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

Facility Information

Facility Name: CTV II

Facility Contact: Will Chessum/Technical Manager
(562) 999-8380/William.chessum@crc.com

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

1. Introduction

Injectors will be operated to inject the desired target rate of carbon dioxide (CO_2) over their operating period. Operating procedures for the five planned injectors in the project are described in the following sections.

2. Injector UI-INJ-1 Operating Procedures

For an average (target) rate of 10 mmscfd, bottom-hole and surface pressures have been estimated for the well over the life of the project. These pressures were estimated using results from the reservoir simulation as an input into PROSPER. The pressures have been currently calculated assuming a 100 percent CO_2 stream. Operating conditions will be updated as CTV defines the injection stream and impurities.

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 2,960 pounds per square inch (psi) and 1,080 psi, respectively.

The expected fracture pressure gradient for the injection zone is estimated to be between 0.7 and 0.8 pounds per square inch per foot (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 percent safety factor per EPA 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 1.

Table 1. Proposed Operational Conditions, UI-INJ-1

Parameters/Conditions	Limit or Permitted Value	Unit
Maximum Injection Pressure	90% of Fracture pressure, using a 0.7 psi/ft frac gradient	
Surface	2,465	psig
Downhole	6,163	psig
Average Injection Rate	10	mmscfd
Average Injection Pressure		
Surface	1,080	psig
Downhole	2,960	psig
Maximum Injection Rate	15	mmscfd
Injection Rate range	10-15 530-794	mmscfd Tonnes/day
Average Injection Volume and/or Mass	4.5 million	tons
Average Annulus Pressure		
Surface	100	psig
Downhole	4,477	psig
Annulus – Tubing pressure differential at Packer	221	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 that a low-pressure alarm can be used to indicate loss of annular pressure as a potential well integrity concern. Surface pressure will be monitored continuously and evaluated according to **Attachment C**.

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

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

The range of annular pressures described in Table 1 is 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 UI-INJ-1, CTV expects a maximum injection rate of 15 mmcfd and a maximum injection pressure of 6,163 psi (calculated at the top perforation using a 0.7 psi/ft fracture gradient and a 10 percent safety factor). To account for fluctuations in rate and pressure in daily operations, a threshold of 10 percent below the expected maximum injection rate and 10 percent below the maximum injection pressure will be used to configure automation and alarms, which equates to 13.5 mmcfd 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 as defined in the Injection Well Monitoring Equipment Failure section of **Attachment F** to ensure that the injector resumes operating within acceptable injection rate and pressure ranges.

2.3 Shutdown Procedures

Under planned, routine shutdown 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 UI-INJ-2 Operating Procedures

For an average (target) rate of 10 mmscfd, bottom-hole and surface pressures have been estimated for the well over the life of the project. These pressures were estimated using results from the reservoir simulation as an input into PROSPER. The pressures have been currently calculated assuming a 100 percent CO_2 stream. Operating conditions will be updated as CTV defines the injection stream and impurities.

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 3,005 psi and 1,092 psi, respectively.

The expected fracture pressure gradient for the injection zone is estimated to be between 0.7 and 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 percent safety factor per EPA 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 2.

Table 2. Proposed Operational Conditions, UI-INJ-2

Parameters/Conditions	Limit or Permitted Value	Unit
Maximum Injection Pressure	90% of fracture pressure, using a 0.7 psi/ft frac gradient	
Surface	2,472	psig
Downhole	6,146	psig
Average Injection Rate	10	mmscfd
Average Injection Pressure		
Surface	1,092	psig
Downhole	3,005	psig
Maximum Injection Rate	15	mmscfd
Injection Rate range	10-15 530-794	mmscfd Tonnes/day
Average Injection Volume and/or Mass	4.5 million	tons
Average Annulus Pressure		
Surface	100	psig
Downhole	4,481	psig
Annulus – Tubing pressure differential at Packer	181	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 that a low-pressure alarm can be used to indicate loss of annular pressure as a potential well integrity concern. Surface pressure will be monitored continuously and evaluated according to **Attachment C**.

