APPENDIX 4: OPERATIONAL PROCEDURES 40 CFR 146.82(a)(10)

CTV V

1.0 Document Version History

Version	Revision Date	File Name	Description of Change
1	5/31/2023	Appendix 4 CTV V Op Procedure_v1	Original Submission

2.0 Facility Information

Facility name: CTV V

Facility contact: William Chessum / Technical Director
(562) 999-8380 / William.chessum@crc.com

Location: [redacted]

3.0 Operational Procedures [40 CFR 146.82(a)(10)]

Injectors will be operated to inject the desired target rate of CO_2 over their operating period. Operating procedures for the six planned injectors (three Upper Injection Zone injectors and three Lower Injection Zone injectors) in the project are described below.

3.1 Injector [redacted] Operating Procedures

For an average (target) rate of [redacted] bottom-hole and surface pressures have been estimated for the well over the life of the project. These pressures were estimated using results from the reservoir simulation as an input into the multiphase well nodal analysis software PROSPER by Petroleum Experts, Ltd. PROSPER has been used extensively in CO_2 Enhanced Oil Recovery (EOR) to model CO_2 injection wells. The pressures have been currently calculated assuming a 100% CO_2 stream. Operating conditions will be updated as Carbon TerraVault Holdings, LLC (CTV) defines the injection stream and impurities.

The average bottom-hole and surface injection pressures required for the injector over the course of the project are expected to be 2,395 pounds per square inch (psi) and 1,055 psi, respectively.

The PROSPER modeling was performed with a conservative fracture pressure gradient for the injection zone of 0.76 psi/foot (psi/ft). Using a 10% safety factor, per the U.S. Environmental Protection Agency's (EPA's) guidelines, the maximum bottom-hole pressure (BHP) is 3,707 psi [calculated at the top perforation true vertical depth (TVD)]. Prior to injection, during pre-operational testing, the reservoir fracture gradient will be determined with step-rate testing to confirm maximum injection pressure. During injection, the well will be controlled using automation to never exceed the maximum injection pressure.

The expected beginning and ending pressures for Injector [redacted] are summarized in **Table 1**.

Table 1. Proposed operational conditions for Injector [redacted]

Parameters/Conditions	Limit or Permitted Value	Unit
Maximum Injection Pressure	90% of fracture pressure, using a 0.76 psi/ft frac gradient	
Surface	1,719	psig
Downhole	3,707	psig
Average Injection Rate	[redacted]	MMSCFD
Average Injection Pressure		
Surface	1,055	psig
Downhole	2,395	psig
Maximum Injection Rate	[redacted]	MMSCFD
Injection Rate Range	13-20.8 688-1,101	MMSCFD Tonnes/day
Average Injection Volume and/or Mass	[redacted]	tons
Average Annulus Pressure		
Surface	204	psig
Downhole	2,449	psig
Annulus – Tubing Pressure Differential at Packer	186	psig

3.1.1 Annulus Pressure

Annular pressure between the tubing and production casing above the packer will be maintained to achieve the requirements of 40 CFR 146.88 (c).

The minimum applied annular surface pressure will be maintained at or greater than 100 psi during injection. This ensures a low-pressure alarm can be used to indicate loss of annular pressure as a potential well integrity concern. Surface pressure will be monitored continuously and evaluated according to **Attachment C**: Testing and Monitoring Plan.

CTV will maintain downhole annular pressure at the packer greater than 100 psi above injection pressure for all bottom-hole injection pressures. This pressure differential is achieved by the combination of hydrostatic pressure from annular packer fluid and surface applied annular pressure. As bottom-hole pressure increases throughout the injection phase of the project, annular pressure will be increased to ensure the target differential pressure between the tubing and tubing annulus is maintained at greater than 100 psi.

CTV intends to use 4% KCl completion fluid with corrosion inhibition and biocide as packer fluid.

A 4% KCl fluid is compatible with all well components and is not corrosive. The specific gravity of the packer fluid is estimated to be 1.024.

The range of annular pressures described in **Table 1** are suitable to the well design and will not impact the well integrity or induce formation fracture.

