SUMMARY OF OPERATING CONDITIONS
LAC 43:XVII.3607(C)(2)(f) and (i) and LAC 43:XVII.3621(A)(6) and (7)

Magnolia Sequestration Project

1.0 Facility Information

Facility name: Magnolia Sequestration Project (Magnolia Hub)
Magnolia CCS 1 Well

Facility contact: Kelly Watson, Project Manager
5 Greenway Plaza Houston, TX 77046
713-552-8613 kelly_watson@oxy.com

Well location: Allen Parish, Louisiana
30° 40' 56.2474" N, 092° 50' 1.2244" W (NAD 27)
30° 40' 56.9387" N, 092° 50' 1.7707" W (NAD 83)

2.0 Injection Well Operating Conditions

Key injection well operating and project reporting requirements are specified in this attachment and summarized below in Table OP-1.

Table OP-1—Injection Well Operating Conditions

Parameter/Condition	Completion 1	Completion 2	Completion 3
Perforation Interval MD[1], top-bottom (ft)	6,662-7,008	6,507-6,635	6,222-6,466
Perforation Interval TVD[2], top-bottom (ft)	6,662-7,008	6,507-6,635	6,222-6,466
Bottomhole gauge depth MD[1]/TVD[2] (ft)	6,120	6,120	6,120
Maximum Injection Rate (metric tonnes per day)	7,700	7,700	7,700
Average Injection Rate (metric tonnes per day)	5,480	5,480	5,480
Total Volume Injected (millions of metric tonnes)	14	6	10
Operating Wellhead Surface Injection Pressure (psig)	1,100-2,100	1,100-2,100	1,100-2,100
Maximum Surface Wellhead Injection Pressure	2,300	2,300	2,300
Maximum Bottomhole Pressure at 90% of frac gradient (0.75 psi/ft) @ top of perforations (psig)	4,497	4,392	4,200
Maximum Bottomhole Pressure at 90% of frac gradient (0.75 psi/ft) @ bottomhole gauge (psig)	4,291	4,245	4,162
Minimum Annulus Pressure/Tubing Differential (psi)	100	100	100

(1) MD: measured depth
(2) TVD: true vertical depth
(3) Maximum rate is limited by tubing size, not by the reservoir

Notes:

- 5 ½ in. tubing select as injection string.
- Assumed 90°F as injection temperature for the CO_2 on surface for maximum pressure calculations for estimations.

2.1 Maximum Bottomhole Injection Pressure

Maximum bottomhole injection pressure is limited to 90 percent of the fracture pressure to prevent confining-formation fracturing, consistent with LAC 43:XVII.3621(A)(1). The maximum pressure considered for the Magnolia CCS 1 well is based on the fracture gradient of 0.75 psi/ft as measured with downhole pressure gauges during the testing of the stratigraphic test well YAMS MLR 004 (SN 975950).

Considering the top of perforations as given in Table OP-1 for the three completions, the maximum bottom injection pressures at the top of perforation are calculated to be:

Completion 1: 6,662 ft x 0.9 x 0.75 psi/ft = 4,497 psig
Completion 2: 6,507 ft x 0.9 x 0.75 psi/ft = 4,392 psig
Completion 3: 6,222 ft x 0.9 x 0.75 psi/ft = 4,200 psig

Considering gauge depths as given in Table OP-1 for the three completions, the maximum bottom injection pressures at the gauge depth are calculated to be:

Completion 1: 4,497 psig – (6,662 – 6,120) ft x 0.38 psi/ft = 4,291 psig
Completion 2: 4,392 psig – (6,507 – 6,120) ft x 0.38 psi/ft = 4,245 psig
Completion 3: 4,200 psig – (6,222 – 6,120) ft x 0.38 psi/ft = 4,161 psig

The packer and gauge settings will be adjusted based on logs and well information after the well is constructed, and pressures will be calibrated during the well testing and startup operations.

2.2 Wellhead Surface Injection Pressure Range

The maximum surface wellhead injection pressure is limited by the CO_2 supply pipeline and a potential future booster pumping system. The design pressure of the supply pipeline is planned to be 2,200 psig, consistent with ASME 900# flange class piping specifications. The design pressure of a proposed booster pumping system will be no greater than 3,600 psig, consistent with ASME 1500# flange class piping specifications, though the operating conditions will be lower than design.

Wellbore tubing curves representative of the Magnolia CCS 1 were created in PROSPER for 5.5 in. tubing. The results showed normal operating pressure at the wellsite as estimated to be between 1,100 psig and 2,100 psig for the proposed operating rate. High and high-high wellsite pressure setpoints of 2,150 and 2,300 psig, respectively, will be set to alarm upon operational pressure fluctuation outside of expected range.

