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

BELL CREEK TEST SITE – INFRASTRUCTURE DEVELOPMENT REPORT

Plains CO_2 Reduction Partnership Phase III
Subtask 6.2 – Deliverable D45

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ABSTRACT

The Plains CO_2 Reduction (PCOR) Partnership, which is led by the Energy & Environmental Research Center (EERC), is working with Denbury Onshore LLC (Denbury) to study carbon dioxide (CO_2) storage associated with a commercial enhanced oil recovery (EOR) project at the Denbury-operated Bell Creek oil field located in southeastern Montana.

The CO_2 for the project is sourced from the ConocoPhillips Lost Cabin Gas Plant and the ExxonMobil Shute Creek Gas-Processing Facility, both of which are in Wyoming. Both gas plants utilize a two-stage Selexol™ process to remove acid gases from the raw natural gas. The CO_2 stream produced at the Lost Cabin Gas Plant consists of roughly 1.4 million m^3/d (50 MMcfd) CO_2 with an average concentration of more than 98 vol% CO_2. This CO_2 is compressed to 15.2 MPa (2200 psi) and transported via Denbury's Greencore pipeline to the Bell Creek oil field in southeastern Montana. The Shute Creek Gas-Processing Facility produces about 65 MMcfd of CO_2 for compression to 12.1 MPa (1750 psi) and transport via the Anadarko and Greencore pipelines to the Bell Creek oil field. The average composition of this CO_2 stream is not publicly available. The composition of the CO_2 arriving at the Bell Creek Field via the Greencore pipeline averages 98% CO_2. As of December 31, 2015, 4.275 million tonnes of CO_2 had been injected into the Bell Creek Field, with 2.753 million tonnes (corrected for a gas composition of approximately 98% CO_2) stored in the field as of the same date. The oil that has been produced at the Bell Creek Field (as of December 31, 2015) totals 1.953 million barrels.

Typical surface facilities at an oil field can produce oil, water, natural gas, CO_2, and H_2S. Each of these can be used on-site, injected or otherwise disposed of, or sold for use off-site. The specific products produced at any oil field depend on the level of processing, which varies based on economic and site-specific conditions, but there are three typical approaches: full-stream reinjection, which consists only of dehydration and compression; partial processing, which adds partial recovery of the C4+ hydrocarbons to full-stream reinjection; and full processing, in which natural gas liquids (NGLs) and methane are recovered and the CO_2 stream is recovered. The Bell Creek EOR facility follows a full-stream reinjection scheme.

The methods used by Denbury to plan, construct, and operate the Greencore pipeline for EOR and the infrastructure utilized by the Bell Creek project and described in this report may apply to future carbon capture and storage (CCS) projects. While the Bell Creek project is a commercial EOR project rather than a CCS project, the data being collected during all of its phases will be invaluable in proving the usefulness of the CCS concept as a way to effectively decrease atmospheric CO_2 levels.

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NOMENCLATURE AND ABBREVIATIONS

°C	degree Celsius
°F	degree Fahrenheit
ANSI	American National Standards Institute
ATWS	additional temporary workspace
BMP	best management practice
CCS	carbon capture and storage
CFZ™	Controlled Freeze Zone™
cm	centimeter
CO_2	carbon dioxide
COS	carbonyl sulfide
d	day
DOT	U.S. Department of Transportation
EERC	Energy & Environmental Research Center
EI	environmental inspector
EOR	enhanced oil recovery
HDD	horizontal directional drilling
H_2S	hydrogen sulfide
hp	horsepower
in.	inch
km	kilometer
LACT	lease access custody transfer
m^3	cubic meter
mi	mile
MLV	mainline valve
mm	millimeter
MMcfd	million cubic feet per day
MMP	minimum miscibility pressure
MMscfd	million standard cubic feet per day (at standard conditions of 1 atm and 60°F)
MMscfh	million standard cubic feet per hour (at standard conditions of 1 atm and 60°F)
MP	mile point
MPa	megapascal
NGL	natural gas liquid
OSHA	Occupational Safety and Health Administration
PCOR	Plains CO_2 Reduction (Partnership)
ppm	part per million
psi	pound force per square inch
psia	pound force per square inch, absolute
psig	pound per square inch, gauge
ROW	right-of-way
RTU	remote terminal unit
SCADA	supervisory control and data acquisition
SSV	surface safety valve
t	tonne (metric ton)
vol%	volume percent
WAG	water alternating gas

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EXECUTIVE SUMMARY

The Plains CO_2 Reduction (PCOR) Partnership, which is led by the Energy & Environmental Research Center (EERC), is working with Denbury Onshore LLC (Denbury) to study carbon dioxide (CO_2) storage associated with a commercial enhanced oil recovery (EOR) project at the Denbury-operated Bell Creek oil field located in southeastern Montana. Denbury is managing all injection, production, and recycle activities as part of its commercial CO_2 EOR operation. Through the PCOR Partnership, the EERC is studying the behavior of reservoir fluids and injected CO_2 to demonstrate safe and effective storage of CO_2 associated with a commercial EOR project. It is anticipated that many of the lessons learned from this EOR operation will also apply to carbon capture and storage (CCS) projects in the future.

The EERC prepared this report to summarize the key elements of infrastructure that are required to cost-effectively capture, compress, transport by pipeline, distribute, and inject CO_2 within an operating oil field as part of an EOR project with associated CO_2 storage. The EOR operation is a business activity, and much of the information is considered to be business-sensitive. With this in mind, this report was compiled exclusively using publicly available information.

The CO_2 for the Bell Creek project is sourced from the ConocoPhillips Lost Cabin Gas Plant and the ExxonMobil Shute Creek Gas-Processing Facility. The Lost Cabin Gas Plant is located about 145 km (90 mi) west of Casper, Wyoming. The raw natural gas that is processed at the Lost Cabin plant comes from the Madden Field in the Wind River Basin in Wyoming, and contains approximately 67% methane, 20% CO_2, 12% hydrogen sulfide (H_2S), and 1% carbonyl sulfide (COS). A two-stage Selexol™ process is used to separate the acid gases H_2S and CO_2 from the methane, with the H_2S preferentially removed in the first stage and CO_2 removed in the second. The CO_2 stream produced by the Selexol process consists of roughly 1.4 million m^3/d (50 MMcfd) CO_2 with an average concentration of more than 98 vol% CO_2. This CO_2 is compressed to 15.2 MPa (2200 psi) and transported via Denbury's Greencore pipeline to Bell Creek.

The Shute Creek Gas-Processing Facility is located on the border between Lincoln and Sweetwater Counties in southwestern Wyoming. It processes raw natural gas produced from the LaBarge Madison Reservoir in Wyoming's Green River Basin that has a composition of approximately 65% CO_2, 22% methane, 7.4% nitrogen, 5% H_2S, and 0.6% helium. The raw natural gas is gathered at the nearby ExxonMobil Black Canyon facility where it is dehydrated to ensure safe pipeline transport over the 64 km (40 mi) to the Shute Creek Gas-Processing Facility. The Shute Creek Facility contains two 2-stage Selexol trains in which the H_2S is removed in the first stage and the CO_2 is removed in the second stage. The Shute Creek Gas-Processing Facility

produces about 65 MMcfd of CO_2 for compression to 12.1 MPa (1750 psi) and transport via the Anadarko and Greencore pipelines to the Bell Creek oil field in southeastern Montana. The average composition of this CO_2 stream is not publicly available.

Multiple pipelines transport the CO_2 from the Lost Cabin and Shute Creek facilities to the Bell Creek Field. The CO_2 from the Shute Creek Gas-Processing Facility is transported 258 km (160 mi) in the 324-mm (12.75-in.) Bairoil CO_2 pipeline until it ties into the 406-mm (16-in.) Anadarko pipeline for travel northeast 201 km (125 mi) to the Salt Creek Field near Casper, Wyoming. At the Salt Creek Field, the Anadarko pipeline ties into the Greencore pipeline. It is at this point that the CO_2 from the Shute Creek Gas-Processing Facility combines with the CO_2 from the Lost Cabin Gas Plant. The Greencore pipeline is approximately 373 km (232 mi) long. The pipeline was designed to be able to transport as much as 20.5 million m^3/d, or 38,150 t/d (725 MMcfd, or 42,053 short tons/d) of CO_2. The pipeline is 508 mm (20 in.) in diameter and was designed for a maximum operating pressure of 15.2 MPa (2200 psi). The pipeline was constructed using standard pipeline construction sequence steps. Construction began in August 2011, and the pipeline was commissioned and started up in December 2012.

Typical surface facilities at an oil field can produce oil, water, natural gas, CO_2, and H_2S. Each of these can be used on-site, injected or otherwise disposed of, or sold for use off-site. The specific products produced at any oil field depend on the level of processing. Initially, gas, oil, and water are separated from each other in a test separator. At the test separators and production separators, gas, oil, and water are separated and their flow rates monitored. Production separators separate the oil and water. Gas that is produced during the various separations is delivered to the CO_2 recovery plant. The level of processing of the recovered CO_2 varies based on economic and site-specific conditions, but there are three typical approaches: full-stream reinjection, which consists only of dehydration and compression; partial processing, which adds partial recovery of the C4+ hydrocarbons to full-stream reinjection; and full processing, in which natural gas liquids (NGLs) and methane are recovered and the CO_2 stream is recovered. Membranes can also be used in full processing, although CO_2 recovery from full processing typically involves cryogenic extractive distillation, also known as the Ryan–Holmes process. The most popular processing for CO_2 prior to reinjection is full-stream reinjection. The Bell Creek EOR facility follows a full-stream reinjection scheme in which the water and CO_2 that are separated from the oil are reinjected.

