OPPORTUNITIES AND CHALLENGES ASSOCIATED WITH CO_2 COMPRESSION AND TRANSPORTATION DURING CCS ACTIVITIES

Plains CO_2 Reduction Partnership Phase III
Task 6 – Deliverable D85

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Cooperative Agreement No. DE-FC26-05NT42592

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March 2011
Approved

2011-EERC-06-10

Plains CO_2 Reduction (PCOR) Partnership
Energy & Environmental Research Center (EERC)

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ABSTRACT

The majority of research on carbon capture and storage has been on capture, injection, and subsequent monitoring of the CO_2 plume in a secure geologic setting, with little attention paid to compression or pipeline transport. Opportunities for improved compression and transport efficiency and cost include precise compressor design made possible through a more thorough understanding of the behavior of mixed CO_2 streams near the critical point of CO_2; better integration of CO_2 capture and compression, especially with respect to the use of the heat generated during interstage cooling; improvement of compression efficiency through the exploration of compression pathways that also include liquefaction and pumping of the CO_2; advanced compressor design, such as the shockwave technology under development by Ramgen; development of compressor electric drives and associated components that can operate at higher power rankings more reliably and efficiently; and development of a large-scale CO_2 pipeline network and the establishment of common carrier CO_2 stream composition requirements.

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NOMENCLATURE LIST

°C	degrees Celsius
°F	degrees Fahrenheit
acfm	actual cubic feet per minute
Ar	argon
bar	unit of pressure equal to 14.5 psi
bbl	barrel
BLM	Bureau of Land Management
BWRS	Benedict-Webb-Rubin-Starling [equation of state]
CCS	carbon capture and storage
CFR	Code of Federal Regulations
CO	carbon monoxide
CO_2	carbon dioxide
COE	cost of electricity
DOE	U.S. Department of Energy
e.g.	for example
EOR	enhanced oil recovery
EOS	equations of state
FERC	Federal Energy Regulatory Commission
ft^3	cubic feet
ft	feet
GE	General Electric
H_2S	hydrogen sulfide
Hz	hertz
in.	inch or inches
kHz	kilohertz
kVA	kilovolt–ampere
mcf	thousand cubic feet
m^3	cubic meters
MIT	Massachusetts Institute of Technology
MMcf	million cubic feet
MMcfh	million cubic feet/hour
MMscfd	million standard cubic feet per day (at Oil and Gas Industry standard conditions of 1 atm [atmosphere] and 60°F)
MPa	megapascal
Mt	million tonnes
MW	megawatt
N_2	nitrogen
NH_3	ammonia
O_2	oxygen
PCOR Partnership	Plains CO_2 Reduction Partnership
PHMSA	Pipeline and Hazardous Materials Safety Administration
ppm	parts per million
ppmv	parts per million by volume

Continued . . .

NOMENCLATURE LIST (continued)

ppmw	parts per million by weight
psi	pounds per square inch
psia	pounds per square inch absolute
psig	pounds per square inch gauge
R&D	research and development
STB	Surface Transportation Board
SwRI	Southwest Research Institute
tonne	metric ton
ton	short ton
vol%	volume percent

PCO2R Partnership

Plains CO_2 Reduction (PCOR) Partnership

Energy & Environmental Research Center (EERC)

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EXECUTIVE SUMMARY

Carbon capture and storage (CCS) includes a set of technologies with the potential to reduce carbon dioxide (CO_2) emissions from large stationary sources of CO_2, such as power plants and industrial facilities, thereby helping to achieve national and international CO_2 reduction goals. CCS consists of capture and compression of CO_2 from a large stationary facility, transport of the CO_2 (most likely via pipeline), and injection of the CO_2 into a secure geologic formation. Technologies exist for all three of the CCS steps, but because they were not developed for CCS, they have not been optimized for the integrated approach. The majority of the research on CCS to date has focused on the capture, injection, and subsequent monitoring of the CO_2, with little attention paid to the compression of the CO_2 and its transport to the injection site. Although these two activities hold some challenges, they may also offer opportunities to bring down the cost of CCS, which could help to advance widespread implementation of the concept.

For CCS applications, CO_2 must be compressed to a supercritical state efficiently transport it and enable its use for enhanced oil or coalbed methane recovery or its injection into unminable coal seams or deep saline formations. Gas compression is a well-developed, mature commercial technology that is used in the natural gas industry. CO_2 compression utilizes equipment similar to that used to compress natural gas, although because CO_2 is an acid gas, parts that contact the gas stream are fabricated from stainless steel. Special O-ring materials are used in order to resist the explosive decompression caused by CO_2 trapped within the seal O-rings.

Traditionally, high-speed reciprocating compressors have been used to compress CO_2 to high pressures. Reciprocating compressors use pistons driven by a crankshaft. They are a very good choice where very high discharge pressures are required. However, because inlet flow rates are limited to approximately 7000 m^3/hr (4000 acfm), their capacity may be too low for CO_2 streams captured from large sources.

Centrifugal compressors are more commonly used for high-capacity CO_2 compression. Centrifugal compressors rotate an impeller (rotor) in a shaped housing to increase the velocity of a gas, pushing it through a stationary diffuser section. The gas is compressed when the kinetic energy is converted to pressure energy. Centrifugal compressors usually supply low compression

ratios for each stage, so several stages are typically packaged together in a single unit to produce the target pressure. Sometimes multiple units are used in series. Two types of centrifugal compressors, in-line (single-shaft) and integrally geared (multishaft), are commonly are commonly used for CO_2 compression. In-line compressors contain two or more compression stages packaged together on a single shaft. Heat removal usually is performed after multiple stages. Integrally geared centrifugal compressors feature impellers mounted on pinions that run on a main gearbox. Two impellers can be attached to each pinion, thereby accommodating two stages of compression. The integral-gear design is efficient, flexible with respect to selection of final pressure, and the number of stages in one machine is not limited. Integral-gear compressors utilize intercooling between stages to remove heat.

A "Workshop on Future Large CO_2 Compression Systems" was held in Gaithersburg, Maryland, on March 30–31, 2009. The workshop was cosponsored by the U.S. Department of Energy Office of Clean Energy Systems, the National Institute of Standards and Technology, and the Electric Power Research Institute. It was attended by compression and pipeline experts and resulted in prioritized lists of CO_2 compression and pipeline challenges and research and development opportunities. The areas that the experts noted as posing challenges to compression and pipeline transport included the following:

- The need for measurement of mixed CO_2 stream properties as functions of temperature and pressure near the CO_2 critical point. These measurements would enable the development of more reliable equations of state for mixtures of CO_2 that can be used for precise compression system design.

- Better integration of CO_2 capture and compression, especially within large stationary sources such as power plants. Maximizing the efficiency of the compression step will likely require the optimization of heat integration within both the CO_2 capture loop and the industrial or utility source. Use of the heat produced during the interstage cooling in solvent/sorbent regeneration is one approach that is being evaluated.

- Improving compression efficiency, thereby reducing the power required for the compression step. Two approaches are being taken.

  – The use of a compression–liquefaction–pumping pathway. This pathway must be evaluated and compared with the compression-only approach.

  – Advanced compressor design. Ramgen Power Systems has developed a novel compressor called the Rampressor that is based on shock compression theory. The Rampressor can achieve very high compression efficiency at high single-stage compression ratios (on the order of 8:1 to 10:1), resulting in product simplicity and smaller size that have the potential to significantly lower costs.

- The need for higher-voltage, higher-power, and higher-speed compressors and drives as well as a determination of optimal machine types, speeds, etc., for CO_2 compression. Several companies are developing electric drives that operate at higher power rankings more reliably and efficiently than currently available products. In addition to the development of the drives themselves, research efforts will need to focus on silicon carbide and other electronic devices capable of providing high switching frequencies at high voltage as well as new magnetic materials that have improved characteristics and/or are lower in cost. These materials can be used in levitation of the power train using magnetic bearings.

- Development of a pipeline network as the most efficient long-term CO_2 transport option. Development of a network could be performed on a regional or national level, but each approach would involve judicious siting of a series of backbone pipeline systems. A pipeline network will have common carrier issues with respect to the content of the CO_2 streams that are transported. Other than a requirement that virtually no water be present in a given CO_2 stream, the common composition of CO_2 mixtures is the subject of debate, and it will be important to establish permissible levels of contaminants in a CO_2 stream that will be transported via pipeline.

Coupled with advances and cost reductions in the capture and storage steps, meeting these compression and pipeline challenges could help to advance the widespread implementation of the CCS concept.

OPPORTUNITIES AND CHALLENGES ASSOCIATED WITH CO_2 COMPRESSION AND TRANSPORTATION DURING CCS ACTIVITIES

INTRODUCTION

Carbon capture and storage (CCS) includes a set of technologies with the potential to reduce carbon dioxide (CO_2) emissions from large stationary sources of CO_2, such as power plants and industrial facilities, thereby helping to achieve national and international CO_2 reduction goals. CCS is essentially a three-step process: capture and compression of CO_2 from a large stationary facility, transport of the CO_2 (most likely via pipeline), and injection of the CO_2 into a secure geologic formation for permanent storage. Technologies exist for all three of the CCS steps, but they have not been integrated in a single large-scale CCS project. Because the technologies were not developed for CCS, they have not been optimized for the integrated approach. The two main drivers for CCS research are to demonstrate the integration of the steps and to decrease the cost of the various technologies employed. The majority of the research on CCS to date has focused on the capture, injection, and subsequent monitoring of the CO_2, with little attention paid to the compression of the CO_2 and its transport to the injection site. Although these two activities hold some challenges, they may also offer opportunities to reduce the cost of CCS, which could help to advance widespread implementation of the concept. Compression cost reductions are most likely to come from improvements in compression efficiency, while pipeline costs can likely only be reduced through judicious siting of pipelines and potentially forming pipeline networks. This report provides basic information about CO_2 compression and pipeline transport and discusses some of the challenges that, if met, might reduce the cost of these steps.

COMPRESSION

What Is Compression?

Gas compression is the act of raising the pressure of a given mass of a gas in order to reduce its volume. Compression is typically done to allow the use of smaller pipes and/or vessels (e.g., gas cylinders, tanker trucks, railcars, ships) when transporting a gas. Figure 1 illustrates the volume occupied by one tonne (metric ton) of CO_2 at a temperature of 40°C (104°F) as a function of pressure. At 0.1 MPa (14.5 psi), the tonne of CO_2 occupies 589 m^3 (20,804 ft^3). When compressed to the typical pipeline pressure of 13.8 MPa (2000 psi), it occupies

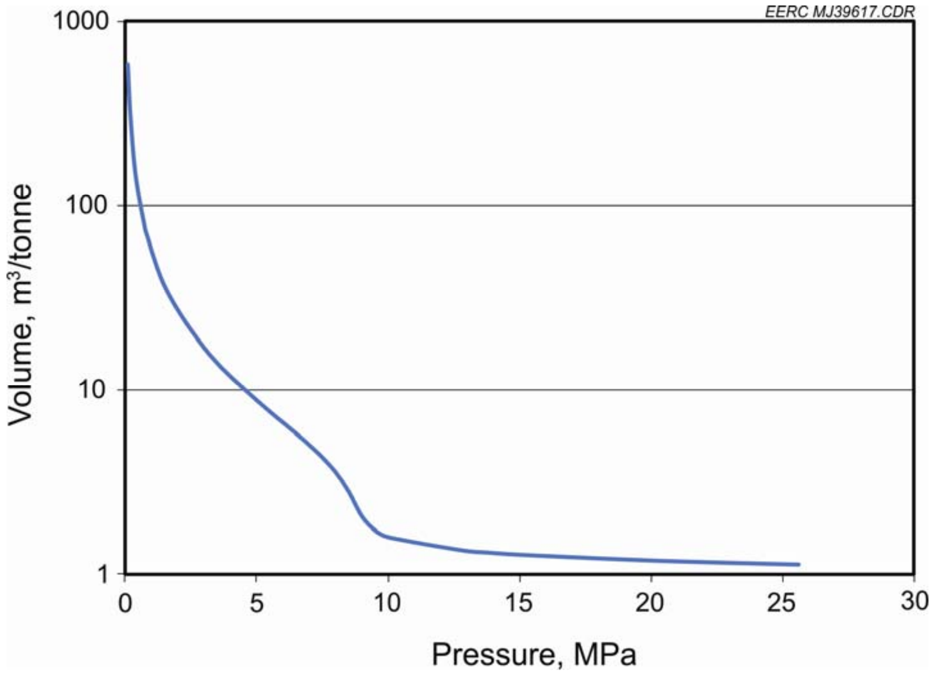

Figure 1. Volume occupied by 1 tonne of CO_2 at 40°C as a function of pressure.