If the downhole pressure gauge fails to function properly, then the maximum injection pressure shall immediately be limited by the maximum surface wellhead injection pressure until the downhole pressure gauge can be repaired or replaced.

2.3 Wellhead Minimum Differential Annulus / Tubing Pressure

The well is designed to inject through tubing and packer. The annulus space will be filled with inhibited completion fluid with a minimum density of 9.8 ppg. The project team will maintain at least 100 psi differential pressure between the annulus and bottom of the injection string as proposed in Table OP-1. The calculated pressure required in the annulus space between the long string casing and tubing will be estimated as follows:

DP (psi) = max bottom hole pressure during injection – hydrostatic pressure in annulus +100 psi calculated at packer depth

3.0 Reporting Frequencies

Magnolia Sequestration Hub, LLC, will maintain the reporting frequencies as summarized below in Table OP-2.

Table OP-2—Class VI Reporting Frequencies

Activity	Minimum Reporting Frequency
CO_2 stream characterization	Semiannually
Monthly injection pressure, flow, rate, volume, pressure on the annulus, annulus fluid level, and temperature (min, max, and avg.)	Semiannually
Corrosion monitoring	Semiannually
Monthly and cumulative volume and mass of the CO_2 stream injected	Semiannually
Monthly annulus fluid volume added	Semiannually
Results and reports for the monitoring systems proposed: plume tracking, above-confining-zone monitoring, surface monitoring	Semiannually
Description of any event that triggers a shutoff device and the response taken	Semiannually
Description of any event that exceeds operating parameters for annulus pressure or injection pressure specified in the permit	Semiannually
Any injectivity test performed in the well	Notification 30 days before and results within 30 days of completion of test
External Mechanical Integrity Test (MIT) and internal MIT	Notification 30 days before and results within 30 days of completion of test
Pressure falloff testing	Notification 30 days before and results within 30 days of completion of test
Planned workover or well stimulation	Notification 30 days before and results within 30 days of completion of test
Monitoring well MITs	Notification 30 days before and results within 30 days of completion of test
Financial responsibility updates pursuant to H.2 and H.3(a) of this permit	Within 60 days of update

Note: All testing and monitoring frequencies as well as methodologies are included in the Testing and Monitoring Plan document of this permit.

The events that trigger an immediate emergency response should be reported within 24 hours, according to the LAC 43:XVII.3621(A)(1)(b)(iii) reporting requirements.

4.0 Startup Monitoring and Reporting Procedures

The special procedures related to the startup of operations, monitoring, and reporting during the first several months are specified in this section. The injection rates will be gradually increased to the planned rate over a period of nine (9) days as CO_2 volumes become available at the site during the commissioning period.

The multi-stage (step-rate) startup procedure and period only apply to the initial start of injection operations until the well reaches the operating injection rate. Monitoring frequencies and methodologies after the initial startup will follow the Testing and Monitoring Plan document of this permit.

(1) This procedure will be performed using the existing surface and downhole pressure and temperature gauges in the CO_2 injector well.

(2) During the startup period, the Magnolia Hub will submit a daily report summarizing and interpreting the operational data. At the request of the Louisiana Department of Conservation and Energy (C&E) the permittee may be required to schedule a daily conference call to discuss this information.

(3) A series of successfully higher injection rates will be performed as shown in Table OP-3 below in Step 4. The elapsed time and pressure values will be read and recorded for each rate and time step. At no point during the procedure will the injection pressure be allowed to exceed the maximum injection pressure of 2,300 psig, which is measured at the wellhead.

(4) The planned injection rates are as follows:

Table OP-3—Planned Injection Rates During Startup

Rate (tonnes per day)	Duration (hours)	Percent of Permit Maximum Injection Rate (%)
2,191	72	40
2,740	24	50
3,616	24	66
4,548	24	83
4,932	24	90
5,206	24	95
5,480	24	100

(5) The injection rates will be controlled by automated surface control valves.

(6) The injection rates will be measured and recorded using Coriolis meters.

(7) Surface and downhole pressures and temperatures will be measured and recorded.

(8) Temperature profile in the well will be continuously read from fiber optic cable installed alongside casing.

(9) During the startup period, a plot of injection rates and their corresponding stabilized pressure values will be graphically represented. During this period, the project team will also look for any evidence of anomalous pressure behavior.

(10) If during the startup period any anomalous pressure behavior is observed, the project team may conduct additional logging and modify the injection rate program to characterize the anomaly. The project team will also determine if the observed anomalous pressure behavior indicates formation fracturing, which will cause the injection to cease and the line valve to be closed, allowing the pressure to bleed off into the injection zone, as discussed below:

(a) The instantaneous shut-in pressure (ISIP) will be measured.

(b) The permittee will notify the C&E within 24 hours of the determination.

(c) The permittee will consult with the C&E before initiating any further injection.

