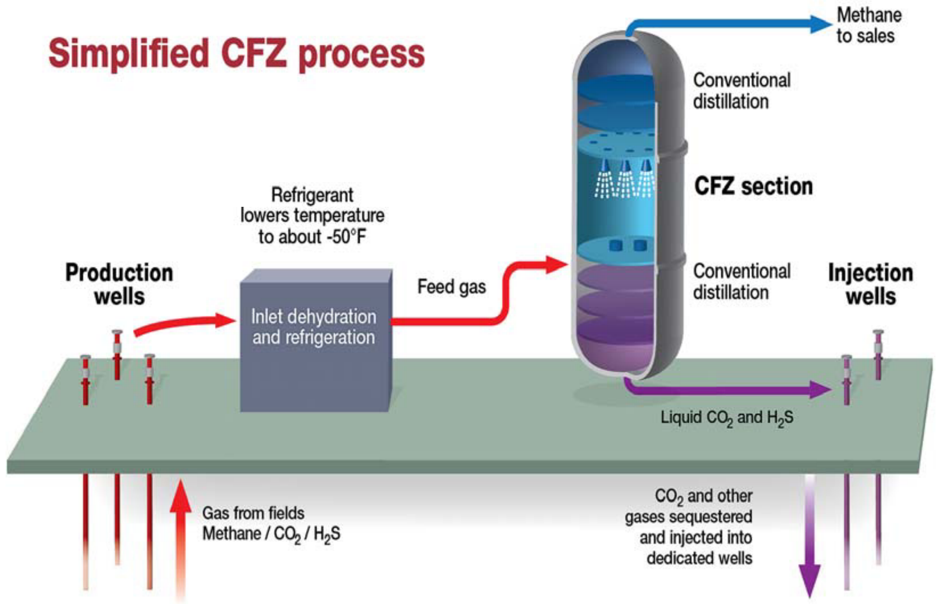

Figure 6. Schematic diagram of CFZ distillation process.

With the CFZ process, heavier hydrocarbons (C_2+) will go with the liquid CO_2/H_2S stream. Thus, if these hydrocarbons are present in significant quantity and desired, they must be recovered separately. In the case of a CO_2 enhanced oil recovery (EOR) application, these hydrocarbons may retain some of their value in the liquid stream by improving CO_2 miscibility.

Pilot Plant Experience

The CFZ technology was invented by Exxon Production Research in 1983 and was patented in 1985 [3]. A 0.6 MCFD (0.02 MNm^3/day) pilot plant was built at Exxon's Clear Lake Gas Plant in Pasadena, near Houston, Texas in 1985. It was operated in 1986 and 1987, the results of which were presented in an earlier paper [5]. The Clear Lake CFZ Pilot Plant was the first application in the industry to successfully demonstrate the freezing and re-melting of CO_2 as part of a natural gas separation process.

The pilot plant processed feed gases with CO_2 contents ranging from 15 to 65% CO_2, at pressures of 550 to 600 psi (37.9 to 41.4 bar). While it was designed to achieve pipeline quality hydrocarbons, the overhead gas stream not only met pipeline quality, but approached LNG feed quality by reducing the CO_2 content to a few hundred parts per million. Methane losses in the bottom stream were targeted for 1%, but performance of as low as 0.5 % was achieved. The Clear Lake Pilot Plant operations were very successful at demonstrating the concept of controlled freezing and re-melting of CO_2 and provided valuable operating and design information.

Renewed Interest in CFZ and the Commercial Development Project

The increasingly sour nature of many undeveloped natural gas resources, coupled with growing environmental concerns and expanding interest in CO_2 for EOR has led to a substantial renewed interest in the CFZ technology. Integration of CFZ with acid gas injection and use of CO_2 for EOR provides very effective alternatives for the disposition of these by-products while enabling production of important, clean burning natural gas.