3.1.2 Maximum Injection Rate

Surface wellhead and downhole conditions will be monitored continuously. Injection rate or mass flow is one of the parameters to be monitored at surface. Thresholds will be established based on limitations of well equipment and geological concerns downhole with respect to the target injection rate.

At this time, for this injection well, CTV expects a maximum injection rate of [redacted] and a maximum downhole injection pressure of 3,707 psi (calculated at the top perforation using a 0.76 psi/ft fracture gradient and 10% safety factor). A threshold of 10% below these values will be used to configure automation and alarms, which equates to [redacted] and 3,336 psi. If either threshold is achieved or exceeded, the system will deliver alarms to indicate there is an issue, and CTV will take appropriate steps to ensure the injector resumes operating within acceptable injection rate and pressure ranges.

3.1.3 Shutdown Procedures

Under planned, routine shutdown events (e.g., for well workovers), CTV will reduce CO_2 injection at a rate of [redacted] over a six-day period to ensure protection of health, safety, and the environment.

3.1.4 Automated Shutdown System

Downhole temperature and pressure along with surface flow or mass movement, surface pressure, and temperatures will be monitored in real-time. Data will be collected in an automated system and monitored by a control system with established operating thresholds. After a threshold is observed or exceeded, the software will issue visual, audible, and digital alerts and/or begin with an unload procedure and transition into the shutdown process for appropriate equipment until it is understood why the thresholds were achieved and whether corrective measures must be implemented.

CTV has not established the monitoring system at this time. Upon establishing the system and thresholds CTV will communicate with the EPA.

3.2 Injector [redacted] Operating Procedures

For an average (target) rate of [redacted] bottom-hole and surface pressures have been estimated for the well over the life of the project. These pressures were estimated using results from the reservoir simulation as an input into the multiphase well nodal analysis software, PROSPER by Petroleum Experts, Ltd. PROSPER has been used extensively in CO_2 EOR to model CO_2 injection wells. The pressures have been currently calculated assuming a 100% CO_2 stream. Operating conditions will be updated as CTV defines the injection stream and impurities.

The average bottom-hole and surface injection pressures required for the injector over the course of the project are expected to be 2,887 psi and 1,106 psi respectively.

The PROSPER modeling was performed with a conservative fracture pressure gradient for the injection zone of 0.76 psi/ft. Using a 10% safety factor, per the EPA's guidelines, the maximum allowable BHP is 4,377 psi (calculated at the top perforation TVD). Prior to injection, during pre-operational testing, the reservoir fracture gradient will be determined with step-rate testing to confirm maximum allowable injection pressure. The injection well will be controlled using automation so as to never cross this maximum BHP.

The expected beginning and ending pressures for Injector [redacted] are summarized in **Table 2**.

Table 2. Proposed operational conditions for Injector [redacted]

Parameters/Conditions	Limit or Permitted Value	Unit
Maximum Injection Pressure	90% of fracture pressure, using a 0.76 psi/ft frac gradient	
Surface	2,003	psig
Downhole	4,377	psig
Average Injection Rate	[redacted]	MMSCFD
Average Injection Pressure		
Surface	1,106	psig
Downhole	2,887	psig
Maximum Injection Rate	[redacted]	MMSCFD
Injection Rate Range	7.765-12.42 411-658	MMSCFD Tonnes/day
Average Injection Volume and/or Mass	[redacted]	tons
Average Annulus Pressure		
Surface	258	psig
Downhole	3,079	psig
Annulus – Tubing Pressure Differential at Packer	110	psig

3.2.1 Annulus Pressure

Annular pressure between the tubing and production casing above the packer will be maintained to achieve the requirements of 40 CFR 146.88 (c).

The minimum applied annular surface pressure will be maintained at or greater than 100 psi during injection. This ensures a low-pressure alarm can be used to indicate loss of annular pressure as a potential well integrity concern. Surface pressure will be monitored continuously and evaluated according to **Attachment C**: Testing and Monitoring Plan.

CTV will maintain downhole annular pressure at the packer greater than 100 psi above injection pressure for all bottom-hole injection pressures. This pressure differential is achieved by the combination of hydrostatic pressure from annular packer fluid and surface applied annular pressure. As bottom-hole pressure increases throughout the injection phase of the project, annular pressure will be increased to ensure the target differential pressure between the tubing and tubing annulus is maintained at greater than 100 psi.

