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

Document Version History

Version	Revision Date	File Name	Description of Change
1	7/31/2024	Appendix 4 CTV VI Op Procedure_v1	Original Submission
2	8/26/2025	Appendix 4 CTV VI Op Procedure_v2	Response to May 15, 2025 EPA Comments

1. Facility Information

Facility name: CTV VI

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Location: Claimed as PBI [redacted]

2. Operational Procedures [40 CFR 146.82(a)(10)]

Injectors will be operated to inject the desired target rate of carbon dioxide (CO_2) over their operating period. Operating procedures for the seven planned injectors Claimed as PBI [redacted] in the project are described below.

2.1 Injector Claimed as PBI [redacted] *Operating Procedures*

For an average (target) rate of Claimed as PBI [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 calculated assuming a 100 percent 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 2,343 pounds per square inch (psi) and 1,137 psi, respectively.

The expected fracture pressure gradient for the Injection Zone is estimated to be 0.8 pounds per square inch per foot (psi/ft). Using a 10 percent safety factor, per U.S. Environmental Protection Agency (EPA) guidelines, the maximum bottom-hole pressure (BHP) is 3,396 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 0.8 psi/ft frac gradient	
Surface	1,714	psig
Downhole	3,396	psig
Average injection rate	[redacted]	mmscfd
Average injection pressure		
Surface	1,137	psig
Downhole	2,343	psig
Maximum injection rate	[redacted]	mmscfd
Injection rate range	26–52 1,376.8–2,753.6	mmscfd Tonnes per day
Average injection volume and/or mass	[redacted]	MMT
Average annulus pressure		
Surface	375	psig
Downhole	2,434	psig
Annulus – Tubing pressure differential at Packer	109	psig

psi/ft = Pounds per square inch per foot
psig = Pounds per square inch gauge
mmscfd = Million standard cubic feet per day
MMT = Million metric tons

2.1.1 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 that 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** (**Attachment C**).

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 percent potassium chloride (KCl) completion fluid with corrosion inhibition and biocide as packer fluid. 4 percent 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 1** is suitable to the well design, and will not impact the well integrity or induce formation fracture.

2.1.2 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 injection well [redacted] CTV expects a maximum injection rate of [redacted] and a maximum downhole injection pressure of 3,396 psi (calculated at the top perforation using a 0.8 psi/ft fracture gradient and 10 percent safety factor). A threshold of 10 percent below these values will be used to configure automation and alarms, which equates to [redacted] and 3,056 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 that the injector resumes operating within acceptable injection rate and pressure ranges.

2.1.3 Shutdown Procedures

Under planned, routine shutdown events (e.g., for well workovers), CTV will reduce CO_2 injection rate in planned, controlled intervals, to minimize stress on the system, ensuring containment and maintaining safe operations.

2.1.4 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 EPA.

2.2 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 PROSPER. The pressures have been currently calculated assuming a 100 percent CO_2 stream. Operating conditions will be updated as CTV defines the injection stream and impurities.

The average BHP and surface injection pressure required for the injector over the course of the project are expected to be 2,250 psi and 1,129 psi, respectively.

The expected fracture pressure gradient for the Injection Zone is estimated to be 0.8 psi/ft. Using a 10 percent safety factor, per EPA guidelines, the maximum BHP is 3,245 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 2**.

Table 2. Proposed Operational Conditions for Injector Claimed as PBI

Parameters/Conditions	Limit or Permitted Value	Unit
Maximum injection pressure	90% of fracture pressure, using a 0.8 psi/ft frac gradient	
Surface	1,646	psig
Downhole	3,245	psig
Average injection rate	[redacted]	mmscfd
Average injection pressure		
Surface	1,129	psig
Downhole	2,250	psig
Maximum injection rate	[redacted]	mmscfd
Injection rate range	27–54 1,429.7–2,859.4	mmscfd Tonnes/day
Average injection volume and/or mass	[redacted]	MMT
Average annulus pressure		
Surface	375	psig
Downhole	2,343	psig
Annulus – tubing pressure differential at packer	110	psig

2.2.1 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 that 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**.

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 percent KCl completion fluid with corrosion inhibition and biocide as packer fluid. 4 percent 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** is suitable to the well design, and will not impact the well integrity or induce formation fracture.

2.2.2 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 injection well [redacted] CTV expects a maximum injection rate of [redacted] and a maximum downhole injection pressure of 3,245 psi (calculated at the top perforation using a 0.8 psi/ft fracture gradient and 10 percent safety factor). A threshold of 10 percent below these values will be used to configure automation and alarms, which equates to [redacted] and 2,920 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 that the injector resumes operating within acceptable injection rate and pressure ranges.

2.2.3 Shutdown Procedures

Under planned, routine shutdown events (e.g., for well workovers), CTV will reduce CO_2 injection rate in planned, controlled intervals, to minimize stress on the system, ensuring containment and maintaining safe operations.

