OPERATIONAL PROCEDURES [40 CFR 146.82(a)(10)]

CTV III

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Document Version History

Version	Revision Date	File Name	Description of Change
1	5/3/2022	Operational Procedures	Original submission
2	8/4/2022	Operational Procedures V2	
3	5/24/2024	Operational Procedures	Response to February 20, 2024 EPA Comments
4	2/14/2025	Operational Procedures_V4	Response to October 31, 2024 EPA Comments

1. Introduction

Injectors will be operated to inject the desired target rate of CO_2 over the specified operating period. Operating procedures for the 6 planned injectors in the project are described below.

2. Injector C1 Operating Procedures

For a target rate of 52 MMSCFPD, 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 Plume 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.

At the start of injection, a surface and bottom hole injection pressure of 1240 psi and 2934 psi respectively, are required to inject. As the pressure in the reservoir builds up, higher surface and bottom hole pressures will be required. At the end of injection, the estimated surface and bottom hole pressures required are 1395 psi and 3106 psi respectively, which is the maximum pressure CTV expects to operate the well under target rate conditions.

The expected fracture pressure gradient for the injection zone is estimated to be 0.76psi/ft. Using a 10% safety factor, as per the EPA's guidelines, the maximum allowable BHP is 4224 psi (calculated at the top perforation). The injection well will be controlled using automation so as to never cross this maximum BHP. As BHP increases throughout the injection phase of the project, annular pressure will be increased to ensure that the target differential pressure between the tubing and tubing annulus is maintained at greater than 100 psi.

The expected pressures for injector C1 over the life of the project are summarized in Table 1.

Table 1. Proposed operational procedures for Injector C1.

Parameters/Conditions	Limit or Permitted Value	Unit
Maximum Allowable Pressure	Using 0.76psi/ft frac gradient with 10% safety factor	
Surface	2243	Psig
Downhole	4224	Psig
Injection Pressure @ Target rate	Expected range over project	
Surface - Start / End	1240 / 1395	Psig
Downhole - Start / End	2934 / 3106	Psig
Target Injection Rate	52	Mmscfpd
	2754	Tonnes/day
Annulus Pressure	Expected range over project	
Surface - Start / End	100 / 581	Psig
Downhole - Start / End	2725 / 3206	Psig
Annulus / Injection Tubing Pressure Differential	>100	Psig

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 needed.

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. The end annular pressures are equal to the maximum operational annulus pressures.

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 maximum injection rate.

At this time, for injection well C1, CTV expects a target injection rate of 52 million cubic feet per day for which the maximum expected bottom hole injection pressure is 3106 psi. A threshold of 10% over these values will be used to configure automation and alarms, which equates to 57.2 million cubic feet per day and 3417 psi. If either threshold is achieved or exceeded, the system will deliver alarms to indicate there is an issue. Resolution will depend on the type of alarm and systems installed to regulate the injection rate. Typically, this will require a reduction in the injection rate without the need for a shutdown. But the situation will be reviewed to understand what systems failed or did not perform properly and thus created an excessive injection rate.

2.3 Shutdown Procedures

Under routine shutdowns (e.g., for well workovers), CTV will reduce CO_2 injection at a rate of 460 tons per day over a 6-day period to ensure protection of health, safety, and the environment.

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 seen 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 what 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. Injector C2 Operating Procedures

For a target rate of 52 MMSCFPD, 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 Plume 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.

At the start of injection, a surface and bottom hole injection pressure of 1390 psi and 3467 psi respectively, are required to inject. As the pressure in the reservoir builds up, higher surface and bottom hole pressures will be required. At the end of injection, the estimated surface and bottom hole pressures required are 1452 psi and 3485 psi respectively, which is the maximum pressure CTV expects to operate the well under target rate conditions.

The expected fracture pressure gradient for the injection zone is estimated to be 0.76psi/ft. Using a 10% safety factor, as per the EPA's guidelines, the maximum allowable BHP is 4919 psi (calculated at the top perforation). The injection well will be controlled using automation so as to never cross this maximum BHP. As BHP increases throughout the injection phase of the project, annular pressure will be increased to ensure that the target differential pressure between the tubing and tubing annulus is maintained at greater than 100 psi.

The expected pressures for injector C2 over the life of the project are summarized in Table 2.

