

Attachment F: Emergency and Remedial Response Plan

Facility Information

Project Name: Hoosier #1

Facility Name: Cardinal Ethanol, CCS1

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Well Location: 1554 N. 600 E.
Union City, Randolph County, IN 47390

CO₂ Injection Well Latitude 40.1874°
CCS1) Longitude -84.8646°

Operator: One Carbon Partnership, LP
1554 N. 600 E.
Union City, IN 47390

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List of Acronyms and Abbreviations

AoR	Area of Review
ACZ1	above confining zone monitoring well
BOP	blow out preventer
BHFP	bottomhole flowing pressure
CCS1	injection well
CO ₂	carbon dioxide
Director	US EPA UIC Program Director
EMS	emergency medical services
EPA	Environmental Protection Agency
ERRP	Emergency and Remedial Response Plan
MAIP	maximum allowable injection pressure
O&G	oil and gas
OBS1	deep observation well
OCP	One Carbon Partnership, LP
P&A	plug and abandon or (past tense) plugged and abandoned
psi	pounds per square inch
QASP	Quality Assurance and Surveillance Plan
SCADA	supervisory control and data acquisition
SOP	standard operating procedure
UIC	underground injection control
USDW	underground source of drinking water
USDW1	dedicated lowermost underground source of drinking water monitoring well
USGS	United States Geological Survey

1. Introduction

This Emergency Remedial and Response Plan (ERRP) describes actions that One Carbon Partnership, LP (hereafter referred to as OCP) shall take to address and remediate mechanical integrity issues, seismic events, or other events that could allow for the movement of the injection fluid, annulus fluid, brine, or formation fluid including, but not limited to, the movement of fluid into an underground source of drinking water (USDW) or any other unauthorized zones during the construction, operation, or post-injection site care periods for the Hoosier #1 Project.

In accordance with 40 CFR 146.94(b), if there is evidence that the injected carbon dioxide (CO₂) stream and/or associated pressure front may cause an endangerment to a USDW, OCP must perform the following actions:

1. Initiate shutdown plan for the injection well (CCS1), including immediate cessation of injection.
2. Take all steps reasonably necessary to identify and characterize any release.
3. Notify the Environmental Protection Agency (EPA) Underground Injection Control (UIC) Program Director (Director) of the emergency event within 24 hours.
4. Implement applicable portions of the approved ERRP.

Where the phrase “initiate shutdown plan” is used, the following protocol will be employed: OCP will immediately cease injection, unless OCP determines, in consultation with the Director, that gradual cessation of injection is necessary for safety. As used in this ERRP, the term “wells” unless otherwise specified, refers to the injection well and all monitoring wells. As used in this ERRP, the term “Area of Review” or “AoR” unless otherwise specified, refers to the AoR as defined in the permit.

2. Local Resources and Infrastructure

Per 40 CFR 146.82(a)(2), there are no deep stratigraphic boreholes; State or Federal EPA approved subsurface clean-up sites; springs; surface or subsurface mines; quarries; State, Tribal, or Territory boundaries; or faults known or suspected within the AoR. The injection well, known active and abandoned oil and gas (O&G) wells, surface bodies of water, water wells, other surface features and structures, and roads within the AoR are shown in Figure 1. Lists of the O&G wells within the AoR and water wells within the AoR are included in Attachment B: AoR and Corrective Action Plan.

Table 1 and Figure 1 summarize the local resources and infrastructure within the Area of Review (AoR) that may be affected as a result of an emergency event at the Hoosier #1 Project site; these include shallow USDWs, surface bodies of water, populations centers, and public infrastructure.

Table 1: Local resources and infrastructure.

Local Resources/ Infrastructure	Feature
Shallow Aquifers	• Unconsolidated glacial aquifers composed of glacial till: ○ New Castle Till Aquifer ○ Bluffton Till Aquifer • Maquoketa Group Aquifer System (lowermost USDW).
Surface Bodies of Water	• Shelley Ditch, • Shelly Ditch, • Price Ditch, • Little Ditch, • White River, • Owl Creek, • Little Mississinewa River, • O’Conner Ditch, • Lows Branch, • Harshman Creek, • Miller Creek, and • Several small unnamed tributaries and reservoirs.
Population Centers and Towns	• Harrisville, • Haysville Corner, • Portions of Union City, Indiana, and • Portions of Wayne Township.
Public Infrastructure (religious organizations, parks, etc.)	• Harter Park, • Union City Swimming Pool (within Harter Park), • Harrisville Congregational Christian Church, and • Flyhigh Ministries, Inc.

The Hoosier #1 AoR is defined by the pressure front with the addition of an approximately 0.5-mile buffer (Attachment B: AoR and Corrective Action Plan). Any potential emergency arising from pressure-related brine migration would be within the inner portion of the AoR, and any well-related incident will be spatially restricted to near the well sites. Therefore, any potential emergency that would arise associated with the project will likely be located within the defined AoR, and any impact to public infrastructure in the general vicinity of the project beyond the limits of the AoR is not expected. Public infrastructure in the general vicinity beyond the AoR is shown in Figure 1 and includes schools, religious centers, libraries, medical facilities, and government buildings.

No major water sources or treatment facilities are located within the AoR. Union City, Indiana, has two water treatment facilities located approximately 0.75 and 0.80 miles east of the limit of the AoR (Figure 1). The water treatment facilities are supplied by seven local water wells drilled into unconsolidated glacial aquifers of the New Castle Till and Bluffton Till aquifer systems. These aquifer systems have discontinuous lenses of sand and gravel deposits that comprise the aquifer units. The source wells are outside the project AoR and given their distance from the project and the discontinuous nature of the aquifer systems, it is not expected that they would be impacted by an event associated with the project. Water for the village of Union City, Ohio is provided from the water wells and water treatment facilities in Union City, Indiana.