The percentage of the gas stream arriving at the Bell Creek Field via the Greencore pipeline that is CO_2 averages 98%. As of December 31, 2015, 4.275 million tonnes of CO_2 had been injected into the Bell Creek Field, with 2.753 million tonnes (corrected for a gas composition of approximately 98% CO_2) stored in the field as of the same date. The oil that has been produced at the Bell Creek Field (as of December 31, 2015) totals 1.953 million barrels.

The infrastructure utilized by the Bell Creek project and described in this report is the type of infrastructure required for any CCS project, although specific pieces may be different. The methods used by Denbury to plan, construct, and operate the Greencore pipeline for EOR may also apply to CO_2 transport during a future CCS project. Even though the Bell Creek project is a commercial EOR project rather than a CCS project, the data being collected during all of its phases will be invaluable in proving the usefulness of the CCS concept as a way to effectively decrease atmospheric CO_2 levels.

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INTRODUCTION

The Plains CO_2 Reduction (PCOR) Partnership, which is led by the Energy & Environmental Research Center (EERC), is working with Denbury Onshore LLC (Denbury) to study carbon dioxide (CO_2) storage associated with commercial enhanced oil recovery (EOR) activities at the Denbury-operated Bell Creek oil field located in southeastern Montana. Denbury is managing the injection, production, and recycle activities as part of its commercial CO_2 EOR operation. Through the PCOR Partnership, the EERC is studying the behavior of reservoir fluids and injected CO_2 in order to demonstrate safe and effective storage of CO_2 when associated with a commercial EOR project. The PCOR Partnership is developing technologies and practices that will allow informed decisions to be made regarding future commercial-scale CO_2 storage projects with respect to site selection, injection programs, operations, and monitoring strategies that maximize storage efficiency and effective storage capacity in geologic formations. It is anticipated that many of the lessons learned from this EOR operation will apply to carbon capture and storage (CCS) projects in the future.

The EERC prepared this report to summarize the key elements of infrastructure that are required to cost-effectively capture, compress, transport by pipeline, distribute, and inject CO_2 within an operating oil field as part of an EOR project with associated CO_2 storage. Because the EOR operation is a business activity and much of the information is considered to be business-sensitive, this report was compiled exclusively using information that has previously been made public.

CAPTURE OF CO_2 FOR INJECTION AT THE BELL CREEK OIL FIELD

The CO_2 for the Bell Creek site is sourced from two gas-processing plants: ConocoPhillips' Lost Cabin Gas Plant and ExxonMobil's Shute Creek Gas-Processing Facility, both of which are located in Wyoming. Because of the high hydrogen sulfide (H_2S) concentration in the raw natural gas, the Selexol™ process, which is a physical solvent process, is used to remove the acid gases H_2S, CO_2, and carbonyl sulfide (COS) at both plants. In fact, they are the only reported locations that utilize Selexol for selective removal of H_2S and CO_2 from natural gas (Walsh and others, 2000). In addition to using the Selexol process, the Shute Creek Gas-Processing Facility is also demonstrating the ExxonMobil-developed Controlled Freeze Zone™ (CFZ™) process for separation of CO_2 from natural gas.

Lost Cabin Gas Plant

The Lost Cabin Gas Plant, pictured in Figure 1, is located about 145 km (90 mi) west of Casper, Wyoming. The raw natural gas that is processed at the Lost Cabin Gas Plant comes from the Madden Field in the Wind River Basin of Wyoming, roughly 5 to 8 km (3 to 5 mi) from the gas plant (Global CCS Institute, 2015). The raw natural gas from the Madden Field contains approximately 67% methane, 20% CO_2, 12% H_2S, and 1% COS (Lohnes, 2007). The Lost Cabin Gas Plant's initial design raw natural gas inlet capacity was 50 MMcfd, although this was increased during a debottlenecking and two expansions to a total of 310 MMcfd (Lohnes, 2007). The Lost Cabin Gas Plant produces about 50 MMcfd of CO_2 that was previously vented from the processing system but is now compressed and transported via pipeline to the Bell Creek oil field in southeastern Montana. The average composition of the CO_2 stream produced by the Lost Cabin Gas Plant is shown in Table 1.

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Figure 1. ConocoPhillips' Lost Cabin Gas Plant (taken from Inberg-Miller Engineers, 2016).

Table 1. Average Lost Cabin Vent Stack CO_2 Composition*

Component	Train 1	Train 2	Train 3	Average
CO_2, vol%	98.318	98.447	98.273	98.346
CH_4, vol%	1.472	1.389	1.550	1.470
C_2H_6, vol%	0.016	0.015	0.027	0.019
N_2, vol%	0.103	0.057	0.052	0.071
COS, vol%	0.091	0.092	0.098	0.094
H_2S, ppm	5.000	4.000	8.000	5.667

* From Lohnes, 2007.

The overall process employed at the plant is shown in the block diagram of Figure 2. The Selexol process fits into the box labeled "Process Area" on this figure. Selexol solvent is manufactured by Dow Chemical and is a mixture of dimethyl ethers of polyethylene glycol. It has a molecular formula of $CH_3O(CH_2CH_2O)_nCH_3$, where n is between 3 and 9 (Kuryachiy, 2007). The process operates as an absorber–stripper technology. The gas contacts the Selexol solvent in the absorption tower, where the acid gases are absorbed. The loaded solvent flows to a stripper tower where the gases are released by heating and/or pressure reduction (flashing). When both H_2S and CO_2 are present, the Selexol solvent preferentially removes H_2S. In this case, a two-stage Selexol absorber is used, with the H_2S removed in the first absorption tower (stage) and the CO_2 removed in the second. The Selexol process contains various recycle loops, heat exchangers, and flash separation drums. Figure 3 shows a two-stage Selexol process as it would apply to a gasification system. When applied to a gas-processing plant, the "sour syngas" stream would be raw natural gas, while the "treated syngas" stream is sweetened natural gas. The Lost Cabin Gas Plant uses three 2-stage Selexol trains. Train 1 was originally commissioned in 1995 and was followed by Train 2 in 1999. In 2002, Train 3 was added (Nelson, 2006).

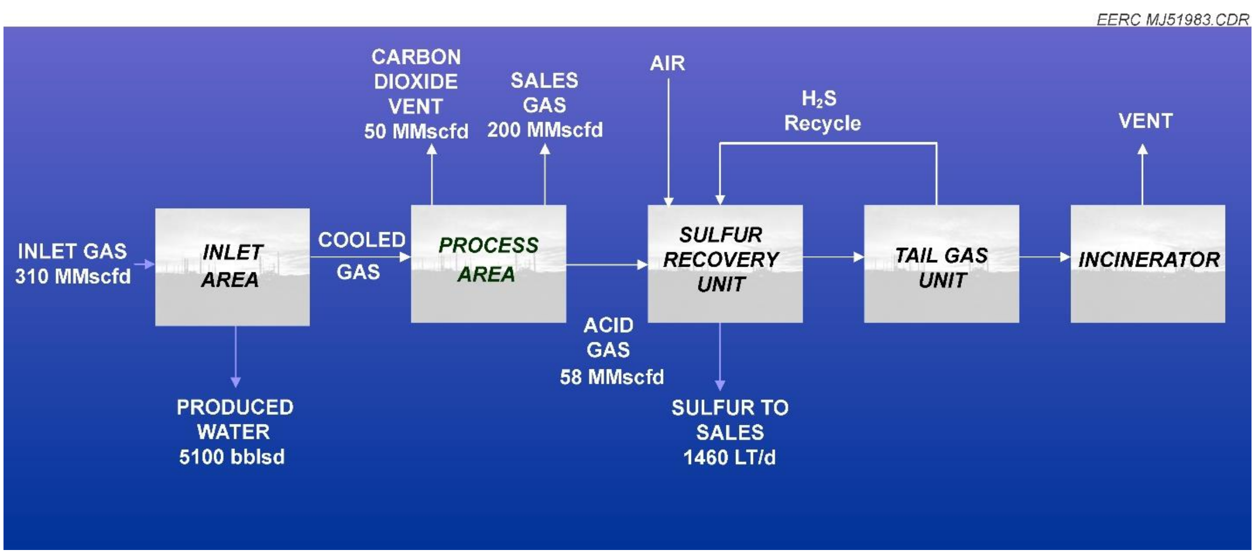

Figure 2. Block diagram summarizing the overall process employed at the Lost Cabin Gas Plant (taken from Lohnes, 2007).