SUMMARY OF OPERATING CONDITIONS
LAC 43:XVII.3607(C)(2)(f) and (i) and LAC 43:XVII.3621(A)(6) and (7)

Magnolia Sequestration Project

1.0 Facility Information

Facility name: Magnolia Sequestration Project (Magnolia Hub)
Magnolia CCS 2 Well

Facility contact: Kelly Watson, Project Manager
5 Greenway Plaza Houston, TX 77046
713-552-8613 kelly_watson@oxy.com

Well location: Allen Parish, Louisiana
30° 41' 40.1623"N, 092° 50' 23.1767"W (NAD 27)
30° 41' 40.8527" N, 092° 50' 23.7241" W (NAD 83)

2.0 Injection Well Operating Conditions

Key injection well operating and project reporting requirements are specified in this attachment and summarized below in Table OP-1.

Table OP-1—Injection Well Operating Conditions

Parameter/Condition	Completion 1	Completion 2	Completion 3
Perforation Interval MD[1], top-bottom (ft)	6,504- 6,854	6,345- 6,471	6,064- 6,308
Perforation Interval TVD[2], top-bottom (ft)	6,504- 6,854	6,345- 6,471	6,064- 6,308
Bottomhole gauge depth MD[1]/TVD[2] (ft)	5,960	5,960	5,960
Maximum Injection Rate (metric tonnes per day)	7,700	7,700	7,700
Average Injection Rate (metric tonnes per day)	5,480	5,480	5,480
Total Volume Injected (millions of metric tonnes)	14	6	10
Operating Wellhead Surface Injection Pressure (psig)	1,100-2,100	1,100-2,100	1,100-2,100
Maximum Surface Wellhead Injection Pressure	2,300	2,300	2,300
Maximum Bottomhole Pressure at 90% of frac gradient (0.75 psi/ft) @ top of perforations (psig)	4,390	4,283	4,093
Maximum Bottomhole Pressure at 90% of frac gradient (0.75 psi/ft) @ bottomhole gauge (psig)	4,183	4,138	4,053
Minimum Annulus Pressure/Tubing Differential (psi)	100	100	100

(1) MD: measured depth
(2) TVD: true vertical depth
(3) Maximum rate is limited by tubing size, not by the reservoir

Notes:

- 5 ½ in. tubing select as injection string.
- Assumed 90°F as injection temperature for the CO_2 on surface for maximum pressure calculations for estimations.

2.1 Maximum Bottomhole Injection Pressure

Maximum bottomhole injection pressure is limited to 90 percent of the fracture pressure to prevent confining-formation fracturing, consistent with LAC 43:XVII.3621(A)(1). The maximum pressure considered for the Magnolia CCS 2 well is based on the fracture gradient of 0.75 psi/ft as measured with downhole pressure gauges during the testing of the stratigraphic test well YAMS MLR 004 (SN 975950).

Considering the top of perforations as given in Table OP-1 for the three completions, the maximum bottom injection pressures at the top of perforation are calculated to be:

Completion 1: 6,504 ft x 0.9 x 0.75 psi/ft = 4,390 psig
Completion 2: 6,345 ft x 0.9 x 0.75 psi/ft = 4,283 psig
Completion 3: 6,064 ft x 0.9 x 0.75 psi/ft = 4,093 psig

Considering gauge depths as given in Table OP-1 for the three completions, the maximum bottom injection pressures at the gauge depth are calculated to be:

Completion 1: 4,390 psig – (6,504 – 5,960) ft x 0.38 psi/ft = 4,183 psig
Completion 2: 4,283 psig – (6,345 – 5,960) ft x 0.38 psi/ft = 4,138 psig
Completion 3: 4,093 psig – (6,064 – 5,960) ft x 0.38 psi/ft = 4,053 psig

The packer and gauge settings will be adjusted based on logs and well information after the well is constructed, and pressures will be calibrated during the well testing and startup operations.

2.2 Wellhead Surface Injection Pressure Range

The maximum surface wellhead injection pressure is limited by the CO_2 supply pipeline and a potential future booster pumping system. The design pressure of the supply pipeline is planned to be 2,200 psig, consistent with ASME 900# flange class piping specifications. The design pressure of a proposed booster pumping system will be no greater than 3,600 psig, consistent with ASME 1500# flange class piping specifications, though the operating conditions will be lower than design.

Wellbore tubing curves representative of the Magnolia CCS 2 were created in PROSPER for 5.5 in. tubing. The results showed normal operating pressure at the wellsite as estimated to be between 1,100 psig and 2,100 psig for the proposed operating rate. High and high-high wellsite pressure setpoints of 2,150 and 2,300 psig, respectively, will be set to alarm upon operational pressure fluctuation outside of expected range.

If the downhole pressure gauge fails to function properly, then the maximum injection pressure shall immediately be limited by the maximum surface wellhead injection pressure until the downhole pressure gauge can be repaired or replaced.

