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

1.0 Document Version History

Version	Revision Date	File Name	Description of Change
1	4/11/2023	Appendix 4 CTV IV Op Procedure_v1	Original Submission

2.0 Facility Information

Facility name: CTV IV

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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 eight planned injectors (three Upper Injection Zone injectors and five 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 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 1,537 psi and 1,001 psi respectively.

The expected fracture pressure gradient for the injection zone is estimated to be 0.76 psi/ft. Using a 10% safety factor, as per the EPA's guidelines, the maximum bottom hole pressure (BHP) is 2,335 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]1 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	1135	psig
Downhole	2335	psig
Average Injection Rate	[redacted]	MMSCFPD
Average Injection Pressure		
Surface	1001	psig
Downhole	1537	psig
Maximum Injection Rate	[redacted]	MMSCFPD
Injection Rate range	3.0-4.8 159-254	MMSCFPD Tonnes/day
Average Injection Volume and/or Mass	[redacted]	tons
Average Annulus Pressure		
Surface	178	psig
Downhole	1678	psig
Annulus – Tubing pressure differential at Packer	147	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 bottomhole injection pressures. This pressure differential is achieved by the combination of hydrostatic pressure from annular packer fluid and surface applied annular pressure. As bottomhole 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. 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 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 injection well [redacted] CTV expects a maximum injection rate of [redacted] and a maximum downhole injection pressure of 2,335 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 2,101 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 shut down events (e.g., for well workovers), CTV will reduce CO_2 injection at a rate of [redacted] over a 6-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 1,649 psi and 1,048 psi respectively.

The expected fracture pressure gradient for the injection zone is estimated to be 0.76 psi/ft. Using a 10% safety factor, as per the EPA's guidelines, the maximum allowable BHP is 2,459 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	1189	psig
Downhole	2459	psig
Average Injection Rate	[redacted]	MMSCFPD
Average Injection Pressure		
Surface	1048	psig
Downhole	1649	psig
Maximum Injection Rate	[redacted]	MMSCFPD
Injection Rate range	18.0-28.8 953-1525	MMSCFPD Tonnes/day
Average Injection Volume and/or Mass	[redacted]	tons
Average Annulus Pressure		
Surface	199	psig
Downhole	1779	psig
Annulus – Tubing pressure differential at Packer	137	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 bottomhole injection pressures. This pressure differential is achieved by the combination of hydrostatic pressure from annular packer fluid and surface applied annular pressure. As bottomhole 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. 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 1 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 injection well [redacted] CTV expects a maximum injection rate of [redacted] and a maximum downhole injection pressure of 2,459 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 2,240 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 shut down events (e.g., for well workovers), CTV will reduce CO_2 injection at a rate of [redacted] over a 6-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 1,611 psi and 1,008 psi respectively.

The expected fracture pressure gradient for the injection zone is estimated to be 0.76 psi/ft. Using a 10% safety factor, as per the EPA's guidelines, the maximum allowable BHP is 2,467 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	1192	psig
Downhole	2467	psig
Average Injection Rate	[redacted]	MMSCFPD
Average Injection Pressure		
Surface	1008	psig
Downhole	1611	psig
Maximum Injection Rate	[redacted]	MMSCFPD
Injection Rate range	4.0-6.4 212-339	MMSCFPD Tonnes/day
Average Injection Volume and/or Mass	[redacted]	tons
Average Annulus Pressure		
Surface	175	psig
Downhole	1761	psig
Annulus – Tubing pressure differential at Packer	157	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 bottomhole injection pressures. This pressure differential is achieved by the combination of hydrostatic pressure from annular packer fluid and surface applied annular pressure. As bottomhole 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. 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 1 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 injection well [redacted] CTV expects a maximum injection rate of [redacted] and a maximum downhole injection pressure of 2,467 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 2,220 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 shut down events (e.g., for well workovers), CTV will reduce CO_2 injection at a rate of [redacted] over a 6-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 1,885 psi and 1,040 psi respectively.

The expected fracture pressure gradient for the injection zone is estimated to be of 0.76 psi/ft. Using a 10% safety factor, as per the EPA's guidelines, the maximum allowable BHP is 2,836 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	1349	psig
Downhole	2836	psig
Average Injection Rate	[redacted]	MMSCFPD
Average Injection Pressure		
Surface	1040	psig
Downhole	1885	psig
Maximum Injection Rate	[redacted]	MMSCFPD
Injection Rate range	13.8-22.1 731-1170	MMSCFPD Tonnes/day
Average Injection Volume and/or Mass	[redacted]	tons
Average Annulus Pressure		
Surface	265	psig
Downhole	2034	psig
Annulus – Tubing pressure differential at Packer	195	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 bottomhole injection pressures. This pressure differential is achieved by the combination of hydrostatic pressure from annular packer fluid and surface applied annular pressure. As bottomhole 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. 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 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 injection well [redacted], CTV expects a maximum injection rate of [redacted] and a maximum downhole injection pressure of 2,836 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 2,552 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 shut down events (e.g., for well workovers), CTV will reduce CO_2 injection at a rate of [redacted] over a 6-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 1,997 psi and 1,050 psi respectively.