1.32 m^3 (46.5 ft^3), just 0.22% of the initial volume. Most of this reduction in volume occurs before the pressure reaches 10 MPa (1450 psi), the typical minimum pipeline transportation pressure for all but very short pipelines. At this pressure, the CO_2 occupies only 0.27% of the initial volume. At 25 MPa (3625.9 psi), it occupies 1.132 m^3 (40 ft^3), just 0.19% of the initial volume.

Compression of a gas does not simply involve increasing its pressure. Temperature also plays a role. Simply put, the pressure of a gas stream is increased by forcing the gas into a given space that is smaller than the space the gas was occupying. Because the gas molecules are forced to be closer together, the temperature of the gas increases. Usually, the gas is cooled and then forced into a smaller volume, which raises the temperature again, and the process is repeated until the desired final pressure is reached.

Compression of CO_2

For CCS applications, CO_2 must be compressed to efficiently transport it for use in enhanced oil or coalbed methane recovery or for injection into unminable coal seams or deep saline formations. The two objectives of compression are to minimize the volume the CO_2 occupies so that its flow rate through the pipeline can be maximized and to pressurize it enough that it can overcome the pressure of the reservoir into which it is being injected. Typically, CO_2 is transported in its supercritical state.

A phase diagram can help to more clearly explain the concept of a supercritical fluid. A phase diagram is a plot of pressure versus temperature that shows the phase (i.e., solid, liquid, or vapor) of a compound at the range of conditions shown on the plot. Figure 2 is a phase diagram for CO_2. The area to the top left of the chart, above the sublimation and melting lines, is the region in which CO_2 is a solid (i.e., dry ice). The region below the sublimation and vaporization lines is where the CO_2 exists in the gas phase. Between the vaporization and melting lines is the region in which the CO_2 exists as a liquid. The reader will note that the vaporization line ends with what is called the "critical point" and that, beyond this point, there is no longer a boundary between the liquid and gas phases. CO_2 that is at temperatures and pressures higher than the critical point is no longer in either the liquid or the gas phase but is instead a supercritical fluid. There is no clear transition boundary such as exists when changing from a gas to a liquid or a liquid to a solid. Fluids that are in their supercritical state are neither liquids nor gases but instead exhibit properties of both. Supercritical fluids tend to have densities similar to those of liquids, but they also tend to be compressible (i.e., their density increases with increasing pressure), as is the case for a gas.

To further understand the phase change behavior of CO_2 and how it presents challenges and opportunities with respect to CO_2 compression, it is necessary to take a closer look at CO_2 behavior near the critical point. This is important because this is the temperature and pressure region near which it is necessary to operate during compression. The CO_2 stream exiting almost all CO_2 capture technologies will be in the gas phase, while it will be transported and injected as a liquid or a dense-phase supercritical fluid. Expected typical inlet and outlet compression conditions for CCS are presented in Table 1.

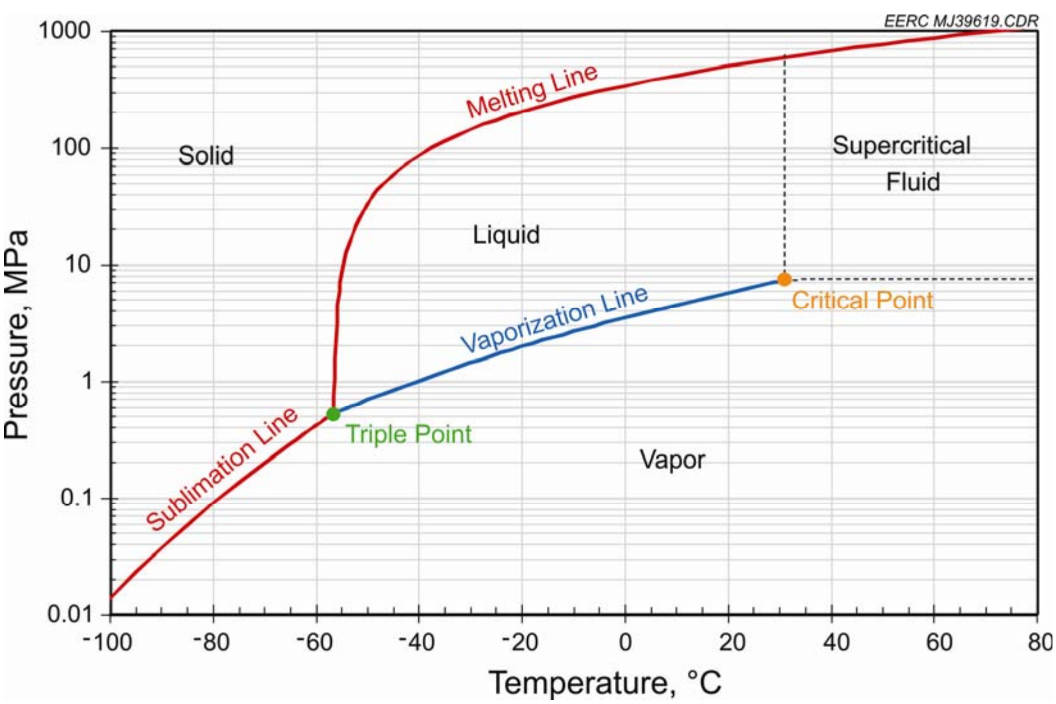

Figure 2. Pressure–temperature phase diagram for CO_2 (constructed using CO_2Tab software available from www.chemicalogic.com).

Table 1. Expected CO_2 Stream Conditions During CCS Compression

	Pressure, MPa (equivalent psi)	Temperature, °C (equivalent °F)	Note
Compression Inlet (from capture process)			
Low	0.1 (14.5)	20–40 (68–104)	Most postcombustion systems, excluding vacuum sources (e.g., membrane systems)
Medium	2.1 (300)	30 (86)	From the chilled ammonia process
High	2.4 (350)		From precombustion systems
Compression Outlet (into pipeline)			
Low	10.0 (1450)	10–25 (50–77)	Absolute minimum for pure CO_2 is closer to 7.5 MPa (1088 psi)
Typical	13.8 (2000)	10–25 (50–77)	11–15.2 MPa (1600–2200 psi)
High	18.7 (2700)	10–25 (50–77)	Great Plains Synfuels Plant pipeline inlet

Details about the thermodynamic behavior of CO_2 can be seen on a pressure–enthalpy diagram such as the one shown in Figure 3. Enthalpy is a measure of the heat content of a chemical system at constant pressure. Where pressure changes occur, such as those that happen during compression, the enthalpy includes the heat content plus a pressure × volume term. Enthalpy is represented on the x axis. Pressure is shown on the y axis. There are three series of lines on the diagram. One set shows the relationship of enthalpy and pressure at a succession of constant temperatures (black solid line). Another set of lines (green dashed) shows the relationship of enthalpy and pressure at a series of constant CO_2 densities. The third set of lines (maroon dotted) shows the relationship of enthalpy and pressure at constant entropy. (Entropy is a measure of the energy in a system that cannot be used for useful work.) Temperatures, densities, and entropies that are not shown on the diagram can be interpolated. In the middle of the diagram is a dome-shaped area. The area within the dome represents the two-phase region associated with transformation of liquid CO_2 to gaseous CO_2 through the addition of heat (enthalpy) and the condensation of CO_2 gas to CO_2 liquid by the removal of heat (e.g., through refrigeration). This area is represented by the blue vaporization line shown on Figure 2. It should be noted that the lines of constant temperature cross the region at constant pressure. They represent the boiling point of CO_2 at the given pressure. The line on the left side of the dome represents the properties of saturated CO_2 liquid, while the line on the right represents the properties of saturated CO_2 gas. Each location within this dome represents a mixture of the saturated vapor CO_2 and saturated liquid CO_2 present at the given combination of pressure, temperature, and enthalpy. The point at the top of the dome is the critical point. At all temperatures and pressures above the critical point, CO_2 is considered to be in the supercritical phase.

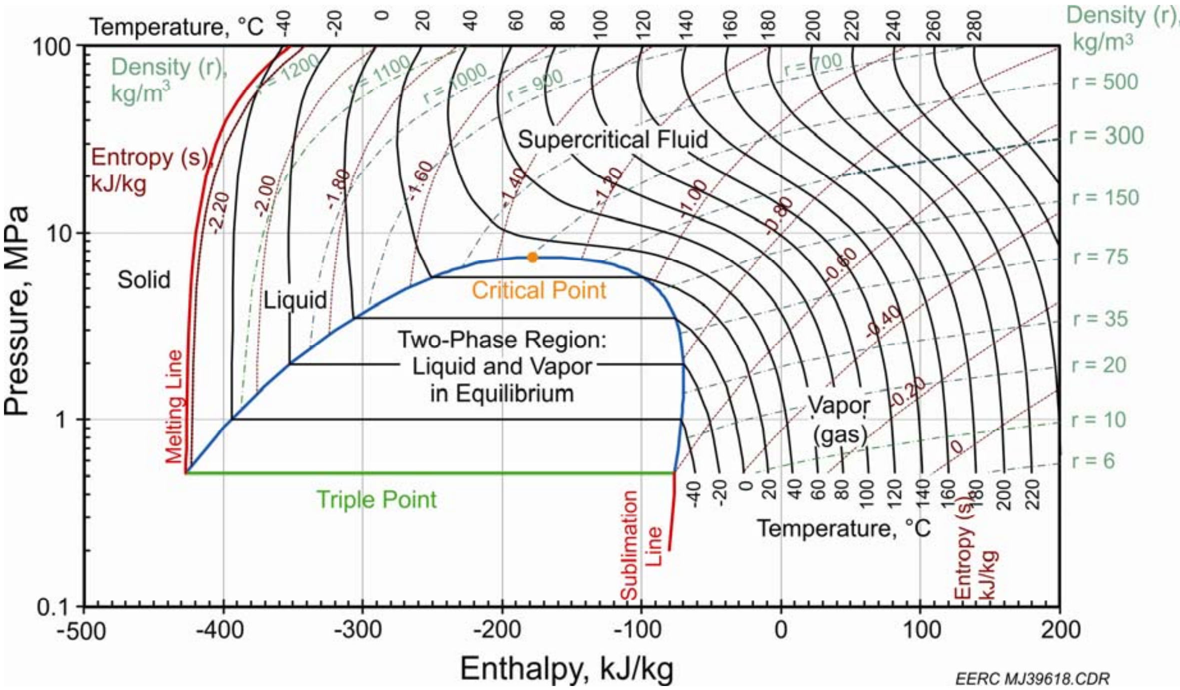

Figure 3. Pressure–enthalpy diagram for CO_2 (constructed using CO_2Tab available from www.chemicalogic.com).

