

CO₂ Recovery and Sequestration at Dakota Gasification Company

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Author Biographies

The co-authors of this paper have Bachelor of Science degrees in Chemical Engineering from the University of North Dakota. Myria and Daren have been employed as Process Engineers at Dakota Gasification Company for 11 and 12 years, respectively, and both have been involved with the design and operation of the CO₂ pipeline project for the last five of those years.

ABSTRACT

The Great Plains Synfuels Plant, located near Beulah, North Dakota, is the only commercial-scale gasification plant operating in the United States that produces Synthetic Natural Gas (SNG) from coal. The plant is owned and operated by Dakota Gasification Company (DGC), which is a subsidiary of Basin Electric Power Cooperative (BEPC), based in Bismarck, North Dakota.

The concept for the Synfuels Plant began in the 1970's and grew from a desire to alleviate the United States dependence on foreign oil. Today upwards of 150 million standard cubic feet per day of SNG are produced and exported to consumers throughout the Midwest via the Northern Border Pipeline. Numerous by-products, including anhydrous ammonia, ammonium sulfate fertilizer, phenol, cresylic acid, krypton/xenon, naphtha and carbon dioxide (CO₂) have been added to the list of products enhancing the viability of the facility.

Since the conception of the plant, the idea was envisioned of adding CO₂ for enhanced oil recovery (EOR) to the list of by-products. In October 2000, this became a reality when Dakota Gasification Company began exporting up to 95 million standard cubic feet per day of high-pressure CO₂ from the Synfuels Plant. The CO₂ is delivered through a 205-mile pipeline to EnCana Corporation's Weyburn Oil Fields in Saskatchewan, Canada, where it is injected into depleting oil formations to increase production and lengthen the life of the field. The feed gas to the carbon dioxide unit was previously a low value fuel, and has now become a source of revenue to the company.

Although this project has presented many challenges to both Dakota Gasification and EnCana, it has proven to be a technical and economic success. In addition, the EOR project has led to an

international research study, which is evaluating this form of geological carbon sequestration from a number of aspects including economics and long-range environmental impacts. This paper discusses some of the regulatory, technical, and mechanical obstacles that DGC has encountered and overcome in building and operating the CO₂ compressors and pipeline system. In addition, a general overview of the coal gasification process is included to define the processing steps required to concentrate the CO₂ into a usable product.

INTRODUCTION

The Great Plains Synfuels Plant is the only commercial-scale coal gasification plant in the United States that manufactures natural gas for sale. The Synfuels Plant is owned and operated by Dakota Gasification Company, a subsidiary of Basin Electric Power Cooperative, based in Bismarck, North Dakota.

The plant's genesis lies in the energy crisis of the 1970's when Americans felt the tightening grip from oil-producing nations of the Middle East. It is the only project operating today that is tied to the Federal Nonnuclear Energy Research and Development Act of 1974, which was enacted to spur developments that could help the United States achieve energy independence.

The \$2.1 billion plant began operating in 1984. Using the Lurgi gasification process, the Synfuels Plant gasifies lignite (a low-rank form of coal) to produce valuable gases and liquids. The gas path portion of the plant is configured in two 50% trains, with a maximum total capacity of 170 million standard cubic feet per day (MMSCFD) of SNG. Including planned and unplanned outages and rate reductions, the average annual plant loading factor is typically about 90-92%. The product SNG is piped into the Northern Border pipeline, which runs to Ventura, Iowa, for distribution in the Midwestern and Eastern United States.

The Synfuels Plant also produces up to 1150 tons per day of anhydrous ammonia, 95 MMSCFD of CO₂, and variety of other byproducts. The ammonia is primarily sold into the regional agricultural market, with smaller amounts purchased by industrial users around the country. The CO₂ is compressed and delivered through a 205-mile pipeline to EnCana Corporation's oilfields near Weyburn, Saskatchewan, Canada, for use in enhanced oil recovery. As an added environmental benefit, virtually all of the injected CO₂ is expected to remain permanently sequestered in the depleted oil fields long after they have been abandoned.

The Synfuels Plant consumes daily about 18,500 tons of lignite supplied by the nearby Freedom Mine. The mine is owned and operated by the Coteau Properties Company, a subsidiary of the North American Coal Corporation.