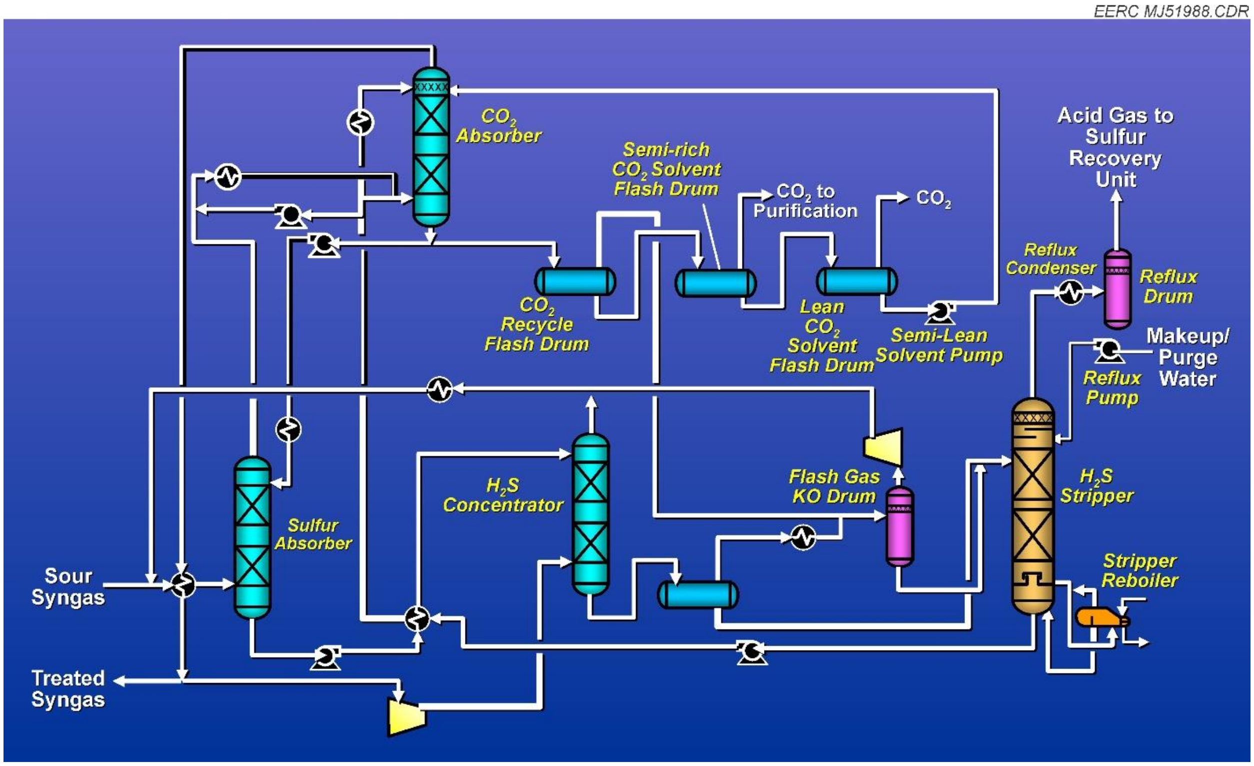

Figure 3. Two-stage Selexol process (taken from Holbrook, 2007).

Shute Creek Gas-Processing Facility

The Shute Creek Gas-Processing Facility is located on the border between Lincoln and Sweetwater Counties in southwestern Wyoming. The plant, which is shown in Figure 4, processes raw natural gas produced from the LaBarge Madison Reservoir in Wyoming's Green River Basin. The raw natural gas has a composition of approximately 65% CO_2, 22% methane, 7.4% nitrogen, 5% H_2S, and 0.6% helium (Wyoming Tax Appeals, 2006). The raw natural gas is gathered to the nearby ExxonMobil Black Canyon facility where it is dehydrated to ensure safe pipeline transport over the 64 km (40 mi) to the Shute Creek Gas-Processing Facility (Wyoming Tax Appeals, 2006). The Shute Creek Gas-Processing Facility contains two 2-stage Selexol trains in which the H_2S is removed in the first stage and the CO_2 is removed in the second stage (Wyoming Tax Appeals, 2006). It is the world's largest Selexol plant (Thomas, 2009). The Shute Creek Gas-Processing Facility produces about 65 MMcfd of CO_2 for compression and transport via pipeline to the Bell Creek oil field in southeastern Montana (Denbury Resources Inc., 2016). The average composition of this CO_2 stream is unknown.

In addition to the Selexol process, the Shute Creek Gas-Processing Facility is the site of a commercial demonstration of the ExxonMobil CFZ™ CO_2 capture technology. The CFZ™ technology removes CO_2 and H_2S from natural gas in a distillation tower featuring a specially designed section in which CO_2 is allowed to freeze in a controlled manner. The CO_2 is then melted and distilled to recover methane. The remaining natural gas is at pipeline purity (ExxonMobil,

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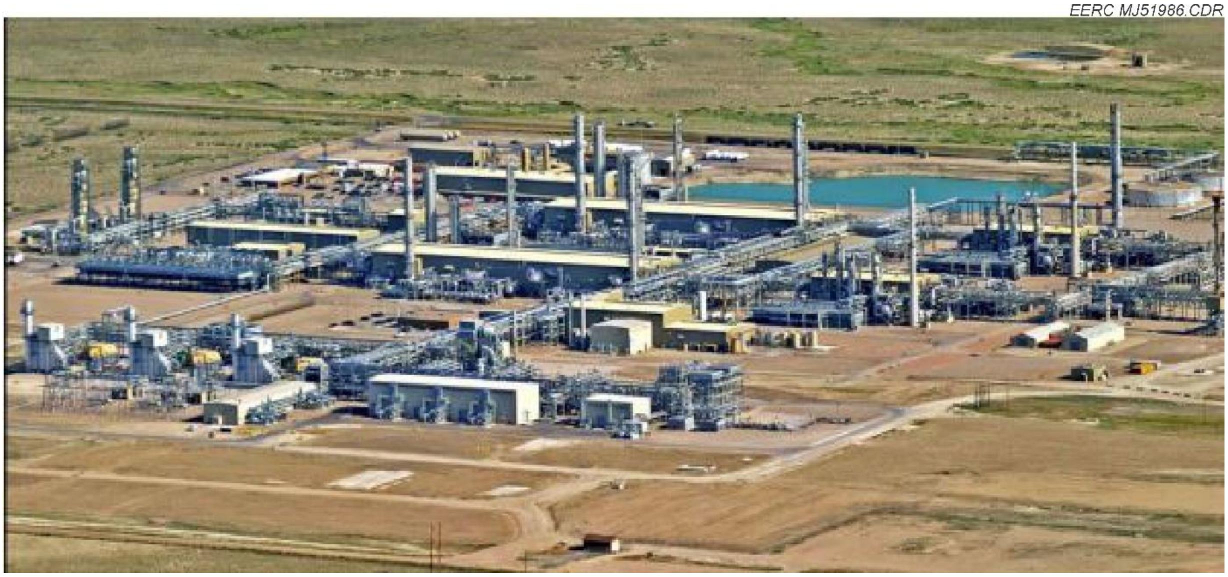

Figure 4. ExxonMobil Shute Creek Gas-Processing Facility (taken from Thomas, 2009).

2016). The CFZ™ discharges the CO_2 as a high-pressure liquid, requiring little additional compression prior to pipeline transport. A schematic of the CFZ™ technology is shown in Figure 5, while the commercial demonstration system at Shute Creek is shown in Figure 6. Information presented at a conference indicates that the separation of CO_2 from methane is nearly complete, with a CO_2 composition in the bottoms product of 99.5% to 100% and with CO_2 making up only 0.9% of the methane (overheads) stream (Condon and Kelman, 2012).

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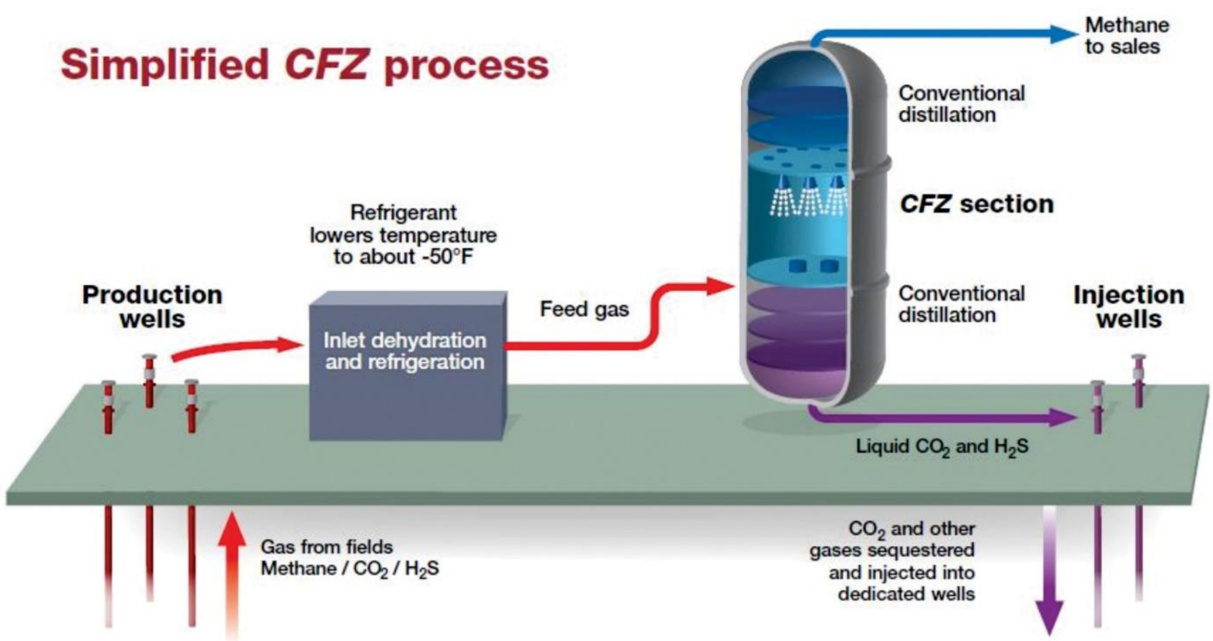

Figure 5. Schematic of the CFZ™ technology (taken from Khayyal, 2013).

Figure 6. Photograph of the CFZ™ demonstration unit at the Shute Creek Gas-Processing Facility (taken from Khayyal, 2013).