In altering a CO_2 stream from the gaseous state in which it is obtained from a capture technology to the condition required for pipeline transportation and use in geological storage, it is necessary to either stay to the right of this dome (use compression only) or to stay to the left of this dome (use cryogenic pumping) while increasing the pressure of the CO_2 stream. Liquefaction by cooling of the CO_2 stream is necessary in order to employ pumping.

Approaches to Compression

In general, three likely pathways can be taken to compress CO_2:

- A near-adiabatic pathway, in which heat is neither gained nor lost by the system. This is the traditional approach used for compressing CO_2. In this case, the compression in the gas phase takes place in discrete steps or stages, with cooling in between them during which the heat generated during the compression is removed. Typical compression stages have a compression ratio (the factor by which the pressure of the stream is increased during the stage) of roughly 1.6 to 2.1 (Habel and Wacker, 2009).

- Compression in the gas phase with cooling and supercritical compression in the high-density area. Once the CO_2 reaches a dense phase, it can be pumped.

- Compression in the gas phase, condensing/cooling to the liquid phase, and pumping to achieve the final desired pressure.

These pathways are superimposed on a pressure–enthalpy diagram in Figure 4. The near-adiabatic pathway, with interstage cooling between each of its multiple stages, is shown on the right as Path C. This pathway remains to the right of the dome, meaning that the CO_2 is in vapor phase during its compression. The second pathway (Path B) utilizes the first stages until the conditions are above the critical point (i.e., the CO_2 is in the supercritical phase), at which point, the CO_2 is cooled to a more dense-phase supercritical fluid and is pumped to the final pressure. The third pathway (Path A) utilizes less of the compression stages and cools the CO_2 to form a liquid and pumps the fluid to the desired final pressure.

Gas compression is a well-developed, mature commercial technology that is used in the natural gas industry. CO_2 compression uses equipment similar to that used to compress natural gas, although differences in the chemical and physical properties of CO_2 relative to natural gas require modifications in compressor design specifics such as in materials of construction. Compressors are typically fabricated from carbon steel. Because CO_2 is an acid gas, if water vapor is present in the CO_2 stream, compressor components that contact the stream are subject to carbonic acid corrosion. If carbon monoxide (CO) is present as a component of a mixed CO_2 stream, the presence of water will create iron carbonyl when it contacts carbon steel. Both of these corrosion issues can be solved by fabricating the affected compressor parts from stainless steel (Miller, 2009). Seal integrity is also an issue when compressing CO_2. Special O-ring materials are used in order to resist the explosive decompression caused by CO_2 trapped within the seal O-rings (Miller, 2009).

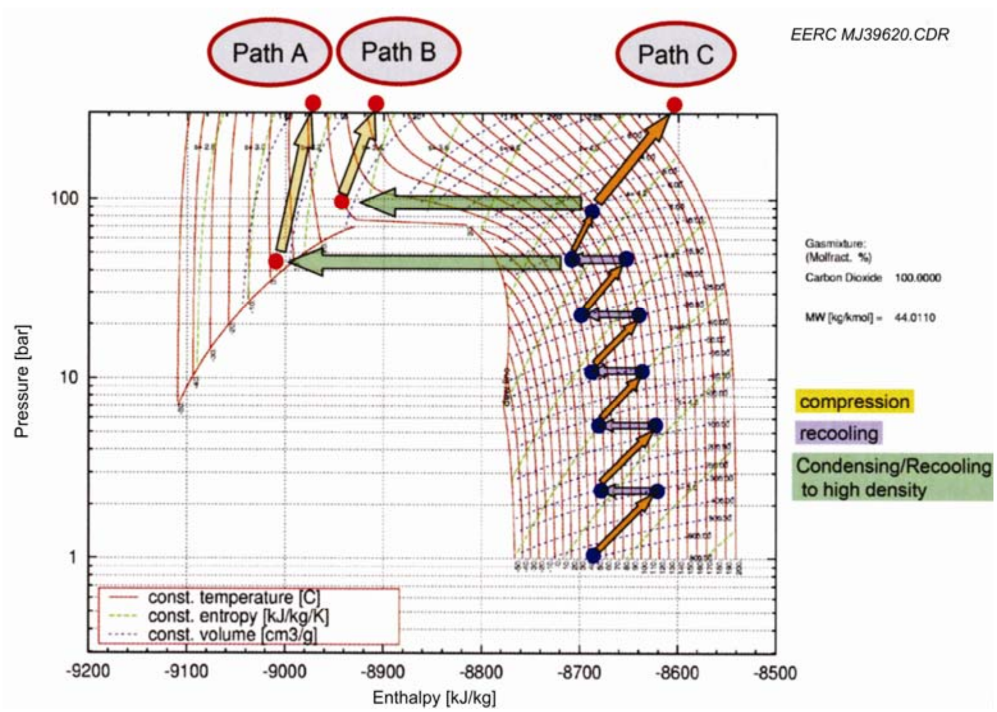

Figure 4. Three compression pathways toward a target pressure of 200 bar (20 MPa, 2900 psig) (taken from Winter, 2009).

Types of CO_2 Compressors

Traditionally, high-speed reciprocating compressors have been used to compress CO_2 to high pressures. Centrifugal compressors are more commonly used for high-capacity CO_2 compression. Two types of centrifugal compressors are used: in-line (single-shaft) compressors and integrally geared (multishaft) compressors (Bovon and Habel, 2007). Diaphragm and positive-displacement (rotary or screw) compressors have been, and still are, used for CO_2 compression but are generally not considered promising for use in CCS applications because their capacities are not large and their maximum discharge pressures tend to be lower than required. The three types of compressors typically used for CO_2 compression can be compared as follows:

- Flow-rate capacity: in-line centrifugal > integrally geared centrifugal > reciprocating

- Single-stage compression ratio: reciprocating > integrally geared centrifugal > in-line centrifugal

- Maximum discharge pressure: reciprocating > in-line centrifugal > integrally geared centrifugal

Figure 5 indicates the approximate ranges of pressures and inlet flow rates that are covered by various types of CO_2 compressors and pumps. It should be noted that the yellow-shaded area labeled “Centrifugal” includes not only the single-shaft centrifugal compressors but also the integrally geared centrifugal compressors. These fall within the green-shaded region that is superimposed over the yellow region. The range of inlet flow rates and discharge pressures for reciprocating compressors and pumps for CO_2 are illustrated by the blue-shaded area. The orange-shaded area covers centrifugal pumps for use with liquid and dense supercritical-phase CO_2. Screw compressors (purple area) are used for low-flow, low-pressure applications.

Major suppliers of large-capacity CO_2 compressors include Dresser-Rand, General Electric (GE), and MAN Turbo AG. Other companies involved with compressor technology include ABB (valves, electric drives and controllers); Curtiss-Wright (valves, pumps, controllers); Elliott (centrifugal and axial compressors); Florida Turbine Technologies (engineering, testing, and research and development (R&D) services for turbines and turbopumps); Mitsubishi Heavy Industries Compressor Corporation (single-shaft and integrally geared centrifugal compressors); Solar Turbines (multistage centrifugal compressors); Turblex, a division of Siemens and Siemens Turbomachinery Equipment GmbH, which includes PGW Turbo, the business unit of AG Kuhnle, Kopp & Kausch (single-shaft and integrally geared centrifugal compressors).

Reciprocating Compressors

Reciprocating compressors use pistons driven by a crankshaft to deliver gases at high pressure. High-speed reciprocating compressors have been used in industry to compress CO_2 since 1928 (Miller, 2009). Reciprocating compressors are easy to install and deliver. They are also flexible in that it is easy to adjust the compression ratio achieved by a given unit if it is

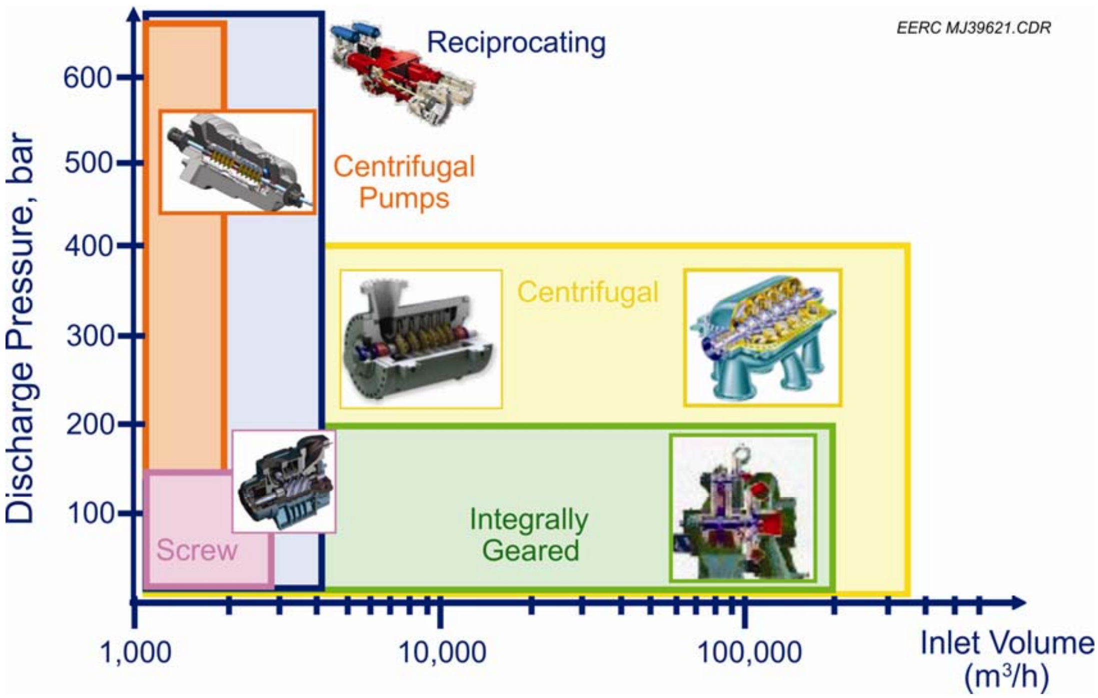

Figure 5. Types of compressors and the approximate ranges of inlet volumetric flow rates and pressures at which they are used (taken from Wadas, 2010). It should be noted that 500 bar = 50 MPa = 7252 psi and 100,000 m^3/hr = 3.53 MMcfh.

equipped with a variable-speed drive or suction valve unloaders. Suction valve unloaders allow the flow to be recycled locally in the cylinder so that only the required gas capacity is compressed. This minimizes the compressor power that is required (Eberle and Howes, 2005). Reciprocating compressors are a very good choice where very high discharge pressures are required (up to 1000 bar, which is equal to 100 MPa, or 14,500 psi). Inlet flow rates are limited to approximately 7000 m^3/hr (4000 acfm), so the capacity may be below the range of CO_2 streams captured from large sources. It has also been reported that reciprocating compressors are maintenance-intensive and high in capital and operating costs (Bovon and Habel, 2007). Figure 6 shows a reciprocating compressor.