THE GREAT PLAINS SYNFUELS PLANT PROCESS

The process of turning lignite into SNG begins by feeding approximately 55 tons/hour of golf-ball-to-baseball-sized coal to each of 14 Lurgi Mark IV gasifiers (see Figure 1). In the Lurgi moving bed gasifiers, steam and oxygen are fed to the bottom of the gasifier and distributed by a

TABLE 1. Raw Gas Composition.

Component	Volume Percent
Hydrogen	38.6
Carbon Dioxide	32.4
Carbon Monoxide	15.4
Methane	11.9
C2 & C3 Hydrocarbons	0.8
Hydrogen Sulfide	0.7
Other	0.2
Total	100.0

revolving grate. The steam and oxygen slowly rise through the coal bed, reacting with the coal to produce a raw gas stream. A typical composition of raw gas is given in Table 1.

The raw gas stream that exits each gasifier is first cooled in a waste heat boiler that generates 100-psig saturated steam. After this initial cooling step, two-thirds of the raw gas is sent to additional waste heat recovery and cooling water exchangers where it is cooled to 95° F.

The remaining one-third of the raw gas is sent to Shift Conversion where the composition of the gas is modified by converting a portion of the carbon monoxide (CO) and water vapor to carbon dioxide (CO₂) and hydrogen. The shifted gas is then cooled to 95° F and combined with the cooled raw gas to become what is called “mixed gas.”

The mixed gas stream is sent to the acid gas unit where CO₂ and sulfur compounds are removed by a cold methanol wash. The Great Plains Synfuels Plant utilizes the Rectisol Process, licensed by Lurgi, a German company, to accomplish this step. Naphtha components are also removed by the cold methanol wash. The naphtha stream, once separated from the methanol, can either be further treated and sold as a byproduct or burned in the plant’s main boilers as a liquid fuel. The synthesis gas product from the Rectisol unit is then sent to Methanation, where SNG is produced. Following Methanation, the SNG is compressed, dried, and sent to the pipeline.

The waste gas stream from the Rectisol Unit is the plant’s primary source of CO₂. This stream is