CO_2 COMPRESSION PRIOR TO TRANSPORT

Lost Cabin Gas Plant

The rich solvent flash drum in a Selexol process produces a gas stream at about 200 psi, while the second (lean) flash drum produces a product gas stream at about 60 psi. The stream that is being transported to the Bell Creek Field is from the rich solvent flash drum. Denbury has set a design pressure for the CO_2 stream of 2200 psig (Denbury Resources Inc., 2010). As Figure 7 shows, meeting this pressure requirement for a flow rate of 50 MMscfd (2.083 MMscfh) will likely require an integrally geared centrifugal compressor. Information about the specific compressor used to compress the CO_2 from the Lost Cabin Gas Plant is not publicly available.

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). 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). The integral gear design offers high efficiency relative to other compressors, is more flexible with respect to selection of the pressure level, and does not limit the number of stages in one machine. Integrally geared compressors have maintenance requirements that are comparable

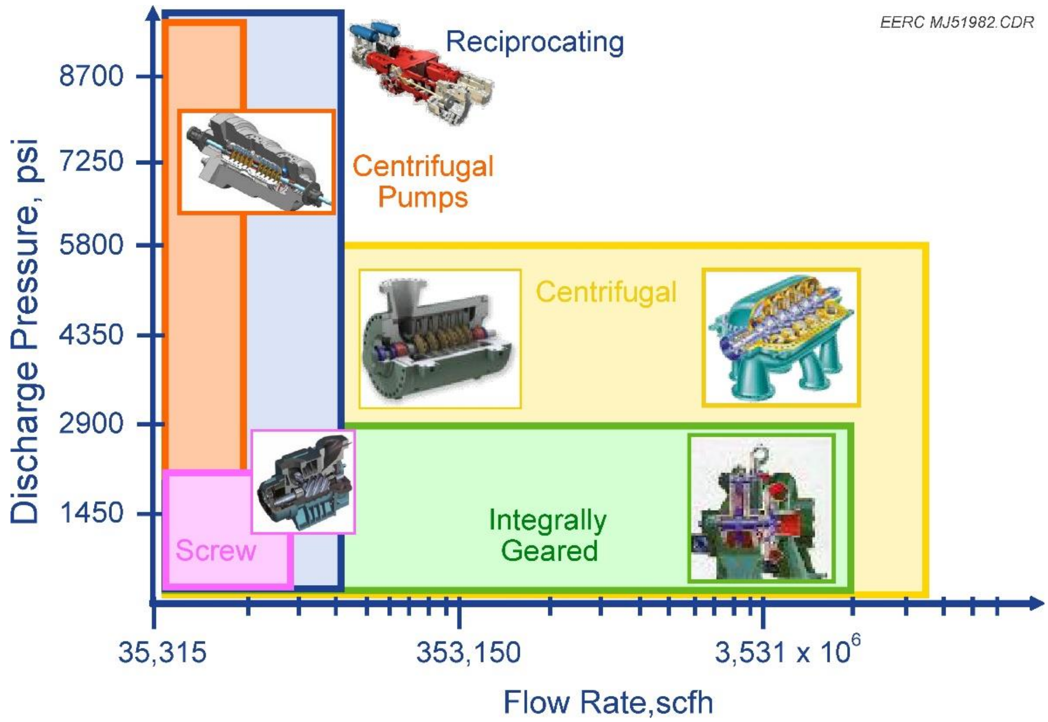

Figure 7. Compressor types with approximate discharge pressures and flow rates (based on Wadas, 2010).

to those of in-line compressors but require only approximately half the number of stages because they can operate at higher compression ratios and utilize intercooling between each stage (Bovon and Habel, 2007).

Shute Creek Gas-Processing Facility

The Shute Creek CO_2 compressor facility is located about 3.2 km (2 mi) from the Shute Creek Gas-Processing Facility. The Selexol process supplies CO_2 at 200 psia and 60 psia (Kubek, 2009). Originally, the 270 MMscfd of CO_2 was compressed to 1750 psig using four compressor trains totaling 49,000 hp (Kubek, 2009). The compressors were supplied by Dresser-Rand. In 2007, a CO_2 sales gas expansion project was initiated to increase CO_2 sales capacity by 110 MMcfd (Geohegan, 2008). Two additional compressors were added to compress the increased quantities of CO_2: a single 20,000-hp medium-pressure/high-pressure compressor and a 3000-hp low-pressure compressor, both of which were supplied by Dresser-Rand (Kubek, 2009). The low-pressure compressor is a Dresser-Rand DATUM Model D6R4S, which has a radial design with four impellers with a straight-through casing configuration (Kubek, 2009). The medium-pressure/high-pressure compressor is a Dresser-Rand DATUM Model D10R8B radial design with eight impellers with a back-to-back casing configuration (Kubek, 2009). The Shute Creek sales compressors are shown in Figure 8.

Figure 8. Shute Creek CO_2 sales gas compressors.

TRANSPORT OF CO_2 BY PIPELINE

Anadarko Pipeline

Following compression to pipeline pressure, the CO_2 from the Shute Creek Gas-Processing Facility is transported 258 km (160 mi) in the 324-mm (12.75-in.) Bairoil CO_2 pipeline until it ties into the 406-mm (16-in.) Anadarko pipeline (sometimes called the Salt Creek pipeline) for its travel northeast 201 km (125 mi) to the Salt Creek Field near Casper, Wyoming (IEA Greenhouse Gas R&D Programme, 2013; Anadarko, 2003). At the Salt Creek Field, the Anadarko pipeline ties into the Greencore pipeline. It is at this point that the CO_2 from the Shute Creek Gas-Processing Facility combines with the CO_2 from the Lost Cabin Gas Plant.

Greencore Pipeline

The information presented in this section was previously reported in the PCOR Partnership Task 8 Deliverable D49 report entitled "Bell Creek Test Site – Transportation and Injection Operations Report" (Jensen and others, 2015). The information from that report is summarized here so that all of the Bell Creek project infrastructure information can be found in one document. For additional detail about the Greencore pipeline, the reader is encouraged to peruse the D49 report.

Purchased CO_2 is delivered to the Bell Creek Field from the Lost Cabin Gas Plant via the Denbury-operated Greencore pipeline and from the Shute Creek Gas-Processing Facility via a tie-in of the Anadarko pipeline to the Greencore pipeline. The pipeline was constructed to move CO_2 from anthropogenic sources to petroleum reservoirs in the Rocky Mountain region (Denbury Resources Inc., 2015). Designed to ultimately transport as much as 20.5 million m^3/d, equal to 38,150 t/d (725 MMcfd, or 42,053 short tons/d) (Denbury Resources Inc., 2015). The pipeline cost an estimated $285 million (Blincow, 2013; Hallerman, 2013).

The Greencore pipeline route is shown in Figure 9. The pipeline consists of 50.8-cm (20-in.)-diameter, Class 900# ANSI (American National Standards Institute) pipe and was designed to operate at a pressure of 15.17 MPa (2200 psig) and a temperature of 37.8°C (100°F) (Denbury Resources Inc., 2010). Denbury has not publicly disclosed the pipeline materials of construction.

Initial construction of the pipeline and mainline valves (MLVs) began on August 29, 2011, on two of four spreads (Denbury Resources Inc., 2011). Spread 2 contained approximately 85.3 km (53 mi) of pipe and four MLV installations. Spread 2 construction was completed on December 8, 2011. The pipeline was purged and packed with nitrogen to preserve it until the next year. Spread 3 comprised approximately 100 km (62 mi) of pipe and seven MLV installations. Following its completion on December 17, 2011, the line was again purged and packed with nitrogen. Spreads 1 and 4 as well as the remaining MLV installations and the metering stations at both ConocoPhillips' Lost Cabin Gas Plant and Denbury's Bell Creek facilities station, were to be constructed in 2012 (Denbury Resources Inc., 2011). The pipeline was commissioned and started up in December 2012 (Blincow, 2013).

The *Greencore CO_2 Pipeline Project Plan of Development* (Greencore Pipeline Company LLC, 2011) contains considerable detail regarding the Greencore pipeline. Select information contained in the document is summarized in Sections 3.2 and 3.3 of this report. Interested readers are encouraged to download the Greencore document for further review.

According to the planning document (Greencore Pipeline Company LLC, 2011), the pipeline contains a launcher, meter run, and block valve at the receipt point at the Lost Cabin Gas Plant as well as a block valve, scraper receipt trap, tee, and meter run at the Bell Creek Field Unit C delivery point/terminus. The document lists an additional 15 block valves as well as scraper receipt traps/ launcher traps and tee and block valves at four other locations. The planned valve operator/actuator types and their location along the pipeline are given in Table 2. Figure 10 shows the location of tees along the pipeline that allow tie-in to other pipelines.

Pump stations were planned for approximate locations along the pipeline of 63.6, 231.7, and 371.9 km (39.5, 1440, and 231.1 mi). When given in miles, these locations are known as mile points [MPs]). Branch tees at mainline block valves were to be installed to facilitate future tie-in of these pump stations. Plans called for construction of the pump stations when product volumes exceeded 4.2 million m^3/d at standard oil and gas conditions (150 MMscfd). Each pump station would include valve manifolds, pumps, pigging equipment, power distribution, and control buildings (Greencore Pipeline Company LLC, 2011).