Centrifugal Compressors

Centrifugal compressors rotate an impeller (called a rotor) in a shaped housing to increase the velocity of gas through a stationary diffuser section. The gas is compressed when the kinetic energy is converted to pressure energy. Centrifugal compressors usually supply low compression ratios for each stage, so several stages are typically packaged together in a single unit to produce the target pressure. Sometimes multiple units are used in series (similar to the use of low-pressure and high-pressure turbines in power generation).

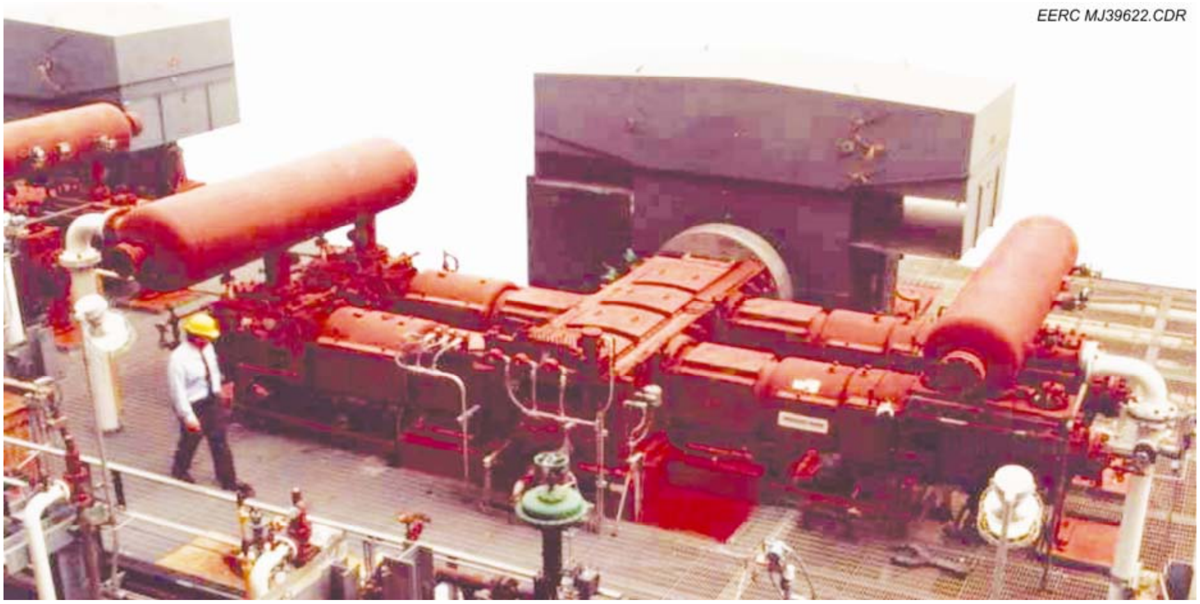

Figure 6. A 5500-horsepower HHE-VL process reciprocating compressor on hydrogen makeup service at a U.S. Gulf Coast refinery (taken from Miller, 2009).

In-line (single-shaft) Centrifugal Compressors

The in-line compressor is a type of centrifugal compressor in which two or more compression stages are packaged together on a single shaft. Compression ratios for each stage of an in-line compressor tend to be very low, but more stages can be packed into a smaller space than occurs in an integrally geared compressor. In addition, the number of seals needed to isolate the stages from the atmosphere is reduced relative to an integrally geared compressor. The in-line compressor can offer superior efficiency, oil-free compression, higher speed matched to high-speed drives and are considered less maintenance-intensive (Habel and Walker, 2009). Some loss of stage efficiency is accepted in in-line compressors, especially those having four or more stages in a single housing. Heat removal usually is performed after multiple stages. Figure 7 is a cutaway view of an in-line multistage centrifugal compressor. A two-stage, in-line CO_2 compressor is shown in Figure 8.

Integrally Geared (multishaft) Centrifugal Compressors

An integrally geared centrifugal compressor features impellers mounted on pinions that run on a main gearbox. Two impellers can be attached to each pinion, meaning that each pinion can accommodate two stages of compression (Reddy and Vyas, 2009). Figure 9 shows a schematic of an integrally geared multistage compressor. The integral-gear design offers high efficiency relative to other compressors, is more flexible with respect to selection of the pressure level, and the number of stages in one machine is not limited. Integral-gear compressors have maintenance requirements that are comparable to those of in-line compressors but require only approximately half the number of stages because they can operate at higher compression ratios

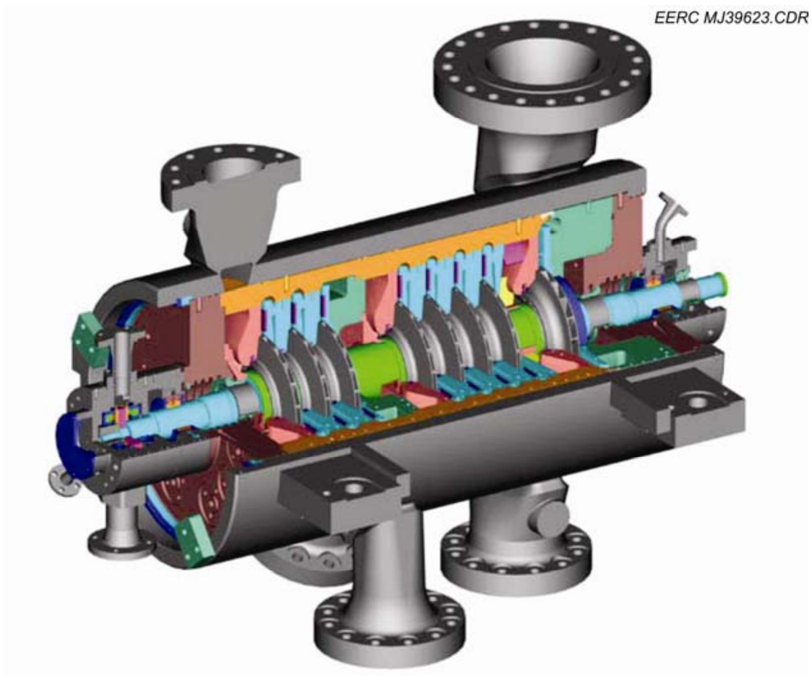

Figure 7. In-line multistage centrifugal compressor (taken from Moore and others, 2009).

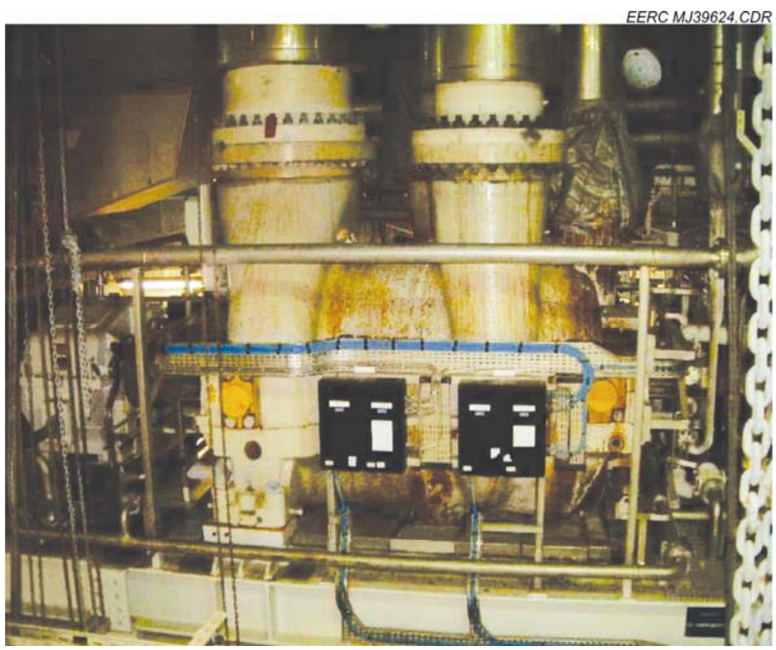

Figure 8. A two-stage in-line compressor (taken from Miller, 2009). This compressor, at the Sleipner project, compresses a million tonnes of CO_2 each year from 0.1 to 0.4 MPa (14.5 to 58 psi) in the first stage and 0.4 to 1.5 MPa (58 to 218 psi) in the second stage. An additional two stages produce a final pressure of 6.6 MPa (957 psi).

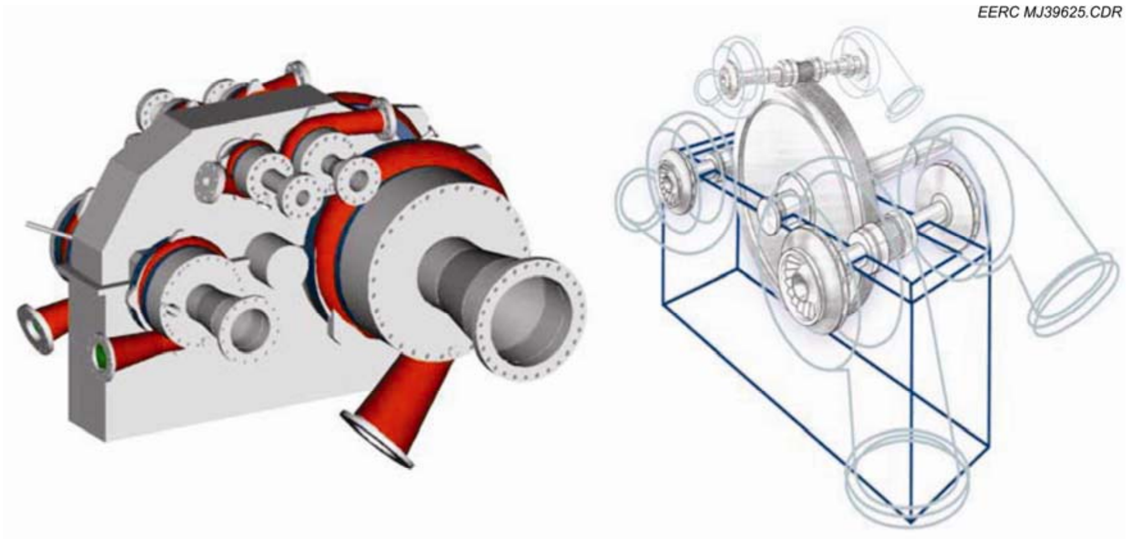

Figure 9. An eight-stage integrally geared compressor (taken from Bovon and Habel, 2007).

and utilize intercooling between each stage (Bovon and Habel, 2007). Intercooling is cooling of the compressed fluid between stages. Winter (2009) states that the energy required to compress CO_2 from 0.1 MPa (14.5 psi) to 20 MPa (290 psi) can be reduced by more than 13% if integrally geared centrifugal compressors are used instead of single-shaft compressors. However, because there are more seals and gears, the machine robustness of geared centrifugal compressors is low compared with the single-shaft type (Winter, 2009). Piping and heat exchangers used for the interstage cooling add significantly to the size and complexity of integrally geared centrifugal compressors. This can be seen in Figure 10, which shows a ten-stage integrally geared wet CO_2 compressor with intercoolers. Figure 11 shows an eight-stage integrally geared dry CO_2 compressor during its installation.

