FACT SHEET

Applicant:	HACKBERRY CARBON SEQUESTRATION, LLC 1500 Post Oak Blvd, Suite 1000 Houston, TX 77056 (713) 208-7838
Project Proposal:	Permit to drill, construct, and operate one Class VI Injection Well
Well Names:	Hackberry Carbon Sequestration Well No. 001
Project Location:	Section 12, Township 12 South, Range 11 West Cameron Parish
Facility Local Address:	30°01'55.08295" N, 93°27'12.07152" W
Application No.:	45026
Docket No.:	IMD 2025-04

Project Summary: The following information is prepared according to the requirements of Statewide Order No. 29-N-6, (LAC 43:XVII, Subpart 6) to briefly set forth the principal facts and significant policy questions considered in preparing a draft permit concerning an application by Hackberry Carbon Sequestration, LLC (HCS) to drill, construct, and operate one Class VI injection well in Cameron Parish, Louisiana.

The application is for the drilling and operation of one proposed Class VI geologic sequestration (injection) well. The total depth of the well is approximately 10,100 feet below ground level.

HCS proposes to inject up to approximately 2 million metric tons of carbon dioxide per year for an estimated 20 years. The potential carbon dioxide stream will be sourced from Cameron LNG, LLC's (CLNG) liquefied natural gas (LNG) export facility, the CLNG Facility.

General Information: HCS proposes to inject carbon dioxide for the purpose of geologic sequestration. The base of the lowermost underground source of drinking water (USDW) is approximately 1,090 feet below ground level. There are no registered water wells located within a one-mile radius of the proposed well location. The principal regional aquifer in the area is the confined Chicot Aquifer.

The complete application consists of the application form (Form UIC-60 Class VI Well Permit application) and technical attachments describing the geology, hydrogeology, area of review, corrective action, well construction, completion, operation, testing and monitoring, plugging and abandonment, closure and post-closure plans, and financial responsibility for the proposed activity.

The draft permit conditions were based on applicable rules and regulations as set forth in Statewide Order No. 29-N-6 (LAC: 43:XVII, Subpart 6) as amended. Such rules provide for the protection

and non-endangerment of USDW regarding the permitting, drilling, completing, operating, and maintaining of Classes VI injection well operations in the State of Louisiana.

Application Location: The application package is available for viewing on the Louisiana Department of Energy and Natural Resources – Injection & Mining Division webpage.

For any information concerning the application, call Gavin Broussard at (225) 342-5515, Monday through Friday, between the hours of 8:00 a.m. to 4:30 p.m.

Comment Period: The public comment period officially commences April 3, 2025, at 8:00 a.m. and concludes May 6, 2025, at 4:30 p.m. Submit all comments in writing to Gavin Broussard, Louisiana Office of Conservation, Injection and Mining Division, 617 N. 3rd St, Baton Rouge, LA 70802. Comments may also be e-mailed to info@la.gov. Please reference: Hackberry Carbon Sequestration – Class VI Permit – Docket No. IMD 2025-04.

Public Hearing: The Commissioner of Conservation will hold a public hearing for the purpose of receiving testimony, facts, or oral or written comments relevant to the Draft Permit. During this hearing, the hearing officer will only receive comments. The Office of Conservation will respond to all relevant comments in a written report after the conclusion of the public comment period.

The hearing will be held in Cameron Parish at the Hackberry Community Center, 980 Main St. Hackberry, LA 70645 at 6:00 pm on May 5, 2025.

STATE OF LOUISIANA
OFFICE OF CONSERVATION
BATON ROUGE, LOUISIANA

ORDER NO. IMD 2025-04 GS

Order approving the drilling, construction, and operation of one new Class VI injection well for geologic sequestration of carbon dioxide for

HACKBERRY CARBON SEQUESTRATION, LLC
Operator Code H8907

at the

Wildcat-So LA Lafayette Dist Field
Cameron Parish, Louisiana
* * * * * * * * * * * *

Pursuant to power delegated under the laws of the State of Louisiana, and particularly Title 30 of the Louisiana Revised Statutes of 1950 as amended and as implemented in the rules and regulations promulgated by the Commissioner of Conservation in LAC 43:XVII, Subpart 6, Chapter 36 (Statewide Order No. 29-N-6) and after a public hearing held on May 5, 2025, in the Hackberry Community Center, 980 Main St, Hackberry LA 70645 under **Docket No. IMD 2025-04** following legal publication of notice, the Commissioner of Conservation issues and promulgates the following Order as being reasonably necessary to carry out the laws of this State.

FINDINGS OF FACTS

THE COMMISSIONER FINDS AS FOLLOWS:

1. That Hackberry Carbon Sequestration, LLC (HCS) of 1500 Post Oak Blvd, Suite 1000, Houston, TX 77056 applied to the Louisiana Office of Conservation as required by Statewide Order 29-N-6 (LAC 43:XVII.3605.C) for approval to drill, complete, and operate one new Class VI injection well for geologic sequestration of carbon dioxide located in Section 12, Township 12 South, Range 11 West at its facility located near Hackberry in Cameron Parish, Louisiana.

2. That the facility's coordinates are 30°01'55.08295" N, 93°27'12.07152" W.

3. That the application submitted by HCS, was assigned Application No. 45026, dated February 5, 2024, was administratively complete on March 15, 2024, was technically complete on March 25, 2025, and supplied all information required by Statewide Order No. 29-N-6 (LAC 43:XVII, Subpart 6) as it pertains to Class VI injection wells.

4. That the new Class VI injection well (injection well) and its location are identified as:

Well Name & Number	Serial Number	API	Latitude*	Longitude*
Hackberry Carbon Sequestration Well No. 001	######	##############	30° 01′ 50.432″	-93° 26′ 53.74″

**Coordinates are listed in the NAD 27 system*

5. That the Commissioner of Conservation held a public hearing in Hackberry, Louisiana on May 5, 2025, after giving public notice in *The Advocate*, the official journal of the State of Louisiana, and in the *Cameron Parish Pilot*, the official journal of Cameron Parish. The Office of Conservation also provided a copy of the public notice to interested parties including the governing authority of Cameron Parish as required by LA R.S. 30:1105.

6. That the Commissioner of Conservation (Commissioner) adequately addressed all relevant public comments presented pertaining to Application No. 45026 and provided as Exhibit A.

7. That the deepest underground source of drinking water (USDW) in the vicinity of the proposed location of the well is at a depth of approximately 1,090 feet below ground level (bgl).

8. That HCS conducted a search of available public records of the wells located in the area of review (AOR), which HCS delineated using computational modeling, and the search showed that no wells penetrated the confining zone.

9. That HCS plans to inject into the injection well for an estimated 20 years.

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10. That HCS plans to inject up to an estimated 2 million metric tons of injectate per year.

11. That HCS demonstrated that the injection well is sited in an area with suitable geology according to the well siting requirements of Statewide Order No. 29-N-6 (LAC 43:XVII.3615.A).

12. That HCS will site the injection well according to the additional siting requirements of Statewide Order No. 29-N-6 (LAC 43:XVII.3615.D).

13. That HCS will construct the injection well according to the construction requirements of Statewide Order No. 29-N-6 (LAC 43:XVII.3617) so as not to pose an endangerment to USDW.

14. That HCS will adhere to the pre-operations requirements of Statewide Order No. 29-N-6 (LAC 43:XVII.3619) before being granted final approval for the operation of the injection well.

15. That HCS will operate the injection well according to the provisions of Statewide Order No. 29-N-6 (LAC 43:XVII.3621).