2.3 Wellhead Minimum Differential Annulus / Tubing Pressure

The well is designed to inject through tubing and packer. The annulus space will be filled with inhibited completion fluid with a minimum density of 9.8 ppg. The project will maintain at least 100 psi differential pressure between the annulus and bottom of the injection string as proposed in Table OP-1. The calculated pressure required in the annulus space between the long-string casing and tubing was estimated as follows:

DP (psi) = max bottom hole pressure during injection – hydrostatic pressure in annulus +100 psi calculated at packer depth

3.0 Reporting Frequencies

Magnolia Sequestration Hub, LLC, will maintain the reporting frequencies as summarized below in Table OP-2.

Table OP-2—Class VI Reporting Frequencies

Activity	Minimum Reporting Frequency
CO_2 stream characterization	Semiannually
Monthly injection pressure, flow, rate, volume, pressure on the annulus, annulus fluid level, and temperature (min, max, and avg.)	Semiannually
Corrosion monitoring	Semiannually
Monthly and cumulative volume and mass of the CO_2 stream injected	Semiannually
Monthly annulus fluid volume added	Semiannually
Results and reports for the monitoring systems proposed: plume tracking, above-confining-zone monitoring, surface monitoring	Semiannually
Description of any event that triggers a shutoff device and the response taken	Semiannually
Description of any event that exceeds operating parameters for annulus pressure or injection pressure specified in the permit	Semiannually
Any injectivity test performed in the well	Notification 30 days before and results within 30 days of completion of test
External Mechanical Integrity Test (MIT) and internal MIT	Notification 30 days before and results within 30 days of completion of test
Pressure falloff testing	Notification 30 days before and results within 30 days of completion of test
Planned workover or well stimulation	Notification 30 days before and results within 30 days of completion of test
Monitoring well MITs	Notification 30 days before and results within 30 days of completion of test
Financial responsibility updates pursuant to H.2 and H.3(a) of this permit	Within 60 days of update

Note: All testing and monitoring frequencies as well as methodologies are included in the Testing and Monitoring Plan document of this permit.

The events that trigger an immediate emergency response should be reported within 24 hours, according to the LAC 43:XVII.3621(A)(1)(b)(iii) reporting requirements.

4.0 Startup Monitoring and Reporting Procedures

The special procedures related to the startup of operations, monitoring, and reporting during the first several months are specified in this section. The injection rates will be gradually increased to the planned rate over a period of nine (9) days as CO_2 volumes become available at the site during the commissioning period.

The multi-stage (step-rate) startup procedure and period only apply to the initial start of injection operations until the well reaches the operating injection rate. Monitoring frequencies and methodologies after the initial startup will follow the Testing and Monitoring Plan document of this permit.

(1) This procedure will be performed using the existing surface and downhole pressure and temperature gauges in the CO_2 injector well.

(2) During the startup period, the Magnolia Hub will submit a daily report summarizing and interpreting the operational data. At the request of the Louisiana Department of Conservation and Energy (C&E), the permittee may be required to schedule a daily conference call to discuss this information.

(3) A series of successfully higher injection rates will be performed as shown in Table OP-3 below in Step 4. The elapsed time and pressure values will be read and recorded for each rate and time step. At no point during the procedure will the injection pressure be allowed to exceed the maximum injection pressure of 2,300 psig, which is measured at the wellhead.

(4) The planned injection rates are as follows:

Table OP-3—Planned Injection Rates During Startup

Rate (tonnes per day)	Duration (hours)	Percent of Permit Maximum Injection Rate (%)
2,191	72	40
2,740	24	50
3,616	24	66
4,548	24	83
4,932	24	90
5,206	24	95
5,480	24	100

(5) The injection rates will be controlled by automated surface control valves.

(6) The injection rates will be measured and recorded using Coriolis meters.

(7) Surface and downhole pressures and temperatures will be measured and recorded.

(8) Temperature profile in the well will be continuously read from fiber optic cable installed alongside casing.

(9) During the startup period, a plot of injection rates and their corresponding stabilized pressure values will be graphically represented. During this period, the project team will also look for any evidence of anomalous pressure behavior.

(10) If during the startup period any anomalous pressure behavior is observed, the project team may conduct additional logging and modify the injection rate program to characterize the anomaly. The project team will also determine if the observed anomalous pressure behavior indicates formation fracturing, which will cause the injection to cease and the line valve to be closed, allowing the pressure to bleed off into the injection zone, as discussed below:

  (a) The instantaneous shut-in pressure (ISIP) will be measured.

  (b) The permittee will notify the C&E within 24 hours of the determination.

  (c) The permittee will consult with the C&E before initiating any further injection.