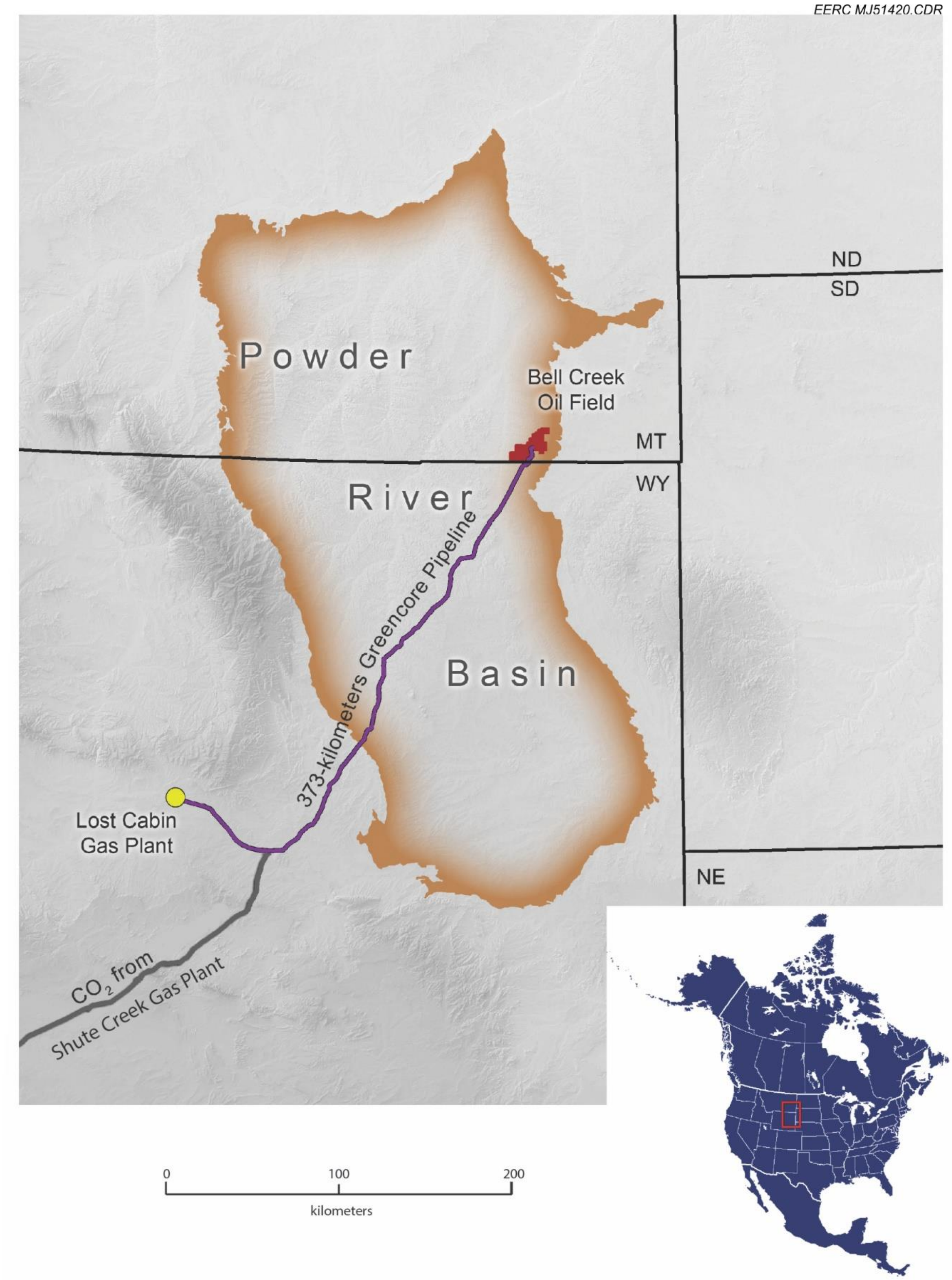

Figure 9. Denbury Greencore pipeline route.

Table 2. Valves and Actuators on the Greencore Pipeline (Greencore Pipeline Company LLC, 2011)

	Location Along the Pipeline	
Type	**km**	**mi**
Lost Cabin – Meter Run and Block Valve	0.0	0.0
Block Valve	31.7	19.7
Block Valve	52.8	32.8
Natrona Hub – Scraper Receipt Trap/Launcher Trap, Tee Block	63.6	39.5
Block Valve	72.6	45.1
Block Valve	104.0	64.6
Block Valve	133.6	83.0
Future Interconnect Station – Scraper Receipt Trap/Launcher Trap, Tee and Block Valve	140.3	87.2
Block Valve	161.7	100.5
Block Valve	189.3	117.6
Block Valve	222.9	138.5
Future Midpoint Pump Station – Block Valve, Scraper Receipt Trap/Launcher Trap, Tee Block Valve	231.7	144.0
Block Valve	239.1	148.6
Block Valve	240.2	149.3
Block Valve	255.1	158.5
Block Valve	287.1	178.4
Block Valve	287.9	178.9
Pigging Station – Block Valve, Scraper Receipt Trap/Launcher Trap, Tee	322.5	200.4
Block Valve	327.5	203.5
Block Valve	350.7	217.9
Belle Creek Unit C Delivery/Terminus Point – Block Valve, Scraper Receipt Trap, Tee and Meter Run	371.9	231.1

Planning for the Bell Creek delivery facility included a 22.9-m-long × 10.7-m-wide × 7.3-m-high (75-ft-long × 35-ft-wide × 24-ft-high) meter building, receiving scraper trap, flow control valve, communications and satellite dish, CO_2 vent, and electric service pole with pad-mounted transformer. The plans call for the entire facility to be enclosed by a 1.8-m (72-in.)-high chain-link security fence (Greencore Pipeline Company LLC, 2011).

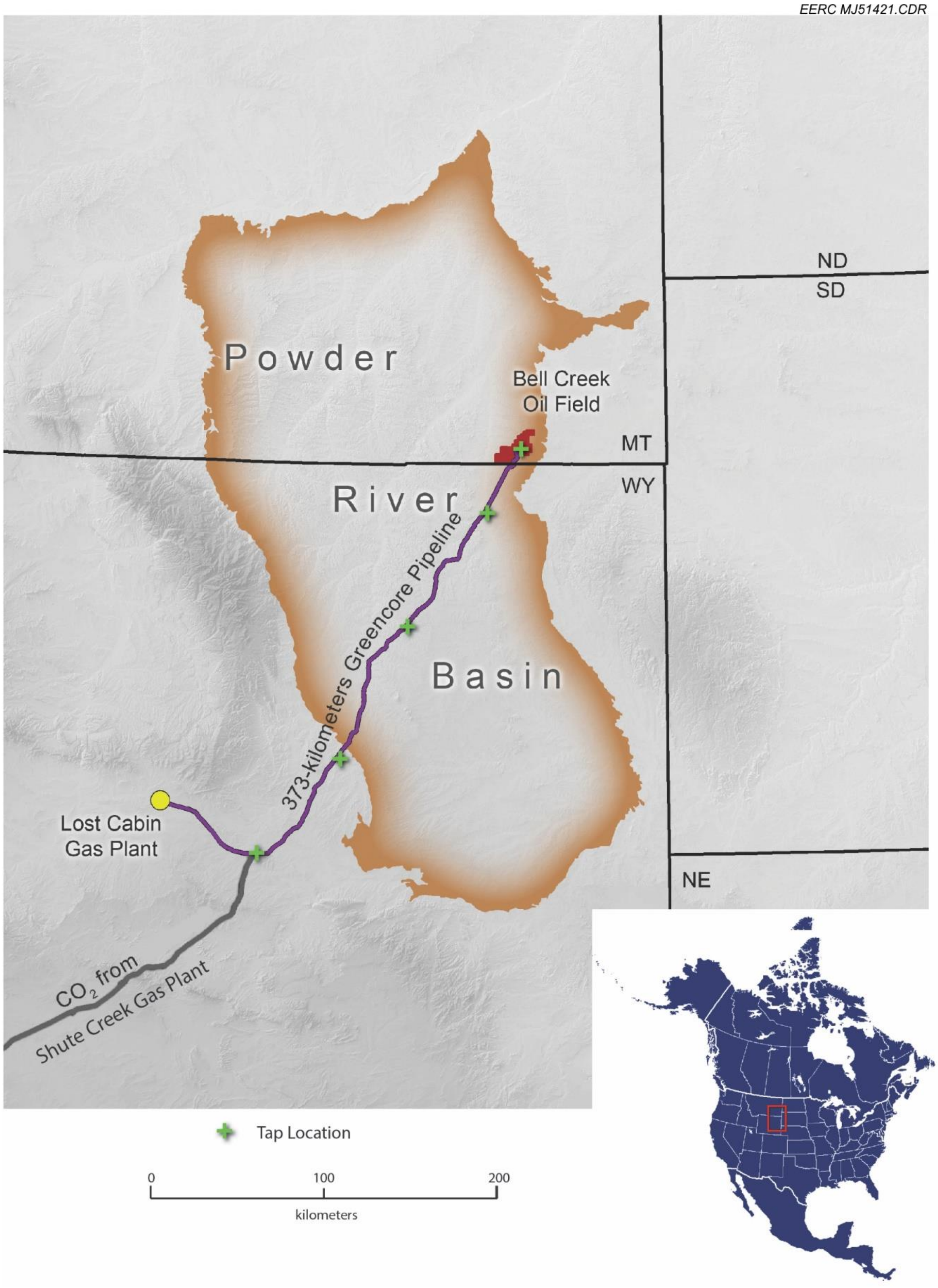

Figure 10. Location of tees along the pipeline.

Construction and Installation of the Greencore CO_2 Pipeline

Several phases are involved in the standard construction and installation of a CO_2 pipeline. Figure 11 shows the steps involved in constructing and installing a CO_2 pipeline. The steps are described in detail in a Greencore Pipeline Company LLC (2011) document and are summarized here. It is assumed that all of these steps were taken during construction of the Greencore pipeline, but that has not been confirmed.