16. That HCS will adhere to the emergency and remedial response requirements of Statewide Order No. 29-N-6 (LAC 43:XVII.3623).

17. That HCS will meet the testing and monitoring requirements of Statewide Order No. 29-N-6 (LAC 43:XVII.3625) and any additional monitoring requirements as may be defined in this Order beyond those minimum regulatory requirements.

18. That HCS will reevaluate the AOR at a fixed frequency not to exceed five years or sooner when monitoring and operating conditions warrant as required by Statewide Order No. 29-N-6 (LAC 43:XVII.3615.B).

19. That HCS will maintain the injection well in such a manner to meet the mechanical integrity requirements of Statewide Order No. 29-N-6 (LAC 43:XVII.3627).

20. That HCS will provide timely reports and keep accurate records of the injection well operation as required by Statewide Order No. 29-N-6 (LAC 43:XVII.3629).

21. That HCS has committed to meeting the plugging and abandonment requirements of Statewide Order No. 29-N-6 (LAC 43:XVII.3631).

22. That HCS will adhere to the closure and post-closure requirements of Statewide Order No. 29-N-6 (LAC 43:XVII.3633).

23. That HCS will maintain the financial resources required by Statewide Order No. 29-N-6 (LAC 43:XVII.3609.C) that are necessary to adequately fulfill corrective action of LAC 43:XVII.3615.C, injection well plugging of LAC 43:XVII.3631, post-injection site care and site closure of LAC 43:XVII.3633, and Emergency and Remedial Response of LAC 43:XVII.3623.

24. That contingency plans to cope with all shut-ins and well failures are reasonable and sound and will be carried out when needed to prevent contamination of USDW.

25. That the proposal of HCS to drill, complete, and operate a new Class VI injection well identified in Findings of Fact No. 4, as set forth in the application, is suitable for Class VI injection operations subject to construction, testing, monitoring, operating conditions, and limitations and/or conditions imposed by Statewide Order No. 29-N-6 or successor document and any subsequent order issued by the commissioner.

26. That to satisfy the requirements of Louisiana Constitution Article IX,§1, La R.S.30:1104.1, and Statewide Order No. 29-N-6 (LAC 43:XVII.3607.D), the Office of Conservation required HCS to furnish appropriate information together with sufficient justification and supporting data, which was considered and examined in light of other information available to this Office.

27. Based on information provided by HCS in the application package, and other information available to this office, it is the conclusion of the Office of Conservation that:

    a. The potential and real adverse environmental effects have been avoided to the maximum extent practicable;

    b. A cost benefit analysis of the environmental impact cost balanced against the social and economic benefits of the project demonstrate that the latter outweighs the former;

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c. There are no alternative activities which would offer more protection of the environment than the proposed activity without unduly curtailing nonenvironmental benefits;

d. There are no alternative sites which would offer more protection to the environment than the proposed site without unduly curtailing nonenvironmental benefits; and

e. There are no mitigating measures which would offer more protection to the environment than the proposed activity without unduly curtailing nonenvironmental benefits.

28. After review of available information, the site geology is suitable for geologic sequestration of carbon dioxide subject to any monitoring and operating conditions or limitations stipulated in this Order.

ORDER

NOW, THEREFORE, IT IS ORDERED:

1. Authority to Drill and Construct

   a. The proposal of HCS to drill and construct Hackberry Carbon Sequestration Well No. 001, Serial Number ######, at its facility located in Section 12, Township 12 South, Range 11 West Cameron Parish, Louisiana as set forth in the application and this Order is hereby approved subject to limitations and/or conditions imposed by this Office as may be defined in this Order.

   b. Approval to drill and construct Hackberry Carbon Sequestration Well No. 001, Serial Number ###### will remain in effect for a period of one year and if not begun in that time, the permit shall be null and void. The permittee may request an extension of this one-year requirement; however the commissioner shall approve the request for extenuating circumstances only.

2. Siting Criteria, Area of Review, and Corrective Action

   a. The final AOR shall be based on modeling, using data obtained during logging and testing of the well and formation as required by Statewide Order 29-N-6 (LAC 43:XVII.3619).

   b. At a fixed frequency not to exceed five years or sooner when monitoring and operating conditions warrant, HCS shall:

      i. Reevaluate the AOR in the same manner specified in LAC 43:XVII.3615.B;

      ii. Identify all wells in the reevaluated AOR that require corrective action in the same manner specified in LAC 43:XVII.3615.B;

      iii. Perform corrective action on wells requiring corrective action in the reevaluated AOR in the same manner specified in LAC 43:XVII.3615.C; and

      iv. Submit an amended AOR and corrective action plan (CAP), or demonstrate to the commissioner through monitoring data and modeling results that no change to the AOR and CAP is needed.

   c. Following each AOR reevaluation or a demonstration that no evaluation is needed, HCS shall submit a report of the resultant information to the commissioner for review and approval.

   d. Amendments to the AOR are subject to the permit modification requirements of LAC 43:XVII.3613.

3. Authority to operate Hackberry Carbon Sequestration Well No. 001, Serial Number ###### is subject to provisions of those applicable portions of the pre-operating requirements of Statewide Order 29-N-6 (LAC 43:XVII.3619).

4. Injection Zone, Injection Interval, and Maximum Authorized Injection Pressure

   a. The injection zone, initial and subsequent injection intervals, and maximum authorized injection pressure for the Class VI well are as indicated in the following table:

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Depths (ft SSTVD)		Initial and Subsequent Injection Interval	Maximum Bottom-Hole Injection Pressure (PSI)
Injection Zone	Injection Interval		
4,022'-10,026'	4,026'-6,643'	Subsequent	TBD
	6,693'-7,524'	Subsequent	TBD
	7,574'-8,239'	Subsequent	TBD
	8,289'-10,026'	Initial	TBD

Table 1- Depths in the table are from the application. Actual depths and maximum authorized parameters will be determined from Hackberry Carbon Sequestration Well No. 001, Serial Number ######.

b. Maximum authorized injection pressure for each interval shall be limited to 90 percent of the fracture pressure of the currently authorized injection formation.

c. The injection zone depths, injection interval depths, and the maximum authorized injection pressure may be revised administratively due to well completion, well recompletion, future injectivity tests, or other pertinent data. A maximum injection pressure shall be established for the subsequent injection interval of Hackberry Carbon Sequestration Well No. 001 if and when the injection well is recompleted in a subsequent injection interval.

5. HCS shall submit a quarterly monitoring report to the Office of Conservation using Form UIC-61 (Class VI Quarterly Report), or subsequent form. The report is due within 30 days after the end of the respective calendar quarter.

6. Annulus Pressure and Annulus Fluid Monitoring

a. HCS shall maintain a tubing-casing annulus pressure that exceeds the operating injection pressure, unless the commissioner determines that such requirement might harm the integrity of the well or endanger a USDW. The minimum tubing-casing annulus pressure maintained in the injection well shall be 200 psig. A request to operate the well at a reduced annulus pressure must be in writing and approved by the commissioner.

b. During periods of actual injection, the tubing-casing annular pressure shall be at least 50 psig greater than the well's actual operating surface injection pressure.

c. The condition of Order Item No. 6.a. and b above, do not apply to periods of workovers, well or reservoir tests, other routine maintenance, or for time periods of less than four consecutive hours where well mechanical integrity is not determined to be lacking and timely action is taken to correct pressure fluctuations.

d. HCS shall thoroughly investigate and take timely action to address all fluctuations below the minimum annular pressure requirements, except as noted in Order Item No. 6.c. HCS shall include an attachment to the Form UIC-61 submission that details the total time duration and cause of each pressure deviation below the minimum, and the action taken to comply with the minimum annular pressure requirements.

e. HCS shall maintain a strict accounting of fluid that is added or removed from the annulus. The values shall be reported on the Class VI Quarterly Report.