Given this renewed interest, ExxonMobil is bringing the CFZ technology to commercial readiness via a demonstration project at LaBarge. Construction of a 14MCFD (0.4 MNm^3/day) CFZ commercial demonstration plant (CDP), shown in Figure 7, has been completed at the SCTF and operations are about to begin.

Figure 7. The CFZ™ Commercial Demonstration Plant.

The CDP will demonstrate the effective and efficient scale-up of the CFZ technology to facilities capable of handling up to a billion CFD (28.3 MNm^3/day) of natural gas. The CDP incorporates many post-pilot plant enhancements and will verify extensions of the range of applicability of the CFZ technology.

The SCTF was chosen to host the commercial demonstration plant because it will allow testing of the CFZ technology not only with CO_2 but also H_2S. In addition, the SCTF acid gas injection facilities will allow the CFZ unit to demonstrate the ability to pump its captured CO_2 and H_2S for geosequestration.

The operational objectives of the CDP include the demonstration of processing of higher volumes of gas with a wide range of CO_2 (15-65%) and H_2S (5-35%) concentrations, representative of global resources of potential applicability, under a variety of operating conditions. This data will establish scale-up parameters, and equipment and mechanical design information for the design and operation of large scale CFZ facilities [4].

The demonstration phase will start in 2010 and extend into 2011.

Conclusions

- CO_2 management has been a key priority for ExxonMobil's LaBarge operations from the onset of natural gas production from this very challenging field, and all components of commercial scale carbon capture and storage (CCS) are being actively demonstrated.
    - Volume capacity for managed CO_2 started at 40% of the CO_2 present in the natural gas produced and have increased to current levels of over 50% (approximately 255 MCFD (7.2 MNm^3/day) of CO_2 (230 MCFD (6.5 MNm^3/day) CO_2 sales, 25 MCFD (0.7 MNm^3/day) AGI)) or 5.2 million tonnes/yr CO_2, roughly equivalent to the CO_2 generated by a 600 MW coal fired power plant.
    - Increased EOR demand for CO_2 has led to a CO_2 Sales Expansion project that will increase sales capacity by an additional 110 MCFD CO_2 (3.1 MNm^3/day) by the time it is operational in 2010, increasing the fraction of managed CO_2 to over 75% (approximately 365 MCFD (10.3 MNm^3/day)) or 7.5 million tonnes/yr.

- Several technologies and approaches have been used to manage CO_2 and H_2S at LaBarge:
    - Capture of CO_2 and H_2S has been based on the Selexol technology, which has proven to be safe and effective at scales necessary for commercial CCS applications.
    - Utilized since 1986, sales and injection of CO_2 for enhanced oil recovery (EOR) and other industrial uses has been proven to be the most effective means of managing CO_2 at LaBarge.
    - Initially H_2S was managed by conversion into elemental sulfur. Recently the sulfur conversion facility was replaced by one of the largest acid gas injection (AGI) facilities in the world, capable of injecting a mixture of 40 MCFD (1.1 MNm^3/day) of H_2S and 25 MCFD (0.7 MNm^3/day) of CO_2.
    - Along with the AGI unit, a 110 MW power cogeneration system was installed.

This system substantially reduces CO_2 emissions when compared to purchased power emissions and reduces NOx emissions as well.

- New promising technologies
    - ExxonMobil is bringing its Controlled Freeze Zone™ technology to commercial readiness via a demonstration plant at the SCTF. This technology has the potential to enable the development of previously uneconomical high CO_2 and H_2S natural gas resources while protecting the environment by greatly facilitating the injection of CO_2 and acid gas components for EOR purposes or geosequestration.

- A legal and regulatory system that balances safe and environmentally sound implementation of CCS with practical consideration of operational controls will be critical to allowing commercial scale CCS to occur at the pace currently thought to be necessary to have a meaningful impact as a GHG emission mitigation strategy. Facilities of the scale, complexity, and cost of ExxonMobil's LaBarge facilities are not expected to be uncommon and therefore will require a stable economic and regulatory environment to encourage such investments.

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