Challenges and Opportunities Associated with Compression of CO_2 for CCS

A "Workshop on Future Large CO_2 Compression Systems," cosponsored by the U.S. Department of Energy (DOE) Office of Clean Energy Systems, the National Institute of Standards and Technology, and the Electric Power Research Institute, was held in Gaithersburg, Maryland, March 30–31, 2009. The workshop was attended by compression and pipeline experts. In addition to presentations on various topics of interest to CO_2 compression and transportation systems, the workshop featured the development of a prioritized list of seven categories in which work could be performed that would have the potential to significantly reduce CO_2 compression and transportation costs. Within the seven categories, 33 specific R&D project topics were identified. The categories and R&D projects identified by the workshop attendees are presented in rank order in Tables 2 and 3, respectively (Wolk, 2009). The challenges within the categories and opportunities presented by those challenges are discussed in the following text. The discussion of pipeline challenges appears in the pipeline section of this report. A discussion of the impacts of CCS legislation is not included here as the workshop attendees noted that a determination of the practical effects of new legislation on CCS could not occur until that new legislation is in place.

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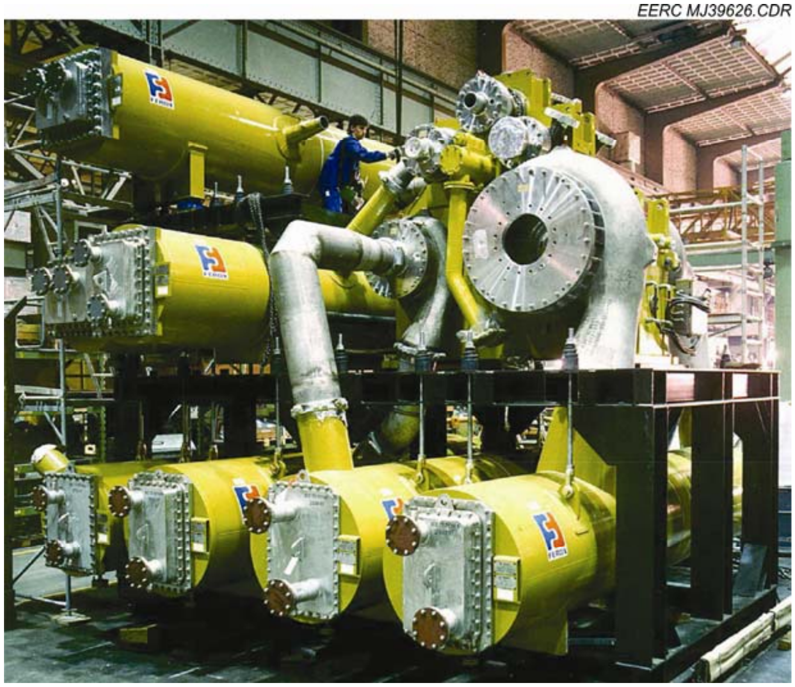

Figure 10. A ten-stage integrally geared centrifugal compressor (at Azot Nowomoskowsk in Moscow, Russia) shown with its intercoolers. It can compress 391 m^3/minute (13,800 acfm) wet CO_2 from 0.1 to 20 MPa (15 to 2900 psi) (taken from Kisor, 2009).

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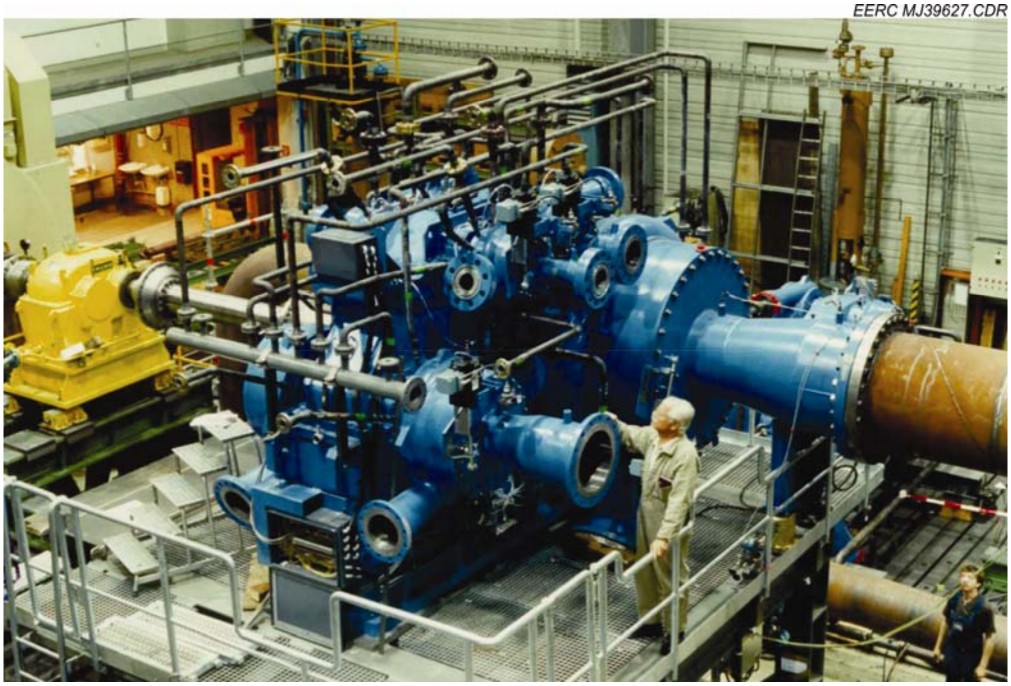

Figure 11. An eight-stage integrally geared compressor that can compress 970 m^3/min (34,240 acfm) dry CO_2 from 0.1 to 18.7 MPa (17 to 2717 psi) (taken from Kisor, 2009). This is one of the three compressors at the Great Plains Synfuels Plant.

Table 2. Compression and Pipeline R&D Categories Identified at the Workshop on Future Large CO_2 Compression Systems (Wolk, 2009)

Rank	Category	Votes
1	Properties of CO_2 and Coconstituents	914
2	Integration of CO_2 Capture and Compression	726
3	Compression Systems Machinery and Components	690
4	Electric Drive Machinery	545
5	Pipeline Issues	456
6	Drive Electronics and Components	326
7	Impacts of Legislation on CCS	43

Table 3. Compression and Pipeline R&D Projects Identified at the Workshop on Future Large CO_2 Compression Systems (Wolk, 2009)

Rank	R&D Project	Votes
1	Perform more gas property measurements of CO_2 mixtures	435
2	Improve equations of state	401
3	Optimize integration of CO_2 capture/compression systems together with the power plant	280
4	Compare and evaluate compression–liquefaction and pumping options and configurations	204
5	Higher-voltage, higher-power, and higher-speed machines and drives	165
6	Install test coupons in existing CO_2 pipelines to obtain corrosion data, then develop CO_2 product specifications	150
7	Determine optimal machine types, speeds, needed voltages, etc., for CO_2 compressors	143
8	Establish allowable levels of contaminants in CO_2 pipeline and/or compressors	120
9	Compressor heat exchanger data for power plant applications including supercritical fluids	117
10	Integrate utilization of waste heat to improve cycle efficiency	113

Properties of CO_2 and Coconstituents

CO_2 is transported through pipelines as a supercritical fluid. In other words, it behaves very much like a liquid although its physical and thermal properties are between those of the pure liquid and a gas. The point at which CO_2 becomes supercritical (i.e., its critical point) is 31.05°C and 7.37 MPa (88°F and 1070 psi). Precise compression system designs require reliable prediction of the properties of CO_2 streams at these conditions. Unfortunately, the equations of state (EOS) that are currently used in these designs are not optimized for real-world CO_2 mixtures that contain other components in the CO_2 stream such as Ar, N_2, O_2, CO, NH_3, and H_2S (Minotti, 2009; Wolk, 2009). When other compounds are present in the CO_2 stream, they affect the properties of the stream (such as its density) near the critical point conditions, so improved and more accurate EOS are needed for these streams (Hustad, 2009). Because of the current EOS shortcomings with respect to CO_2 mixtures near the critical point, compressor designers and manufacturers typically design their products with larger margins of error than may be necessary, thereby increasing equipment costs (Wolk, 2009).

Lack of confidence in EOS predictions is not true for all EOS. GE has used the Benedict-Webb-Rubin-Starling (BWRS) EOS for 30 years at pressures up to 300 bar (30 MPa, or 4351 psi) and up to 540 bar (54 MPa, or 7832 psi) in specific cases for CO_2 and hydrocarbon gas mixtures. Use of the BWRS EOS at pressures above 480 bar (48 MPa, or 6962 psi) requires careful verification of literature data and is not suitable for liquid–vapor equilibrium calculations (Minotti, 2009). GE is introducing a new thermodynamic model that can be used to improve CO_2 property predictability (Minotti, 2009).

Measurement of mixed CO_2 stream properties as functions of temperature and pressure near the CO_2 critical point will enable improvements to be made to the EOS. The need for these measurements is so important to the compression experts that it was rated as the first R&D priority by the attendees of the Workshop on Future Large CO_2 Compression Systems. This is shown in Table 3.

Integration of CO_2 Capture and Compression

Compression to the high pressures that are required for CCS produces a significant amount of heat. Maximizing the efficiency of the compression step with CO_2 capture and power production will likely require the optimization of the integration of this heat (Wolk, 2009).

Interstage Cooling

DOE has supported studies by the Southwest Research Institute (SwRI) and Dresser-Rand that have demonstrated that compression power requirements could be reduced by as much as 20%–35% when isothermal compression is combined with cryogenic pumping. The goals of this work were to develop an internally cooled compressor stage and to qualify a liquid CO_2 pump for CCS service (Wolk, 2009). Work on the internally cooled compressor stage focused on providing:

- Performance equal to that of an integrally geared compressor.
- Reliability on par with that of an in-line centrifugal compressor.
- A reduced overall footprint.
- Less pressure drop than an external intercooler.

Liquefaction/Cryogenic Pumping

SwRI has identified a CO_2 liquefaction process that holds promise for reducing compression requirements by as much as 35% over a conventional eight-stage centrifugal compressor. In the SwRI approach, centrifugal compression is used to attain a pressure of 1.7 MPa absolute (250 psia). A refrigeration system reduces the CO_2 temperature to –31.5°C (–25°F), where it liquefies. The liquid CO_2 is then pumped from 1.7 MPa absolute (250 psia) to 15.3 MPa absolute (2215 psia) (Moore, 2009). GE has also studied this pathway. Its approach involves four-stage refrigerated compression, cooling the CO_2 to roughly –30°C, and pumping to the desired final pressure (Wadas, 2010).