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

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

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

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 UI-INJ-2, CTV expects a maximum injection rate of 15 mmcfd and a maximum injection pressure of 6,146 psi (calculated at the top perforation using a 0.7 psi/ft fracture gradient and a 10 percent safety factor). To account for fluctuations in rate and pressure in daily operations, a threshold of 10 percent below the expected maximum injection rate and 10 percent below the maximum injection pressure will be used to configure automation and alarms, which equates to 13.5 mmcfd 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 as defined in the Injection Well Monitoring Equipment Failure section of **Attachment F** to ensure that the injector resumes operating within acceptable injection rate and pressure ranges.

3.3 Shutdown Procedures

Under planned, routine shutdown situations (e.g., for well workovers), CTV will reduce CO_2 injection at a rate of ~1.7 mmscfd 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-3 Operating Procedures

For an average (target) rate of 10 mmscfd, bottom-hole and surface pressures have been estimated for the well over the life of the project. These pressures were estimated using results from the reservoir simulation as an input into PROSPER. The pressures have been currently calculated assuming a 100 percent CO_2 stream. Operating conditions will be updated as CTV defines the injection stream and impurities.

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 3,009 psi and 1,100 psi, respectively.

The expected fracture pressure gradient for the injection zone is estimated to be between 0.7 and 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 percent safety factor per EPA guidelines, the maximum injection pressure is 6,142 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-3 are summarized in Table 3.

Table 3. Proposed Operational Conditions, UI-INJ-3

Parameters/Conditions	Limit or Permitted Value	Unit
Maximum Injection Pressure	90% of Fracture pressure, using a 0.7psi/ft frac gradient	
Surface	2,639	psig
Downhole	6,142	psig
Average Injection Rate	10	mmscfd
Average Injection Pressure		
Surface	1,100	psig
Downhole	3,009	psig
Maximum Injection Rate	15	mmscfd
Injection Rate range	10-15 530-794	mmscfd Tonnes/day
Average Injection Volume and/or Mass	4.5 million	tons
Average Annulus Pressure		
Surface	100	psig
Downhole	4,445	psig
Annulus – Tubing pressure differential at Packer	232	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 that a low-pressure alarm can be used to indicate loss of annular pressure as a potential well integrity concern. Surface pressure will be monitored continuously and evaluated according to **Attachment C**.

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

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

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

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-3, CTV expects a maximum injection rate of 15 mmcfd and a maximum injection pressure of 6,142 psi (calculated at the top perforation using a 0.7 psi/ft fracture gradient and a 10 percent safety factor). To account for fluctuations in rate and pressure in daily operations, a threshold of 10 percent 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 mmcfd and 5,528 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 as defined in the Injection Well Monitoring Equipment Failure section of **Attachment F** to ensure that the injector resumes operating within acceptable injection rate and pressure ranges.

4.3 Shutdown Procedures

Under planned, routine shutdown 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-4 Operating Procedures

For an average (target) rate of 10 million standard cubic feet per day (mmscfd), 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 percent CO_2 stream. Operating conditions will be updated as CarbonTerravault Holdings, LLC (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 are expected to be 3,344 psi and 1,298 psi, respectively.

The expected fracture pressure gradient for the injection zone is estimated to be between 0.7 and 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 percent safety factor per U.S. Environmental Protection Agency (EPA) guidelines, the maximum injection pressure is 6,034 psi (calculated at the top perforation true vertical depth [TVD]). Prior to injection, during pre-operational testing, the reservoir fracture gradient will be determined with step-rate testing to confirm maximum injection pressure. During injection, the well will be controlled using automation to never exceed the maximum injection pressure.

The expected beginning and ending pressures for injector UI-INJ-4 are summarized in Table 4.