CTV intends to use 4% KCl completion fluid with corrosion inhibition and biocide as packer fluid. The 4% KCl is compatible with all well components and is not corrosive. The specific gravity of the packer fluid is estimated to be 1.024.

The range of annular pressures described in **Table 2** are suitable to the well design and will not impact the well integrity or induce formation fracture.

3.2.2 Maximum Injection Rate

Surface wellhead and downhole conditions will be monitored continuously. Injection rate or mass flow is one of the parameters to be monitored at surface. Thresholds will be established based on limitations of well equipment and geological concerns downhole with respect to the target injection rate.

At this time, for this injection, CTV expects a maximum injection rate of [redacted] and a maximum downhole injection pressure of 4,377 psi (calculated at the top perforation using a 0.76 psi/ft fracture gradient and 10% safety factor). A threshold of 10% below these values will be used to configure automation and alarms, which equates to [redacted] and 3,939 psi. If either threshold is achieved or exceeded, the system will deliver alarms to indicate there is an issue and CTV will take appropriate steps to ensure the injector resumes operating within acceptable injection rate and pressure ranges.

3.2.3 Shutdown Procedures

Under planned, routine shutdown events (e.g., for well workovers), CTV will reduce CO_2 injection at a rate of [redacted] over a six-day period to ensure protection of health, safety, and the environment.

3.2.4 Automated Shutdown System

Downhole temperature and pressure along with surface flow or mass movement, surface pressure, and temperatures will be monitored in real time. Data will be collected in an automated system and monitored by a control system with established operating thresholds. After a threshold is observed or exceeded, the software will issue visual, audible, and digital alerts and/or begin with an unload procedure and transition into the shutdown process for appropriate equipment until it is understood why the thresholds were achieved and whether corrective measures must be implemented.

CTV has not established the monitoring system at this time. Upon establishing the system and thresholds CTV will communicate with the EPA.

3.3 Injector [redacted] Operating Procedures

For an average (target) rate of [redacted] bottom-hole and surface pressures have been estimated for the well over the life of the project. These pressures were estimated using results from the reservoir simulation as an input into the multiphase well nodal analysis software, PROSPER by Petroleum Experts, Ltd. PROSPER has been used extensively in CO_2 EOR to model CO_2 injection wells. The pressures have been currently calculated assuming a 100% CO_2 stream.

Operating conditions will be updated as CTV defines the injection stream and impurities.

The average bottom-hole and surface injection pressures required for the injector over the course of the project are expected to be 2,903 psi and 1,233 psi respectively.

The PROSPER modeling was performed with a conservative fracture-pressure gradient for the injection zone of 0.76 psi/ft. Using a 10% safety factor, as per the EPA's guidelines, the maximum allowable BHP is 3,968 psi (calculated at the top perforation TVD). Prior to injection, during pre-operational testing, the reservoir fracture gradient will be determined with step-rate testing to confirm maximum injection pressure. During injection, the well will be controlled using automation to never exceed the maximum BHP.

The expected beginning and ending pressures for Injector [redacted] are summarized in **Table 3**.

Table 3. Proposed operational conditions for Injector [redacted]

Parameters/Conditions	Limit or Permitted Value	Unit
Maximum Injection Pressure	90% of fracture pressure, using a 0.76 psi/ft frac gradient	
Surface	1,830	psig
Downhole	3,968	psig
Average Injection Rate	[redacted]	MMSCFD
Average Injection Pressure		
Surface	1,233	psig
Downhole	2,903	psig
Maximum Injection Rate	[redacted]	MMSCFD
Injection Rate Range	13-20.8 688-1,101	MMSCFD Tonnes/day
Average Injection Volume and/or Mass	[redacted]	tons
Average Annulus Pressure		
Surface	479	psig
Downhole	2,975	psig
Annulus – Tubing Pressure Differential at Packer	153	psig

3.3.1 Annulus Pressure

Annular pressure between the tubing and production casing above the packer will be maintained to achieve the requirements of 40 CFR 146.88 (c).