7. Alarm and Automatic Shutdown Systems

a. HCS shall install, test, and maintain alarms and automatic surface shut-off valves or, at the discretion of the commissioner, down-hole shut-off systems (e.g., automatic shut-off, check valves) or, other mechanical devices that provide equivalent protection designed to actuate on exceedance of operating parameters such as injection pressure, annulus pressure differential, or any other parameter specified in this Order.

b. If a shutdown (i.e., down-hole or at the surface) is triggered or evidence of a loss of mechanical integrity is discovered, HCS must immediately investigate and identify as expeditiously as possible the cause of the shutoff or the evidence of a loss of mechanical integrity. If, upon such investigation, the well is lacking mechanical integrity, or if monitored well parameters indicate that the well may be lacking mechanical integrity, HCS must:

i. Immediately cease injection;

ii. Take all steps reasonably necessary to determine whether there may have been a release of the injected carbon dioxide stream or formation fluids into any unauthorized zone;

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iii. Notify the commissioner within 24 hours;

iv. Restore and demonstrate mechanical integrity to the satisfaction of the commissioner prior to resuming injection; and

v. Notify the commissioner when injection can be expected to resume.

c. All emergency shutdown systems shall be fail-safe. HCS shall function-test all critical systems of control and safety at least once every six months. This includes testing of alarms, test tripping of emergency shutdown valves ensuring their closure times are within design specifications, and ensuring the integrity of all electrical, pneumatic, and hydraulic circuits. Test dates and results shall be documented and be available for inspection by an agent of the Office of Conservation.

8. HCS shall report to the commissioner any noncompliance which may endanger health or the environment. Any information pertinent to the noncompliance shall be reported by telephone at (225) 342-5515 within 24 hours from the time the permittee becomes aware of the circumstances. A written submission shall also be provided within five days of the time the permittee becomes aware of the circumstances and shall contain a description of the noncompliance and its cause; the period of noncompliance, including exact dates and times, and if the noncompliance has not been corrected, the anticipated time it is expected to continue; and steps taken or planned to reduce, eliminate, and prevent reoccurrence of the non-compliance.:

a. Any evidence that the injected carbon dioxide stream or associated pressure front may cause an endangerment to the USDW;

b. Any noncompliance with a permit condition or malfunction of the injection system, which may cause fluid migration out of the injection zone or into or between USDWs;

c. Any triggering of a shut-off system, either downhole or at surface;

d. Any release of carbon dioxide to the atmosphere or biosphere indicated by any of the monitoring technologies required by Statewide Order No. 29-N-6 (LAC 43:XVII.3625) or the Testing and Monitoring Plan; and

e. Any failure to maintain mechanical integrity.

9. Well Mechanical Integrity and Injection Reservoir Testing Requirements After Well Construction

a. HCS shall perform an annulus pressure test at least once every 12 months witnessed by an agent of the Office of Conservation, and after performing any well remedial work.

b. HCS shall perform an approved test method at least once every 12 months to determine the absence of significant fluid movement.

c. Pressure fall-off testing will be done at least every five years on each active subsurface injection interval as required by Statewide Order No. 29-N-6 (LAC 43:XVII.3625.A.6).

d. HCS shall perform a casing inspection log to determine the presence or absence of corrosion in the long-string casing as required by Statewide Order No. 29-N-6 (LAC 43:XVII.3627.A.4).

e. The commissioner may require other tests to evaluate mechanical integrity.

10. HCS shall review the Testing and Monitoring Plan at least once every five years in accordance with Statewide Order No. 29-N-6 (LAC 43:XVII.3625.A.10). Based on this review, HCS shall submit an amended Testing and Monitoring Plan or demonstrate to the commissioner that no amendment to the Testing and Monitoring Plan is needed. Amended plans or demonstrations shall be submitted to the commissioner as follows:

a. Within one year of an AOR reevaluation;

b. Following any significant changes to the facility, such as addition of monitoring wells or newly permitted injection wells within the AOR, on a schedule determined by the commissioner; or

c. When required by the commissioner.

11. Carbon Dioxide Stream Analysis

a. HCS shall analyze the carbon dioxide stream on a quarterly basis in order to yield data

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representative of its chemical and physical characteristics in accordance with Statewide Order No. 29-N-6 (LAC 43:XVII.3625.A.1). The injection stream has been identified as including the following constituents at these relative concentrations in Table 2:

Carbon Dioxide	Methane	Other
98.3%	1.6%	0.1%

Table 2

b. HCS shall report the maximum fluctuation in relative concentration for each constituent monthly using Form UIC-61 or subsequent form. Substantial fluctuations in relative concentrations of the injection steam constituents may result in the amendment of permit conditions by the commissioner.

12. Carbon Dioxide Plume and Pressure Front Tracking

a. HCS shall utilize the direct methods identified in the Testing and Monitoring Plan to detect potential vertical fluid migration around the wellbore and shall notify the commissioner within 24 hours of detecting fluid migration outside the permitted injection zone.

b. HCS shall utilize the direct methods identified in the Testing and Monitoring Plan to collect dynamic data from the injection zones including but not limited to: pressure, temperature, carbon dioxide saturation distribution, and permeability in order to calibrate the AOR model.

c. HCS shall utilize the direct methods identified in the Testing and Monitoring Plan to track the extent of the carbon dioxide plume.

13. HCS shall submit the appropriate work permit request form (Form UIC-17 or successor document) to the Office of Conservation, Injection & Mining Division for approval before well recompletion, any workover, well/formation stimulation, well cleanout, injection reservoir test, or other well maintenance. Prior notification or approval is not required for the performance of routine annular pressure tests provided an annular pressure test is the singular operation performed.

14. HCS shall maintain current and up-to-date documentation of financial responsibility acceptable to the Office of Conservation to fulfill the requirements of corrective action, closure (plug and abandon), post-injection site care and site closure, and emergency and remedial response as required by Statewide Order No. 29-N-6 (LAC 43:XVII.3609.C)

15. HCS shall allow entry into and inspection of the permitted facility by Office of Conservation personnel as prescribed in La R.S. 30:1104.

16. Except as to the extent supplemented by these Findings and Order, the provisions of Statewide Order No. 29-N-6 (LAC 43:XVII, Subpart 6) of the Louisiana Office of Conservation shall apply to the operation of the well in particular the Legal Permit Conditions of Statewide Order No. 29-N-6 (LAC 43:XVII.3609).

17. HCS shall refer to Statewide Order No. 29-N-7 (LAC 43:XVII.Chapter 38) or any subsequent Order or Act for regulatory fees and fee schedule associated with the operation of the Class VI Injection Well.

18. This Order is granted exclusively unto HCS for Hackberry Carbon Sequestration Well No. 001, Serial Number ######. The decisions rendered by and through this Order shall establish no precedence on similar proposals for any other existing or future Class VI injection well, operation, or project at this or other sites under the jurisdiction of the Louisiana Office of Conservation.