DEPARTMENT OF CONSERVATION AND ENERGY - OFFICE OF PERMITTING AND COMPLIANCE - JUN 18 2026, Page 13 of 24

SUMMARY OF OPERATING CONDITIONS
LAC 43:XVII.3607(C)(2)(f) and (i) and LAC 43:XVII.3621(A)(6) and (7)

Magnolia Sequestration Project

1.0 Facility Information

Facility name: Magnolia Sequestration Project (Magnolia Hub)
Magnolia CCS 3 Well

Facility contact: Kelly Watson, Project Manager
5 Greenway Plaza Houston, TX 77046
713-552-8613 kelly_watson@oxy.com

Well location: Allen Parish, Louisiana
30° 41' 6.1794" N, 092° 50' 24.1145" W (NAD 27)
30° 41' 6.8705" N, 092° 50' 24.6617" W (NAD 83)

2.0 Injection Well Operating Conditions

Key injection well operating and project reporting requirements are specified in this attachment and summarized below in Table OP-1.

Table OP-1—Injection Well Operating Conditions

Parameter/Condition	Completion 1	Completion 2	Completion 3
Perforation Interval MD[1], top-bottom (ft)	5,788- 6,149	5,473- 5,749	4,985- 5,443
Perforation Interval TVD[2], top-bottom (ft)	5,788- 6,149	5,473- 5,749	4,985- 5,443
Bottomhole gauge depth MD[1]/TVD[2] (ft)	4,885	4,885	4,885
Maximum Injection Rate (metric tonnes per day)	7,700	7,700	7,700
Average Injection Rate (metric tonnes per day)	5,480	5,480	5,480
Total Volume Injected (millions of metric tonnes)	11	6	13
Operating Wellhead Surface Injection Pressure (psig)	950-1,800	950-1,950	900-1,800
Maximum Surface Wellhead Injection Pressure	2,300	2,300	2,300
Maximum Bottomhole Pressure at 90% of frac gradient (0.75 psi/ft) @ top of perforations (psig)	3,907	3,694	3,365
Maximum Bottomhole Pressure at 90% of frac gradient (0.75 psi/ft) @ bottomhole gauge (psig)	3,564	3,471	3,327
Minimum Annulus Pressure/Tubing Differential (psi)	100	100	100

(1) MD: measured depth
(2) TVD: true vertical depth
(3) Maximum rate is limited by tubing size, not by the reservoir

Notes:

- 5 ½ in. tubing select as injection string.
- Assumed 90°F as injection temperature for the CO_2 on surface for maximum pressure calculations for estimations.

2.1 Maximum Bottomhole Injection Pressure

Maximum bottomhole injection pressure is limited to 90 percent of the fracture pressure to prevent confining-formation fracturing, consistent with LAC 43:XVII.3621(A)(1). The maximum pressure considered for the Magnolia CCS 3 well is based on the fracture gradient of 0.75 psi/ft as measured with downhole pressure gauges during the testing of the stratigraphic test well YAMS MLR 004 (SN 975950).

Considering the top of perforations as given in Table OP-1 for the three completions, the maximum bottom injection pressures at the top of perforation are calculated to be:

Completion 1: 5,788 ft x 0.9 x 0.75 psi/ft = 3,907 psig
Completion 2: 5,473 ft x 0.9 x 0.75 psi/ft = 3,694 psig
Completion 3: 4,985 ft x 0.9 x 0.75 psi/ft = 3,365 psig

Considering gauge depths as given in Table OP-1 for the three completions, the maximum bottom injection pressures at the gauge depth are calculated to be:

Completion 1: 3,907 psig – (5,788 – 4,885) ft x 0.38 psi/ft = 3,564 psig
Completion 2: 3,694 psig – (5,473 – 4,885) ft x 0.38 psi/ft = 3,471 psig
Completion 3: 3,365 psig – (4,985 – 4,885) ft x 0.38 psi/ft = 3,327 psig

The packer and gauge settings will be adjusted based on logs and well information after the well is constructed, and pressures will be calibrated during the well testing and startup operations.

2.2 Wellhead Surface Injection Pressure Range

The maximum surface wellhead injection pressure is limited by the third-party CO_2 supply pipeline and a potential future booster pumping system. The design pressure of the supply pipeline is planned to be 2,200 psig, consistent with ASME 900# flange class piping specifications. The design pressure of a proposed booster pumping system will be no greater than 3,600 psig, consistent with ASME 1500# flange class piping specifications, though the operating conditions will be lower than design.

Wellbore tubing curves representative of the Magnolia CCS 3 were created in PROSPER for 5.5 in. tubing. The results showed normal operating pressure at the wellsite as estimated to be between 900 psig and 1,950 psig for the proposed operating rate. High and high-high wellsite pressure setpoints of 2,150 and 2,300 psig, respectively, will be set to alarm upon operational pressure fluctuation outside of expected range.