Table 2. Proposed Operational Procedures for Injector C2

Parameters/Conditions	Limit or Permitted Value	Unit
Maximum Allowable Pressure	Using 0.76psi/ft frac gradient with 10% safety factor	
Surface	2539	Psig
Downhole	4919	Psig
Injection Pressure @ Target rate	Expected range over project	
Surface - Start / End	1390 / 1452	Psig
Downhole - Start / End	3467 / 3485	Psig
Target Injection Rate	52	Mmscfpd
	2754	Tonnes/day
Annulus Pressure	Expected range over project	
Surface - Start / End	100 / 960	Psig
Downhole - Start / End	2725 / 3585	Psig
Annulus / Injection Tubing Pressure Differential	>100	Psig

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 needed.

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 2 are suitable to the well design and will not impact the well integrity or induce formation fracture. The end annular pressures are equal to the maximum operational annulus pressures

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 C1, CTV expects a target injection rate of 52 million cubic feet per day for which the maximum expected bottom hole injection pressure is 3485 psi. A threshold of 10% over these values will be used to configure automation and alarms, which equates to 57.2 million cubic feet per day and 3833 psi. If either threshold is achieved or exceeded, the system will deliver alarms to indicate there is an issue. Resolution will depend on the type of alarm and systems installed to regulate the injection rate. Typically, this will require a reduction in the injection rate without the need for a shutdown. But the situation will be reviewed to understand what systems failed or did not perform properly and thus created an excessive injection rate.

3.3 Shutdown Procedures

Under routine shutdowns (e.g., for well workovers), CTV will reduce CO_2 injection at a rate of 460 tons per day over a 6-day period to ensure protection of health, safety, and the environment.

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 seen 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 what 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.

4. Injector E1 Operating Procedures

For a target rate of 13 MMSCFPD, bottom hole and surface pressures have been estimated for the well over the life of the injection period. These pressures were estimated using results from the Plume 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.

At the start of injection, a surface and bottom hole injection pressure of 1060 psi and 2760 psi respectively, are required. As the pressure in the reservoir builds up, higher surface and bottom hole pressures will be required. At the end of injection, the estimated surface and bottom hole pressures required are 1117 psi and 2791 psi respectively, which is the maximum pressure CTV expects to operate the well under target rate conditions.

The expected fracture pressure gradient for the injection zone is estimated to be 0.76psi/ft. Using a 10% safety factor, as per the EPA's guidelines, the maximum allowable BHP is 4111 psi (calculated at the top perforation). The injection well will be controlled using automation so as to never cross this maximum BHP. As BHP increases throughout the injection phase of the project, annular pressure will be increased to ensure that the target differential pressure between the tubing and tubing annulus is maintained at greater than 100 psi.

The expected pressures for injector E1 over the life of the project are summarized in Table 3.

Table 3. Proposed operational Procedures for Injector E1

Parameters/Conditions	Limit or Permitted Value	Unit
Maximum Allowable Pressure	Using 0.76psi/ft frac gradient with 10% safety factor	
Surface	2300	Psig
Downhole	4111	Psig
Injection Pressure @ Target rate	Expected range over project	
Surface - Start / End	1060 / 1117	Psig
Downhole - Start / End	2760 / 2791	Psig
Target Injection Rate	13	Mmscfpd
	688	Tonnes/day
Annulus Pressure	Expected range over project	
Surface - Start / End	100 / 337	Psig
Downhole - Start / End	2654 / 2891	Psig
Annulus / Injection Tubing Pressure Differential	>100	Psig

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 needed.

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 3 are suitable to the well design and will not impact the well integrity or induce formation fracture. The end annular pressures are equal to the maximum operational annulus pressures.

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 maximum injection rate.

At this time, for injection well C1, CTV expects a target injection rate of 13 million cubic feet per day for which the maximum expected bottom hole injection pressure is 2791 psi. A threshold of 10% over these values will be used to configure automation and alarms, which equates to 14.3 million cubic feet per day and 3070 psi. If either threshold is achieved or exceeded, the system will deliver alarms to indicate there is an issue. Resolution will depend on the type of alarm and systems installed to regulate the injection rate. Typically, this will require a reduction in the injection rate without the need for a shutdown. But the situation will be reviewed to understand what systems failed or did not perform properly and thus created an excessive injection rate.