Thermal Integration of CO_2 Compressors in a Power Plant

As discussed earlier in this document, significant waste heat can be produced during CO_2 compression. At the same time, most of the precombustion and postcombustion CO_2 capture technologies require the use of steam or other forms of heat to drive the CO_2 off the sorbent (adsorbent or absorbent) during regeneration to produce the purified CO_2 stream that will be compressed. Sorbent thermal regeneration will likely be performed using low-pressure steam from the power plant, which will have a significant impact on power output and plant efficiency. Therefore, it is important to consider how energy demands and waste heat from a compression process might best be integrated with the power and CO_2 capture plants. Jockenhoevel and others (2009) examined the energy interfaces between the power plant, the CO_2 capture plant, and CO_2 compressors, yielding the results summarized in Figure 12. The diagram illustrates the mass, electricity, heat integration, and cooling water flows between the power plant, CO_2 capture, and CO_2 compression. Examples of electricity flow from the power plant to the CO_2 capture plant includes the electricity required to operate blowers, pumps, and other equipment as well as the power needs for cooling and reboiler heating. The CO_2 compression block requires electrical power from the power plant for compressor operation as well as for the interstage cooling. The exothermic capture reaction provides opportunities to recover waste heat from the absorber. The

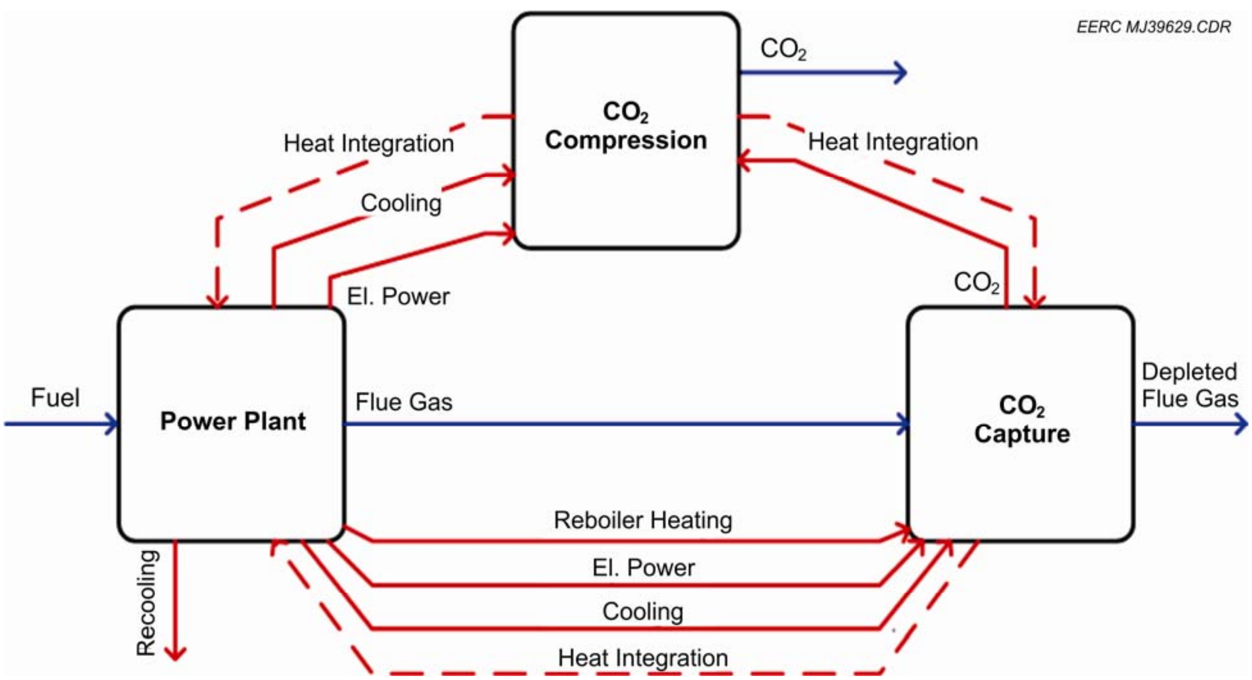

Figure 12. Energy interface and integration of capture plant, power plant, and CO_2 compressors (taken from Jockenhoevel and others, 2009).

intercoolers and postcompression coolers in the CO_2 compressor system may also offer an opportunity for heat recovery. Detailed analysis on a case-by-case basis is required to maximize heat integration in order to determine if the recovered waste heat would meet the pressure and temperature criteria for utilization and if the cost to install and operate the heat recovery system would provide true benefits.

One particularly interesting place to look for useful waste heat is that derived from the intercooling of CO_2 between compression stages. Romeo and others (2009) investigated methods to minimize the energy requirement during the intercooling process. Their approach was to integrate the intercooling compression into the low-pressure part of a steam cycle to take advantage of the intercooling heat. The proposed process is shown as Figure 13. Triethylene glycol is used to remove moisture from the flue gas.

The novelty of this approach is that each intercooling cooling step is divided in two-stages, allowing heat from the first stage to be present at a higher temperature. This permits the heat extracted from the first part (Q_{SCn}) to be used in preheating water for the low-pressure steam cycle. The second cooling stage for each intercooling step ($Q_{cooling}$) dissipates the heat to cooling water or the ambient environment. This strategy could reduce the need to bleed steam from the turbine for boiler water preheat, which would increase the steam turbine gross power output. The analysis shows that, for a compression chain of 80% compressor efficiency and four stages, the incremental cost of electricity (COE) of the compression process is reduced by 8% to 23%, depending on the intermediate inlet temperature. With higher compressor efficiency, it is expected that the COE could be further reduced.

Compression Systems Machinery and Components

Ramgen Power Systems, LLC, has developed a novel compressor (called the Rampressor™) based on shock compression theory. Effectively, the company has applied supersonic jet engine inlet concepts to a stationary compressor. A rotating disk is operated at a sufficiently high peripheral speed that a supersonic effect occurs inside the compressor (Baldwin, 2009). Figure 14 shows the Rampressor rotor disk, while Figure 15 shows a cutaway view of a single-stage Rampressor. The rim of the rotating disk is machined to behave in a manner similar to a ramjet inlet. The CO_2 enters through a common inlet and then passes into the annular space between the supersonically spinning disk and the outer edge of the casing. When the flow of CO_2 enters this space, the raised sections of the disk rim instantaneously slow it to subsonic speeds, creating shock waves. These shock waves are associated with a dramatic increase in pressure or, in other words, "shock compression." The Ramgen shock compression technology can achieve very high compression efficiency at high single-stage compression ratios (on the order of between 8:1 and 10:1), resulting in product simplicity and smaller size that have the potential to lower both manufacturing and operating costs while meeting the needs of any CO_2 capture system pressure and flow requirements. Because of its high compression ratios, the usable heat produced by the Rampressor is significantly higher than any other CO_2 compression technology. Ramgen states that 71.8% of the heat is recoverable (Jensen and others, 2009b). Dresser-Rand is supporting the Rampressor development (Baldwin, 2009; Miller, 2009).

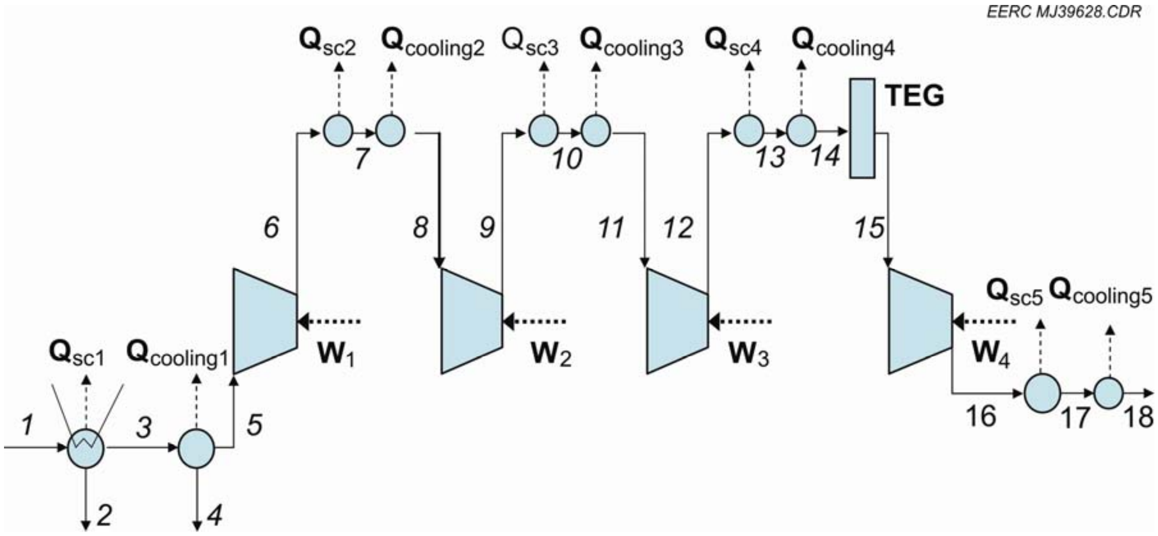

Figure 13. Optimized intercooling process (taken from Romeo and others, 2009).

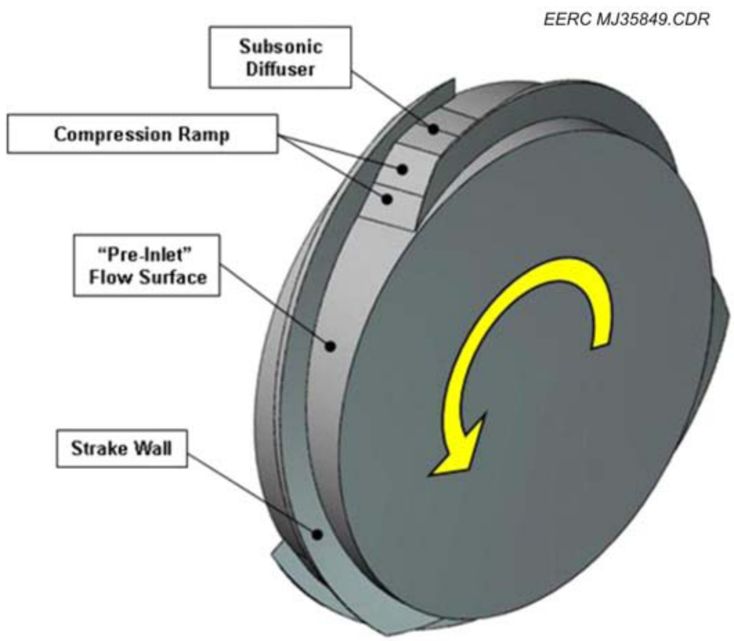

Figure 14. Rampressor rotor disk (courtesy of Ramgen Power Systems).

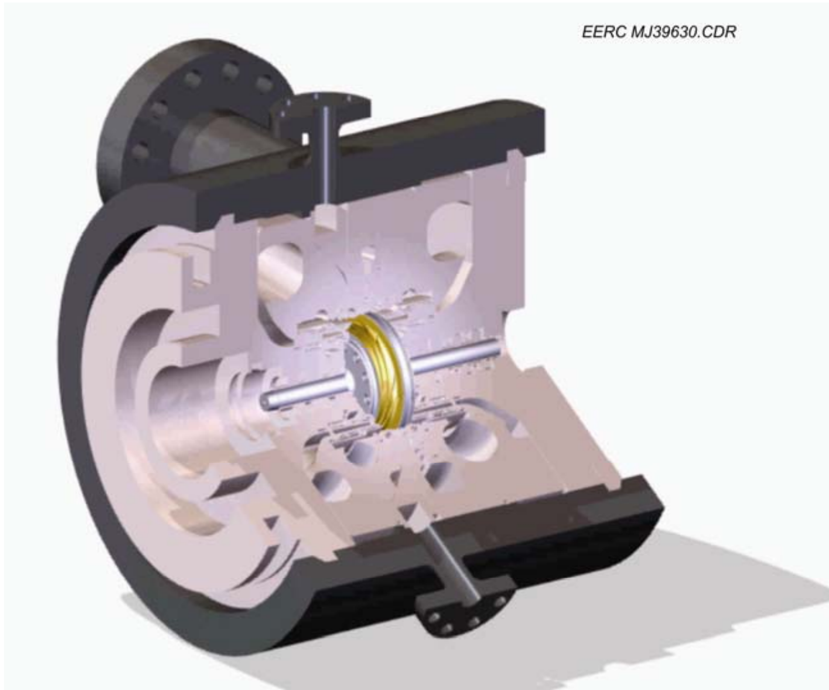

Figure 15. Cutaway view of the Rampressor (screen capture from an animation provided courtesy of Ramgen Power Systems).