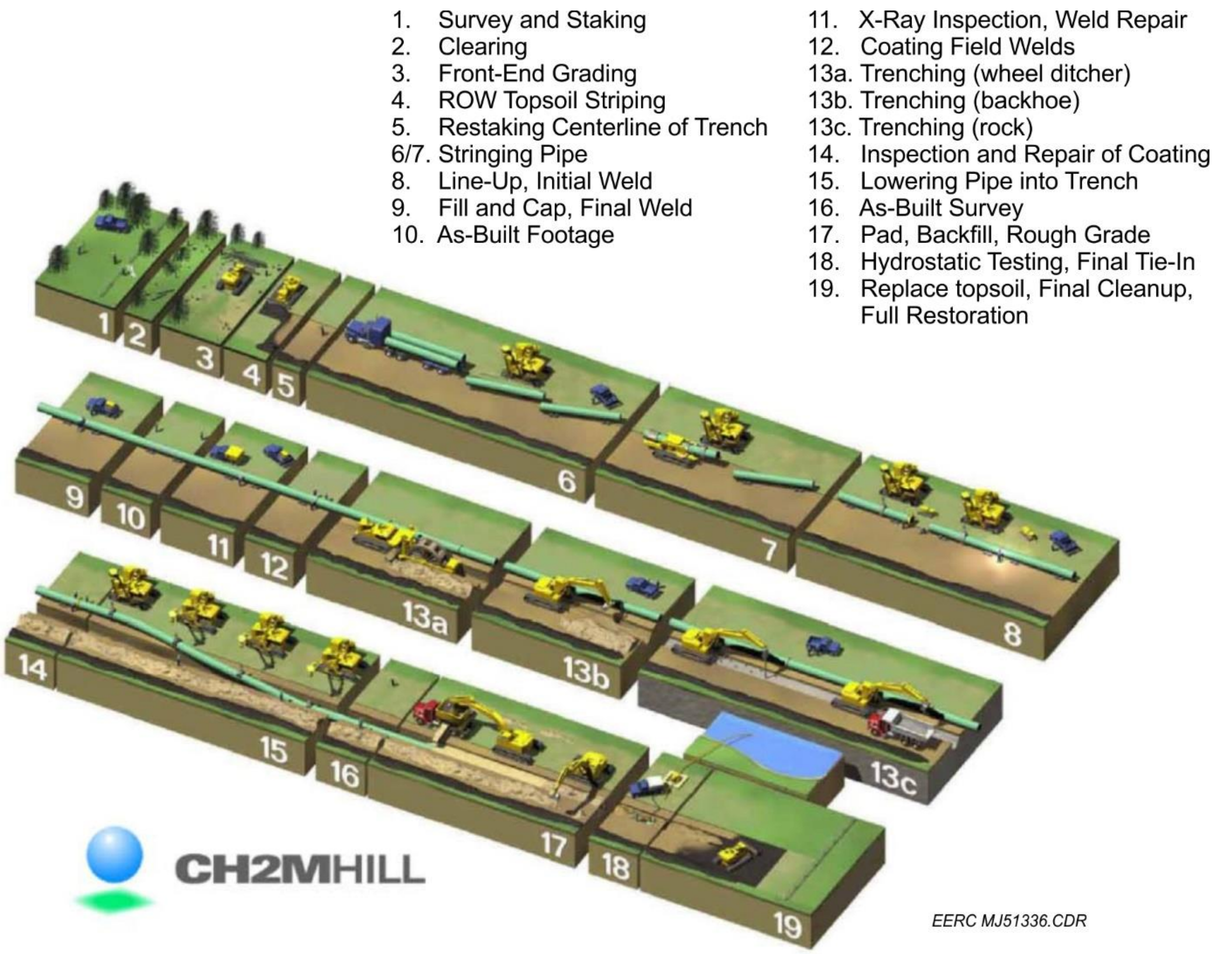

Figure 11. CO_2 pipeline construction sequence (taken from Greencore Pipeline Company LLC, 2011).

Preconstruction (summarized from Greencore Pipeline Company LLC, 2011)

All biological and cultural impacts and permit stipulations will have been determined by the time the pipeline is constructed. Engineering surveys are used to identify the pipeline centerline as well as the boundaries of the areas in which the construction will be performed. The permanent right-of-way (ROW) is 15.2 m (50 ft) wide. An additional temporary workspace (ATWS) of

15.2 m (50 ft) width is located parallel and adjacent to the ROW. Best management practices (BMPs) are used to limit erosion and transport of sediment. BMPs are usually site-specific and depend upon weather and site conditions. Therefore, there will be many BMPs for the length of the pipeline, and they may require adjustment during construction. A stormwater pollution prevention plan will also be prepared to ensure proper control of sediment and erosion as well as to document reporting procedures should they be needed.

Construction (summarized from Greencore Pipeline Company LLC, 2011)

Clearing, grading, and topsoiling are the first steps that are undertaken during pipeline construction. Grading will not be performed over ATWS, drainages, wetlands, or historic trails. Ground disturbance and construction are limited to areas approved for such activities. When possible, grading is limited so as to preserve vegetation and reduce environmental impact. This might occur in a level field or pasture, where topsoil would be removed only over the trench line. When the terrain is mountainous or hilly and contains slopes that cross the ROW, a level work area must be cut out of the hillside. These areas will be reclaimed to the natural contours to the extent possible. Figure 12 shows a hilly area that was reclaimed. Topsoil is stockpiled separately and used only as the final layer of soil during reclamation. When the pipeline crosses wetlands, the topsoil is only removed above the trench line. It is placed on the banks of drainage such as wetlands, floodplains, dry drainages, or washes so that natural flows are not blocked and the topsoil is not washed away.

Figure 12. Photograph of Greencore pipeline route through a hilly area taken postreclamation (taken from Blincow, 2013).

Construction methods for excavating a pipeline trench vary depending on soil, rock, terrain, and other related factors. Excavated subsoil is stored separately from the topsoil and, as is the case with topsoil, is not stored where water bodies, dry drainages, or washes cross the ROW.

The width and depth of the trench depend on pipe diameter and soil type. A typical ditch is excavated approximately 0.9–1.2 m (3–4 ft) wide at the base with the sides sloped to Occupational Safety and Health Administration (OSHA) specifications, which would be approximately 2.4 m (8 ft) wide. The standard depth of a trench ranges from 0.8 to 1.5 m (30 to 60 in.), being deeper at water, drainage, and road crossings and on agricultural lands and shallower elsewhere. Mechanical rippers or rock-trenching equipment may be used during the excavation when rock is encountered. Should these not be sufficient or practical because of site conditions, blasting may be used, although only when necessary.

Boring or open-cut techniques may be used at road crossings depending on regulations, traffic, equipment availability, and cost. The open-cut technique is typically used for crossings at two-track or gravel roads, while the slick bore or small directional drill bore methods are used for county roads and state highways.

Crossing water or wetlands requires special permitting to be in place. A nationwide permit must be obtained from the Army Corps of Engineers if jurisdictional waters will be crossed. In these cases, ROW clearing is limited to 22.9 m (75 ft). BMPs are used to protect water resources, and ATWS will be designated to provide additional work space.

In wetlands and waterbodies, equipment is limited to that required for ROW clearing, trench excavation, pipe fabrication and installation, and backfilling. Water quality is protected by reclaiming water and wetland crossings as soon as practical. Accumulated material will be removed and, to the extent possible, drainages returned to preconstruction form. Seed for wetlands will be obtained from the wetland topsoil that was segregated for reclamation, although stream banks that contain upland vegetation will be reseeded.

Horizontal directional drilling (HDD) was planned for water body and road crossings because the technique minimizes surface impact except at the equipment entry and exit sites. Table 3 shows the location of these crossings and their length. In fact, there is no surface ground disturbance between the entry and exit drill path locations. The typical minimum depth of the drill under a stream is either 7.6 m (25 ft) or 1.8 m (6 ft) below the stream bed, whichever provides the higher margin of safety. A heavy-wall line pipe with an abrasive coating will be utilized to ensure pipeline integrity at the crossing. The HDD method eliminates future disturbance of the ground surface that might occur during annual maintenance typically required with an open-ditch crossing.

The pipeline route crosses various types of terrain, each having different erosion potentials. The environmental inspector (EI) will identify or modify BMPs for highly erodible areas to increase their stability. Water body crossings will be reviewed during the design phase to ensure that all potential bank erosion issues are addressed.

Table 3. Proposed Horizontal Directionally Drilled Crossings on the Greencore CO_2 Pipeline (Greencore Pipeline Company LLC, 2011)

Name	MP	Length, m (ft)
Lost Cabin Road/CR 158	0.2	36.6 (120)
Diagonal HDD Crossing of Foreign Line, Arminto Road/ CR 104 and Foreign Line	25.2	237.7 (780)
Highway 20/26	33.1	167.6 (550)
I-25 Service Rd, I-25 North- and Southbound Lanes	86.9	239.2 (785)
I-90	149.8	527.9 (1732)
Wild Horse Creek–Extended Wetland	160.0	426.7 (1400)
BNSF Railroad	165.9	137.2 (450)
Horse Creek	199.5	396.2 (1300)
Little Powder River	203.1	30.5 (100)
Donner Reservoir	218.3	91.4 (300)

The pipeline is collocated with existing utilities for about 90% of the pipeline route. In the areas in which the Greencore pipeline must be within 6.1 m (20 ft) of the utility, added precautions will be taken to support pipeline construction. A representative of the utility will be notified prior to initiation of pipeline construction, and activity would be limited over the adjacent utility.