The expected fracture pressure gradient for the injection zone is estimated to be 0.76 psi/ft. Using a 10% safety factor, as per the EPA's guidelines, the maximum allowable BHP 2,993 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	1416	psig
Downhole	2993	psig
Average Injection Rate	[redacted]	MMSCFPD
Average Injection Pressure		
Surface	1050	psig
Downhole	1997	psig
Maximum Injection Rate	[redacted]	MMSCFPD
Injection Rate range	15.8-25.3 837-1340	MMSCFPD Tonnes/day
Average Injection Volume and/or Mass	[redacted]	tons
Average Annulus Pressure		
Surface	249	psig
Downhole	2120	psig
Annulus – Tubing pressure differential at Packer	199	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 bottomhole injection pressures. This pressure differential is achieved by the combination of hydrostatic pressure from annular packer fluid and surface applied annular pressure. As bottomhole 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. 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 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 injection well [redacted] CTV expects a maximum injection rate of [redacted] and a maximum downhole injection pressure of 2,993 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 2,694 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 shut down events (e.g., for well workovers), CTV will reduce CO_2 injection at a rate of [redacted] over a 6-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 1,856 psi and 1,039 psi respectively.

The expected fracture pressure gradient for the injection zone is estimated to be 0.76 psi/ft. Using a 10% safety factor, as per the EPA's guidelines, the maximum Injection Pressure is 2,809 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	1338	psig
Downhole	2809	psig
Average Injection Rate	[redacted]	MMSCFPD
Average Injection Pressure		
Surface	1039	psig
Downhole	1856	psig
Maximum Injection Rate	[redacted]	MMSCFPD
Injection Rate range	13.8-22.1 731-1170	MMSCFPD Tonnes/day
Average Injection Volume and/or Mass	[redacted]	tons
Average Annulus Pressure		
Surface	160	psig
Downhole	1993	psig
Annulus – Tubing pressure differential at Packer	145	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 bottomhole injection pressures. This pressure differential is achieved by the combination of hydrostatic pressure from annular packer fluid and surface applied annular pressure. As bottomhole 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.

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 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 injection well [redacted], CTV expects a maximum injection rate of [redacted] and a maximum downhole injection pressure of 2,809 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 2,528 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 shut down events (e.g., for well workovers), CTV will reduce CO_2 injection at a rate of [redacted] over a 6-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.

3.7 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 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 1,927 psi and 1,042 psi respectively.

The expected fracture pressure gradient for the injection zone is estimated to be 0.76 psi/ft. Using a 10% safety factor, as per the EPA's guidelines, the maximum allowable BHP is 2,865 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 0.76 psi/ft frac gradient	
Surface	1362	psig
Downhole	2865	psig
Average Injection Rate	[redacted]	MMSCFPD
Average Injection Pressure		
Surface	1042	psig
Downhole	1927	psig
Maximum Injection Rate	[redacted]	MMSCFPD
Injection Rate range	13.8-22.1 731-1170	MMSCFPD Tonnes/day
Average Injection Volume and/or Mass	[redacted]	tons
Average Annulus Pressure		
Surface	262	psig
Downhole	2049	psig
Annulus – Tubing pressure differential at Packer	201	psig

3.7.1 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 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 bottomhole injection pressures. This pressure differential is achieved by the combination of hydrostatic pressure from annular packer fluid and surface applied annular pressure. As bottomhole 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. 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 7 are suitable to the well design and will not impact the well integrity or induce formation fracture.

3.7.2 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 2,865 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 2,579 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.

3.7.3 Shutdown Procedures

Under planned, routine shut down events (e.g., for well workovers), CTV will reduce CO_2 injection at a rate of [redacted] over a 6-day period to ensure protection of health, safety, and the environment.

3.7.4 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 the EPA.

3.8 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 2,022 psi and 1,040 psi respectively.

The expected fracture pressure gradient for the injection zone is estimated to be 0.76 psi/ft. Using a 10% safety factor, as per the EPA's guidelines, the maximum allowable BHP is 3,019 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 8.

Table 8. 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	1426	psig
Downhole	3019	psig
Average Injection Rate	[redacted]	MMSCFPD
Average Injection Pressure		
Surface	1040	psig
Downhole	2022	psig
Maximum Injection Rate	[redacted]	MMSCFPD
Injection Rate range	11.8-18.9 625-1001	MMSCFPD Tonnes/day
Average Injection Volume and/or Mass	[redacted]	tons
Average Annulus Pressure		
Surface	202	psig
Downhole	2035	psig
Annulus – Tubing pressure differential at Packer	184	psig

3.8.1 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 bottomhole injection pressures. This pressure differential is achieved by the combination of hydrostatic pressure from annular packer fluid and surface applied annular pressure. As bottomhole 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. 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 8 are suitable to the well design and will not impact the well integrity or induce formation fracture.

3.8.2 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 3,019 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 2,717 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.

3.8.3 Shutdown Procedures

Under planned, routine shut down events (e.g., for well workovers), CTV will reduce CO_2 injection at a rate of [redacted] over a 6-day period to ensure protection of health, safety, and the environment.

3.8.4 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.