2.2.4 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 EPA.

2.3 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 PROSPER. The pressures have been currently calculated assuming a 100 percent CO_2 stream. Operating conditions will be updated as CTV defines the injection stream and impurities.

The average BHP and surface injection pressure required for the injector over the course of the project are expected to be 2,267 psi and 1,127 psi, respectively.

The expected fracture pressure gradient for the Injection Zone is estimated to be 0.8 psi/ft. Using a 10 percent safety factor, per EPA guidelines, the maximum BHP is 3,304 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 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 0.8 psi/ft frac gradient	
Surface	1,670	psig
Downhole	3,304	psig
Average injection rate	[redacted]	mmscfd
Average injection pressure		
Surface	1,127	psig
Downhole	2,267	psig
Maximum injection rate	[redacted]	mmscfd
Injection rate range	27–54 1,429.7–2,859.4	mmscfd Tonnes/day
Average injection volume and/or mass	[redacted]	MMT
Average annulus pressure		
Surface	356	psig
Downhole	2,359	psig
Annulus – tubing pressure differential at packer	109	psig

2.3.1 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 that 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**.

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 percent KCl completion fluid with corrosion inhibition and biocide as packer fluid. 4 percent 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 3** is suitable to the well design, and will not impact the well integrity or induce formation fracture.

2.3.2 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 target injection rate.

At this time, for injection well [redacted] CTV expects a maximum injection rate of [redacted] and a maximum downhole injection pressure of 3,304 psi (calculated at the top perforation using a 0.8 psi/ft fracture gradient and 10 percent safety factor). A threshold of 10 percent below these values will be used to configure automation and alarms, which equates to [redacted] and 2,973 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 that the injector resumes operating within acceptable injection rate and pressure ranges.

2.3.3 Shutdown Procedures

Under planned, routine shutdown events (e.g., for well workovers), CTV will reduce CO_2 injection rate in planned, controlled intervals, to minimize stress on the system, ensuring containment and maintaining safe operations.

2.3.4 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 EPA.

2.4 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 PROSPER. The pressures have been currently calculated assuming a 100 percent CO_2 stream. Operating conditions will be updated as CTV defines the injection stream and impurities.

The average BHP and surface injection pressure required for the injector over the course of the project are expected to be 4,026 psi and 1,373 psi, respectively.

The expected fracture pressure gradient for the Injection Zone is estimated to be 0.8 psi/ft. Using a 10 percent safety factor, per EPA guidelines, the maximum BHP is 5,957 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 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 0.8 psi/ft frac gradient	
Surface	2,833	psig
Downhole	5,957	psig
Average injection rate	[redacted]	mmscfd
Average injection pressure		
Surface	1,373	psig
Downhole	4,026	psig
Maximum injection rate	[redacted]	mmscfd
Injection rate range	25–50 1,323.8–2,647.6	mmscfd Tonnes/day
Average injection volume and/or mass	[redacted]	MMT
Average annulus pressure		
Surface	478	psig
Downhole	4,115	psig
Annulus – tubing pressure differential at packer	112	psig

2.4.1 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 that 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**.

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 percent KCl completion fluid with corrosion inhibition and biocide as packer fluid. 4 percent 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 4** is suitable to the well design, and will not impact the well integrity or induce formation fracture.

2.4.2 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 injection well [redacted] CTV expects a maximum injection rate of [redacted] and a maximum downhole injection pressure of 5,957 psi (calculated at the top perforation using a 0.8 psi/ft fracture gradient and 10 percent safety factor). A threshold of 10 percent below these values will be used to configure automation and alarms, which equates to [redacted] and 5,361 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 that the injector resumes operating within acceptable injection rate and pressure ranges.

2.4.3 Shutdown Procedures

Under planned, routine shutdown events (e.g., for well workovers), CTV will reduce CO_2 injection rate in planned, controlled intervals to minimize stress on the system, ensuring containment and maintaining safe operations.

2.4.4 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 EPA.

2.5 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 PROSPER. The pressures have been currently calculated assuming a 100 percent CO_2 stream. Operating conditions will be updated as CTV defines the injection stream and impurities.

The average BHP and surface injection pressure required for the injector over the course of the project are expected to be 3,816 psi and 1,323 psi, respectively.

The expected fracture pressure gradient for the Injection Zone is estimated to be 0.8 psi/ft. Using a 10 percent safety factor, per EPA guidelines, the maximum BHP is 5,697 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 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 0.8 psi/ft frac gradient	
Surface	2,721	psig
Downhole	5,697	psig
Average injection rate	[redacted]	mmscfd
Average injection pressure		
Surface	1,323	psig
Downhole	3,816	psig
Maximum injection rate	[redacted]	mmscfd
Injection rate range	25–50 1,323.8–2,647.6	mmscfd Tonnes/day
Average injection volume and/or mass	[redacted]	MMT
Average annulus pressure		
Surface	344	psig
Downhole	3,906	psig
Annulus – tubing pressure differential at packer	112	psig

2.5.1 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 that 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**.