Pipe Installation (summarized from Greencore Pipeline Company LLC, 2011)

Pipe installation includes stringing, bending pipe for angles in the alignment, welding the segments together, inspecting the pipeline, applying corrosion prevention coating, lowering the pipe into the ditch, and padding the ditch. Figures 13 and 14 show installation of the Greencore pipe.

Backfilling (summarized from Greencore Pipeline Company LLC, 2011)

After a section of pipe has been placed in the ditch, the trench is checked to ascertain that there are no wildlife or livestock present. Backfilling is conducted using suitable equipment such as a bulldozer or rotary auger backfiller. Subsoil previously excavated from the trench is generally used as backfill. Rocky areas may need imported fill material. The backfill is graded and compacted to the extent that the trench does not contain any voids. In irrigated agricultural areas, the soil is compacted to the same density as the adjacent undisturbed soil. A 0.2-m (0.5-ft) mound generally will be placed over the trench to account for subsidence.

Pressure Testing and Water Use (summarized from Greencore Pipeline Company LLC, 2011)

Each pipeline is tested in compliance with DOT regulations. Every section of pipeline is cleaned by passing reinforced poly pigs through the pipeline interior. The entire pipeline is then hydrostatically tested to at least 125% of maximum operating pressure. Directional drilling and dust abatement would require that water be consumed. The water would be obtained from permitted sources for both uses.

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Figure 13. Greencore pipeline construction (taken from Snyder, 2012).

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Figure 14. Greencore pipeline construction with pipe in trench (taken from Blincow, 2013).

Cleanup and Reclamation (summarized from Greencore Pipeline Company LLC, 2011)

All construction debris and miscellaneous items were removed from the construction site and disposed of properly. Fences and roads were replaced/rebuilt as negotiated with the landowner(s). Disturbed areas were returned to preconstruction grades and contours as nearly as possible. Original drainage patterns were reestablished. Topsoil was replaced over the ROW at the approximate area from which it was stripped. All disturbed areas will be seeded and mulched, with reseeding and mulching generally completed as soon as possible. Land that has been disturbed by pipeline construction activities is reclaimed in accordance with applicable regulations and permit requirements. Figure 15 shows a photograph taken after the Greencore pipeline was constructed and the trench reclaimed.

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Figure 15. Photograph of the Greencore pipeline route taken postreclamation (taken from Blincow, 2013).

Pipeline Operation and Monitoring (summarized from Greencore Pipeline Company LLC, 2011)

An existing Denbury pipeline supervisory control and data acquisition (SCADA) control center is being utilized. SCADA is an industrial automation control system that provides control of remote equipment. Field SCADA equipment is located at the Lost Cabin supply station, mainline valve sites, and Bell Creek meter stations. Future pump stations will also have unit control centers that communicate status back to the Denbury SCADA control center. The main center will continuously monitor pipeline pressure and flow conditions at all supply and delivery points. It is programmed to alarm whenever a deviation in pressure or flow indicates an abnormal condition within the pipeline system. The pipeline will be operated and maintained in accordance with industry standards and regulations.

Denbury's pipeline management plans to promote safe, reliable operation include 24-hr monitoring of pipeline operations, aerial and ground surveillance, regular testing of pipelines, an integrity management program, and installation of pipeline marker signs at varying intervals and on both sides of road crossings. Denbury will also work closely with communities along the pipeline route to provide them with current information on emergency response procedures.

DISTRIBUTION AND INJECTION OF CO_2

Typical Surface Facilities for Distribution and Injection of CO_2

Surface facilities at an oil field can provide oil, the main product for sale; water for reinjection; gas for injection or processing to natural gas liquids (NGLs), natural gas for use off-site (called sales gas) or use on-site (called fuel gas), or purified CO_2; and H_2S, which can be converted to sulfur for sale or disposal. The specific products produced at any site depend on the level of processing.

Oil and water are separated in several steps. Initially, a mixture of gas, oil, and water is recovered at the production well and is piped to test separators. At the test separators and production separators, gas, oil, and water are separated and flow rates monitored. Gas is delivered to the CO_2 recovery plant, and oil and water are sent to production separators where the oil and water are separated and more gas is recovered. The gas is sent to the CO_2 recovery facility. At the lease access custody transfer (LACT), additional oil and gas are separated from the oil and the oil is metered into the oil pipeline. At the LACT, gas may be combusted, flared, or sent to the CO_2 recovery plant. During water processing, additional oil and gas are separated from the water and sent to the LACT and CO_2 recovery plant.

The level of processing of the recovered CO_2 varies based on economic and site-specific conditions (for example, the minimum miscibility pressure, or MMP). Full-stream reinjection consists only of dehydration and compression. Partial processing adds partial hydrocarbon recovery (of the C4+ hydrocarbons) to full-stream reinjection. Full processing, in which NGLs and methane are recovered, adds purification of the CO_2 stream to partial processing. Membranes can also be used in full processing.

CO_2 recovery from full processing typically involves cryogenic extractive distillation, the Ryan–Holmes process. In this process, C4+ hydrocarbons are used as a solvent in the distillation separation of CO_2 and methane. This is a difficult separation, with a CO_2 concentration in the methane stream of 12% to 15% of the effective limit.

The most popular processing for CO_2 prior to reinjection is drying and compression (i.e., full-stream reinjection). Partial recovery of the NGLs is not difficult or expensive, but C3 and C2 hydrocarbons should not be removed because methane increases MMP.

Full processing is becoming more popular, with membrane separation for full processing becoming more popular than extractive distillation.

Bell Creek Surface Facilities

The information presented in this section was previously reported in the PCOR Partnership Task 8 Deliverable D49 report entitled "Bell Creek Test Site – Transportation and Injection Operations Report" (Jensen and others, 2015). The information from that report is reprinted here so that all of the Bell Creek project infrastructure information can be found in one document.

The Bell Creek EOR facility follows a scheme in which the water and CO_2 that are separated from the oil are reinjected (full-stream reinjection). Fluids from the individual wells are transported through flow lines and enter the header system of the production manifold in the manifold building. From the production manifold, the commingled stream flows to the process building for separation (Walsh and others, 2013). The oil is piped to oil storage and sales tanks. The water is piped to temporary water storage tanks prior to being pumped back to the field for reinjection. The CO_2 is piped to the compressor building. Following pressurization, the CO_2 discharges back to the manifold building where it is combined with the purchase CO_2 for reinjection (Walsh and others, 2013). Water and CO_2 are distributed to the field through injection manifolds (Walsh and others, 2013). The surface facilities associated with these activities at Bell Creek are shown in Figure 16, and some are discussed in more detail in the following paragraphs.

A production manifold is an arrangement of piping and valves that routes fluid flowing from individual wells to a specific test or separation process (Jarrell and others, 2002). Production manifolds usually are of modular construction and make use of flange connections to enable the system to be expanded or reduced as needed over time during the CO_2 flood (Jarrell and others, 2002). The fluids from each Bell Creek well flow into the low-pressure or high-pressure production system, depending upon the well pressure (Walsh and others, 2013). Each well is individually tested at least once each month to determine its oil, gas, and water volumes, which are then used to allocate total field production. A surface jet pump system is used to reduce the flow line pressure of a well that produces little or no fluid as this should allow the well to begin flowing (Walsh and others, 2013). The jet pump works as follows. Power fluid at a high pressure (but low velocity) is converted to a low pressure, high-velocity jet by the jet pump nozzle. The pressure at the entrance of the throat drops as the power fluid rate is increased. Because the pressure is lower, fluid is drawn from the wellbore (Walsh and others, 2013). A portion of the test site production manifold is shown in Figure 17.

After it is separated from the oil and water, the CO_2 is piped to the compressor building, where there are currently two compressors: one low pressure having a 1.7-MPa (250-psi) suction and the other a high-pressure compressor with a 4.1–5.5-MPa (600–800-psi) suction (Walsh and others, 2013). The interior of the compressor building is shown in Figure 18. The Bell Creek site currently has the capacity to recycle 2.3 million–2.8 million m^3/d at oil and gas standard conditions (80–100 MMscfd) of CO_2, although long-term plans aim to increase the recycle capacity to 8.5 million m^3/d at oil and gas standard conditions (300 MMscfd) through the addition of more compressor trains as field development continues (Walsh and others, 2013). Wells are initially put into the low-pressure system that feeds the low-pressure compressor. Once a well's flow pressure