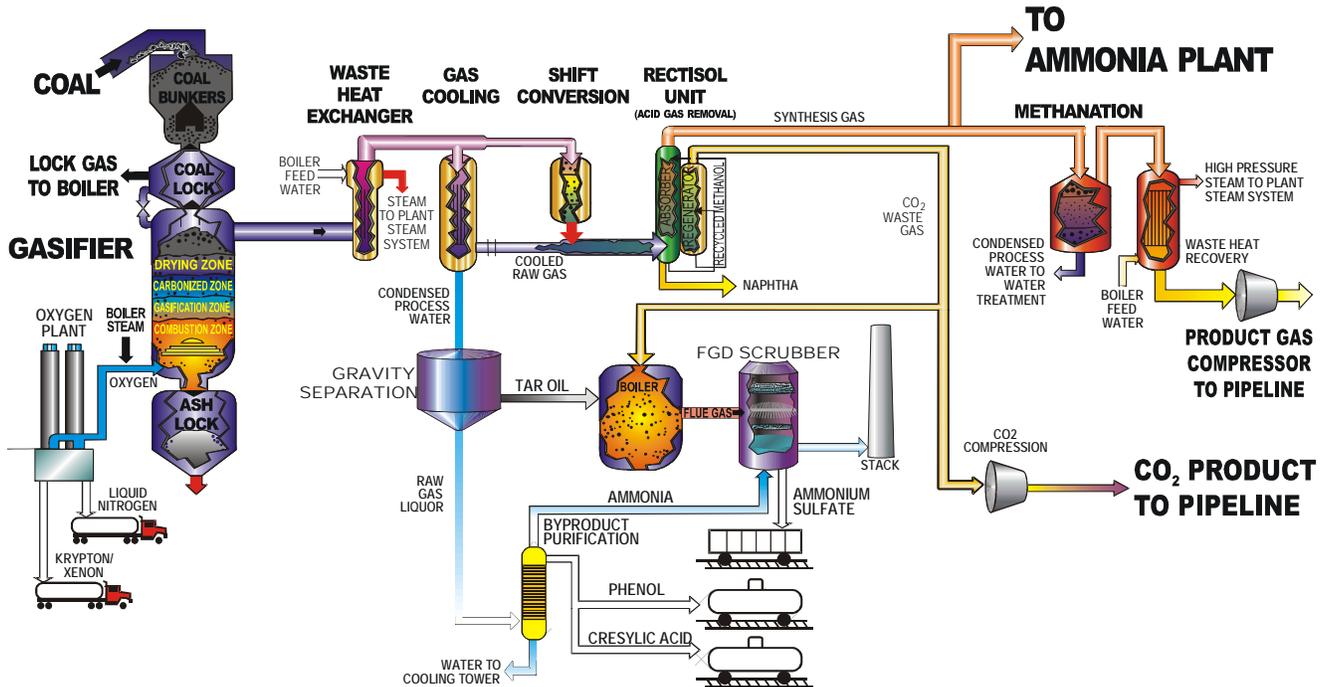


FIGURE 1. Great Plains Synfuels Plant Process Flow

comprised primarily of the CO₂ and sulfur compounds removed from the mixed gas, but it also contains smaller amounts of combustible hydrocarbons. The entire waste gas stream had historically been used as gaseous fuel in the plant's three main boilers, to recover its 40-50 Btu/SCF of heating value and oxidize the H₂S (hydrogen sulfide) and other sulfur components into SO₂ (sulfur dioxide). However, beginning in 2000 a portion of this stream has become our newest byproduct. The CO₂ is now compressed to 2700 psig and sent to Canada via a new 205-mile pipeline (Figure 2).

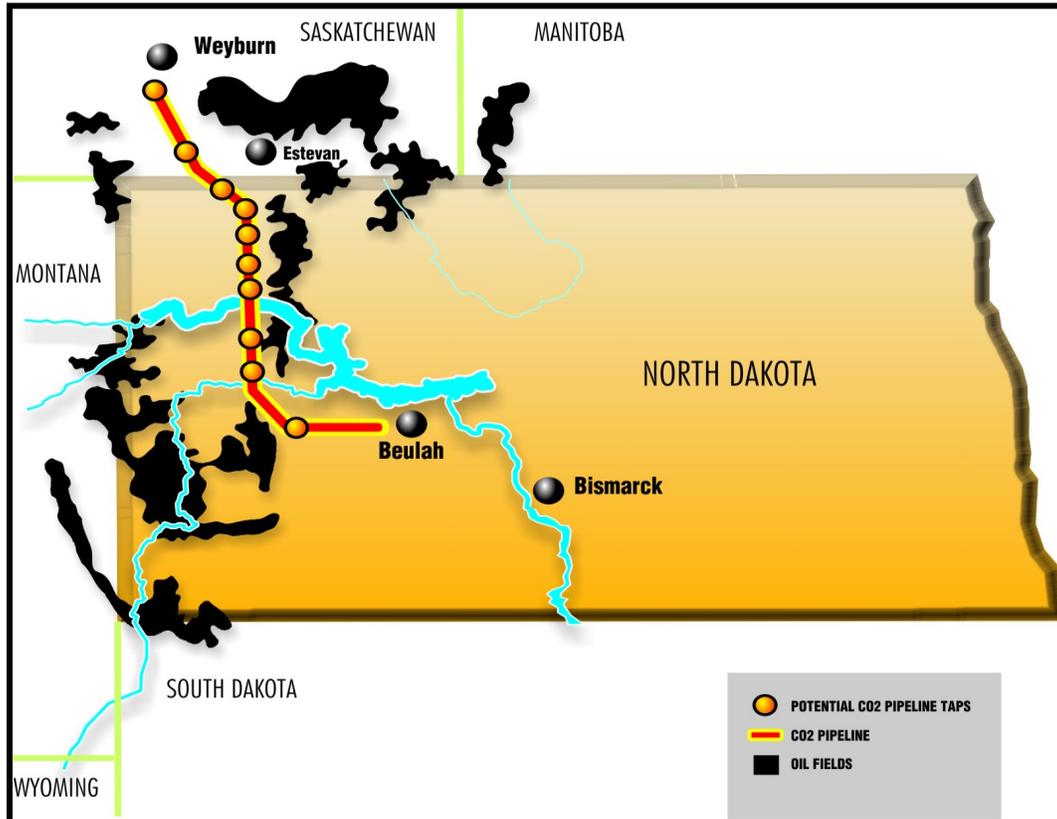


FIGURE 2. CO₂ Pipeline Route.

Gasification of lignite (which contains an average of 36 wt. % moisture) also produces a dirty water stream called gas liquor. Gas liquor contains in part tars, oils, phenolic compounds, and ammonia. This liquor stream is condensed from raw gas and shifted gas at the various steps where these gases are cooled prior to the cold methanol wash in the Rectisol Unit.