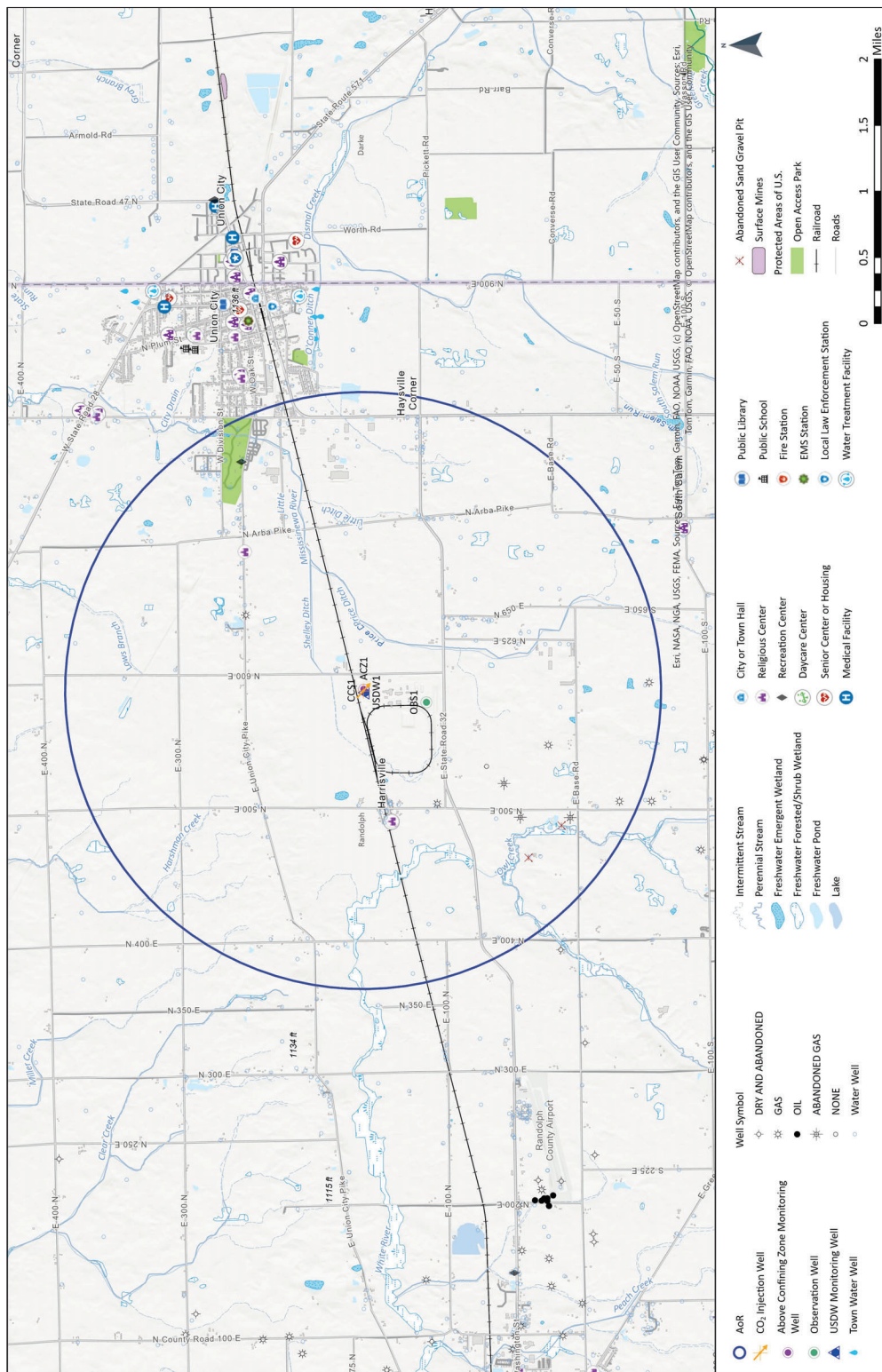


Figure 1. Map of the site resources and infrastructure. Most daycare centers outside of the AoR are co-located with religious centers or schools and not shown separately.

3. Potential Risk Scenarios

The following events related to the Hoosier #1 Project that could potentially result in an emergency response are included in Table 2. This table lists the types of potential adverse incidents that will trigger response actions to protect USDWs and prevent CO₂, brines, annulus fluid, or formation fluid migration into any unauthorized zones if the incidents occur during the construction, injection, or post-injection site care periods. OCP will undertake emergency or remedial actions in response to these incidents. This is a non-exhaustive list of potential risk scenario events.

Table 2: Potential emergency events.

Construction/Pre-injection Period
• Well construction event during drilling or completion with loss of containment. • Evidence suggesting potential leakage to a USDW or other unauthorized zone (including the surface), for example: ◦ Elevated concentrations of indicator parameter(s) in groundwater sample(s) or other evidence suggesting potential fluid leakage into a USDW or other Unauthorized Zone including the surface). ◦ Unanticipated emergency corrective action(s) needed on a well(s) within the AoR. ◦ Evidence of migration of CO₂, brines, annulus fluid, or formation fluid between formations through injection or monitoring well bores. ◦ Evidence of migration of CO₂, brines, annulus fluid, or formation fluid from the injection zone through plugged and abandoned (P&A) wells or undocumented wells in the AoR. ◦ Evidence of migration of CO₂, brines, annulus fluid, or formation fluid from the injection zone through failure of the confining zone, faults, and fractures (loss of containment). ◦ Evidence of migration of CO₂, brines, annulus fluid, or formation fluid from the injection zone, including due to metal leaching or corrosion due to prolonged wetted CO₂ exposure. ◦ Evidence of migration of CO₂, brines, annulus fluid, or formation fluid outside of the AoR. • Severe weather disaster (e.g., tornado, hurricane, lightning strike). • Seismic event. (e.g., natural or induced).
Injection Period
• Mechanical integrity failure, for example: ◦ Loss of internal mechanical integrity due to tubing, packer, or casing leak in injection or monitoring wells. ◦ Loss of external mechanical well integrity due to fluid movement through vertical channels adjacent to well bores. ◦ Loss of external mechanical well integrity from metal leaching or corrosion due to prolonged wetted CO₂ exposure. • Evidence suggesting potential leakage to a USDW or other unauthorized zone (including the surface), for example: ◦ Elevated concentrations of indicator parameter(s) in groundwater sample s) or other evidence suggesting potential fluid leakage into a USDW or other Unauthorized Zone (including the surface). ◦ Unanticipated emergency corrective action(s) needed on a well(s) within the AoR. ◦ Evidence of migration of CO₂, brines, annulus fluid, or formation fluid between formations through injection or monitoring well bores.