19. The decision to issue this Order was preceded by a determination made on the record as a whole that the proposal to drill, construct, and operate Hackberry Carbon Sequestration Well No. 001, Serial Number ######, as set forth in the application and this Order is reasonable, is justified by the particular circumstances, is consistent with the intent of applicable regulations and laws of the State of Louisiana regarding physical and environmental safety and the prevention of waste, is proposed in a way that will ensure protection of the State's natural resources, and is consistent with protection of the health, safety, and welfare of the people.

20. This Order is subject to modification, revocation and reissuance, or termination upon receipt and review by this Office of future mechanical integrity test data or any information or data that would show the conditions by which this Order was issued are no longer valid.

21. Findings of Facts Nos. 3, 4, 7, 8, 11, 12, 13, 14, 15, 16, 17, 18, 19, 20, 21, 22, 23, 24, 25, 26, and 27, are hereby approved and expressly ordered.

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22. This Order shall be effective on and after **Order Date**, and shall be valid for the operating life of the facility and the post-injection site care period. The commissioner shall review this Order at least once every five years to determine whether it should be modified, revoked and reissued, terminated, or a minor modification made.

BY ORDER OF:

STEVEN M. GIAMBRONE
OFFICE OF CONSERVATION

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CLASS VI WELL PERMIT APPLICATION

OFFICE OF CONSERVATION
INJECTION & MINING DIVISION
617 N. Third St., 9th FLOOR
BATON ROUGE, LA 70802

Injection-Mining@la.gov
(225) 342-5515

UIC-60 CCS TYPE ONLY

APPLICATION NO. (FOR OFFICE USE ONLY)

1. APPLICATION TYPE: (Check One)
- ■ DRILL AND COMPLETE NEW CLASS VI WELL
- ❒ CONVERT AN EXISTING WELL TO CLASS VI

2. PROJECT NAME
HACKBERRY CARBON SEQUESTRATION PROJECT

3. OWNER/OPERATOR NAME
HACKBERRY CARBON SEQUESTRATION, LLC

4. OPERATOR CODE
H8907

5. OWNER/OPERATOR MAILING ADDRESS
1500 POST OAK BLVD, SUITE 1000
HOUSTON, TX 77056

6. FACILITY ADDRESS
30°01'55.08295" N, 93°27'12.07152" W

7. TELEPHONE NO
832-417-3785

8. E-MAIL ADDRESS
JKOSS@SEMPRAGLOBAL.COM

9. WELL NAME
HACKBERRY CARBON SEQUESTRATION WELL

10. WELL NO
001

11. WELL SERIAL NO (Well Conversions Only)

WELL LOCATION INFORMATION

12. FIELD NAME
WILDCAT-SO LA LAFAYETTE DIST

13. FIELD CODE
9727

14. PARISH NAME
CAMERON

15. SECTION
12

16. TOWNSHIP
12S

17. RANGE
11W

18. LOCATION COORDINATES (GCS, NAD 27)
LATITUDE: 30 ° 01 MIN 50.432 SEC
LONGITUDE: -93 ° 26 MIN 53.74 SEC

19. STATE PLANE COORDINATES (LAMBERT, NAD 27)
❒ NORTH ZONE ■ SOUTH ZONE
X: 502189.634 Y: 1330788.286

20. LEGAL LOCATION DESCRIPTION (FROM LOCATION PLAT):
BEGINNING AT THE NORTHWEST CORNER OF SECTION TWELVE(12), TOWNSHIP TWELVE (12) SOUTH, RANGE ELEVEN (11) WEST, LOUISIANA MERIDIAN, CAMERON PARISH, LOUISIANA; THENCE SOUTH 00° 40' 00" WEST, FOR A DISTANCE OF 2500.33 FEET; THENCE SOUTH 89° 20' 00" EAST, FOR A DISTANCE OF 769.27 FEET TO THE PROPOSED LOCATION

21. WELL CONSTRUCTION INFORMATION

CASING SIZE (IN)	HOLE DIAMETER (IN)	CASING WEIGHT (LB/FT)	CASING GRADE	CASING SETTING DEPTHS TOP	CASING SETTING DEPTHS BOTTOM	TOTAL SACKS	SACKS CEMENT (Lead/Tail)	TYPE (Lead/Tail)	YIELD (CU FT/SACK) (Lead/Tail)	CEMENT TOP
18-5/8"	N/A	84.51	X-42	0	+-200'	N/A	N/A	N/A	N/A	N/A
13-3/8"	17-1/2"	68	L-80	0	2,500'	1,880	853/1027	TYPE 1	2.34/1.29	SURF
9-5/8	12-1/4"	47	L-80	0	3,550'					
9-5/8	12-1.4"	47	22/25 CR	3,550'	3,950'					
7"	10-3/4"	29	22/25 CR	3,950'	10,100'	2947*	523/2,424*	PERMASET*	2.2/1.32*	SURF

22. BASE OF USDW (FT): 1,090' REFERENCE E-LOG (SERIAL NUMBER): 61098	23. ELEVATION OF DATUM FOR PROPOSED WELL (FT): ■ KB ☐ GL ☐ MSL
24. PLUGGED BACK DEPTH (FT): 10,100'	25. TOTAL DEPTH (FT): 10,100'
26. TUBING SIZE: 7" DEPTH: 3,950'	27. PACKER SIZE: 7" X 9-5/8" DEPTH: 3,940'

PROPOSED INJECTION INTERVAL INFORMATION

28. WELL COMPLETION ☐ OPEN HOLE ■ PERFORATIONS ☐ SCREEN

29. PROPOSED INJECTION FORMATION NAME(S):
MIOCENE

30. PROPOSED INJECTION ZONES:
4,022' TO 10,026

31. PROPOSED PERFORATION INTERVALS:
8,289'-10,026'; 7,574'-8,239'; 6,693'-7,524'; 4,026'-6,643'

PROPOSED INJECTION STREAM INFORMATION

32. PROJECTED TOTAL MASS (MM-T): 40.0	33. PROJECTED INJECTION PERIOD (YR): 20

34. INJECTION STREAM COMPOSITION (RELATIVE PERCENTAGE):
98.3% CO2, 1.6% CH4, 0.1% OTHER

35. SITE PERMITS

PERMITTING AUTHORITY	PERMIT/APPLICATION NUMBER	CURRENT STATUS
FEDERAL ENERGY REGULATORY COMMISSION	CP22-41-000	RECEIVED NTP PENDING
US ARMY COPRS OF ENGINEERS	MVN-2021-01265-WQQ	RECEIVED
US FISH AND WILDLIFE SERVICE	2024-0125764	RECEIVED
NOAA MATIONAL MARINE FISHERIES SERVICE	PROJECT COMMENTS	RECEIVED
LDEQ - 401 WATER QUALITY	WQC 211229-01	RECEIVED
LDEQ - HYDROSTATIC TEST WATER DISCHARGE		TBD
LA OFFICE OF CULTURAL DEVELOPMENT	REPORT NO. 22-6871	RECEIVED
LDNR - COASTAL USE	P20210822	RECEIVED
LDENR - PIPELINE CONSTRUCTION & OPERATING		TBD
LA DEPT. OF WILDLIFE AND FISHERIES	PROJECT COMMENTS	RECEIVED

36. LIST ANY RELEVANT OFFICE OF CONSERVATION ORDERS (e.g., 29-E exemptions and field orders related to offset production):