Additional details on the science and engineering behind the Rampressor design are available in the Plains CO_2 Reduction (PCOR) Partnership document entitled *Deliverable D47 – Plains CO_2 Reduction (PCOR) Partnership (Phase III) – Preliminary Design of Advanced Compression Technology* (Jensen and others, 2009b).

Electric Drive Machinery, Drive Electronics, and Components

Mechanically driven compressors have been used historically because they were independent of the electricity supply infrastructure and high ratings were available (Weeber, 2009). The oil and gas industry is following the global trend toward increased electrification (Zhang, 2009). There are many advantages to electric drives. Electric drives permit the direct coupling of the motor and the compressor rotors, which eliminates the gear box. They improve speed control; exhibit higher system efficiency; produce no on-site emissions; reduce site noise impacts; reduce maintenance, thereby increasing uptime; exhibit dynamic braking capability; and have a short start-up time (Weeber, 2009). However, the need exists for electric drive machinery that can operate at higher power rankings even more reliably and efficiently than currently available products (Wolk, 2009). Meeting these demands will require electric drives that can operate reliably at voltages above 10 kVA and frequencies above 10 kHz (Wolk, 2009). Electric drive component R&D needs include (Weeber, 2009):

- Advanced stator and rotor cooling schemes.

- Advanced materials for stators and rotors that are tolerant of corrosive gases and that allow rotors to reach higher speeds.

- Improved drive electronics that permit higher fundamental frequencies for high-speed machines and offer improved controls and bandwidth to provide low torque ripple (the difference between maximum and minimum torque during the same motor revolution).

- Tighter integration of the compressor, motor, and drive components.

Several companies are developing improved electric drives. According to Kullinger (2009), ABB's synchronous motors are a proven, reliable compressor drive technology. Synchronous 4–6 pole high-megawatt motors are typically used for large compressors in air separation and various gas compression applications (Kullinger, 2009). Coverteam offers variable-speed drive systems in power ranges of 2 to 32 MW and 10 to 100 MW that can be used with synchronous motors (Moran, 2009). GE has reported advancements in electric drive systems that provide highly reliable 35-MW output at 100 Hz (Zhang, 2009).

The areas of R&D effort that will help support the development of improved drive electronics and components include basic and applied research efforts that are focused on the development of the following (Wolk, 2009):

- Silicon carbide and other electronic devices capable of providing high switching frequencies at high voltage.

- New magnetic materials that have improved characteristics and/or are lower in cost. These materials can be used in levitation of the power train using magnetic bearings. The recent spike in the price of rare earth elements has accelerated the demand for work to find other materials with appropriate characteristics (U.S. Department of Energy, 2010).

CO_2 PIPELINES

CO_2 Pipelines Within the United States

According to the Massachusetts Institute of Technology (MIT) report entitled *The Future of Coal*, about 1.5 billion tons of CO_2 are produced annually in the United States from coal-fired power plants. If all of this CO_2 were to be transported for sequestration, the quantity would be equivalent to three times the weight and, under typical operating conditions, one-third the volume of natural gas transported annually by the U.S. gas pipeline system (Ansolabehere and others, 2007). These statistics highlight the scale-up challenge that faces the widespread deployment of carbon capture and sequestration.

There are more than 4000 miles of CO_2 pipeline in the United States. The existing CO_2 pipelines within the United States are shown in Figure 16. The PCOR Partnership region has several CO_2 pipelines that either already exist or are under construction. These are summarized in Table 4.

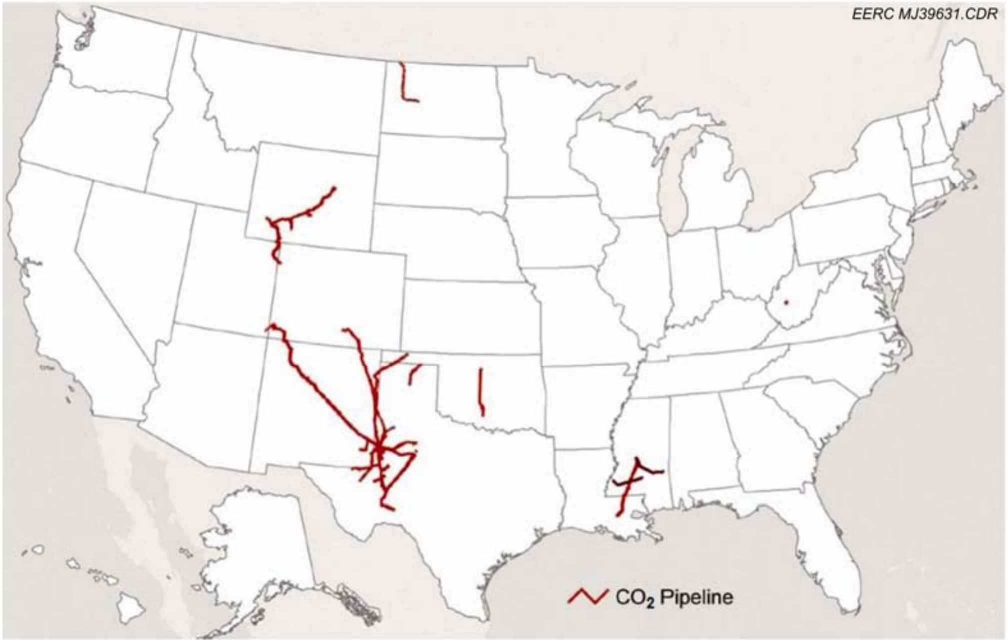

Figure 16. CO_2 pipeline routes in the United States (Bliss and others, 2010).

Table 4. Existing CO_2 Pipelines Within the PCOR Partnership

Pipeline	Location	Approximate Length, miles
Alberta Carbon Trunk Line	Alberta, Canada	150
Anadarko*	Wyoming	125
Dakota Gasification Company	North Dakota to Saskatchewan	205
Denbury	Wyoming and Montana	226
Fort Nelson	British Columbia, Canada	10

* While not technically within the boundaries of the PCOR Partnership region, this pipeline is regionally significant.

CO_2 Pipeline Design

CO_2 pipelines are similar in design and operation to natural gas pipelines, although there are some significant differences because CO_2 pipelines are operated at higher pressure. Natural gas pipeline operating pressures range from 1.4 to 10.3 MPa (200 to 1500 psi); compressors are used at booster stations along the pipeline route to maintain the necessary pipeline pressure (Naturalgas.org, 2009). CO_2 is transported as a supercritical fluid at pressures of 8.3 MPa (1200 psi) (Metz and others, 2005) to 18.6 MPa (2700 psi) (Perry and Eliason, 2004). Because the dense-phase CO_2 behaves as a liquid, pumps (rather than compressors) can be used at booster stations (ICF International, 2009). The increased pressure in CO_2 pipelines can be accommodated with thicker-walled pipe (ICF International, 2009). Pipeline materials of construction (typically carbon steel) can account for 15% to 35% of the total pipeline cost (Parfomak and Folger, 2008).

Pipeline diameters are calculated using rigorous iterative calculations (Rubin and others, 2007), but estimations correlating pipeline diameter and CO_2 flow rates can be made. Table 5 shows such an estimation made by MIT (Carbon Capture and Sequestration Technologies Program, 2009).

A rule of thumb that can be used to estimate capacity for CO_2 pipelines operating at 15.2 MPa (2200 psi) is (Hattenbach, 2009):

$$(\text{Pipeline Diameter})^2 \times 1.15 = \text{Maximum Flow Capacity in MMscfd}$$

Pipeline capital costs have increased dramatically in the last decade, as shown in Table 6. (Please note that some of these costs were calculated using the information presented in the referenced documents.)

Table 5. Estimated CO_2 Pipeline Design Capacity

	CO_2 Flow Rate			
	Lower Bound		Upper Bound	
Pipeline Diameter, in.	Mt/yr	MMscfd	Mt/yr	MMscfd
4			0.19	10
6	0.19	10	0.54	28
8	0.54	28	1.13	59
12	1.13	59	3.25	169
16	3.25	169	6.86	357
20	6.86	357	12.26	639
24	12.26	639	19.69	1025
30	19.69	1025	35.16	1831
36	35.16	1831	56.46	2945

Table 6. CO_2 Pipeline Capital Costs for Various Pipelines

Project	Year	Cost, $/in. diameter-mile
Dakota Gasification[a]	2000	37,300
Hall-Gurney (KS)[b]	2001	22,000
Regression Analysis of FERC Data[c]	2003	33,800
Coffeyville Resources[d, e]	2007, 2009	52,100–83,300
Oil and Gas Journal Average of Natural Gas Pipelines[f]	2008	65,100
Green Pipeline[g]	2009	93,750

[a] J.E. Sinor and Associates, 2000.
[b] Willhite, 2001.
[c] Heddle and others, 2003.
[d] National Energy Technology Laboratory, 2008.
[e] ICF International, 2009.
[f] Oil and Gas Journal, 2008.
[g] Perilloux, 2009.

CO_2 Quality Specifications

D85 Quality Specifications

The composition of CO_2 streams varies depending upon the source of the CO_2, as can be seen in Table 7. Pipeline quality issues come into play when the CO_2 will be entering a pipeline containing CO_2 from other sources or if the CO_2 in the pipeline will be delivered to different sinks with different quality requirements. Most existing specifications relating to pipeline CO_2 quality are found only within private contracts between buyers and sellers (Bliss and others, 2010). Consequently, little public information is available regarding quality specifications for CO_2 pipelines. If a national pipeline network were to be developed, common carrier issues would most likely force some type of quality specification to be employed. According to the Interstate Oil and Gas Compact Commission's topical report *A Policy, Legal, and Regulatory Evaluation of the Feasibility of a National Pipeline Infrastructure for the Transport and Storage of Carbon Dioxide*, determining what might be a suitable specification could prove to be very helpful in the early stages of source and pipeline design (Bliss and others, 2010).

Several compounds can impact the end use of a CO_2 stream. It is important that the nitrogen and methane concentrations in a CO_2 stream be low so as not to rule out dense-phase operations. The most common specification is 5% of each or an aggregate of 10% (Bliss and others, 2010). Higher concentrations of nitrous oxide or methane raise minimum miscibility pressures to levels that are unacceptable for use in enhanced oil recovery (EOR) (Bliss and others, 2010). Sulfur compounds such as H_2S are hazardous to both humans and wildlife and, therefore, require robust safety strategies for sources, sinks, and pipelines. High oxygen content can lead to microbial-related corrosion of iron and steel as well as chemical reactions and/or aerobic bacterial growth within the injection tubular or in the geologic formation (Bliss and others, 2010). Concentrations of less than 10–20 ppm are accepted. Finally, as mentioned earlier in this report, minimization of water within the CO_2 stream is crucial to avoid corrosion. The typical maximum allowable water vapor concentration is in the range of 20–30 lb/MMcf (Bliss and others, 2010).

In the World Resources Institute's *CCS Guidelines: Guidelines for Carbon Dioxide Capture, Transport, and Storage* (World Resources Institute, 2008), CO_2 pipelines were split into three types: those developed for a specific single use (Type I), those developed to serve multiple sources and sinks (Type II), and those that may have multiple sources and/or sinks but have a more relaxed composition standard to accommodate a particular component contained in the CO_2 stream that does not have a deleterious effect on the specific sink(s) (Type III). The Type I pipelines developed for a single specific use do not exist in today's CO_2 EOR industry, but could be applied to a single CCS project.