◦ Evidence of migration of CO₂, brines, annulus fluid, or formation fluid from the injection zone through plugged and abandoned (P&A) wells or undocumented wells in the AoR. ◦ Evidence of migration of CO₂, brines, annulus fluid, or formation fluid from the injection zone through failure of the confining zone, faults, and fractures (loss of containment). ◦ Evidence of migration of CO₂, brines, annulus fluid, or formation fluid from the injection zone, including due to metal leaching or corrosion due to prolonged wetted CO₂ exposure. ◦ Evidence of migration of CO₂, brines, annulus fluid, or formation fluid outside of the AoR. • Well monitoring equipment failure or malfunction (e.g., all valves and gauges, pressure, and temperature sensors downhole and at the wellheads, etc.). • Severe weather disaster (e.g., tornado, hurricane, lightning strike). • Seismic event (e.g., natural or induced).
Post-injection Site Care Period
• Mechanical integrity failure, for example ◦ Loss of internal mechanical integrity due to tubing, packer, or casing leak in injection or monitoring wells. ◦ Loss of external mechanical well integrity due to fluid movement through vertical channels adjacent to the well bores. • Evidence suggesting potential leakage to a USDW or other unauthorized zone (including the surface , for example: ◦ Elevated concentrations of indicator parameter(s) in groundwater sample(s) or other evidence suggesting potential fluid leakage into a USDW or other Unauthorized Zone (including the surface). ◦ Unanticipated emergency corrective action(s) needed on a well(s) within the AoR. ◦ Evidence of migration of CO₂, brines, annulus fluid, or formation fluid between formations through injection or monitoring well bores. ◦ Evidence of migration of CO₂, brines, annulus fluid, or formation fluid from the injection zone through plugged and abandoned (P&A) wells or undocumented wells in the AoR. ◦ Evidence of migration of CO₂, brines, annulus fluid, or formation fluid from the injection zone through failure of the confining zone, faults, and fractures (loss of containment). ◦ Evidence of migration of CO₂, brines, annulus fluid, or formation fluid from the injection zone, including due to metal leaching or corrosion due to prolonged wetted CO₂ exposure. ◦ Evidence of migration of CO₂, brines, annulus fluid, or formation fluid outside of the AoR. • Well monitoring equipment failure or malfunction (e.g., all valves and gauges, pressure, and temperature sensors downhole and at the wellheads, etc.) • Severe weather disaster (e.g., tornado, hurricane, lightning strike). • Seismic event. (e.g., natural or induced).

4. Emergency Identification and Response Actions

OCP must report to the Director within 24 hours if there is any evidence that the injected CO₂ stream or associated pressure front may cause an endangerment to a USDW, including migration of fluid into an unauthorized zone (40 CFR 146.91(c)(1)); any noncompliance with a Permit Condition, or malfunction of the injection system, which may cause fluid migration into or between USDWs (40 CFR 146.91(c)(2)); any triggering of a shut-off system (i.e. down-hole or at the surface (40 CFR 146.91(c)(3)); and any failure of mechanical integrity (40 CFR 146.91(c)(4)). If required by the Director, any release of CO₂ to the atmosphere or biosphere

must also be reported within 24 hours (40 CFR 146.91(c)(5)); this excludes the release of CO₂ to the atmosphere as a result of well maintenance or workover activities.

Steps to identify and characterize the event will be dependent on the specific issue identified, and the severity of the event. The potential risk scenarios identified in Table 2 are detailed below.

Once equipment placement and location is finalized and prior to injection, a figure will be provided to the Director that displays the following:

- Major facility components,
- Project wells,
- Monitoring equipment,
- Emergency shut down equipment, and
- Flowlines.

It is important to note that in emergency events, emergency services may be contacted prior to any other actions taking place.

Within this ERRP, several mentions are made to evacuation plans. A formal evacuation plan will be provided to EPA prior to commencing injection. Different evacuation plans will be provided for each of the following groups:

- Non-key site personnel,
- Key site personnel,
- Offsite personnel.

In addition, primary and secondary muster points will be provided for each of these groups. This plan will be integrated with the current Cardinal facility evacuation plan. These plans will be provided as part of operator training and dispersed throughout the facility.

Should an event such as a natural disaster, severe fire, or other event occur that requires the evacuation of the ethanol production part of the Cardinal facility and CO₂ production ceases, the control system will automatically shut in the injection well. The only situation when a manual shut-in will be required is if the control system is inoperable, and it is safe to operate the shut-in valves manually. An event at the ethanol production facility that ceases CO₂ production will not be considered an emergency directly related to the project unless the event otherwise triggers the ERRP.

4.1 Well Construction Event

Loss of containment could occur during drilling and completion operations if the hydrostatic column controlling the well decreases below the formation pressure, allowing fluids to enter the well. Table 3 summarizes the expected timing, avoidance measures, and detection methods as well as the expected response actions, required personnel, and equipment needed for a well construction event.

Table 3: Summary of timing, avoidance measures, detection methods, and response actions, personnel, and equipment for a well construction event. Lists are non-exhaustive.