4.3 Shutdown Procedures

Under routine shutdowns (e.g., for well workovers), CTV will reduce CO_2 injection at a rate of 115 tons per day over a 6-day period to ensure protection of health, safety, and the environment.

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 seen 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 what 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.

5. Injector E2 Operating Procedures

For a target rate of 13 MMSCFPD, bottomhole and surface pressures have been estimated for the well over the life of the injection period. These pressures were estimated using results from the Plume 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.

At the start of injection, a surface and bottom hole injection pressure of 1140 psi and 3210 psi respectively, are required. As the pressure in the reservoir builds up, higher surface and bottom hole pressures will be required. At the end of injection, the estimated surface and bottom hole pressures required are 1186 psi and 3270 psi respectively, which is the maximum pressure CTV expects to operate the well under target rate conditions.

The expected fracture pressure gradient for the injection zone is estimated to be 0.76psi/ft. Using a 10% safety factor, as per the EPA's guidelines, the maximum allowable BHP is 4776 psi (calculated at the top perforation). The injection well will be controlled using automation so as to never cross this maximum BHP. As BHP increases throughout the injection phase of the project, annular pressure will be increased to ensure that the target differential pressure between the tubing and tubing annulus is maintained at greater than 100 psi.

The expected pressures for injector E2 over the life of the project are summarized in Table 4.

Table 4. Proposed Operational Procedures for Injector E2

Parameters/Conditions	Limit or Permitted Value	Unit
Maximum Allowable Pressure	Using 0.76psi/ft frac gradient with 10% safety factor	
Surface	2254	Psig
Downhole	4776	Psig
Injection Pressure @ Target rate	Expected range over project	
Surface - Start / End	1140 / 1186	Psig
Downhole - Start / End	3210 / 3270	Psig
Target Injection Rate	13	Mmscfpd
	688	Tonnes/day
Annulus Pressure	Expected range over project	
Surface - Start / End	100 / 816	Psig
Downhole - Start / End	2654 / 3370	Psig
Annulus / Injection Tubing Pressure Differential	>100	Psig

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 needed.

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. The end annular pressures are equal to the maximum operational annulus pressures.

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 maximum injection rate.

At this time, for injection well C1, CTV expects a target injection rate of 13 million cubic feet per day for which the maximum expected bottom hole injection pressure is 3270 psi. A threshold of 10% over these values will be used to configure automation and alarms, which equates to 14.3 million cubic feet per day and 3597 psi. If either threshold is achieved or exceeded, the system will deliver alarms to indicate there is an issue. Resolution will depend on the type of alarm and systems installed to regulate the injection rate. Typically, this will require a reduction in the injection rate without the need for a shutdown. But the situation will be reviewed to understand what systems failed or did not perform properly and thus created an excessive injection rate.

5.3 Shutdown Procedures

Under routine shutdowns (e.g., for well workovers), CTV will reduce CO_2 injection at a rate of 115 tons per day over a 6-day period to ensure protection of health, safety, and the environment.

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 seen 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 what 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.

6. Injector W1 Operating Procedures

For a target rate of 13 MMSCFPD, bottom hole and surface pressures have been estimated for the well over the life of the injection period. These pressures were estimated using results from the Plume 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.

At the start of injection, a surface and bottom hole injection pressure of 1080 psi and 2856 psi respectively, are required. As the pressure in the reservoir builds up, higher surface and bottom hole pressures will be required. At the end of injection, the estimated surface and bottom hole pressures required are 1148 psi and 2903 psi respectively, which is the maximum pressure CTV expects to operate the well under target rate conditions.

The expected fracture pressure gradient for the injection zone is estimated to be 0.76psi/ft. Using a 10% safety factor, as per the EPA's guidelines, the maximum allowable BHP is 4209 psi (calculated at the top perforation). The injection well will be controlled using automation so as to never cross this maximum BHP. As BHP increases throughout the injection phase of the project, annular pressure will be increased to ensure that the target differential pressure between the tubing and tubing annulus is maintained at greater than 100 psi.

The expected pressures for injector W1 over the life of the project are summarized in Table 5.