37. IS THE WELL LOCATED WITHIN THE LOUISIANA COASTAL ZONE? ☑ YES ☐ NO

OTHER INFORMATION		
38. IS THE WELL OR PROPOSED AOR BOUNDARY LOCATED ON INDIAN LANDS OR OTHER LANDS OWNED BY OR UNDER THE JURISDICTION OR PROTECTION OF THE FEDERAL GOVERNMENT?	☐ YES	☑ NO
39. IS THE WELL OR PROPOSED PLUME LOCATED ON STATE WATER BOTTOMS OR OTHER LANDS OWNED BY OR UNDER THE JURISDICTION OR PROTECTION OF THE STATE OF LOUISIANA?	☐ YES	☑ NO
40. IS THE WELL OR PROPOSED AOR BOUNDARY LOCATED ON LANDS OWNED BY OR UNDER THE JURISDICTION OR PROTECTION OF THE STATE OF ARKANSAS, THE STATE OF MISSISSIPPI, OR THE STATE OF TEXAS?	☐ YES	☑ NO

41. AGENT OR CONTACT AUTHORIZED TO ACT ON BEHALF OF THE APPLICANT DURING THE PROCESSING OF THIS APPLICATION

NAME: JOHN KOSS
COMPANY: HACKBERRY CARBON SEQUESTRATION, LLC
MAILING ADDRESS: 1500 POST OAK BLVD, SUTE 1000 // HOUSTON, TX 77056
PHONE: 832-417-3785
EMAIL: JKOSS@SEMPRAGLOBAL.COM CC: NROBINSON@SEMPRAGLOBAL.COM

42. CERTIFICATION BY WELL OWNER/OPERATOR (LAC 43:XVII.3605.E)

I certify that as the owner/operator of the injection well, the person identified in Item No. 46 above is authorized to act on my behalf during the processing of this application, to submit additional information as requested, and to give oral statements in support of this application. I will grant an authorized agent of the Office of Conservation entry onto the property to inspect the injection well and related appurtenances as per LSA-R.S. 30:4. I agree to operate the well in accordance with Office of Conservation guidelines. I further certify under penalty of law that I have examined and am familiar with the information submitted in this document and all attachments and that based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine or imprisonment or both (LSA-R.S. 30:17).

PRINT NAME OF WELL OWNER/OPERATOR	TITLE OF COMPANY OFFICIAL
HACKBERRY CARBON SEQUESTRATION, LLC	VP DEVELOPMENT LOW CARBON SOLUTIONS

DIGITAL SIGNATURE OF WELL OWNER/OPERATOR

Eekhout, Juancho

Digitally signed by Eekhout, Juancho
Date: 2025.03.31 12:24:54 -07'00'

SUBMIT THE FOLLOW AS A COMPLETE APPLICATION FOR A CLASS VI WELL:

- All application materials must be prepared in accordance with LAC 43:XVII.Chapter 36 and should be submitted electronically following LDENR Class VI Application Submittal Guidelines. Hard copy materials should not be submitted unless otherwise directed by the Office of Conservation. Redacted materials should be submitted while CBI rules are being developed within the Office of Conservation.

- Form UIC-60 CCS
  - The field designation will be based upon which Office of Conservation district the well is to be located in (click here to see the district outlines):
    - WILDCAT-SO LA LAFAYETTE DIST (9727)
    - WILDCAT-NO LA SHREVEPORT DIST (9715)
    - WILDCAT-NO LA MONROE DIST (9709)
  - USDW Information
    - The depth of the base of the Underground Source of Drinking Water (USDW) should be based on the e-log of the nearest offset well that shows the USDW. Please ensure that an annotated copy of this well log is included in the GSDT submission.
    - Conduct a search from the proposed well location to locate the closest well with an e-log that shows the lowermost USDW. The USDW can be determined from the deep induction curve on the e-log. Resistivity changes with temperature and depth, therefore the guidelines below are used to approximate the lowermost USDW in sands at the following depths:
      i. Ground surface to 1,000 feet: 3 ohms or higher is considered USDW;
      ii. 1,000 feet to 2,000 feet: 2 ½ ohms or higher is considered USDW; and
      iii. 2,000 feet and deeper: 2 ohms or higher is considered USDW.
    - Clay or shale intervals with resistivity values higher than these are not considered USDW.
  - Proposed Well Information
    - Well construction depths and formation depths for the Class VI well should be based on projected subsurface information as indicated in the application rather than a single offset e-log.
  - The signature of the well owner/operator must be a verifiable digital signature rather than a scan.

- One Form MD-10-R-A for each existing well to be converted (only required if conversion is proposed)

- One original Certified Location Plat that complies with the requirements of the IMD-GS-10 Policy;

- Freshwater Wells
  - Applicants must submit a tabulation of all freshwater wells within the area of review (AOR). A diligent search must be attempted to locate all freshwater wells within the AOR of the proposed injection well. You may use the attached Freshwater Well List example or make up your own list, so long as all the information is included.
  - **A DILIGENT SEARCH MUST BE ATTEMPTED TO LOCATE ALL REGISTERED FRESHWATER WELLS WITHIN THE AOR**, which involves conducting a foot search of the AOR and searching the water well registry on SONRIS.
  - Applicants must submit laboratory analyses of water samples from a representative sampling of the freshwater wells included on the Freshwater Well List. IMD should be consulted on the final list of wells to be sampled, otherwise additional sampling may be required during the application process. The laboratory analyses must be signed originals from a LDEQ LELAP accredited laboratory. The analysis sheet(s) must identify the freshwater well sampled and, at minimum, include measurements of chlorides, TDS, pH, alkalinity, dissolved CO2, specific gravity, and temperature of the fluid sample when specific gravity was measured.

- Certification of geoscientific and engineering submittals
  - Per LAC 43:XVII.3603.H.2, all applications, reports, plans, requests, maps, cross-sections, drawings, opinions, recommendations, calculations, evaluations, or other submittals including or comprising geoscientific work as defined by La. R.S. 37:711.1 et seq. must be prepared, sealed, signed, and dated by a licensed Professional Geoscientist (P.G.) authorized to practice by and in good standing with the Louisiana Board of Professional Geoscientists.
  - Per LAC 43:XVII.3603.H.3, all applications, reports, plans, requests, specifications, details, calculations, drawings, opinions, recommendations, evaluations or other submittals including or comprising the practice of engineering as defined by La. R.S. 37:681 et seq. must be prepared, sealed, signed, and dated by a licensed Professional Engineer (P.E.) authorized to practice by and in good standing with the Louisiana Professional Engineering and Land Surveying Board.
  - For electronic submission, the seal, signature, and date of signature must be transmitted in a secure mode that reasonably precludes the seal, signature, and date being reproduced or modified. Examples of programs that provide a secure mode include DocuSign and Adobe Acrobat Pro. The seal must follow the same design as prescribed by the relevant professional board.
  - A signature page with the relevant seals, signatures, dates, and other information should be included immediately after the application cover page. A table identifying which attachments and portions of the application each professional is responsible for should be included. See attached example.

- Answer the following questions regarding the proposed permit activity as part of the environmental analysis required by La R.S. 30:1104. See attached guidance for additional information.
  - Have the potential and real adverse environmental effects of the proposed permit activity been avoided to the maximum extent possible?
  - Does a cost-benefit analysis of the environmental impact costs versus the social and economic benefits of the proposed activities demonstrate that the latter outweighs the former?
  - Are there alternative activities which would offer more protection to the environment than the proposed activity without unduly curtailing nonenvironmental benefits?
  - Are there alternative sites which would offer more protection to the environment than the proposed site without unduly curtailing nonenvironmental benefits?
  - Are there mitigating measures which would offer more protection to the environment than the proposed activity without unduly curtailing nonenvironmental benefits?