The minimum applied annular surface pressure will be maintained at or greater than 100 psi during injection. This ensures a low-pressure alarm can be used to indicate loss of annular pressure as a potential well integrity concern. Surface pressure will be monitored continuously and evaluated according to **Attachment C**: Testing and Monitoring Plan.

CTV will maintain downhole annular pressure at the packer greater than 100 psi above injection pressure for all bottom-hole injection pressures. This pressure differential is achieved by the combination of hydrostatic pressure from annular packer fluid and surface applied annular pressure. As bottom-hole pressure increases throughout the injection phase of the project, annular pressure will be increased to ensure the target differential pressure between the tubing and tubing annulus is maintained at greater than 100 psi.

CTV intends to use 4% KCl completion fluid with corrosion inhibition and biocide as packer fluid. The 4% KCl fluid is compatible with all well components and is not corrosive. The specific gravity of the packer fluid is estimated to be 1.024.

The range of annular pressures described in **Table 3** are suitable to the well design and will not impact the well integrity or induce formation fracture.

3.3.2 Maximum Injection Rate

Surface wellhead and downhole conditions will be monitored continuously. Injection rate or mass flow is one of the parameters to be monitored at surface. Thresholds will be established based on limitations of well equipment and geological concerns downhole with respect to the maximum injection rate.

At this time, for this injection well, CTV expects a maximum injection rate of [redacted] and a maximum downhole injection pressure of 3,968 psi (calculated at the top perforation using a 0.76 psi/ft fracture gradient and 10% safety factor). A threshold of 10% below these values will be used to configure automation and alarms, which equates to [redacted] and 3,571 psi. If either threshold is achieved or exceeded, the system will deliver alarms to indicate there is an issue and CTV will take appropriate steps to ensure the injector resumes operating within acceptable injection rate and pressure ranges.

3.3.3 Shutdown Procedures

Under planned, routine shutdown events (e.g., for well workovers), CTV will reduce CO_2 injection at a rate of [redacted] over a six-day period to ensure protection of health, safety, and the environment.

3.3.4 Automated Shutdown System

Downhole temperature and pressure along with surface flow or mass movement, surface pressure, and temperatures will be monitored in real time. Data will be collected in an automated system and monitored by a control system with established operating thresholds. After a threshold is observed or exceeded, the software will issue visual, audible, and digital alerts and/or begin with an unload procedure and transition into the shutdown process for appropriate equipment until it is understood why the thresholds were achieved and whether corrective measures must be implemented.

CTV has not established the monitoring system at this time. Upon establishing the system and thresholds CTV will communicate with the EPA.

3.4 Injector [redacted] Operating Procedures

For an average (target) rate of [redacted] bottom-hole and surface pressures have been estimated for the well over the life of the project. These pressures were estimated using results from the reservoir simulation as an input into the multiphase well nodal analysis software, PROSPER by Petroleum Experts, Ltd. PROSPER has been used extensively in CO_2 EOR to model CO_2 injection wells. The pressures have been currently calculated assuming a 100% CO_2 stream. Operating conditions will be updated as CTV defines the injection stream and impurities.

The average bottom-hole and surface injection pressures required for the injector over the course of the project are expected to be 2,911 psi and 1,112 psi respectively.

The PROSPER modeling was performed with a conservative fracture pressure gradient for the injection zone of 0.76 psi/ft. Using a 10% safety factor, per the EPA's guidelines, the maximum allowable BHP is 4,311 psi (calculated at the top perforation TVD). Prior to injection, during pre-operational testing, the reservoir fracture gradient will be determined with step-rate testing to confirm maximum injection pressure. The injection well will be controlled using automation so as to never cross this maximum BHP.

The expected beginning and ending pressures for Injector [redacted] are summarized in **Table 4.**

Table 4. Proposed operational conditions for Injector [redacted]

Parameters/Conditions	**Limit or Permitted Value**	**Unit**
Maximum Injection Pressure	90% of fracture pressure, using a 0.76 psi/ft frac gradient	
Surface	1,924	psig
Downhole	4,311	psig
Average Injection Rate	[redacted]	MMSCFD
Average Injection Pressure		
Surface	1,112	psig
Downhole	2,911	psig
Maximum Injection Rate	[redacted]	MMSCFD
Injection Rate Range	9.85-15.76 521-834	MMSCFD Tonnes/day
Average Injection Volume and/or Mass	[redacted]	tons
Average Annulus Pressure		
Surface	132	psig
Downhole	2,913	psig
Annulus – Tubing Pressure Differential at Packer	108	psig

3.4.1 Annulus Pressure

Annular pressure between the tubing and production casing above the packer will be maintained to achieve the requirements of 40 CFR 146.88 (c).