Category	Item
Timing of Event	• Construction/Pre-injection
Avoidance Measures ¹	• Well control training, • Blow out preventer (BOP) equipment and testing protocols, • Kill fluid, • Kick drill, • Lubricators for wireline operations.
Detection Methods	• Flow sensor, • Pressure sensor, • Tank level indicator, • Tripping displacement practices, • Mud weight control.
Response Actions	• Notify the Director about the emergency event within 24 hours. • Stop operation. • Close BOP. • Clear floor and secure area. • Execute well control procedure. • Evaluate drilling parameters and identify root cause.
Response Personnel	• Rig crew • Rig supervisor • OCP operations supervisor • Project manager (notify if not present) • Plant manager (notify if not present) • Third party contractors (i.e., wireline crew), (if present)
Response Equipment	• BOP, • Pressured accumulator, • Full open safety valve, on rig floor, • Mud pump, • Mud weighting agent, • Trip tank, • Casing (if required), • Cement (if required), • High pressure lubricator (if required).
¹ Avoidance and detection measures identified throughout this ERRP do not replace or supersede any terms or conditions of the permit	

4.2 Mechanical Integrity Failure

Loss of integrity in CCS1 and in-zone deep observation well (OBS1) may endanger USDWs through the movement of CO₂, brines, annulus fluid, or formation fluid into an unauthorized zone. Set points for alarms and shutdown points are provided in Table 4. All set points will be updated based on results from Pre-operational Testing Program (Attachment G: Pre-operational Testing Plan).

Further details on the alarm set points are discussed in the Summary of Requirements, Testing and Monitoring Plan, and the Quality Assurance and Surveillance Plan (QASP) - Table 11 (Attachment G: Pre-operational Testing Plan; Attachment A: Summary of Requirements; Attachment K: Quality Assurance and Surveillance Plan).

Bottomhole flowing pressure (BHFP) refers to the pressure at the top of the injection zone during injection. BHFP will be determined by adding the surface or downhole injection pressure to the established hydrostatic correction to determine the BHFP at the top of the injection zone.

Table 4: Operational emergency shut down set points.

Alarm Type		Set Point	Unit
Maximum Injection Pressure, Surface	Maximum allowable injection pressure (MAIP)	2,015	psi
	Shutdown point: 5% less than MAIP ¹	1,910	psi
Maximum Injection Pressure, Bottomhole	Maximum allowable BHFP	2,325	psi
	Shutdown point: 5% less than maximum allowable BHFP ^{1,2}	2,200	psi
Annulus Pressure ¹	Shutdown point: Maximum	1,500	psi
	Shutdown point: Minimum	100	psi
	Shutdown point: Less than minimum allowable annulus-tubing differential	100	psi
¹ Rounded down to the lowest 10. ² May be calculated using surface pressure gauges and determined fluid gradient if approved by the Director.			

Integrity loss may have occurred if the following events occur note, this is not an exhaustive list):

- Automatic shutdown devices are activated Table 4).
- Wellhead pressure exceeds the shutdown pressure specified in the permit and in Table 4. Shutdown pressure limit will be set to 5% less than the maximum allowable injection pressure (MAIP) in the permit.
 - BHFP exceeds the maximum allowable BHFP specified in the permit and in Table 4. Shutdown pressure limit will be 5% less than the maximum allowable BHFP.
 - Annulus pressure indicates a loss of well containment.
 - The annulus pressure is outside (above or below) of the emergency shutdown points detailed in Table 4.
- Mechanical integrity test results identify a loss of mechanical integrity:
 - Loss of mechanical integrity due to a tubing or packer leak in CCS1 or OBS1.
 - Loss of mechanical integrity due to a casing leak in CCS1 and OBS1.

Table 5 summarizes the expected timing, avoidance measures, and detection methods as well as the expected response actions, required personnel, and equipment needed for a mechanical integrity loss event.

Table 5: Summary of timing, avoidance measures, detection methods, and response actions, personnel, and equipment for a mechanical integrity failure. Lists are non-exhaustive.

Category	Item
Timing of Event	• Injection • Post-injection
Avoidance Measures	• Injecting within operational parameters • Utilizing properly rated equipment • Thorough pre-operational assessment of cement, casing, and other materials • Following manufacturer care and safe handling guidance
Detection Methods	• Mechanical integrity testing • Monitoring operational parameters • Inspection of corrosion coupons
Response Actions (CCS1 and OBS1)	• In the case of a shutdown event, OCP will first determine the nature of the shutdown event and whether it was spurious or due to an actual loss of well integrity • If loss of well integrity has occurred, notify the Director about the emergency event within 24 hours of the loss of well integrity (40 CFR 146.94(b) 3); 40 C.F.R. 146.91(c) . • Initiate the shutdown plan (40 CFR 146.94(b)(1) . ○ Shut in the well (all necessary valves closed and locked out . ○ Vent CO₂ from surface lines and CO₂ facility as necessary. ○ Limit access to wellhead and sequestration facilities to only those authorized (caution tape and/or rope may be used to limit access). ○ Monitor wellhead pressure (tubing and annulus) and temperature as is feasible. This information should be used to assess and determine the nature or cause and extent of the mechanical integrity failure. • Identify and implement appropriate remedial actions to repair damage to the well (in consultation with the Director). • If loss of mechanical integrity has resulted in a failure of monitoring equipment, implement response actions from Table 6. • If there is evidence suggesting potential fluid leakage into a USDW or unauthorized zone, implement response actions from Table 8. • Perform mechanical integrity test prior to bringing well back online and resuming injection.
Response Actions (other monitor wells)	Other monitoring wells • Notify the Director about the emergency event within 24 hours (40 CFR 146.94(b); 40 CFR 146.91(c) . • Identify and implement appropriate remedial actions to repair the well (in consultation with the Director). Within 30 days of the event, inform the Direction of the schedule for repairs. • Identify and implement appropriate remedial actions (in consultation with the Director).

Category	Item
Response Personnel	• Facility operations staff • OCP operations supervisor • Project manager • Plant manager • Third party contractors • Rig crew • Rig supervisor
Response Equipment	• Tubing • Cement • Casing patches • Wellhead equipment • Packer • Logging equipment • Workover rig

4.3 Well Monitoring Equipment Failure or Malfunction

The failure of monitoring equipment for wellhead pressure, temperature, and/or annulus pressure, including a malfunctioning monitoring well, may indicate a problem that could pose a risk of endangerment to USDWs. Table 6 summarizes the well monitoring equipment that may fail or malfunction. Table 7 summarizes the expected timing, avoidance measures, and detection methods as well as the expected response actions, required personnel, and equipment needed for a well monitoring equipment failure or malfunction event.