If the downhole pressure gauge fails to function properly, then the maximum injection pressure shall immediately be limited by the maximum surface wellhead injection pressure until the downhole pressure gauge can be repaired or replaced.

2.3 Wellhead Minimum Differential Annulus / Tubing Pressure

The well is designed to inject through tubing and packer. The annulus space will be filled with inhibited completion fluid with a minimum density of 9.8 ppg. The project will maintain at least

100 psi differential pressure between the annulus and bottom of the injection string as proposed in Table OP-1. The calculated pressure required in the annulus space between the long-string casing and tubing was estimated as follows:

DP (psi) = max bottom hole pressure during injection – hydrostatic pressure in annulus +100 psi calculated at packer depth

3.0 Reporting Frequencies

Magnolia Sequestration Hub, LLC, will maintain the reporting frequencies as summarized below in Table OP-2.

Table OP-2—Class VI Reporting Frequencies

Activity	Minimum Reporting Frequency
CO_2 stream characterization	Semiannually
Monthly injection pressure, flow, rate, volume, pressure on the annulus, annulus fluid level, and temperature (min, max, and avg.)	Semiannually
Corrosion monitoring	Semiannually
Monthly and cumulative volume and mass of the CO_2 stream injected	Semiannually
Monthly annulus fluid volume added	Semiannually
Results and reports for the monitoring systems proposed: plume tracking, above-confining-zone monitoring, surface monitoring	Semiannually
Description of any event that triggers a shutoff device and the response taken	Semiannually
Description of any event that exceeds operating parameters for annulus pressure or injection pressure specified in the permit	Semiannually
Any injectivity test performed in the well	Notification 30 days before and results within 30 days of completion of test
External Mechanical Integrity Test (MIT) and internal MIT	Notification 30 days before and results within 30 days of completion of test
Pressure falloff testing	Notification 30 days before and results within 30 days of completion of test
Planned workover or well stimulation	Notification 30 days before and results within 30 days of completion of test
Monitoring well MITs	Notification 30 days before and results within 30 days of completion of test
Financial responsibility updates pursuant to H.2 and H.3(a) of this permit	Within 60 days of update

Note: All testing and monitoring frequencies as well as methodologies are included in the Testing and Monitoring Plan document of this permit.

The events that trigger an immediate emergency response should be reported within 24 hours, according to the LAC 43:XVII.3621(A)(1)(b)(iii) reporting requirements.

4.0 Startup Monitoring and Reporting Procedures

The special procedures related to the startup of operations, monitoring, and reporting during the first several months are specified in this section. The injection rates will be gradually increased to the planned rate over a period of nine (9) days as CO_2 volumes become available at the site during the commissioning period.

The multi-stage (step-rate) startup procedure and period only apply to the initial start of injection operations until the well reaches the operating injection rate. Monitoring frequencies and methodologies after the initial startup will follow the Testing and Monitoring Plan document of this permit.

(1) This procedure will be performed using the existing surface and downhole pressure and temperature gauges in the CO_2 injector well.

(2) During the startup period, the Magnolia Hub will submit a daily report summarizing and interpreting the operational data. At the request of the Louisiana Department of Conservation and Energy (C&E), the permittee may be required to schedule a daily conference call to discuss this information.

(3) A series of successfully higher injection rates will be performed as shown in Table OP-3 below in Step 4. The elapsed time and pressure values will be read and recorded for each rate and time step. At no point during the procedure will the injection pressure be allowed to exceed the maximum injection pressure of 2,300 psig, which is measured at the wellhead.

(4) The planned injection rates are as follows:

Table OP-3—Planned Injection Rates During Startup

Rate (tonnes per day)	Duration (hours)	Percent of Permit Maximum Injection Rate (%)
2,191	72	40
2,740	24	50
3,616	24	66
4,548	24	83
4,932	24	90
5,206	24	95
5,480	24	100

(5) The injection rates will be controlled by automated surface control valves.

(6) The injection rates will be measured and recorded using Coriolis meters.

(7) Surface and downhole pressures and temperatures will be measured and recorded.

(8) Temperature profile in the well will be continuously read from fiber optic cable installed alongside casing.

(9) During the startup period, a plot of injection rates and their corresponding stabilized pressure values will be graphically represented. During this period, the project team will also look for any evidence of anomalous pressure behavior.

(10) If during the startup period any anomalous pressure behavior is observed, the project team may conduct additional logging and modify the injection rate program to characterize the anomaly. The project team will also determine if the observed anomalous pressure behavior indicates formation fracturing, which will cause the injection to cease and the line valve to be closed, allowing the pressure to bleed off into the injection zone, as discussed below:

(a) The instantaneous shut-in pressure (ISIP) will be measured.

(b) The permittee will notify the C&E within 24 hours of the determination.