- Financial Responsibility
  - Applicants must submit documentation of active financial responsibility for plugging and abandonment of injection wells prior to issuance of the Permit to Construct.
  - Active financial responsibility instruments to cover the cost of corrective action, post-injection site care and site closure, and emergency and remedial response are not required prior to the issuance of the Permit to Construct but are required prior to the Authorization to Inject.

The Injection & Mining Division can be reached by telephone at 225-342-5515 or email Injection-Mining@la.gov.

FRESHWATER WELL LIST

☐ A DILIGENT SEARCH WAS MADE TO LOCATE ALL FRESHWATER WELLS WITHIN THE PROPOSED AOR AND NO WELLS WERE LOCATED.

☐ A DILIGENT SEARCH WAS MADE TO LOCATE ALL FRESHWATER WELLS WITHIN THE PROPOSED AOR AND THE FOLLOWING WELLS WERE LOCATED.

Map ID No.	Well Name	Owner	Total Depth (ft.)	Water Level (ft.)	Geologic Unit	Use Description	Well Status	Location Coordinates (GCS, NAD 27)	
								Latitude	Longitude

ACRONYMS AND ABBREVIATIONS

%	Percent(age)
§45Q	IRS Tax Code §45Q
°C	Degrees Celsius
°F	Degrees Fahrenheit
1D	One-Dimensional
2D	Two-Dimensional
3D	Three-Dimensional
4D	Four-Dimensional
AFI	Active Fracture Images
AOR	Area of Review
ARM	Ambient Reservoir Monitoring
ATSM	American Society for Testing and Materials
bbl	Barrel(s)
Bcf	Billion Cubic Feet
bpm	Barrels per Minute
CAA	Clean Air Act
CH_4	Methane
CO_2	Carbon Dioxide (may also refer to other Carbon Oxides)
CRA	Corrosion Resistant Alloy
CWA	Clean Water Act
DTS	Distributed Temperature Sensing
EPA	U.S. Environmental Protection Agency
ft	Foot (Feet)
g/cc	Grams per Cubic Centimeter
GR	Gamma Ray
H2O	Water
HCS	Hackberry Carbon Storage
hz	Hertz
ID	Inner Diameter

IGSN 71	International Gravity Standardization Net 1971
km	Kilometer(s)
LAC	Louisiana Administrative Code
LDENR	Louisiana Department of Natural Resources
Lat	Latitude
LNG	Liquified Natural Gas
Long	Longitude
MASIP	Maximum Allowable Surface Pressure
Mbbls	Thousand Cubic Feet
mD	Millidarcy(ies)
MEQ	Microseismic Earthquakes
mg/l	Milligrams per Liter
mGal	Milligals
mi	Mile(s)
MIT	Mechanical Integrity Test
MM	Million
MMbbls	Million Barrels
MMcf	Million Cubic Feet
mmscf	Million Standard Cubic Feet
mmscf/d	Million Standard Cubic Feet per Day
MT	Metric Tons
MMT/yr	Million Metric Tons per Year
NPDES	National Pollutant Discharge Ellimination System
OD	Outer Diameter
pH	Scale of Acidity
PHIX_EFF	Effective Porosity
ppm	Parts per Million
psi	Pounds per Square Inch
psig	Pounds per Square Inch Gauge

QA/QC	Quality Assurance / Quality Control
QPT	Quartz Pressure Temperature
RCRA	Resource Conservation and Recovery Act
SC	Specific Conductivity
SCADA	Supervisory Control and Data Acquisition
scf	Standard Cubic Feet
sDAS	Seismic Distributed Acoustic Sensing
SDI	Stream Depth Imaging
SDWA	Safe Water Drinking Act
S_{Hmax}	Maximum Horizontal Stress
SP	Spontaneous Potential
S_v	Vertical Stress
SWO	State-wide Order
TD	Total Depth
TDS	Total Dissolved Solids
TEC	Tubing Encapsulated Conductor
UIC	Underground Injection Control
USDW	Underground Source of Drinking Water
USGS	United States Geological Survey
Vshale	Volume Shale
VSP	Vertical Seismic Profile
XRD	X-Ray Diffraction
$\emptyset_{eff}$	Effective Porosity
$\emptyset$	Porosity

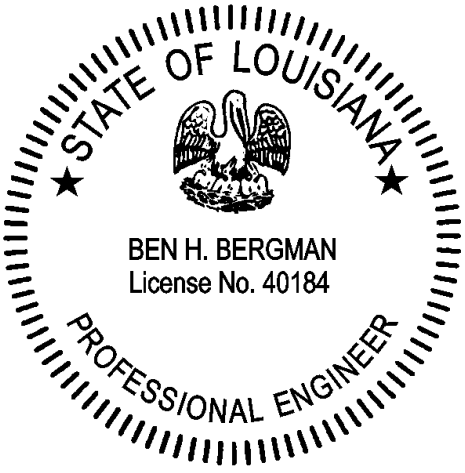
Class VI Permit Application for Hackberry Carbon Sequestration Well No. 001

Hackberry Carbon Sequestration, LLC
Cameron, LA

August 2021
Revised January 2025

Stephen Pattee, P.G.
Date: 1/29/2025 10:12 am

Ben H. Bergman P.E.
Ben Bergman, P.E.
Date: 1/29/25



STAMP BY	APPLICABLE SECTIONS
Stephen Pattee, P.G.	Section 1 – Site Characterization
	Appendix B – Site Characterization
	Appendix C - Hydrogeology
Ben Bergman, P.E.	Section 4 – Engineering Design and Operating Strategy
	Section 6 – Plugging and Abandonment
	Section 7 – Financial Assurance
	Appendix W – ERRP Cost Estimates

Underground Injection Control – Class VI Permit Application for Hackberry Carbon Sequestration Well No. 001

Cameron Parish, Louisiana

Prepared for *Hackberry Carbon Sequestration, LLC*
Cameron, LA

By

Lonquist Sequestration, LLC
Austin, TX

August 2021
Revised January 2025

FOREWORD

Hackberry Carbon Sequestration, LLC is proposing to develop a carbon sequestration facility in Cameron Parish, Louisiana near the town of Hackberry. The project is being designed to handle captured carbon oxides from the various industries in southwest Louisiana and the location for this proposed facility is ideally suited for that purpose. This site was selected for several reasons such as favorable geology, controlled pore space storage rights, numerous industrial facilities with sequestration needs, and existing pipeline right of ways by which to transport the captured gases for disposal.

The following application will fully detail and characterize the geology of the proposed well location, evaluate the formation for properties necessary to contain the sequestered CO_2 permanently, and describe the engineering designs and safety considerations for the well. The application will also discuss the proposed monitoring system which will be utilized to compare and contrast actual injectate plume migration to reservoir modeling and simulation of the anticipated plume.

The application has been developed to meet all of the requirements of both US Code ***40 CFR 146.82*** thru ***146.95*** as well as Louisiana Code ***LAC 43:XVII Chapter 6, Statewide Order No. 29-N-6*** ("SWO 29-N-6"), both of which detail regulations for Underground Injection Control ("UIC") Class VI wells. Once the permit has been issued, per the requirements of ***40 CFR 144.36(a)*** and SWO 29-N-6 ***§607.M.1***, the permit will be updated every five (5) years thereafter for the active injection life of the well.