Table 6: Project wells and monitoring equipment that may fail or malfunction

Well	Equipment
CCS1	• Wellhead injection pressure (surface gauge) • Wellhead injection temperature (surface sensor) • Downhole pressure at packer (downhole pressure/temperature gauge) • Downhole temperature at packer (downhole pressure/temperature gauge) • Annulus pressure • Annulus fluid volume • Injection flowrate
OBS1	• Wellhead tubing pressure (surface gauge) • Downhole pressure at packer (downhole pressure/temperature gauge) • Annulus pressure • Annulus fluid volume
ACZ1	• Wellhead pressure
Shallow groundwater wells	• PVC casing collapse

Table 7: Summary of timing, avoidance measures, detection methods, and response actions, personnel, and equipment for a well monitoring equipment failure. Lists are non-exhaustive.

Category	Item
Timing of Event	• Injection • Post-injection
Avoidance Measures	• Utilizing properly rated equipment. • Following all manufacturer handling and operational specifications and guidelines. • Routine maintenance and calibration.
Detection Methods	• Continuous monitoring devices. • Redundant monitoring devices.
Response Actions (CCS1 and OBS1)	• Notify the Director in the event of any failure of well monitoring equipment caused by a well integrity failure within 24 hours (40 CFR 146.94(b)(3); 40 CFR 146.91(c)). Routine repairs of surface well monitoring equipment not associated with well integrity failure will not be reported to the Director as an emergency. • Determine the impact of the event based on the information available within 24 hours of the event occurring. This includes: ○ Assessing the impact of the lost monitoring equipment. ○ Determine and implement a viable alternative monitoring method if surface equipment replacement is not possible within 24 hours. ○ Report this information to the Director. ○ Note that a viable alternative monitoring method is not a substitute for any permit condition, including compliance with the Testing and Monitoring Plan. • If there has been a loss of mechanical integrity, implement response action from Section 4.2 <i>Mechanical Integrity Failure</i>. • Identify and implement appropriate remedial actions to repair the well (in consultation with the Director). • Assess whether there is evidence suggesting potential fluid leakage into a USDW or unauthorized zone, and if there is such evidence, implement Response Actions from Table 8. • Assess the cause of the equipment failure and report the details to the Director within 30 days. • Replacement of equipment (if needed) should be done as soon as is feasible based on operational conditions and suitability of the alternative method of monitoring. • Assess (in consultation with the Director) whether monitoring capabilities at the project are sufficient to ensure non-endangerment to USDWs. If monitoring capabilities are not sufficient, treat the event as an immediate risk and see Response Actions listed below. ○ Initiate the shutdown plan (40 CFR 146.94(b)(1)). ○ Shut in the well (all necessary valves closed and locked out) and isolate monitoring wells. ○ Vent CO₂ from surface lines and CO₂ facility as necessary. ○ Limit access to wellhead and sequestration facilities to only those authorized (caution tape and/or rope may be used to limit access). ○ Monitor wellhead pressure (tubing and annulus) and temperature as is feasible. This information should be used to assess and determine the nature or cause and extent of the mechanical integrity failure
Response Actions	• Notify the Director in the event of any failure of well monitoring

Category	Item
(ACZ1)	equipment caused by a well integrity failure within 24 hours (40 CFR 146.94 b)(3 ; 40 CFR 146.91(c)). Routine repairs of surface well monitoring equipment not associated with well integrity failure will not be reported to the Director as an emergency. • Determine the impact of the event based on the information available within 24 hours of the event occurring. This includes: ○ Assessing the impact of the lost monitoring equipment. ○ Determine and implement a viable alternative monitoring method if surface equipment replacement is not possible within 24 hours. ○ Report this information to the Director. ○ Note that a viable alternative monitoring method is not a substitute for any permit condition, including compliance with the Testing and Monitoring Plan. • If there has been a loss of mechanical integrity, implement response action from Section 4.2 <i>Mechanical Integrity Failure</i>. • Identify and implement appropriate remedial actions to repair the well (in consultation with the Director). • Assess whether there is evidence suggesting potential fluid leakage into a USDW or unauthorized zone, and if there is such evidence, implement Response Actions from Table 8. • Assess the cause of the equipment failure and report the details to the Director within 30 days. • Replacement of equipment (if needed) should be done as soon as is feasible based on operational conditions and suitability of the alternative method of monitoring. • Assess (in consultation with the Director) whether monitoring capabilities at the project are sufficient to ensure non-endangerment to USDWs. If monitoring capabilities are not sufficient, treat the event as an immediate risk and see Response Actions listed below. ○ Initiate the shutdown plan (40 CFR 146.94(b)(1)). ○ Shut in the well (all necessary valves closed and locked out) and isolate monitoring wells. ○ Vent CO₂ from surface lines and CO₂ facility as necessary. ○ Limit access to wellhead and sequestration facilities to only those authorized (caution tape and/or rope may be used to limit access). • Monitor wellhead pressure (tubing and annulus) and temperature as is feasible. This information should be used to assess and determine the nature or cause and extent of the mechanical integrity failure
Response Actions Shallow groundwater wells	• Notify the Director about the event within one week. • Identify an alternative monitoring method as appropriate (in consultation with the Director). • If any of the shallow groundwater wells are damaged or become inaccessible for monitoring: ○ A different existing shallow groundwater well(s) for monitoring will be selected, or ○ A new well(s) will be drilled in an appropriate location.

