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

Facility Information

Facility Name: CTV II

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Well locations: Union Island Gas Field, San Joaquin County, CA
37.86 / -121.42

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 five planned injectors in the project are described below.

1. Injector SONOL SECURITIES 1-A Operating Procedures

For an average (target) rate of 10 million standard cubic feet per day (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 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.

As the injection zone is a depleted Gas reservoir, lower injection pressure are required at the start of the project, and higher injection pressure is expected to be required as the reservoir pressure builds up over the project life. The average bottom hole and surface injection pressures required for the injector over the course of the project is expected to be 3388 psi and 1297 psi respectively.

The expected fracture pressure gradient for the injection zone is estimated to be between 0.7 – 0.8 psi/ft. A conservative assumption of fracture gradient of 0.70 psi/ft is used to estimate the Maximum Injection pressure for the injector. Using a 10% safety factor, as per the EPA's guidelines, the maximum Injection Pressure is 6,043 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 SONOL SECURITIES 1-A are summarized in Table 1.

Table 1: Proposed operational conditions

Parameters/Conditions	Limit or Permitted Value	Unit
Maximum Injection Pressure	90% of Fracture pressure, using a 0.7psi/ft frac gradient	
Surface	2448	psig
Downhole	6043	psig
Average Injection Rate	10	mmscfpd
Average Injection Pressure		
Surface	1297	psig
Downhole	3388	psig
Maximum Injection Rate	15	mmscfpd
Injection Rate range	10-15 530-794	mmscfpd Tonnes/day
Average Injection Volume and/or Mass	4.5 million	tons
Average Annulus Pressure		
Surface	100	psig
Downhole	4635	psig
Annulus – Tubing pressure differential at Packer	1247	psig

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.

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 SONOL SECURITIES 1-A, CTV expects a maximum injection rate of 15 million cubic feet per day and a maximum injection pressure of 6043 psi (calculated at the top perforation using a 0.7psi/ft fracture gradient and a 10% safety factor). To account for fluctuations in rate and pressure in daily operations, a threshold of 10% below the expected maximum injection rate and 10% below the Maximum Injection Pressure will be used to configure automation and alarms, which equates to 13.5 million cubic feet per day and 5,439 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.

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 ~1.7 mmscfpd over a 6-day period to ensure protection of health, safety, and the environment.

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.

2. Injector SONOL SECURITIES 3 Operating Procedures

For an average (target) rate of 10 million standard cubic feet per day (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 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.

As the injection zone is a depleted Gas reservoir, lower injection pressures are required at the start of the project, and higher injection pressure is expected to be required as the reservoir pressure builds up over the project life. The average bottom hole and surface injection pressures required for the injector over the course of the project are expected to be 3372 psi and 1274 psi respectively.

The expected fracture pressure gradient for the injection zone is estimated to be between 0.7 – 0.8 psi/ft. A conservative assumption of fracture gradient of 0.70 psi/ft is used to estimate the Maximum Injection pressure for the injector. Using a 10% safety factor, as per the EPA's guidelines, the maximum Injection Pressure is 6,061 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 SONOL SECURITIES 3 are summarized in Table 2.

Table 2: Proposed operational conditions

Parameters/Conditions	Limit or Permitted Value	Unit
Maximum Injection Pressure	90% of Fracture pressure, using a 0.7psi/ft frac gradient	
Surface	2447	psig
Downhole	6061	psig
Average Injection Rate	10	mmscfpd
Average Injection Pressure		
Surface	1274	psig
Downhole	3372	psig
Maximum Injection Rate	15	mmscfpd
Injection Rate range	10-15 530-794	mmscfpd Tonnes/day
Average Injection Volume and/or Mass	4.5 million	tons
Average Annulus Pressure		
Surface	100	psig
Downhole	4649	psig
Annulus – Tubing pressure differential at Packer	1277	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 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 2 are suitable to the well design and will not impact the well integrity or induce formation fracture.

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 SONOL SECURITIES 3, CTV expects a maximum injection rate of 15 million cubic feet per day and a maximum injection pressure of 6061 psi (calculated at the top perforation using a 0.7psi/ft fracture gradient and a 10% safety factor). To account for fluctuations in rate and pressure in daily operations, a threshold of 10% below the expected maximum injection rate and 10% below the Maximum Injection Pressure will be used to configure automation and alarms, which equates to 13.5 million cubic feet per day and 5,455 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.

2.3 Shutdown Procedures

Under planned, routine shut down situations (e.g., for well workovers), CTV will reduce CO_2 injection at a rate of ~1.7 mmscfpd 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 Pool B-2 Operating Procedures

For an average (target) rate of 10 million standard cubic feet per day (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 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.

As the injection zone is a depleted Gas reservoir, lower injection pressures are required at the start of the project, and higher injection pressure is expected to be required as the reservoir pressure builds up over the project life. The average bottom hole and surface injection pressures required for the injector over the course of the project are expected to be 3065 psi and 1098 psi respectively.

The expected fracture pressure gradient for the injection zone is estimated to be between 0.7 – 0.8 psi/ft. A conservative assumption of fracture gradient of 0.70 psi/ft is used to estimate the Maximum Injection pressure for the injector. Using a 10% safety factor, as per the EPA's guidelines, the maximum Injection Pressure is 6,178 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 Pool B-2 are summarized in Table 3.