The condensed liquor is first treated in the Gas Liquor Separation Unit where, through gravity separation, any tar, coal fines and tar oil are removed. The tar and coal fines are recycled back to the gasifiers. The tar oil is used as a liquid fuel in the main plant boilers.

The treated raw gas liquor from the Gas Liquor Separation Unit is further processed in two additional units, Phenosolvan and Phosam, which remove crude phenolic compounds and ammonia, respectively. Stripped gas liquor, which is the treated water from these two areas, is sent to the plant's cooling tower as make-up water. The crude phenol stream is further processed

in a Phenol Purification Unit where pure phenol and cresylic acid are produced as saleable by-products.

In 1996, a used 1000-ton per day CF Braun ammonia plant was purchased and relocated from Ft. Madison, Iowa to the Great Plains Synfuels Plant. The ammonia plant is a conventional unit with the exception that it does not need a primary reformer due to the composition of the feed gas. Air and a portion of the synthesis gas from the Rectisol Unit are preheated and fed directly to the secondary reformer. The remainder of the ammonia process is like any other conventional plant. Several improvements to the original design have increased the maximum production capacity to 1150 tons per day. Recently, however, the ammonia plant has been operated for only part of each year, depending on ammonia and natural gas market conditions. At the maximum ammonia rate the plant's output of SNG is reduced by 20-25%, but in an average year approximately 10% of the total gas output is diverted to ammonia production.

The Great Plains Synfuels Plant has three Riley Stoker boilers and two CE direct-fired superheaters. The Riley boilers convert purified boiler feedwater into 1150 psig superheated steam, while the "superheaters" superheat 1250 PSIG saturated steam produced from waste heat in the Methanation Unit and Ammonia Plant. The steam from both sources is combined and used in turbine drivers for several large compressors throughout the plant. A majority of the 550 psig exhaust steam from these turbines is used as reaction steam in the gasifiers, with the remainder sent to distillation column reboilers and other plant users.

The flue gas from the boilers is processed in a unique FGD (Flue Gas Desulfurization) unit, where ammonia is used as the reagent in a solution that absorbs a minimum of 93% of the incoming SO₂. The solution is then dewatered, and the resulting solid product further processed to produce a granular ammonium sulfate fertilizer, marketed under the trade name Daksul 45[®].

CARBON DIOXIDE FOR ENHANCED OIL RECOVERY (EOR)

The idea for selling carbon dioxide from the Great Plains Synfuels plant arose during the initial design phase in the 1970's, well before the plant was actually built. The focus was to use carbon dioxide from the plant for injecting into aging oil fields and thus recover additional oil that would otherwise be lost. In particular, EOR using carbon dioxide from the Great Plains Synfuels plant would make economic sense for certain reservoirs within the huge Williston Basin field underlying parts of North Dakota, South Dakota and Montana in the United States, and Manitoba and Saskatchewan in Canada.

Other sources of CO₂, such as natural CO₂ reservoirs and flue gas from power plants, have also long been considered for EOR. Natural CO₂ is currently being used successfully in several areas of the world where oil fields are in close proximity to the CO₂ reservoirs. However, flue gas has yet to become a major player in the EOR market due to its low concentration of CO₂ and the additional processing necessary to remove nitrogen and water vapor (water is a primary product of combustion for any fuel containing hydrogen, which is the case for natural gas, coal, fuel oil, and most other fuels). If the water vapor is not removed prior to compression, the CO₂ product will be very corrosive and the pipeline would have to be built with much more expensive

TABLE 2. Composition of Product CO₂.

Component	Volume Percent
Carbon Dioxide	96.8
Hydrogen Sulfide	1.1
Ethane	1.0
Methane	0.3
Other	0.8
Total	100.00

cold methanol absorption and regeneration processes used to remove it from the product gas stream.

After passing through the absorber, the CO₂-rich methanol is regenerated for reuse by flashing it from operating pressure to sub-atmospheric (vacuum) pressure. As the pressure is reduced, CO₂ and the sulfur compounds, along with a small amount of hydrocarbons are released in the gas form. This gas stream is called “CO₂ waste gas”, part of which is now fed to the CO₂ Compression Unit, with the remainder going to the boilers. A typical analysis of the CO₂ that is sold is shown in Table 2.