Category	Item
Response Personnel	• Facility operations staff • OCP operations supervisor • Project manager • Plant manager • Third party contractors • Rig crew (if workover is required) • Rig supervisor (if workover is required)
Response Equipment	• Pressure gauges (if necessary) • Temperature sensors (if necessary) • Logging equipment • Workover rig • Auxiliary temporary monitoring equipment

4.4 Evidence Suggesting Potential Fluid Leakage into a USDW or Other Unauthorized Zone (including the Surface)

Potential CO₂, brine, annulus fluid, or formation fluid leakage to a USDW or other unauthorized zone may endanger USDWs. Table 8 summarizes the expected timing, avoidance measures, and detection methods as well as the expected response actions, required personnel, and equipment needed for a potential fluid leakage event. This scenario includes but is not limited to:

- Elevated concentrations of indicator parameter(s) in groundwater sample(s) or other evidence suggesting potential fluid leakage into a USDW or other unauthorized zone including the surface).
- Unanticipated emergency corrective action(s) needed on a well(s) within the AoR.
- Evidence of migration of CO₂, brine, annulus fluid, or formation fluid between formations through injection, monitoring, or water withdrawal well bores.
- Evidence of migration of CO₂, brine, annulus fluid, or formation fluid from the injection zone through plugged and abandoned wells or through undocumented wells in the AoR.
- Evidence of migration of CO₂, brine, annulus fluid, or formation fluid from the injection zone through failure of the confining zone, faults, and fractures (loss of containment).
- Evidence of migration of CO₂, brine, annulus fluid, or formation fluid from the injection zone, including due to metal leaching or to corrosion due to prolonged wetted CO₂ exposure.
- Evidence of migration of CO₂, brine, annulus fluid, or formation fluid outside of the AoR.

Table 8: Summary of timing, avoidance measures, detection methods, and response actions, personnel, and equipment for scenario when evidence suggests potential fluid leakage into a USDW or other unauthorized zone. Lists are non-exhaustive.

Category	Item
Timing of Event	• Construction/Pre-injection • Injection • Post injection
Avoidance Measures	• Routine mechanical integrity testing • Regular inspection and servicing of valves and surface equipment • Thorough site characterization during the pre-operational and well construction phase • Evaluation of monitoring data • Strict adherence to approved operational parameters • Period surface seismic surveys
Detection Methods	• Surface gas/CO₂ monitors • Continuous monitoring parameters • Routine mechanical integrity testing • Pulsed Neutron Logs • Routine groundwater sampling
Response Actions	If OCP obtains evidence of potential CO₂, brines, annulus fluid, or formation fluid leakage to a USDW or other unauthorized zone, OCP must perform the following actions: • Notify the Director about the emergency event within 24 hours (40 CFR 146.94(b)(3); 40 C.F.R. 146.91(c)). • Initiate the shutdown plan (40 CFR 146.94(b)(1) . ○ Shut in the well (all necessary valves closed and locked out . ○ Vent CO₂ from surface lines and CO₂ facility as necessary. ○ Limit access to wellhead and sequestration facilities to only those authorized caution tape and/or rope may be used to limit access). ○ Monitor wellhead pressure (tubing and annulus) and temperature as is feasible. This information should be used to assess and determine the nature or cause and extent of the mechanical integrity failure. ○ Take all steps reasonably necessary to identify and characterize any release within 24 hours (40 CFR 146.94(b 2)), including: Collection of confirmation samples of USDWs or any other potentially relevant formation(s) (in consultation with the Director) and performance of constituent analysis to determine elevated parameters. • The parameters to be tested are provided in the Testing and Monitoring Plan and QASP Attachment C: Testing and Monitoring Plan; Attachment K: Quality Assurance and Surveillance Plan). ○ If the presence of leaked fluid or other contamination is confirmed in a USDW or other unauthorized zone: ○ Identify and implement a remediation plan (in consultation with the Director) as soon as possible and no later than 30 days. ○ Arrange for an alternate potable water supply if the USDW was being utilized for water supply and the contamination has caused an exceedance of drinking water standards ○ Continue USDW monitoring (in consultation with the Director) until potential endangerment of or adverse impacts to USDWs have been fully addressed.
Response Personnel	• Facility operations staff • OCP operation supervisor • Project manager • Plant manager • Third party contractors • Rig crew • Rig supervisor • Groundwater remediation contractors
Response Equipment	• Tubing • Cement • Casing patches • Wellhead equipment • Packer • Logging equipment • Workover rig • Pump and treat groundwater remediation equipment and infrastructure if required (Attachment I: Financial Assurance Plan) • Other response actions may include supplying replacement residential water and installation of reverse osmosis units at impacted locations.

4.5 Severe Weather Disaster

Well problems (integrity loss, leakage, or malfunction) may arise as a result of a natural disaster affecting the normal operation of the CCS1 well. Weather-related disasters (e.g., tornado or lightning strike) may affect project facilities. Table 9 summarizes the expected timing, avoidance measures, and detection methods as well as the expected response actions, required personnel, and equipment needed for a natural disaster event.

Disturbance or damage as a result of a severe weather disaster may impact the normal operation of the project.

A non-exhaustive list of examples of such potential events and the impact to the project they may cause are:

- Lightning strikes the wellhead and damages all surface monitoring equipment,
- Severe flooding (i.e., 100-year flood) limits access to the well or injection facility.

These events may impact or damage the ability to properly operate the well or utilize the facility for the intended purposes of the project. Should a natural severe weather event occur that causes extended power loss, the OCP facility is designed to automatically shut down the injection systems safely. The system does not have onsite backup power generation that allows CO₂ injection to continue in the event the power grid is offline. A backup power system is in place to control the safe shutdown of all OCP facility equipment in the event of power loss.

Table 9: Summary of timing, avoidance measures, detection methods, and response actions, personnel, and equipment for a severe weather disaster. Lists are non-exhaustive.