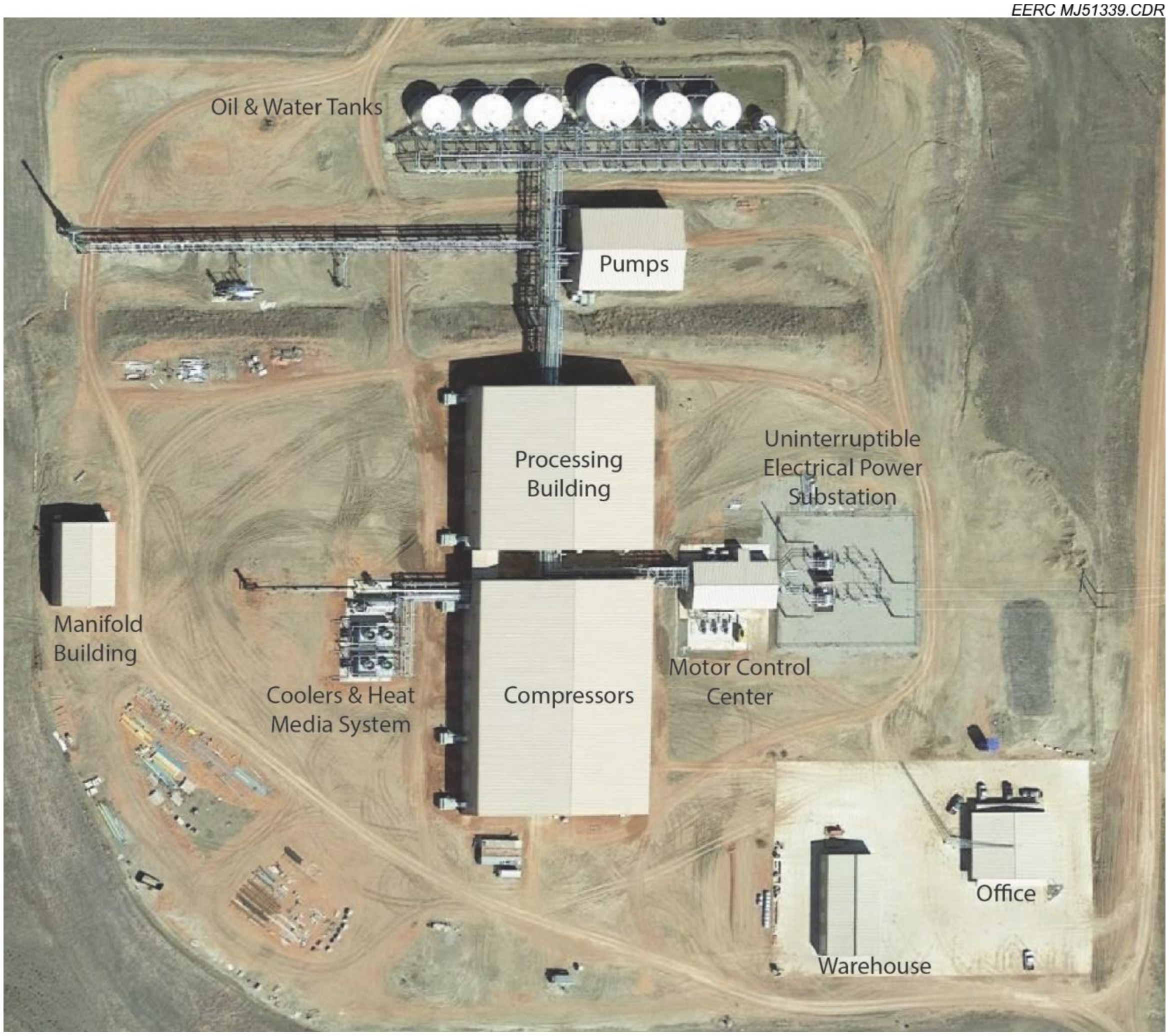

Figure 16. Bell Creek surface facilities (provided by Denbury Resources Inc., 2015).

is high enough, it is fed into the high-pressure system that feeds the high-pressure compressor (Walsh and others, 2013). This is advantageous in terms of power savings. Both compressors have a discharge pressure of slightly less than 13.8 MPa (2000 psi) (Walsh and others, 2013). Therefore, power is saved when the high-pressure compressor can be utilized because the difference between the suction and discharge pressures is not as great as it is for the low-pressure compressor.

The CO_2 returns to the manifold building, the interior of which is shown in Figure 19. As the figure shows, there are two production lines (high-pressure and low-pressure) coming from the field and two lines (recycle CO_2 and produced water) that are returned to the field. The recycle CO_2 is combined with purchase CO_2 then fed to individual wells through the header of the injection manifold (Walsh and others, 2013).

The injection manifold is shown in Figure 20. The bulk CO_2 and water injection lines feed wells through the header. Sweep efficiency and CO_2 utilization rates can be improved within the

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Figure 17. Bell Creek test site production manifold (taken from Rawson, 2014).

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Figure 18. Interior of the Bell Creek compressor building (taken from Walsh and others, 2013).

EERC MJ51342.CDR

Figure 19. Interior of the Bell Creek manifold building (taken from Rawson, 2014).

EERC MJ51343.CDR

Figure 20. An injection manifold at Bell Creek (taken from Rawson, 2014).

reservoir by alternating the injection of water and CO_2, a process called WAG (water alternating gas). The injection pressure for both water and CO_2 is slightly less than 13.8 MPa (2000 psi) (Walsh and others, 2013). Each well can inject either CO_2 or water by the opening or closing of valves attached to the bulk line. Rates and pressures are monitored at the test site or in the control center in the operations building. Rates are adjusted at the test site (Walsh and others, 2013).

As of September 2013, 26,822 m (88,000 ft) of bulk lines that are 15.2, 20.3, and 25.4 cm (6, 8, and 10 in.) in diameter; 58,522 m (192,000 ft) of 7.6-cm (3-in.) diameter injection line; and 55,169 m (181,000 ft) of 7.6-cm (3-in.) diameter production line had been installed (Walsh and others, 2013). Figure 21 shows the bulk lines coming to the surface facility from Test Site 1 during their construction.

This is the first Denbury project where the process is totally enclosed, which is necessary because of the cold winters. A heat media system (shown in Figure 22 during its construction) was built to reduce or eliminate the expense of stand-alone heating systems. Radiator fluid is pumped in a closed-loop system, capturing heat from the process operations such as the compressors. This is used to heat the storage tanks, vessels, and all buildings (Walsh and others, 2013).

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Figure 21. Bulk lines coming into the Bell Creek surface facility from Test Site 1 (taken from Walsh and others, 2013).

EERC MJ51345.CDR

Figure 22. Bell Creek heat media system during its construction (taken from Walsh and others, 2013).

Bell Creek Field Wells

The Bell Creek Field includes both producer and injector CO_2 wellhead configurations. The two wellhead configurations are shown in Figures 23 and 24. Each of these is equipped with remote terminal units (RTUs) to send wellhead data back to the SCADA system (Walsh and others, 2013). The pressure on tubing and all casing strings is monitored continuously, with any abnormal casing pressure flagged for attention (Walsh and others, 2013). Each well has a surface safety valve (SSV) that will shut in the well should a flow line leak (exhibited by low pressure) or a plugged flow line (exhibited by high pressure) be detected. Wells also can be shut in remotely should it be necessary (Walsh and others, 2013). Capillary strings are incorporated into the producer wells, allowing chemical treatment of the production stream near the perforations (Walsh and others, 2013).

CO_2 Delivered to the Bell Creek Field

The average CO_2 fraction of the purchase gas stream (i.e., the CO_2 arriving at the Bell Creek Field via the Greencore pipeline) averages 0.98. As of December 31, 2015, 4.275 million tonnes of CO_2 had been injected into the Bell Creek Field, with 2.753 million tonnes (corrected for a gas composition of approximately 98% CO_2) stored in the field as of the same date. The oil that has been produced at the Bell Creek Field (as of December 31, 2015) totals 1.953 million barrels.

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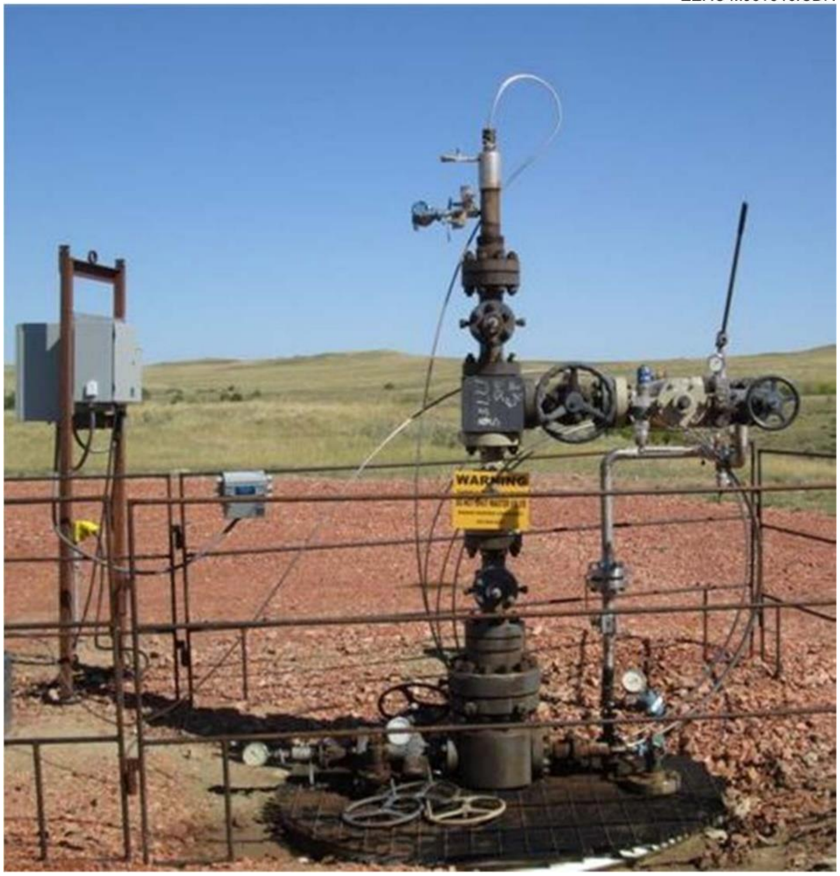

Figure 23. Producer well with capillary string (taken from Rawson, 2014).

CONCLUSIONS AND RECOMMENDATIONS

The infrastructure utilized by the Bell Creek project and described in this report is the type of infrastructure required for any CCS project, although specific pieces may be different. While the Bell Creek project is a commercial EOR project rather than a CCS project, the data being collected during all of its phases will be invaluable in proving the usefulness of the CCS concept as a way to effectively decrease atmospheric CO_2 levels.

EERC MJ51347.CDR

Figure 24. CO_2 or water injector wellhead (taken from Rawson, 2014).

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