(c) The permittee will consult with the C&E before initiating any further injection.

SUMMARY OF OPERATING CONDITIONS
LAC 43:XVII.3607(C)(2)(f) and (i) and LAC 43:XVII.3621(A)(6) and (7)

Magnolia Sequestration Project

1.0 Facility Information

Facility name: Magnolia Sequestration Project (Magnolia Hub)
Magnolia CCS 4 Well

Facility contact: Kelly Watson, Project Manager
5 Greenway Plaza Houston, TX 77046
713-552-8613 kelly_watson@oxy.com

Well location: Allen Parish, Louisiana
30° 41' 38.4597" N, 092° 50' 23.1814" W (NAD 27)
30° 40' 39.1501" N, 092° 50' 23.7288" W (NAD 83)

2.0 Injection Well Operating Conditions

Key injection well operating and project reporting requirements are specified in this attachment and summarized below in Table OP-1.

Table OP-1—Injection Well Operating Conditions

Parameter/Condition	Completion 1	Completion 2	Completion 3
Perforation Interval MD[1], top-bottom (ft)	5,683- 6,035	5,376- 5,646	4,883- 5,344
Perforation Interval TVD[2], top-bottom (ft)	5,683- 6,035	5,376- 5,646	4,883- 5,344
Bottomhole gauge depth MD[1]/TVD[2] (ft)	4,780	4,780	4,780
Maximum Injection Rate (metric tonnes per day)	7,700	7,700	7,700
Average Injection Rate (metric tonnes per day)	5,480	5,480	5,480
Total Volume Injected (millions of metric tonnes)	11	6	13
Operating Wellhead Surface Injection Pressure (psig)	950-1,800	950-1,900	900-1,800
Maximum Surface Wellhead Injection Pressure	2,300	2,300	2,300
Maximum Bottomhole Pressure at 90% of frac gradient (0.75 psi/ft) @ top of perforations (psig)	3,836	3,629	3,296
Maximum Bottomhole Pressure at 90% of frac gradient (0.75 psi/ft) @ bottomhole gauge (psig)	3,493	3,403	3,257
Minimum Annulus Pressure/Tubing Differential (psi)	100	100	100

(1) MD: measured depth
(2) TVD: true vertical depth
(3) Maximum rate is limited by tubing size, not by the reservoir

Notes:

- 5 ½ in. tubing select as injection string.
- Assumed 90°F as injection temperature for the CO_2 on surface for maximum pressure calculations for estimations.

2.1 Maximum Bottomhole Injection Pressure

Maximum bottomhole injection pressure is limited to 90 percent of the fracture pressure to prevent confining-formation fracturing, consistent with LAC 43:XVII.3621(A)(1). The maximum pressure considered for the Magnolia CCS 4 well is based on the fracture gradient of 0.75 psi/ft as measured with downhole pressure gauges during the testing of the stratigraphic test well YAMS MLR 004 (SN 975950).

Considering the top of perforations as given in Table OP-1 for the three completions, the maximum bottom injection pressures at the top of perforation are calculated to be:

Completion 1: 5,683 ft x 0.9 x 0.75 psi/ft = 3,836 psig
Completion 2: 5,376 ft x 0.9 x 0.75 psi/ft = 3,629 psig
Completion 3: 4,883 ft x 0.9 x 0.75 psi/ft = 3,296 psig

Considering gauge depths as given in Table OP-1 for the three completions, the maximum bottom injection pressures at the gauge depth are calculated to be:

Completion 1: 3,836 psig – (5,683 – 4,780) ft x 0.38 psi/ft = 3,493 psig
Completion 2: 3,629 psig – (5,376 – 4,780) ft x 0.38 psi/ft = 3,403 psig
Completion 3: 3,296 psig – (4,883 – 4,780) ft x 0.38 psi/ft = 3,257 psig

The packer and gauge settings will be adjusted based on logs and well information after the well is constructed, and pressures will be calibrated during the well testing and startup operations.

2.2 Wellhead Surface Injection Pressure Range

The maximum surface wellhead injection pressure is limited by the third-party CO_2 supply pipeline and a potential future booster pumping system. The design pressure of the supply pipeline is planned to be 2,200 psig, consistent with ASME 900# flange class piping specifications. The design pressure of a proposed booster pumping system will be no greater than 3,600 psig, consistent with ASME 1500# flange class piping specifications, though the operating conditions will be lower than design.

Wellbore tubing curves representative of the Magnolia CCS 4 were created in PROSPER for 5.5 in. tubing. The results showed normal operating pressure at the wellsite as estimated to be between 900 psig and 1,900 psig for the proposed operating rate. High and high-high wellsite pressure setpoints of 2,150 and 2,300 psig, respectively, will be set to alarm upon operational pressure fluctuation outside of expected range.