Category	Item
Timing of Event	• Construction/Pre-injection • Injection • Post-injection
Avoidance Measures	• Installing equipment to lessen the impact of naturally occurring events (i.e., lightning rod in elevated position) • Elevate well, wellsite, and wellsite access roads above local elevation • Following appropriate building codes
Detection Methods	• Observance of local forecasts
Response Actions	• Notify the Director about the emergency event within 24 hours (40 CFR 146.91(c) and (e)). • Trigger alarm by the monitoring system or monitoring personnel. • If appropriate, contact the plant manager to activate emergency evacuation and secure the location. • If there has been a loss on mechanical integrity, implement Response Actions from Table 5. • Determine if all monitoring equipment remains functional. If there has been a failure of monitoring equipment, implement Response Actions from Table 6. • Conduct assessment to determine if there is evidence suggesting potential fluid leakage into a USDW or unauthorized zone. If there is such evidence, implement Response Actions from Table 8. • Assess potential impact to the project and the Local Resources and Infrastructure (Section 2 <i>Local Resources and Infrastructure</i>). • Identify and implement appropriate remedial actions (in consultation with the Director).
Response Personnel	• OCP operations supervisor • Project manager (if present) • Plant manager (if present) • Third party contractors i.e., supervisory control and data acquisition (SCADA) technician
Response Equipment	• Pressure gauge (if necessary) • Temperature sensors (if necessary) • SCADA equipment • Wellhead or wellhead components

4.6 Seismic Events

A major natural seismic event may disturb the surface or subsurface facilities. There is also a possibility that injection operations may cause induced microseismicity. This portion of the response plan is developed for any seismic event with an epicenter within an 8-mile radius of CCS1.

A surface-based microseismic monitoring array will be designed with microseismic monitoring stations at a range of azimuths to optimize the accuracy of the event locations and magnitudes. This network can easily be expanded in response to monitoring results or future AoR re-evaluations, if necessary.

In addition to the local project array, state or national monitoring networks will be used to monitor the area for seismicity (Attachment C: Testing and Monitoring Plan). The microseismic monitoring will be used to accurately determine the locations and magnitudes of potential injection-induced seismic events with the primary goals of:

- Addressing public and stakeholder concerns related to induced seismicity,
- Monitoring the spatial extent of the pressure front from the distribution of seismic events, and
- Identifying activity that may indicate failure of the confining zone and possible containment loss.

Based on the periodic analysis of the monitoring data, observed level of seismic activity, and local reporting of felt events, the site will be assigned an operating state with associated response actions (Table 10). The operating state is determined using threshold criteria which correspond to the site's potential risk and level of seismic activity. The operating state provides operating personnel with information about the potential risk of further seismic activity and guides them through a series of response actions.

Personnel who may be involved in the response as well as equipment that may be required in the response are provided in Table 11.

Table 10: Seismic monitoring system for seismic events > M1.0 with an epicenter within an 8-mile radius of the injection well.

Operating State	Threshold Condition ¹	Response Action ²
Green	Seismic events less than or equal to M1.5	1. Continue normal operation within permitted levels.
Yellow	Five or more seismic events within a 30 day period having a magnitude greater than M1.5 but less than or equal to M2.0	1. Continue normal operation within permitted levels. 2. Within 24 hours of the event, notify the Director of the operating status of the well. 3. Review seismic and operational data to determine the cause of the events
Orange	Seismic event greater than M1.5 and local observation or felt report	1. Continue normal operation within permitted levels. 2. Within 24 hours of the incident, notify the Director of the operating status of the well. 3. Review seismic and operational data to determine the cause of the events. 4. Report findings to the Director and identify and implement appropriate remedial actions (in consultation with the Director), if necessary.
	Seismic event greater than M2.0 and no felt report	
Magenta	Seismic event greater than M2.0 and local observation or report	1. Initiate injection rate reduction plan in consultation with the Director). 2. Within 24 hours of the event, notify the Director of the operating status of the well. 3. Limit access to wellhead to authorized personnel only. 4. Communicate with facility personnel and local authorities to initiate evacuation plans, if necessary. 5. Review seismic and operational data to determine the cause of the events. 6. Monitor well pressure, temperature, and annulus pressure to verify well status and determine the extent of any failure. 7. Report findings to the Director and identify and implement appropriate remedial actions (in consultation with the Director), if necessary. 8. If there has been a loss mechanical integrity at any of the wells, implement Response Actions from Section 4.2 <i>Mechanical Integrity Failure</i> . 9. Determine if all monitoring equipment remains functional. If there has been a failure of monitoring equipment, implement Response Actions from Section 4.3 <i>Well Monitoring Equipment Failure or Malfunction</i> . 10. Conduct assessment to determine if there is evidence suggesting potential fluid leakage into a USDW or unauthorized zone. If there is such evidence, implement Response Actions from Section 4.4 <i>Evidence Suggesting Potential Fluid Leakage into a USDW or Other Unauthorized Zone</i> .

Operating State	Threshold Condition ¹	Response Action ²
Red	Seismic event greater than M2.0, and local observation or report, and local report and confirmation of damage	1. Initiate shutdown plan. 2. Within 24 hours of the incident, notify the Director of the emergency event (40 CFR 146.94(b)(3)) 3. Limit access to wellhead to authorized personnel only. 4. Communicate with facility personnel and local authorities to initiate evacuation plans, as necessary. 5. Review seismic and operational data to determine the cause of the events. 6. Monitor well pressure, temperature, and annulus pressure to verify well status and determine the extent of any failure. 7. Report findings to the Director and identify and implement appropriate remedial actions (in consultation with the Director), if necessary. 8. If there has been a loss of mechanical integrity, implement Response Actions from Section 4.2 <i>Mechanical Integrity Failure</i>. 9. Determine if all monitoring equipment remains functional. If there has been a failure of monitoring equipment, implement Response Actions from Section 4.3 <i>Well Monitoring Equipment Failure or Malfunction</i>. 10. Conduct assessment to determine if there is evidence suggesting potential fluid leakage into a USDW or Unauthorized Zone. If there is such evidence, implement Response Actions from Section 4.4 <i>Evidence Suggesting Potential Fluid Leakage into a USDW or Other Unauthorized Zone</i>.
	Seismic event >M3.5	

¹ Specified magnitudes refer to moment magnitudes determined by local seismic monitoring stations or United States Geological Survey (USGS) seismic monitoring stations or reported by the USGS National Earthquake Information Center using the national seismic network. "Felt report" and "local observation or report" refer to events confirmed by local reports of felt ground motion or reported on the USGS "Did You Feel It?" reporting system.