Table 4. Proposed Operational Conditions, UI-INJ-4

Parameters/Conditions	Limit or Permitted Value	Unit
Maximum Injection Pressure	90% of fracture pressure, using a 0.7 psi/ft frac gradient	
Surface	2,596	psig
Downhole	6,034	psig
Average Injection Rate	10	mmscfd
Average Injection Pressure		
Surface	1,298	psig
Downhole	3,344	psig
Maximum Injection Rate	15	mmscfd
Injection Rate range	10–15 530–794	mmscfd Tonnes/day
Average Injection Volume and/or Mass	4.5 million	tons
Average Annulus Pressure		
Surface	397	psig
Downhole	4,645	psig
Annulus – Tubing pressure differential at Packer	296	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 that a low-pressure alarm can be used to indicate loss of annular pressure as a potential well integrity concern. Surface pressure will be monitored continuously and evaluated according to **Attachment C: Testing and Monitoring Plan** (**Attachment C**).

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

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

The range of annular pressures described in Table 4 is 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 UI-INJ-4, CTV expects a maximum injection rate of 15 million cubic feet per day (mmcfd) and a maximum injection pressure of 6,034 psi (calculated at the top perforation using a 0.7 psi/ft fracture gradient and a 10 percent safety factor). To account for fluctuations in rate and pressure in daily operations, a threshold of 10 percent below the expected maximum injection rate and 10 percent below the maximum injection pressure will be used to configure automation and alarms, which equates to 13.5 mmcfd and 5,430 psi. If either threshold is achieved or exceeded, the system will deliver alarms to indicate there is an issue and CTV will take the appropriate steps as defined in the Injection Well Monitoring Equipment Failure section of **Attachment F: Emergency and Remedial Response Plan** (**Attachment F**) to ensure that the injector resumes operating within acceptable injection rate and pressure ranges.

5.3 Shutdown Procedures

Under planned, routine shutdown events (e.g., for well workovers), CTV will reduce CO_2 injection at a rate of ~1.7 mmscfd 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 observed or exceeded, the software will issue visual, audible, and digital alerts and/or begin with an unload procedure and transition into the shutdown process for appropriate equipment until it is understood why the thresholds were achieved and whether corrective measures must be implemented.

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

6. Injector UI-INJ-5 Operating Procedures

For an average (target) rate of 10 mmscfd, bottom-hole and surface pressures have been estimated for the well over the life of the project. These pressures were estimated using results from the reservoir simulation as an input into PROSPER. The pressures have been currently calculated assuming a 100 percent CO_2 stream. Operating conditions will be updated as CTV defines the injection stream and impurities.

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 3,352 psi and 1,301 psi, respectively.

The expected fracture pressure gradient for the injection zone is estimated to be between 0.7 and 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 percent safety factor per EPA guidelines, the maximum injection pressure is 6,046 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-5 are summarized in Table 5.

Table 5. Proposed Operational Conditions, UI-INJ-5

Parameters/Conditions	Limit or Permitted Value	Unit
Maximum Injection Pressure	90% of Fracture pressure, using a 0.7 psi/ft frac gradient	
Surface	2,599	psig
Downhole	6,046	psig
Average Injection Rate	10	mmscfd
Average Injection Pressure		
Surface	1,301	psig
Downhole	3,352	psig
Maximum Injection Rate	15	mmscfd
Injection Rate range	10-15 530-794	mmscfd Tonnes/day
Average Injection Volume and/or Mass	4.5 million	tons
Average Annulus Pressure		
Surface	404	psig
Downhole	4,645	psig
Annulus – Tubing pressure differential at Packer	303	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 that a low-pressure alarm can be used to indicate loss of annular pressure as a potential well integrity concern. Surface pressure will be monitored continuously and evaluated according to **Attachment C**.

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

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

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

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 UI-INJ-5, CTV expects a maximum injection rate of 15 mmcfd and a maximum injection pressure of 6,046 psi (calculated at the top perforation using a 0.7 psi/ft fracture gradient and a 10 percent safety factor). To account for fluctuations in rate and pressure in daily operations, a threshold of 10 percent below the expected maximum injection rate and 10 percent below the maximum injection pressure will be used to configure automation and alarms, which equates to 13.5 mmcfd and 5,441 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 as defined in the Injection Well Monitoring Equipment Failure section of **Attachment F** to ensure the injector resumes operating within acceptable injection rate and pressure ranges.

6.3 Shutdown Procedures

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