If the downhole pressure gauge fails to function properly, then the maximum injection pressure shall immediately be limited by the maximum surface wellhead injection pressure until the downhole pressure gauge can be repaired or replaced.

2.3 Wellhead Minimum Differential Annulus / Tubing Pressure

The well is designed to inject through tubing and packer. The annulus space will be filled with inhibited completion fluid with a minimum density of 9.8 ppg. The project will maintain at least 100 psi differential pressure between the annulus and bottom of the injection string as proposed in Table OP-1. The calculated pressure required in the annulus space between the long-string casing and tubing was estimated as follows:

DP (psi) = max bottom hole pressure during injection – hydrostatic pressure in annulus +100 psi calculated at packer depth

3.0 Reporting Frequencies

Magnolia Sequestration Hub, LLC, will maintain the reporting frequencies as summarized below in Table OP-2.

Table OP-2—Class VI Reporting Frequencies

Activity	Minimum Reporting Frequency
CO_2 stream characterization	Semiannually
Monthly injection pressure, flow, rate, volume, pressure on the annulus, annulus fluid level, and temperature (min, max, and avg.)	Semiannually
Corrosion monitoring	Semiannually
Monthly and cumulative volume and mass of the CO_2 stream injected	Semiannually
Monthly annulus fluid volume added	Semiannually
Results and reports for the monitoring systems proposed: plume tracking, above-confining-zone monitoring, surface monitoring	Semiannually
Description of any event that triggers a shutoff device and the response taken	Semiannually
Description of any event that exceeds operating parameters for annulus pressure or injection pressure specified in the permit	Semiannually
Any injectivity test performed in the well	Notification 30 days before and results within 30 days of completion of test
External Mechanical Integrity Test (MIT) and internal MIT	Notification 30 days before and results within 30 days of completion of test
Pressure falloff testing	Notification 30 days before and results within 30 days of completion of test
Planned workover or well stimulation	Notification 30 days before and results within 30 days of completion of test
Monitoring well MITs	Notification 30 days before and results within 30 days of completion of test
Financial responsibility updates pursuant to H.2 and H.3(a) of this permit	Within 60 days of update

Note: All testing and monitoring frequencies as well as methodologies are included in the Testing and Monitoring Plan document of this permit.

The events that trigger an immediate emergency response should be reported within 24 hours, according to the LAC 43:XVII.3621(A)(1)(b)(iii) reporting requirements.

4.0 Startup Monitoring and Reporting Procedures

The special procedures related to the startup of operations, monitoring, and reporting during the first several months are specified in this section. The injection rates will be gradually increased to the planned rate over a period of nine (9) days as CO_2 volumes become available at the site during the commissioning period.

The multi-stage (step-rate) startup procedure and period only apply to the initial start of injection operations until the well reaches the operating injection rate. Monitoring frequencies and methodologies after the initial startup will follow the Testing and Monitoring Plan document of this permit.

(1) This procedure will be performed using the existing surface and downhole pressure and temperature gauges in the CO_2 injector well.

(2) During the startup period, the Magnolia Hub will submit a daily report summarizing and interpreting the operational data. At the request of the Louisiana Department of Conservation and Energy (C&E), the permittee may be required to schedule a daily conference call to discuss this information.

(3) A series of successfully higher injection rates will be performed as shown in Table OP-3 below in Step 4. The elapsed time and pressure values will be read and recorded for each rate and time step. At no point during the procedure will the injection pressure be allowed to exceed the maximum injection pressure of 2,300 psig, which is measured at the wellhead.

(4) The planned injection rates are as follows:

Table OP-3—Planned Injection Rates During Startup

Rate (tonnes per day)	Duration (hours)	Percent of Permit Maximum Injection Rate (%)
2,191	72	40
2,740	24	50
3,616	24	66
4,548	24	83
4,932	24	90
5,206	24	95
5,480	24	100

(5) The injection rates will be controlled by automated surface control valves.

(6) The injection rates will be measured and recorded using Coriolis meters.

(7) Surface and downhole pressures and temperatures will be measured and recorded.

(8) Temperature profile in the well will be continuously read from fiber optic cable installed alongside casing.

(9) During the startup period, a plot of injection rates and their corresponding stabilized pressure values will be graphically represented. During this period, the project team will also look for any evidence of anomalous pressure behavior.

(10) If during the startup period any anomalous pressure behavior is observed, the project team may conduct additional logging and modify the injection rate program to characterize the anomaly. The project team will also determine if the observed anomalous pressure behavior indicates formation fracturing, which will cause the injection to cease and the line valve to be closed, allowing the pressure to bleed off into the injection zone, as discussed below:

(a) The instantaneous shut-in pressure (ISIP) will be measured.

(b) The permittee will notify the C&E within 24 hours of the determination.

(c) The permittee will consult with the C&E before initiating any further injection.