Due to the relatively low price of oil in the 1980’s and early 1990’s, and questions about the long-term viability of the Synfuels Plant during the same time period due to low natural gas prices, sales of CO₂ did not materialize as rapidly as had been anticipated. However, negotiations with potential customers heated up in the mid 1990’s, and finally in 1997 Dakota Gasification entered into a contract with Pan Canadian Resources (now EnCana Corporation) for the sale of up to 95 MMSCFD of CO₂ to their Weyburn oil fields.

CO₂ COMPRESSION

The compression unit at the Great Plains Synfuels Plant consists of two 8-stage compressors manufactured by GHH BORSIG (now MAN Turbomaschinen AG). Feed gas is taken at 3 psig and compressed to 2700 psig, which is in the supercritical range for CO₂. Interstage cooling is accomplished with air-cooled heat exchangers. Each compressor has a capacity of 55 MMSCFD and is driven by a 19,500 horsepower fixed-speed motor. The power is transferred to the compressor through a single bull gear and 4 pinions. Each pinion drives the compressor wheels for 2 stages, with the 7th and 8th-stage pinion operating at 26,400 rpm. This integral bull gear design allows for the use of a single machine to achieve the desired discharge pressure, compared with the need for several compressors in series for other similar applications. Dakota Gasification engineers worked closely with the BORSIG engineers during the design of these machines, and both parties are very proud of the end result. They are serial numbers 1 and 2 of their kind in the world, although there is now a similar 10-stage machine operating in Russia.

The interstage temperatures and pressures were specified such that the CO₂ would pass directly from the gas phase to supercritical without ever going through the liquid phase. Once the fluid is supercritical, it is important to never allow it to drop back into the liquid-vapor 2-phase region,

materials than carbon steel. Nitrogen is undesirable because it raises the minimum miscibility pressure of the fluid and makes the injection process less efficient.

On the other hand, the Rectisol unit at the Great Plains Synfuels Plant already produces a 95% pure CO₂ stream just from the nature of the process. It is also “bone-dry”, with a dew point of around -100° F, because of the

which would occur below about 1000 psig at ambient temperatures (otherwise there could be freeze-up issues and a much higher pressure drop in the pipeline). Compressor operation is monitored by a sophisticated Turbolog[®] control system that regulates startups, shutdowns, and normal operation to keep the compressors out of the liquid-vapor phase and out of the critical vibration region of each of the pinions.

In the pipeline, with the typical compressor discharge pressure of 2700 psig, and the customer receiving the product at a minimum of 2175 psig, the CO₂ stays well above the phase-change region. However, if CO₂ sales were to increase significantly, a booster pump would be required at Tioga, North Dakota (about the halfway point), to keep the fluid in the supercritical phase and to ensure delivery at greater than 2175 psig.

Other than a few issues early in the commissioning process with seal design and o-ring material compatibility, the compressors have operated as designed. The seal problems were mechanical in nature and were solved by a redesign of the carbon seal pack. A change from Fluoraz to Chemraz material solved the o-ring problems.

CO₂ PIPELINE

Construction

Prior to starting construction of any pipeline, the appropriate permits must be obtained. Since this one is an international pipeline, there were numerous government agencies involved. There were also right-of-way issues to acquire a corridor for building the pipeline. All of this was successfully completed without having to resort to condemnation proceedings.

Groundbreaking was held in May 1999. 205 miles of 14" and 12" carbon steel pipe was laid through western North Dakota and southern Saskatchewan. Pipe thickness is 0.375", except at road, railroad, and water crossings, where 0.500" or 0.625" wall thickness was used. Stainless steel or other exotic metals were not necessary, because the lack of water in the CO₂ makes it a non-corrosive fluid. Design MAOP (maximum allowable operating pressure) is 2700 psig in the first half of the pipeline up to Tioga, and 2964 psig the rest of the way.

Challenges during construction included the crossings of the Little Missouri River and Lake Sakakawea, the latter of which is 3 miles long. At the shoreline the pipe was buried and covered with rock to prevent erosion, but out in the water the pipe was simply laid along the bottom of the river or lakebed. Remotely operated MLV's (main-line valves) are located on either side of these water crossings, as well as approximately every 20 miles overland, in order to allow for quick isolation and to minimize the impact of a leak. In total there are 12 of these intermediate valve stations.

Construction of the new compressor and pipeline system was completed in 2000 and operation began in the fall of that year.