The minimum applied annular surface pressure will be maintained at or greater than 100 psi during injection. This ensures a low-pressure alarm can be used to indicate loss of annular pressure as a potential well integrity concern. Surface pressure will be monitored continuously and evaluated according to **Attachment C**: Testing and Monitoring Plan.

CTV will maintain downhole annular pressure at the packer greater than 100 psi above injection pressure for all bottom-hole injection pressures. This pressure differential is achieved by the combination of hydrostatic pressure from annular packer fluid and surface applied annular pressure. As bottom-hole pressure increases throughout the injection phase of the project, annular pressure will be increased to ensure the target differential pressure between the tubing and tubing annulus is maintained at greater than 100 psi.

CTV intends to use 4% KCl completion fluid with corrosion inhibition and biocide as packer fluid. The 4% KCl fluid is compatible with all well components and is not corrosive. The specific gravity of the packer fluid is estimated to be 1.024.

The range of annular pressures described in **Table 4** are suitable to the well design and will not impact the well integrity or induce formation fracture.

3.4.2 Maximum Injection Rate

Surface wellhead and downhole conditions will be monitored continuously. Injection rate or mass flow is one of the parameters to be monitored at surface. Thresholds will be established based on limitations of well equipment and geological concerns downhole with respect to the target injection rate.

At this time, for this injection well, CTV expects a maximum injection rate of [redacted] and a maximum downhole injection pressure of 4,311 psi (calculated at the top perforation using a 0.76 psi/ft fracture gradient and 10% safety factor). A threshold of 10% below these values will be used to configure automation and alarms, which equates to [redacted] and 3,880 psi. If either threshold is achieved or exceeded, the system will deliver alarms to indicate there is an issue and CTV will take appropriate steps to ensure the injector resumes operating within acceptable injection rate and pressure ranges.

3.4.3 Shutdown Procedures

Under planned, routine shutdown events (e.g., for well workovers), CTV will reduce CO_2 injection at a rate of [redacted] over a six-day period to ensure protection of health, safety, and the environment.

3.4.4 Automated Shutdown System

Downhole temperature and pressure along with surface flow or mass movement, surface pressure, and temperatures will be monitored in real time. Data will be collected in an automated system and monitored by a control system with established operating thresholds. After a threshold is observed or exceeded, the software will issue visual, audible, and digital alerts and/or begin with an unload procedure and transition into the shutdown process for appropriate equipment until it is understood why the thresholds were achieved and whether corrective measures must be implemented.

CTV has not established the monitoring system at this time. Upon establishing the system and thresholds CTV will communicate with the EPA.

3.5 Injector [redacted] Operating Procedures

For an average (target) rate of [redacted] bottom-hole and surface pressures have been estimated for the well over the life of the project. These pressures were estimated using results from the reservoir simulation as an input into the multiphase well nodal analysis software, PROSPER by Petroleum Experts, Ltd. PROSPER has been used extensively in CO_2 EOR to model CO_2 injection wells. The pressures have been currently calculated assuming a 100% CO_2 stream. Operating conditions will be updated as CTV defines the injection stream and impurities.

The average bottom-hole and surface injection pressures required for the injector over the course of the project are expected to be 3,348 psi and 1,138 psi respectively.

The PROSPER modeling was performed with a conservative fracture pressure gradient for the injection zone of 0.76 psi/ft. Using a 10% safety factor, per the EPA's guidelines, the maximum allowable BHP 5,018 psi (calculated at the top perforation TVD). Prior to injection, during pre-operational testing, the reservoir fracture gradient will be determined with step-rate testing to confirm maximum injection pressure. The injection well will be controlled using automation so as to never cross this maximum BHP.