Table 1 : 40 CFR - Subpart H - Criteria and Standards Applicable to Class VI Wells			
EPA 40 CFR	**LAC 43:XVII.Chapter 6**	**Description**	**Permit Application**
§146.82		**Required Class VI permit information**	
§146.82(a)	§603.A.3	(a) Prior to the issuance of a permit for the construction of a new Class VI well or the conversion of an existing Class I, Class II, or Class V well to a Class VI well, the owner or operator shall submit, pursuant to §146.91(e), and the Director shall consider the following:	
	§605.C.1	Permit Application. New applicants, permittees, and any person required to have a permit shall complete, sign, and submit an appplication to the commissioner as described in this section.	
	§605.C.1.a	the applicant shall submit one signed paper version of the application and an exact duplicate of the application in an electronic format approved by the commissioner. The commissioner may request additional paper copies of the application - either in its entirety or in part - as needed.	
	§605.C.1.b	the electronic version of the application shall contain the following certification statement: ***"This document is an electronic version of the application titled (insert doc title) dated (insert date). This electronic version is an exact duplicate of the paper copy submitted in (insert number of volumes comprising the full application) to the Louisiana Office of Conservation."***	Electronic Document Certification
	§605.C.1.c	the applicant shall submit the application identified in §605.C.1 above to the USEPA in an electronic format approved by the USEPA.	
	§605.G	Certification. Any person signing a document under §605.E shall make the following certification on the application: "I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that	Master Documents
§146.82(a)(1)		Information required in §144.31 (e)(1) through (6) of this Section;	
§144.31 (e)(1)	§607.B	The activities conducted by the applicant which require it to obtain permits under RCRA, UIC, the National Pollution Discharge Elimination System (NPDES) program under the Clean Water Act, or the Prevention of Significant Deterioration (PSD) program under the Clean Air Act.	Intro - Required Administrative Info
§144.31 (e)(2)	§607.B.3-4	Name, mailing address, and location of the facility for which the application is submitted.	Intro - Required Administrative Info
§144.31 (e)(3)	§607.B.8	Up to four SIC codes which best reflect the principal products or services provided by the facility.	Intro - Required Administrative Info
§144.31 (e)(4)	§607.B.3-5	The operator's name, address, telephone number, ownership status, and status as Federal, State, private, public, or other entity.	Intro - Required Administrative Info
	§607.B.6	a brief description of the nature of the business associated with the activity;	Intro - Required Administrative Info
	§607.B.7	the activity or activities conducted by the applicant which require the applicant to obtain a permit under these regulations;	Introduction
	§607.B.11	documentation of financial responsibility or documentation of the method by which proof of financial responsibility will be provided as required in §609.C. Before making a final permit decision, final (official) documentation of financial responsibility must be submitted to and approved by the Office of Conservation;	Introduction
	§607.B.12	names and addresses of all property owners within the area of review of the Class VI well or project.	N/A - Sec. 3 - AOR Results
§144.31 (e)(5)	§607.B.10	Whether the facility is located on Indian lands.	Intro - Required Administrative Info
§144.31 (e)(6)	§607.B.9	A listing of all permits or construction approvals received or applied for under any of the following programs:	Intro - Required Administrative Info
§144.31 (e)(6)(i)	§607.B.9.a	Hazardous Waste Management program under RCRA.	Intro - Required Administrative Info
§144.31 (e)(6)(ii)	§607.B.9.b	UIC program under SDWA.	Intro - Required Administrative Info
§144.31 (e)(6)(iii)	§607.B.9.c	NPDES program under CWA.	Intro - Required Administrative Info
§144.31 (e)(6)(iv)	§607.B.9.d	Prevention of Significant Deterioration (PSD) program under the Clean Air Act.	Intro - Required Administrative Info
§144.31 (e)(6)(ix)	§607.B.9.i	Other relevant environmental permits, including State permits.	Intro - Required Administrative Info
§144.31 (e)(6)(v)	§607.B.9.e	Nonattainment program under the Clean Air Act.	Intro - Required Administrative Info
§144.31 (e)(6)(vi)	§607.B.9.f	National Emission Standards for Hazardous Pollutants (NESHAPS) preconstruction approval under the Clean Air Act.	Intro - Required Administrative Info
§144.31 (e)(6)(vii)	§607.B.9.g	Ocean dumping permits under the Marine Protection Research and Sanctuaries Act.	Intro - Required Administrative Info
§144.31 (e)(6)(viii)	§607.B.9.h	Dredge and fill permits under section 404 of CWA	Intro - Required Administrative Info

EPA 40 CFR	LAC 43:XVII.Chapter 6	Description	Permit Application
§146.82(a)(2)	§607.C.1	A map showing the injection well for which a permit is sought and the applicable area of review consistent with §146.84. Within the area of review, the map must show the number or name, and location of all injection wells, producing wells, abandoned wells, plugged wells or dry holes, deep stratigraphic boreholes, State- or EPA-approved subsurface cleanup sites, surface bodies of water, springs, mines (surface and subsurface), quarries, water wells, other pertinent surface features including structures intended for human occupancy, State, Tribal, and Territory boundaries, and roads. The map should also show faults, if known or suspected. Only information of public record is required to be included on this map;	Sect. 3 - Figure 3.3, Appendix E-1, E-3, E-5, E-6
§146.82(a)(3)	§607.C.1.b	Information on the geologic structure and hydrogeologic properties of the proposed storage site and overlying formations, including:	Section 1 - Site Characterization
§146.82(a)(3)(i)	§607.C.1.b.ii	Maps and cross sections of the area of review;	Appendix E
§146.82(a)(3)(ii)	§607.C.1.b.iii	The location, orientation, and properties of known or suspected faults and fractures that may transect the confining zone(s) in the area of review and a determination that they would not interfere with containment;	Section 1, Geologic Structure
§146.82(a)(3)(iii)	§607.C.2.a	Data on the depth, areal extent, thickness, mineralogy, porosity, permeability, and capillary pressure of the injection and confining zone(s); including geology/facies changes based on field data which may include geologic cores, outcrop data, seismic surveys, well logs, and names and lithologic descriptions;	Section 1 - Site Characterization
§146.82(a)(3)(iv)	§607.C.2.b	Geomechanical information on fractures, stress, ductility, rock strength, and in situ fluid pressures within the confining zone(s);	Section 1, Geomechanics
§146.82(a)(3)(v)	§607.C.2.c	Information on the seismic history including the presence and depth of seismic sources and a determination that the seismicity would not interfere with containment; and	Section 1, Seismic History
§146.82(a)(3)(vi)	§607.C.1.b.i	Geologic and topographic maps and cross sections illustrating regional geology, hydrogeology, and the geologic structure of the local area.	Appendix B, C
§146.82(a)(4)	§607.C.2.d (Similar language specific to USDW)	A tabulation of all wells within the area of review which penetrate the injection or confining zone(s). Such data must include a description of each well's type, construction, date drilled, location, depth, record of plugging and/or completion, and any additional information the Director may require;	N/A: Water bottom
§146.82(a)(5)		Maps and stratigraphic cross sections indicating the general vertical and lateral limits of all USDWs, water wells and springs within the area of review, their positions relative to the injection zone(s), and the direction of water movement, where known;	Appendix B
§146.82(a)(6)	§607.C.2.e	Baseline geochemical data on subsurface formations, including all USDWs in the area of review;	Section 1, Geochemistry
§146.82(a)(7)	§607.C.2.f	Proposed operating data for the proposed geologic sequestration site:	Section 4
§146.82(a)(7)(i)	§607.C.2.f.i	Average and maximum daily rate and volume and/or mass and total anticipated volume and/or mass of the carbon dioxide stream;	Section 4, Detailed Discussion of Well Design
§146.82(a)(7)(ii)	§607.C.2.f.ii	Average and maximum injection pressure;	Section 2/Section 4
§146.82(a)(7)(iii)	§607.C.2.f.iii	The source(s) of the carbon dioxide stream; and	Intro - Injectate Information
§146.82(a)(7)(iv)	§607.C.2.f.iv	An analysis of the chemical and physical characteristics of the carbon dioxide stream.	Intro - Injectate Information
§146.82(a)(8)	§607.C.2.g	Proposed pre-operational formation testing program to obtain an analysis of the chemical and physical characteristics of the injection zone(s) and confining zone(s) and that meets the requirements at §146.87	Appendix F
§146.82(a)(9)	§607.C.2.h	Proposed stimulation program, a description of stimulation fluids to be used and a determination that stimulation will not interfere with containment	N/A
§146.82(a)(10)	§607.C.2.i	Proposed procedure to outline steps necessary to conduct injection operation	Appendix F
§146.82(a)(11)	§607.C.2.j	Schematics or other appropriate drawings of the surface and subsurface construction details of the well	Section 4, App F
§146.82(a)(12)	§607.C.2.k	Injection well construction procedures that meet the requirements of §146.86	Section 4, App F
§146.82(a)(13)	§607.C.2.l	Proposed area of review and corrective action plan that meets the requirements under §146.84	Section 3
§146.82(a)(14)	§607.C.2.m	A demonstration, satisfactory to the Director, that the applicant has met the financial responsibility requirements under §146.85	Section 10
§146.82(a)(15)	§607.C.2.n	Proposed testing and monitoring plan required by §146.90	Section 5
§146.82(a)(16)	§607.C.2.o	Proposed injection well plugging plan required by §146.92(b);	Section 6, Appendix G
§146.82(a)(17)	§607.C.2.p	Proposed post-injection site care and site closure plan required by §146.93(a);	Section 7
§146.82(a)(18)	§607.C.2.q	At the Director's discretion, a demonstration of an alternative post-injection site care timeframe required by §146.93(c);	N/A
§146.82(a)(19)	§607.C.2.r	Proposed emergency and remedial response plan required by §146.94(a);	Section 8, Appendix I
§146.82(a)(20)	§607.C.2.s	A list of contacts, submitted to the Director, for those States, Tribes, and Territories identified to be within the area of review of the Class VI project based on information provided in paragraph (a)(2) of this section; and	N/A
§146.82(a)(21)	§607.C.2.t	Any other information requested by the Director.	