Operation

Supercritical CO₂ pipelines are considered hazardous liquid pipelines, which are regulated under 49 CFR (Code of Federal Regulations) Part 195 in the United States and the Canadian Standard Association Z662 in Canada. As a result, Dakota Gasification must follow all of the same regulations as a pipeline operator transporting petroleum products.

One of the requirements for operating a hazardous liquid pipeline on either side of the border is to have a dependable form of on-line leak detection. In addition, the Canadian NEB (National Energy Board) specifically requires a computational leak detection system (LDS). The LDS in operation at the Synfuels Plant to monitor the CO₂ pipeline is a sophisticated computer model that continuously queries pipeline operating data to identify potential leaks in the piping system. Pressure and temperature readings are taken at both ends of the pipeline and at each of the 12 MLV stations. There is also a highly accurate mass flowmeter at each end of the pipeline to aid in the volume balance calculations of the LDS. The data is transmitted via microwave, hard wire, or radio communication to the control room at the Great Plains Synfuels Plant, where it is automatically forwarded to the LDS computer. The software uses this information to identify a potential leak and generate an audible and visual alarm on the pipeline control room screens. It can identify a potential leak location to within two miles, estimate the leak rate and report the total volume lost. A great deal of development work has gone into this system, by both the software vendor and Dakota Gasification personnel, because it is the first of its kind on a supercritical CO₂ pipeline.

There is also a reverse 911 system at the Synfuels Plant. If a leak is suspected due to an LDS alarm or any other means, plant supervision will trigger the reverse 911 procedure. A computer at the plant is pre-programmed to call specific groups of the residents and businesses that are determined by the supervisor to be in the vicinity of the potential leak. The recording gives them general instructions on the nature of the potential emergency and advises them of the appropriate response.

One of the current projects under development is a smart-pig capable of withstanding supercritical CO₂ at 2700 psig. This piece of equipment travels down the inside of the pipeline while it is in operation to allow for assessment of the pipeline condition. It is one of the most important diagnostic tools necessary to maintain compliance with the integrity management portion of the hazardous liquid pipeline regulations.

THE CUSTOMER

EnCana Corporation, the customer, has also made a significant investment in this enhanced oil recovery project. This included equipment to distribute and inject the CO₂ into the oil fields, and facilities to recover and recycle the dissolved CO₂ that returns with the crude oil.

There were also environmental issues to overcome. EnCana and their neighbors were already familiar with the smell of hydrogen sulfide (H₂S) in and around the oil fields, because that has been a "cost" of doing business in the oil industry for decades. However, DGC's CO₂ also

contains trace amounts of mercaptans and other malodorous sulfur compounds, which were creating a new and unwanted smell in the vicinity of the wells and processing equipment. EnCana invested in sealed stuffing boxes and other changes at the wellheads to capture fugitive emissions and to minimize these odors.

Notwithstanding the challenges that were overcome, this project has the potential to be a tremendous economic success for EnCana, especially considering today's high oil prices. Their initial pre-project projections indicated that up to 130 million barrels of additional oil could be recovered from their Weyburn field due to CO₂ flooding. This is oil that would not have otherwise been recovered following a conventional water flood or other secondary or tertiary means.

CO₂ SEQUESTRATION

Sequestration is defined as the act of setting apart for safekeeping.

CO₂ sequestration can be divided into two categories, terrestrial and geological. Terrestrial sequestration takes advantage of the fact that vegetation and soils are known carbon sinks. Through photosynthesis, plants convert CO₂ into carbon, which remains stored in the roots of the plants and the soil. Geological sequestration involves permanent storage of CO₂ in geological formations below the surface of the earth. Using CO₂ to increase oil production from an aging oil field is an example of geological sequestration with an added economic benefit.

To date, there are two successful projects involving geological sequestration. The first is off the coast of Norway where CO₂ is removed from a natural gas source and injected into a saline reservoir that is deep under the bottom of the North Sea. The second is the Dakota Gasification project, which uses CO₂ to extend the life of the Weyburn Oil Fields.

Why worry about CO₂ sequestration? Carbon dioxide (CO₂) is considered by many to be a "greenhouse gas", which means that it may be contributing to the phenomenon of "global warming." There is much debate over this issue, including the Kyoto Protocol, which at the time of this writing the United States was not a participant. Even so, popular opinion appears to be that lower overall emission of "man-made" CO₂ is a step in the right direction. On that basis, enhanced oil recovery via CO₂ flooding is an example of how one project can be a benefit to both industry and the environment.