Table 5. Proposed Operational Procedures for Injector W1

Parameters/Conditions	Limit or Permitted Value	Unit
Maximum Allowable Pressure	Using 0.76psi/ft frac gradient with 10% safety factor	
Surface	2036	Psig
Downhole	4209	Psig
Injection Pressure @ Target rate	Expected range over project	
Surface - Start / End	1080 / 1148	Psig
Downhole - Start / End	2856 / 2903	Psig
Target Injection Rate	13	Mmscfpd
	688	Tonnes/day
Annulus Pressure	Expected range over project	
Surface - Start / End	100 / 303	Psig
Downhole - Start / End	2800 / 3003	Psig
Annulus / Injection Tubing Pressure Differential	>100	Psig

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 needed.

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. The end annular pressures are equal to the maximum operational annulus pressures.

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 maximum injection rate.

At this time, for injection well C1, CTV expects a target injection rate of 13 million cubic feet per day for which the maximum expected bottom hole injection pressure is 2903 psi. A threshold of 10% over these values will be used to configure automation and alarms, which equates to 14.3 million cubic feet per day and 3193 psi. If either threshold is achieved or exceeded, the system will deliver alarms to indicate there is an issue. Resolution will depend on the type of alarm and systems installed to regulate the injection rate. Typically, this will require a reduction in the injection rate without the need for a shutdown. But the situation will be reviewed to understand what systems failed or did not perform properly and thus created an excessive injection rate.

6.3 Shutdown Procedures

Under routine shutdowns (e.g., for well workovers), CTV will reduce CO_2 injection at a rate of 115 tons per day over a 6-day period to ensure protection of health, safety, and the environment.

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 seen 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 what 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.

7. Injector W2 Operating Procedures

For a target rate of 26 MMSCFPD, bottom hole and surface pressures have been estimated for the well over the life of the injection period. These pressures were estimated using results from the Plume 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.

At the start of injection, a surface and bottom hole injection pressure of 1170 psi and 3370 psi respectively, are required. As the pressure in the reservoir builds up, higher surface and bottom hole pressures will be required. At the end of injection, the estimated surface and bottom hole pressures required are 1256 psi and 3420 psi respectively, which is the maximum pressure CTV expects to operate the well under target rate conditions.

The expected fracture pressure gradient for the injection zone is estimated to be 0.76psi/ft. Using a 10% safety factor, as per the EPA's guidelines, the maximum allowable BHP is 4802 psi (calculated at the top perforation). The injection well will be controlled using automation so as to never cross this maximum BHP. As BHP increases throughout the injection phase of the project, annular pressure will be increased to ensure that the target differential pressure between the tubing and tubing annulus is maintained at greater than 100 psi.

The expected pressures for injector W2 over the life of the project are summarized in Table 6.

Table 6. Proposed Operational Procedures for Injector W2

Parameters/Conditions	Limit or Permitted Value	Unit
Maximum Allowable Pressure	Using 0.76psi/ft frac gradient with 10% safety factor	
Surface	2272	Psig
Downhole	4802	Psig
Injection Pressure @ Target rate	Expected range over project	

Surface - Start / End	1170 / 1256	psig
Downhole - Start / End	3370 / 3420	psig
Target Injection Rate	26	mmscfpd
	1377	Tonnes/day
Annulus Pressure	Expected range over project	
Surface - Start / End	100 / 829	psig
Downhole - Start / End	2791 / 3520	psig
Annulus / Injection Tubing Pressure Differential	>100	psig

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 needed.

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. The end annular pressures are equal to the maximum operational annulus pressures.

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 maximum injection rate.

At this time, for injection well W2, CTV expects a target injection rate of 26 million cubic feet per day for which the maximum expected bottom hole injection pressure is 3420 psi. A threshold of 10% over these values will be used to configure automation and alarms, which equates to 28.6 million cubic feet per day and 3762 psi. If either threshold is achieved or exceeded, the system will deliver alarms to indicate there is an issue. Resolution will depend on the type of alarm and systems installed to regulate the injection rate. Typically, this will require a reduction in the injection rate without the need for a shutdown. But the situation will be reviewed to understand what systems failed or did not perform properly and thus created an excessive injection rate.

7.3 Shutdown Procedures

Under routine shutdowns (e.g., for well workovers), CTV will reduce CO_2 injection at a rate of 230 tons per day over a 6-day period to ensure protection of health, safety, and the environment.

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 seen 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 what 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.