The expected beginning and ending pressures for Injector [redacted] are summarized in **Table 5**.

Table 5. Proposed operational conditions for Injector [redacted]

Parameters/Conditions	Limit or Permitted Value	Unit
Maximum Injection Pressure	90% of fracture pressure, using a 0.76 psi/ft frac gradient	
Surface	2,206	psig
Downhole	5,018	psig
Average Injection Rate	[redacted]	MMSCFD
Average Injection Pressure		
Surface	1,138	psig
Downhole	3,348	psig
Maximum Injection Rate	[redacted]	MMSCFD
Injection Rate Range	7.765-12.42 411-658	MMSCFD Tonnes/day
Average Injection Volume and/or Mass	[redacted]	tons
Average Annulus Pressure		
Surface	394	psig
Downhole	3,343	psig
Annulus – Tubing Pressure Differential at Packer	265	psig

3.5.1 Annulus Pressure

Annular pressure between the tubing and production casing above the packer will be maintained to achieve the requirements of 40 CFR 146.88 (c).

The minimum applied annular surface pressure will be maintained at or greater than 100 psi during injection. This ensures a low-pressure alarm can be used to indicate loss of annular pressure as a potential well integrity concern. Surface pressure will be monitored continuously and evaluated according to **Attachment C**: Testing and Monitoring Plan.

CTV will maintain downhole annular pressure at the packer greater than 100 psi above injection pressure for all bottom-hole injection pressures. This pressure differential is achieved by the combination of hydrostatic pressure from annular packer fluid and surface applied annular pressure. As bottom-hole pressure increases throughout the injection phase of the project, annular pressure will be increased to ensure the target differential pressure between the tubing and tubing annulus is maintained at greater than 100 psi.

CTV intends to use 4% KCl completion fluid with corrosion inhibition and biocide as packer fluid. The 4% KCl fluid is compatible with all well components and is not corrosive. The specific gravity of the packer fluid is estimated to be 1.024.

The range of annular pressures described in **Table 5** are suitable to the well design and will not impact the well integrity or induce formation fracture.

3.5.2 Maximum Injection Rate

Surface wellhead and downhole conditions will be monitored continuously. Injection rate or mass flow is one of the parameters to be monitored at surface. Thresholds will be established based on limitations of well equipment and geological concerns downhole with respect to the target injection rate.

At this time, for this injection well, CTV expects a maximum injection rate of [redacted] and a maximum downhole injection pressure of 5,018 psi (calculated at the top perforation using a 0.76 psi/ft fracture gradient and 10% safety factor). A threshold of 10% below these values will be used to configure automation and alarms, which equates to [redacted] and 4,516 psi. If either threshold is achieved or exceeded, the system will deliver alarms to indicate there is an issue and CTV will take appropriate steps to ensure the injector resumes operating within acceptable injection rate and pressure ranges.

3.5.3 Shutdown Procedures

Under planned, routine shutdown events (e.g., for well workovers), CTV will reduce CO_2 injection at a rate of [redacted] over a six-day period to ensure protection of health, safety, and the environment.

3.5.4 Automated Shutdown System

Downhole temperature and pressure along with surface flow or mass movement, surface pressure, and temperatures will be monitored in real time. Data will be collected in an automated system and monitored by a control system with established operating thresholds. After a threshold is observed or exceeded, the software will issue visual, audible, and digital alerts and/or begin with an unload procedure and transition into the shutdown process for appropriate equipment until it is understood why the thresholds were achieved and whether corrective measures must be implemented.

CTV has not established the monitoring system at this time. Upon establishing the system and thresholds CTV will communicate with the EPA.

3.6 Injector [redacted] Operating Procedures

For an average (target) rate of [redacted], bottom-hole and surface pressures have been estimated for the well over the life of the project. These pressures were estimated using results from the reservoir simulation as an input into the multiphase well nodal analysis software, PROSPER by Petroleum Experts, Ltd. PROSPER has been used extensively in CO_2 EOR to model CO_2 injection wells. The pressures have been currently calculated assuming a 100% CO_2 stream. Operating conditions will be updated as CTV defines the injection stream and impurities.