Typically, oil recovery can be categorized as primary, secondary, and tertiary or enhanced. In primary oil recovery, the natural pressure of the oil reservoir is used to drive the crude into the well bore from where it is brought to the surface with conventional pumps. In the 1940s, producers incorporated secondary recovery by utilizing injected water or natural gas to drive the crude to the well bore prior to pumping it to the surface. With the easily extracted oil already recovered, producers have turned to tertiary or enhanced oil recovery techniques, one of which is CO₂ injection. Tertiary oil recovery uses supercritical CO₂. In this state CO₂ acts as a solvent, dissolving the residual oil, reducing the viscosity, increasing its flow characteristics, and allowing it to be pumped out of an aging reservoir. EOR using CO₂ was first implemented in

1972 in Scurry County, Texas. Since then, CO₂ injection has been employed in many oil-producing areas in the United States.

Although the use of CO₂ to increase oil production is not new, prior to the DGC and EnCana project the CO₂ primarily came from natural sources. The CO₂ was removed from a naturally occurring ground source and injected into the geological structure. There was no net reduction in CO₂ emissions to the atmosphere. However, the Weyburn project is unique. Dakota Gasification is taking a source of CO₂ that was previously emitted to the atmosphere and permanently injecting it into a geological sink, thus reducing the total annual emissions of CO₂. Currently there are several international research projects underway to study CO₂ reduction and/or sequestration. The Petroleum Technology Research Center (PTRC), located in Regina, Saskatchewan, is coordinating one of these efforts. They are focusing specifically on the Weyburn project, using the oilfields themselves as a macro-scale laboratory to monitor the long-range effects of CO₂ sequestration and geological storage. Fifteen sponsors from government and industry have contributed to this study, among them the United States Department of Energy, Natural Resources Canada, Alberta Energy Research Institute, Dakota Gasification Company, and EnCana Corporation. The primary goal of this research is to understand the feasibility of permanent CO₂ containment for long-term sequestration within a geological reservoir.

Tax Credits

There is also the potential for both companies to realize future tax credits for permanent CO₂ sequestration. Although there is no current monetary benefit, DGC has voluntarily chosen to file Form EIA-1605 (Long Form for Voluntary Reporting of Greenhouse Gases) on an annual basis with the United States Department of Energy (DOE). These reports show a total sequestered quantity of 2,725,000 metric tons of CO₂ from project start-up in late 2000 through the end of 2003. This figure already accounts for reductions in the credit due to indirect increases in emissions from (1) CO₂ emissions necessary to generate the additional electricity to drive the compressors and other auxiliary equipment at DGC and EnCana; (2) CO₂ emissions resulting from the use by DGC of substitute fuel to compensate for the small amount of heating value in the exported CO₂ that had been previously burned in the plant's boilers; (3) Flared CO₂ and fugitive emissions at EnCana directly attributable to this project; and (4) Other smaller indirect impacts as calculated in order to prepare Form EIA-1605. After accounting for these reductions, the net sequestration credit for 2003 still amounted to 73% of the total sales volume.

FUTURE EXPANSION

Although current sales of CO₂ average 95 MMSCFD, there is up to 200 MMSCFD produced at full plant rates. Dakota Gasification continues to look for new customers in the region for this remaining capacity. As Figure 2 shows, the pipeline route was strategically laid out to pass through or near many other oil fields in western North Dakota and southern Saskatchewan on its way up to Weyburn. In addition, a number of taps were installed along the pipeline in anticipation of these future sales.

While the pipeline itself could handle the increased volume, such an expansion would require up to two additional compressors at the plant and a booster pump at about the halfway point along the pipeline. During construction, provisions were made to allow for this future expansion with minimal disruption to existing production.

CONCLUSION

Geological CO₂ sequestration is being successfully accomplished at the Weyburn Oil Fields, at a rate now in excess of 1 million metric tons per year. Due to the additional oil recovery, the CO₂, which was previously a waste stream for Dakota Gasification Company, has value to the oil producer. And because the Rectisol process already produces a relatively pure stream of bone-dry CO₂ ready for compression and sale at the Great Plains Synfuels Plant, this project is profitable for Dakota Gasification Company as well. Most other industrial sources of CO₂, such as flue gas, would need expensive purification and dehydration steps before being used for the same purpose. Although the project is still in its early stages, it appears to be a technical and economic success for both Dakota Gasification Company and EnCana Corporation.