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 percent KCl completion fluid with corrosion inhibition and biocide as packer fluid. 4 percent 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 5** is suitable to the well design, and will not impact the well integrity or induce formation fracture.

2.5.2 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 injection well [redacted] CTV expects a maximum injection rate of [redacted] and a maximum downhole injection pressure of 5,697 psi (calculated at the top perforation using a 0.8 psi/ft fracture gradient and 10 percent safety factor). A threshold of 10 percent below these values will be used to configure automation and alarms, which equates to [redacted] and 5,127 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.

2.5.3 Shutdown Procedures

Under planned, routine shutdown events (e.g., for well workovers), CTV will reduce CO_2 injection rate in planned, controlled intervals, to minimize stress on the system, ensuring containment and maintaining safe operations.

2.5.4 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.

2.6 Injector Claimed as PBI Operating Procedures

For an average (target) rate of Claimed as PBI 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 PROSPER. The pressures have been currently calculated assuming a 100 percent CO_2 stream. Operating conditions will be updated as CTV defines the injection stream and impurities.

The average BHP and surface injection pressure required for the injector over the course of the project are expected to be 3,896 psi and 1,334 psi, respectively.

The expected fracture pressure gradient for the Injection Zone is estimated to be 0.8 psi/ft. Using a 10 percent safety factor, per EPA guidelines, the maximum BHP is 5,833 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 Claimed as PBI 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 0.8 psi/ft frac gradient	
Surface	2,778	psig
Downhole	5,833	psig
Average injection rate	[redacted]	mmscfd
Average injection pressure		
Surface	1,334	psig
Downhole	3,896	psig
Maximum injection rate	[redacted]	mmscfd
Injection rate range	25–50 1,323.8–2,647.6	mmscfd Tonnes/day
Average injection volume and/or mass	[redacted]	MMT
Average annulus pressure		
Surface	425	psig
Downhole	3,986	psig
Annulus – tubing pressure differential at packer	112	psig

2.6.1 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 that 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**.

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 percent KCl completion fluid with corrosion inhibition and biocide as packer fluid. 4 percent 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 6** is suitable to the well design, and will not impact the well integrity or induce formation fracture.

2.6.2 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 injection well [redacted] CTV expects a maximum injection rate of [redacted] and a maximum downhole injection pressure of 5,833 psi (calculated at the top perforation using a 0.8 psi/ft fracture gradient and 10 percent safety factor). A threshold of 10 percent below these values will be used to configure automation and alarms, which equates to [redacted] and 5,249 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.

2.6.3 Shutdown Procedures

Under planned, routine shutdown events (e.g., for well workovers), CTV will reduce CO_2 injection rate in planned, controlled intervals, to minimize stress on the system, ensuring containment and maintaining safe operations.

2.6.4 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 EPA.

2.7 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 PROSPER. The pressures have been currently calculated assuming a 100 percent CO_2 stream. Operating conditions will be updated as CTV defines the injection stream and impurities.

The average BHP and surface injection pressure required for the injector over the course of the project are expected to be 4,727 psi and 1,568 psi, respectively.

The expected fracture pressure gradient for the Injection Zone is estimated to be 0.8 psi/ft. Using a 10 percent safety factor, per EPA guidelines, the maximum BHP is 6,674 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 7**.

Table 7. Proposed Operational Conditions for Injector [redacted]

Parameters/Conditions	Limit or Permitted Value	Unit
Maximum injection pressure	90% of Fracture pressure, using a 0.8 psi/ft frac gradient	
Surface	3,147	psig
Downhole	6,674	psig
Average injection rate	[redacted]	mmscfd
Average injection pressure		
Surface	1,568	psig
Downhole	4,727	psig
Maximum injection rate	[redacted]	mmscfd
Injection rate range	20–40 1,059–2,118	mmscfd Tonnes/day
Average injection volume and/or mass	[redacted]	MMT
Average annulus pressure		
Surface	737	psig
Downhole	4,816	psig
Annulus – tubing pressure differential at packer	113	psig

2.7.1 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 that 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**.

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 percent KCl completion fluid with corrosion inhibition and biocide as packer fluid. 4 percent 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 7** is suitable to the well design, and will not impact the well integrity or induce formation fracture.

2.7.2 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 injection well [redacted] CTV expects a maximum injection rate of [redacted] and a maximum downhole injection pressure of 6,674 psi (calculated at the top perforation using a 0.8 psi/ft fracture gradient and 10 percent safety factor). A threshold of 10 percent below these values will be used to configure automation and alarms, which equates to [redacted] and 6,006 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.

2.7.3 Shutdown Procedures

Under planned, routine shutdown events (e.g., for well workovers), CTV will reduce CO_2 injection rate in planned, controlled intervals, to minimize stress on the system, ensuring containment and maintaining safe operations.

2.7.4 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 EPA.