Type II pipelines would incorporate CO_2 quality restrictions that are designed to be compatible with existing contracts between sources and sinks and that allow interconnections with future pipelines. A network of interconnected pipelines between multiple sources and sinks would provide pipeline "buffer" storage as well as more reliable source volumes and injection capacity (Bliss and others, 2010). The compositional standards of such a network would need to

Table 7. CO_2 Stream Compositions from Various Processes

Component	Kinder Morgan CO_2 Pipeline Specs[a]	Ethanol Plant[b]	Great Plains Synfuels Plant[c, d]	Gas Processing Plant[e]	Coffeyville Resources Ammonia–UAN Fertilizer Plant[f]	Food-Grade CO_2 Specs[g]
CO_2	≥ 95 vol%	> 98 vol%	96.8 vol%	≥ 96 vol%	99.32 vol%	≥ 99.9 vol%
Water	≤ 30 lb/MMcf	dry	< 25 ppm	≤ 12 lb/MMcf	0.68 vol%	≤ 20 ppmw
H_2S	≤ 20 ppmw		< 2 vol%	≤ 10 ppmw		≤ 0.1 ppmv
Total Sulfur	≤ 35 ppmw	40 ppmv	< 3 vol%	≤ 10 ppmw		≤ 0.1 ppmv
N_2	≤ 4 vol%	0.9 vol%	0 ppm			None
Hydrocarbons	≤ 5 vol%	2300 ppmv	1.3 vol%	≤ 4 vol%		CH_4: ≤ 50 ppmw; others: ≤ 20 ppmw
O_2	≤ 10 ppmw	0.3 vol%	0 ppm	≤ 10 ppmw		≤ 30 ppmw
Other	Glycol: ≤ 0.3 gal/MMcf		0.8 vol%			≤ 330 ppmw
Temperature	≤ 120°F	120°F	100°F	≤ 100°F	100°F	

[a] Kinder Morgan, 2007.
[b] Chen and others, 2004.
[c] Perry and Eliason, 2004.
[d] Hattenbach, 2009.
[e] Tracy, 2009.
[f] Kubek, 2009.
[g] Logichem Process Engineering, 2009.

be reflected in existing and future contracts between the CO_2 sources and sinks. Most of the current CO_2 pipelines in the United States fall within this category (Bliss and others, 2010).

Type III pipelines would allow one or more of the quality specifications to vary. This type of scenario could be appropriate for small, proprietary networks. Such networks could not be connected to Type II pipelines without treatment to ensure that the CO_2 quality would meet the Type II standards. There are a few Type III pipelines in operation: Dakota Gasification, Val Verde, Canyon Reef Carriers, and Zama. All of these pipelines allow a higher level of H_2S in the CO_2 stream than is acceptable in Type II pipelines (Bliss and others, 2010).

CO_2 Pipeline Risks

Pipeline transportation of CO_2 is not without risk. Risks include pipeline damage, corrosion, and leaks/blowouts. These are reasonably rare events. According to the National Response Center's accident database, there were 12 accidents in 3500 miles of CO_2 pipelines between 1986 and 2008. **No human injuries or fatalities were reported** for any of these accidents (Parfomak and Folger, 2008). By contrast, there were 5610 accidents causing 107 fatalities and 520 injuries related to natural gas and hazardous liquid (excluding CO_2) pipelines during the same period (Parfomak and Folger, 2008). Strategies taken to manage risks include block valves to isolate pipe sections that are leaking, the inclusion of fracture arrestors approximately every 1000 ft, the use of high durometer elastomer seals, and automatic control systems that monitor volumetric flow rates and pressure fluctuations (Gale and Davison, 2004). Other methods include aircraft and/or satellite monitoring of pipelines, implementation of periodic corrosion assessments, and internal cleaning and inspection using pipeline "pigs." The specific strategies used to minimize risk will vary depending on pipeline size, pressure, and location (Bliss and others, 2010).

CO_2 Pipeline Regulation

Pipeline safety is regulated under a provision in the federal Pipeline Safety Reauthorization Act of 1988 (Pipeline Safety Reauthorization Act of 1988). Pipelines that exist entirely within a single state are regulated by that state's authority, provided that the authority has adopted safety regulations at least as rigorous as the applicable federal regulations (Bliss and others, 2010). Pipelines that continue through more than one state are regulated by the federal Pipeline and Hazardous Materials Safety Administration (PHMSA) within the U.S. Department of Transportation. PHMSA also regulates the intrastate pipelines within any state that has not adopted regulations that are as stringent as the federal safety regulations (Bliss and others, 2010). Safety regulations for the transport of supercritical CO_2 by pipeline were established in June 1991 by the Research and Special Programs Administration within the Department of Transportation (Bliss and others, 2010).

The Code of Federal Regulations (CFR) Title 49, Part 195 Department of Transportation Office of Pipeline Safety regulates pipeline transport of CO_2. The CFR defines CO_2 as "a fluid consisting of more than 90 percent carbon dioxide molecules compressed to a supercritical state." CO_2 is not considered hazardous by the regulation, which covers design, pipe, valves, fittings, flange connections, welding, breakout tanks, leak detection, inspection, pumps, and compressors, etc. The regulations governing CO_2 pipelines are included within the section addressing hazardous liquids “for administrative convenience” (Bliss and others, 2010).

The siting of new CO_2 pipelines is not regulated by any federal agency. Both the Federal Energy Regulatory Commission (FERC) and Surface Transportation Board (STB) have declined jurisdiction over CO_2 pipelines (Wolfe, 2009) because they are neither “common carriers” under the Interstate Commerce Act administered by STB nor are they “natural gas companies” under the Natural Gas Act administered by FERC (Bliss and others, 2010).

There is no federal eminent domain for CO_2 pipelines (Wolfe, 2009). If a pipeline crosses federal land, permits from the federal agencies will need to be acquired and National Environmental Policy Act compliance undertaken (i.e., environmental assessment or environmental impact statement) (Wolfe, 2009). The Bureau of Land Management (BLM) can regulate CO_2 pipelines that cross federal land and that have received right-of-way authorizations issued by BLM under the Mineral Leasing Act as a commodity shipped by a common carrier (Wolfe, 2009; Bliss and others, 2010).

For the reader who is interested in pursuing this topic in more depth, the Interstate Oil and Gas Compact Commission’s topical report *A Policy, Legal, and Regulatory Evaluation of the Feasibility of a National Pipeline Infrastructure for the Transport and Storage of Carbon Dioxide* (Bliss and others, 2010) provides detailed information about the safety regulations and regulatory infrastructure that apply to CO_2 pipelines within the United States.

CO_2 Price

The delivered price of CO_2 from natural underground CO_2 sources has been about \$1.25/mcf (\$22/ton) (Wolk, 2009). For new contracts, a base price of \$1.25 to \$1.50/mcf (\$22 to \$26/ton) is tied to \$60 to \$70/bbl oil; the CO_2 price increases with the price of oil by a mutually agreed-upon formula (Hattenbach, 2009). By comparison, the cost to compress and transport for 50 miles the CO_2 captured from high-purity (>95%) anthropogenic sources such as natural gas-processing plants and hydrogen production plants is estimated to be \$1.30 to \$1.75/mcf (\$23 to \$30/ton) (Wolk, 2009). The cost of compressing and transporting a similar amount of CO_2 recovered from low-purity (<15%) sources a similar distance would range from an estimated \$2.85 to \$4.00/mcf (\$50 to \$70/ton) (Wolk, 2009). The Great Plains Synfuels Plant sells its CO_2 to Encana for about \$19/ton (\$1.10/mcf) (Remson, 2008).

CO_2 Pipeline Challenges and Opportunities

Initial CCS projects each may involve a dedicated pipeline constructed specifically to transport the CO_2 from the source to the injection site, but it is clear that widespread implementation of CCS from existing sources will require extensive expansion of the current pipeline system. The most efficient approach would be a planned pipeline network.

Development of a pipeline network could be performed on a regional or national level, but each approach would involve judicious siting of a series of backbone pipeline systems. A preliminary pipeline network for the PCOR Partnership region consisting of backbone and secondary pipelines was developed solely for the purpose of estimating regional transportation costs for early implementation of CCS. More information about this preliminary pipeline network is available in *Regional Emissions and Capture Opportunities Assessment – Plains CO_2 Reduction (PCOR) Partnership (Phase III)* (Jensen and others, 2009a). A study commissioned by the CO_2 Capture Project and carried out by Environmental Resources Management confirmed that an integrated backbone pipeline network would probably be the most efficient long-term CO_2 transport option (Chrysostomidis, 2008). The study concluded that the approach would offer the lowest average cost on a per-tonne basis, particularly if enough of the capacity were utilized early in the pipeline's life. Pipeline networks would most likely lead to the faster development and deployment of CCS as an integrated approach would provide equitable, open access to emitters. However, the study did note that point-to-point pipelines would be the least expensive for the early adopters and would not carry the same capacity utilization risk. Therefore, it is imperative that financial support (from the government and/or elsewhere) or incentives be found to develop optimized networks. Pipeline challenges include guaranteeing capacity utilization, probably through a public policy mechanism, and providing incentives and financial support to construct a backbone infrastructure and encourage the development of integrated pipeline networks (Chrysostomidis, 2008).

A pipeline network will have common carrier issues with respect to the content of the CO_2 streams that are transported. Other than a requirement that virtually no water be present in a given CO_2 stream, the common composition of CO_2 mixtures is the subject of debate. It will be important to establish permissible levels of contaminants in any CO_2 stream that will be transported via pipeline. CO_2 product specifications will likely be based on realistic data concerning the effects of the CO_2 streams on the materials of pipeline construction and the requirements of the geologic setting. Corrosion data could be obtained through the installation of test coupons within existing CO_2 pipelines. The tolerance of the geologic sinks toward contaminants will be considerably more difficult to determine.

Nonpolicy challenges that were identified at the Workshop on Future Large CO_2 Compression Systems focus on the concerns associated with CO_2 pipelines, including the potential for emergency blowdown of large, dense-phase inventories; accidental denting; CO_2 corrosion leaks in the case of an accidental intake of water; compatibility of materials, e.g., polymers and elastomers; and ductile fracture of the pipeline (Bratfos, 2009).

CONCLUSIONS

It is expected that significant reductions in the currently high cost of CCS will likely come from advances in CO_2 capture technologies. However, the compression and transport steps may be able to contribute incremental cost reductions to the overall process.

- More efficient compressor design may be possible if the properties of mixed CO_2 streams are better understood and can be more reliably predicted near the CO_2 critical point.

- Improving the integration and efficiency of the compression step within the capture–compression system is possible through the use of the heat produced during the interstage cooling step in various points within the capture plant, most likely during solvent/sorbent regeneration.

- Use of a compression–liquefaction–pumping pathway rather than a compression-only pathway may reduce the power required to compress the CO_2 to its supercritical state.

- Advanced compressor design offers the hope of a significant improvement in compression system efficiency and cost reduction. The high compression ratio, the improvements in efficiency, the dramatically smaller footprint, and the production of significant usable heat make the Ramgen Rampressor a potential step-change improvement in CO_2 compression.

- Improvements in compressor electric drives and their various components will simplify compressor systems, thereby improving their efficiency, reliability, and cost.

- Development of a large-scale pipeline network will likely be the most efficient and cost-effective long-term CO_2 transport option. Common carrier issues with respect to the content of the CO_2 streams that are transported will need to be addressed.

Coupled with advances and cost reductions in the capture and storage steps, meeting these compression and pipeline challenges could help to advance the widespread implementation of the CCS concept.

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