Table 3: Proposed operational conditions

Parameters/Conditions	Limit or Permitted Value	Unit
Maximum Injection Pressure	90% of Fracture pressure, using a 0.7psi/ft frac gradient	
Surface	2471	psig
Downhole	6178	psig
Average Injection Rate	10	mmscfpd
Average Injection Pressure		
Surface	1098	psig
Downhole	3065	psig
Maximum Injection Rate	15	mmscfpd
Injection Rate range	10-15 530-794	mmscfpd Tonnes/day
Average Injection Volume and/or Mass	4.5 million	tons
Average Annulus Pressure		
Surface	100	psig
Downhole	4356	psig
Annulus – Tubing pressure differential at Packer	1291	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 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 3 are suitable to the well design and will not impact the well integrity or induce formation fracture.

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 Pool B-2, CTV expects a maximum injection rate of 15 million cubic feet per day and a maximum injection pressure of 6178 psi (calculated at the top perforation using a 0.7psi/ft fracture gradient and a 10% safety factor). To account for fluctuations in rate and pressure in daily operations, a threshold of 10% below the expected maximum injection rate and 10% below the Maximum Injection Pressure will be used to configure automation and alarms, which equates to 13.5 million cubic feet per day and 5,560 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 Shutdown Procedures

Under planned, routine shut down situations (e.g., for well workovers), CTV will reduce CO_2 injection at a rate of ~1.7 mmscfpd 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 UI-INJ-1 Operating Procedures

For an average (target) rate of 10 million standard cubic feet per day (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 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.

As the injection zone is a depleted Gas reservoir, lower injection pressures are required at the start of the project, and higher injection pressure is expected to be required as the reservoir pressure builds up over the project life. The average bottom hole and surface injection pressures required for the injector over the course of the project are expected to be 2960 psi and 1080 psi respectively.

The expected fracture pressure gradient for the injection zone is estimated to be between 0.7 – 0.8 psi/ft. A conservative assumption of fracture gradient of 0.70 psi/ft is used to estimate the Maximum Injection pressure for the injector. Using a 10% safety factor, as per the EPA's guidelines, the maximum Injection Pressure is 6,163 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 UI-INJ-1 are summarized in Table 4.

Table 4: Proposed operational conditions

Parameters/Conditions	Limit or Permitted Value	Unit
Maximum Injection Pressure	90% of Fracture pressure, using a 0.7psi/ft frac gradient	
Surface	2465	psig
Downhole	6163	psig
Average Injection Rate	10	mmscfpd
Average Injection Pressure		
Surface	1080	psig
Downhole	2960	psig
Maximum Injection Rate	15	mmscfpd
Injection Rate range	10-15 530-794	mmscfpd Tonnes/day
Average Injection Volume and/or Mass	4.5 million	tons
Average Annulus Pressure		
Surface	100	psig
Downhole	4342	psig
Annulus – Tubing pressure differential at Packer	1382	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 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.

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 UI-INJ-1, CTV expects a maximum injection rate of 15 million cubic feet per day and a maximum injection pressure of 6163 psi (calculated at the top perforation using a 0.7psi/ft fracture gradient and a 10% safety factor). To account for fluctuations in rate and pressure in daily operations, a threshold of 10% below the expected maximum injection rate and 10% below the Maximum Injection Pressure will be used to configure automation and alarms, which equates to 13.5 million cubic feet per day and 5,547 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.

4.3 Shutdown Procedures

Under planned, routine shut down situations (e.g., for well workovers), CTV will reduce CO_2 injection at a rate of ~1.7 mmscfpd 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 UI-INJ-2 Operating Procedures

For an average (target) rate of 10 million standard cubic feet per day (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 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.

As the injection zone is a depleted Gas reservoir, lower injection pressures are required at the start of the project, and higher injection pressure is expected to be required as the reservoir pressure builds up over the project life. The average bottom hole and surface injection pressures required for the injector over the course of the project are expected to be 3005 psi and 1092 psi respectively.

The expected fracture pressure gradient for the injection zone is estimated to be between 0.7 – 0.8 psi/ft. A conservative assumption of fracture gradient of 0.70 psi/ft is used to estimate the Maximum Injection pressure for the injector. Using a 10% safety factor, as per the EPA's guidelines, the maximum Injection Pressure is 6,146 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 UI-INJ-2 are summarized in Table 5.

Table 5: Proposed operational conditions

Parameters/Conditions	Limit or Permitted Value	Unit
Maximum Injection Pressure	90% of Fracture pressure, using a 0.7psi/ft frac gradient	
Surface	2472	psig
Downhole	6146	psig
Average Injection Rate	10	mmscfpd
Average Injection Pressure		
Surface	1092	psig
Downhole	3005	psig
Maximum Injection Rate	15	mmscfpd
Injection Rate range	10-15 530-794	Mmscfpd Tonnes/day
Average Injection Volume and/or Mass	4.5 million	tons
Average Annulus Pressure		
Surface	100	psig
Downhole	4365	psig
Annulus – Tubing pressure differential at Packer	1360	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 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.

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 Pool B-2, CTV expects a maximum injection rate of 15 million cubic feet per day and a maximum injection pressure of 6178 psi (calculated at the top perforation using a 0.7psi/ft fracture gradient and a 10% safety factor). To account for fluctuations in rate and pressure in daily operations, a threshold of 10% below the expected maximum injection rate and 10% below the Maximum Injection Pressure will be used to configure automation and alarms, which equates to 13.5 million cubic feet per day and 5,531 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.

5.3 Shutdown Procedures

Under planned, routine shut down situations (e.g., for well workovers), CTV will reduce CO_2 injection at a rate of ~1.7 mmscfpd 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.