² Remedial action will occur within 25 business days (five weeks).

Table 11: Timing of potential events, response personnel, and equipment for a seismic event.

Category	Item
Timing of Major Event	Construction, injection, and post-injection
Response Personnel (including but not limited to)	OCP operations supervisor Project manager Plant manager Third party contractors OCP geologist OCP reservoir engineer
Response Equipment	Additional monitoring stations (if required)

5. Unforeseen Events

Should unforeseen events occur (i.e., global pandemic, etc.) that could impact the operations and integrity of the project, proposed response steps will be provided to the Director within 7 days and implemented once approved.

6. Overall Response Personnel and Equipment

Site personnel, project personnel, and local authorities will be relied upon to implement this ERRP. The project wells, CCS1, OBS1, above zone monitoring well (ACZ1) and dedicated lowermost underground source of drinking water monitoring well USDW1), are located on Cardinal Ethanol property. Offsite monitoring of shallow groundwater will occur at up to twelve locations within the AoR. As such, local responders for these places will be utilized for emergency contacts and will be notified of an incident as necessary. In addition, state agencies may need to be notified as well.

In addition to the Director, site personnel to be notified include (not listed in order of notification):

1. Project Engineer(s),
2. Plant Safety Manager(s),
3. Environmental Manager(s),
4. Project Manager,
5. Project Operations Manager.

All staff will be trained in the methods described in Section 9 *Staff Training and Exercise Procedures*.

Table 12 is the current list of contact information for key local, state, and other authorities. A site-specific emergency contact list will be developed, maintained, and periodically updated during the life of the project. The list will include phone numbers and email addresses for facility emergency 24-hour contacts. OCP will provide the current site-specific emergency contact list to the Director prior to commencement of injection operations.

Table 12: Contact information for key local, state, and other authorities.

Agency	Phone Number
Union City Police Department	765-964-5353
Union City Fire Emergency Medical Services (EMS)	765-964-4488 Indiana 937-968-5605 Ohio
Randolph County Sheriff	765-584-1721
Indiana State Police	765-778-2121
Indiana Emergency Management and Preparedness Division	765-584-1721 Local
Environmental services contractor	516-333-4526 (RTP – Environmental Consultant) 260-489-7062 ERS – Emergency Spill Response)
UIC Program Director Region 5	312-353-7648
EPA National Response Center 24 hours)	800-424-8802
Indiana DNR	317-232-4200

Equipment needed in the event of an emergency and remedial response will vary, depending upon the triggering emergency event. Response actions (cessation of injection, well shut-in, and evacuation) will generally not require specialized equipment to implement. Where specialized equipment (such as a workover rig or logging equipment) is required, OCP shall be responsible for its procurement.

7. Emergency Communications Plan

Subject to provisions elsewhere in this ERRP requiring notification to EPA, the order of contact when an emergency occurs is the following:

1. Plant Manager,
2. Necessary emergency authorities,
3. Impacted landowners (if any),
4. OCP Management Teams,
5. OCP Public Response Personnel *Section 6 Overall Response Personnel and Equipment .*

Based on the appropriate level of emergency response and the magnitude of the event, a crisis event center will be established. For minor emergencies, this will be held on Cardinal property. For major or serious emergencies, a crisis event center will be established at a safe location. This will serve as the headquarters for communication about the emergency. OCP will communicate with the public and impacted landowners.

OCP will communicate to the public and impacted landowners about any event that requires an emergency response to ensure that the public understands what happened and whether there are any environmental or safety implications. The amount of information, timing, and communications method(s) will be appropriate to the event, its severity, whether any impacts to drinking water or other environmental resources occurred, any impacts to the surrounding community, and their awareness of the event.

OCP will describe what happened, any impacts to the environment or other local resources, how the event was investigated, what responses were taken, and the status of the response. For responses that occur over the long-term (e.g., ongoing cleanups), OCP will provide periodic updates on the progress of the response action(s).

OCP will also communicate with entities who may need to be informed about or take action in response to the event, including local water systems, CO₂ source(s) and pipeline operators, landowners, and Regional Response Teams (as part of the National Response Team). A detailed list of these people will be developed and updated periodically.

8. Plan Review

In accordance with 40 CFR 146.94(d), OCP shall periodically review this ERRP. If the review indicates that no amendments to the ERRP are necessary, OCP will provide a demonstration to the Director with documentation supporting the “no amendment necessary” determination. If the review indicates that amendments to the ERRP are necessary, OCP shall submit an amended emergency and remedial response plan to the Director pursuant to the timelines listed below depending on the event triggering the review. Any approved amendments to the ERRP will be incorporated into the Permit.

Amended ERRPs or demonstrations shall be submitted to the Director as follows:

- Any significant changes to the facility, such as an addition of injection or monitoring wells, on a schedule determined by the Director.
- At least once every five years, from the date of issuance of final permit.
- Within one year of an AoR re-evaluation,
- Within six months following the occurrence of an emergency event under the ERRP, and
- When required by the Director (40 CFR § 146.94(d)(3)).

9. Staff Training and Exercise Procedures

OCP will develop a standard operating procedure (SOP) in tandem with the contractors that provides the surface capture and compression equipment, the surface monitoring system, and the operational procedures to be followed in the event of an emergency.

Included in this SOP will be specific details that can be used to train the project operators regarding the ERRP. Based on these SOPs, annual training and testing will be provided to all those involved with the project. All OCP personnel identified and assigned as responding personnel in the document will complete initial training prior to the commencement of operations. Documentation of this initial training as well as annual certifications will be documented and retained. OCP will integrate the ERRP into the plant-specific standard operating procedures and training program.