The average bottom-hole and surface injection pressures required for the injector over the course of the project are expected to be 3,206 psi and 1,116 psi respectively.

The PROSPER modeling was performed with a conservative fracture pressure gradient for the injection zone of 0.76 psi/ft. Using a 10% safety factor, as per the EPA's guidelines, the maximum Injection Pressure is 4,759 psi (calculated at the top perforation TVD). Prior to injection, during pre-operational testing, the reservoir fracture gradient will be determined with step-rate testing to confirm maximum injection pressure. During injection, the well will be controlled using automation to never exceed the maximum injection pressure.

The expected beginning and ending pressures for Injector [redacted] are summarized in **Table 6.**

Table 6. Proposed operational conditions for Injector [redacted]

Parameters/Conditions	Limit or Permitted Value	Unit
Maximum Injection Pressure	90% of Fracture pressure, using a 0.76 psi/ft frac gradient	
Surface	2,103	psig
Downhole	4,759	psig
Average Injection Rate	[redacted]	MMSCFD
Average Injection Pressure		
Surface	1,149	psig
Downhole	3,205	psig
Maximum Injection Rate	[redacted]	MMSCFD
Injection Rate Range	10.35-16.56 548-877	MMSCFD Tonnes/day
Average Injection Volume and/or Mass	[redacted]	tons
Average Annulus Pressure		
Surface	313	psig
Downhole	3,232	psig
Annulus – Tubing Pressure Differential at Packer	190	psig

3.6.1 Annulus Pressure

Annular pressure between the tubing and production casing above the packer will be maintained to achieve the requirements of 40 CFR 146.88 (c).

The minimum applied annular surface pressure will be maintained at or greater than 100 psi during injection. This ensures a low-pressure alarm can be used to indicate loss of annular pressure as a potential well integrity concern. Surface pressure will be monitored continuously and evaluated according to **Attachment C**: Testing and Monitoring Plan.

CTV will maintain downhole annular pressure at the packer greater than 100 psi above injection pressure for all bottom-hole injection pressures. This pressure differential is achieved by the combination of hydrostatic pressure from annular packer fluid and surface applied annular pressure. As bottom-hole pressure increases throughout the injection phase of the project, annular pressure will be increased to ensure the target differential pressure between the tubing and tubing annulus is maintained at greater than 100 psi.

CTV intends to use 4% KCl completion fluid with corrosion inhibition and biocide as packer fluid. The 4% KCl fluid is compatible with all well components and is not corrosive. The specific gravity of the packer fluid is estimated to be 1.024.

The range of annular pressures described in **Table 6** are suitable to the well design and will not impact the well integrity or induce formation fracture.

3.6.2 Maximum Injection Rate

Surface wellhead and downhole conditions will be monitored continuously. Injection rate or mass flow is one of the parameters to be monitored at surface. Thresholds will be established based on limitations of well equipment and geological concerns downhole with respect to the target injection rate.

At this time, for this injection well, CTV expects a maximum injection rate of [redacted] and a maximum downhole injection pressure of 4,759 psi (calculated at the top perforation using a 0.76 psi/ft fracture gradient and 10% safety factor). A threshold of 10% below these values will be used to configure automation and alarms, which equates to [redacted] and 4,283 psi. If either threshold is achieved or exceeded, the system will deliver alarms to indicate there is an issue and CTV will take appropriate steps to ensure the injector resumes operating within acceptable injection rate and pressure ranges.

3.6.3 Shutdown Procedures

Under planned, routine shutdown events (e.g., for well workovers), CTV will reduce CO_2 injection at a rate of [redacted] over a six-day period to ensure protection of health, safety, and the environment.

3.6.4 Automated Shutdown System

Downhole temperature and pressure along with surface flow or mass movement, surface pressure, and temperatures will be monitored in real time. Data will be collected in an automated system and monitored by a control system with established operating thresholds. After a threshold is observed or exceeded, the software will issue visual, audible, and digital alerts and/or begin with an unload procedure and transition into the shutdown process for appropriate equipment until it is understood why the thresholds were achieved and whether corrective measures must be implemented.

CTV has not established the monitoring system at this time. Upon establishing the system and thresholds CTV will communicate with the EPA.