EPA 40 CFR	LAC 43:XVII.Chapter 6	Description	Permit Application
§146.82(b)		The Director shall notify, in writing, any States, Tribes, or Territories within the area of review of the Class VI project based on information provided in paragraphs (a)(2) and (a)(20) of this section of the permit application and pursuant to the requirements at § 145.23(f)(13) of this chapter.	
§146.82(c)		Prior to granting approval for the operation of a Class VI well, the Director shall consider the following information:	
§146.82(c)(1)		The final area of review based on modeling, using data obtained during logging and testing of the well and the formation as required by paragraphs (c)(2), (3), (4), (6), (7), and (10) of this section;	Post drilling
§146.82(c)(10)		Any other information requested by the Director.	Post drilling
§146.82(c)(2)		Any relevant updates, based on data obtained during logging and testing of the well and the formation as required by paragraphs (c)(3), (4), (6), (7), and (10) of this section, to the information on the geologic structure and hydrogeologic properties of the proposed storage site and overlying formations, submitted to satisfy the requirements of paragraph (a)(3) of this section;	Post drilling
§146.82(c)(3)		Information on the compatibility of the carbon dioxide stream with fluids in the injection zone(s) and minerals in both the injection and the confining zone(s), based on the results of the formation testing program, and with the materials used to construct the well;	Post drilling
§146.82(c)(4)		The results of the formation testing program required at paragraph (a)(8) of this section;	Post drilling
§146.82(c)(5)		Final injection well construction procedures that meet the requirements of § 146.86;	N/A
§146.82(c)(6)		The status of corrective action on wells in the area of review;	Post drilling
§146.82(c)(7)		All available logging and testing program data on the well required by § 146.87;	Post drilling
§146.82(c)(8)		A demonstration of mechanical integrity pursuant to § 146.89;	Post drilling
§146.82(c)(9)		Any updates to the proposed area of review and corrective action plan, testing and monitoring plan, injection well plugging plan, post-injection site care and site closure plan, or the emergency and remedial response plan submitted under paragraph (a) of this section, which are necessary to address new information collected during logging and testing of the well and the formation as required by all paragraphs of this section, and any updates to the alternative post-injection site care timeframe demonstration submitted under paragraph (a) of this section, which are necessary to address new information collected during the logging and testing of the well and the formation as required by all paragraphs of this section; and	Post drilling
§146.82(d)		Owners or operators seeking a waiver of the requirement to inject below the lowermost USDW must also refer to § 146.95 and submit a supplemental report, as required at § 146.95(a). The supplemental report is not part of the permit application.	N/A
§146.83(a)	§615.A	Owners or operators of Class VI wells must demonstrate to the satisfaction of the Director that the wells will be sited in areas with a suitable geologic system. The owners or operators must demonstrate that the geologic system comprises:	Section 1, App B
§146.83(a)(1)	§615.A.1	An injection zone(s) of sufficient areal extent, thickness, porosity, and permeability to receive the total anticipated volume of the carbon dioxide stream;	Section 1, App B
§146.83(a)(2)	§615.A.2	Confining zone(s) free of transmissive faults or fractures and of sufficient areal extent and integrity to contain the injected carbon dioxide stream and displaced formation fluids and allow injection at proposed maximum pressures and volumes without initiating or propagating fractures in the confining zone(s).	Section 1, App B
§146.83(b)	§615.A.2.a	The Director may require owners or operators of Class VI wells to identify and characterize additional zones that will impede vertical fluid movement, are free of faults and fractures that may interfere with containment, allow for pressure dissipation, and provide additional opportunities for monitoring, mitigation, and remediation.	
§146.84	§615.B	**Area of Review and Corrective Action**	
§146.84(a)	§615.B.1	The area of review is the region surrounding the geologic sequestration project where USDWs may be endangered by the injection activity. The area of review is delineated using computational modeling that accounts for the physical and chemical properties of all phases of the injected carbon dioxide stream and is based on available site characterization, monitoring, and operational data.	Section 3, Section 2
§146.84(b)	§615.B.2	The owner or operator of a Class VI well must prepare, maintain, and comply with a plan to delineate the area of review for a proposed geologic sequestration project, periodically reevaluate the delineation, and perform corrective action that meets the requirements of this section and is acceptable to the Director. The requirement to maintain and implement an approved plan is directly enforceable regardless of whether the requirement is a condition of the permit. As a part of the permit application for approval by the Director, the owner or operator must submit an area of review and corrective action plan that includes the following information:	Section 3

EPA 40 CFR	LAC 43:XVII.Chapter 6	Description	Permit Application
§146.84(b)(1)	§615.B.2.a	The method for delineating the area of review that meets the requirements of paragraph (c) of this section, including the model to be used, assumptions that will be made, and the site characterization data on which the model will be based;	Section 3
§146.84(b)(2)		A description of:	
§146.84(b)(2)(i)	§615.B.2.b.i	The minimum fixed frequency, not to exceed five years, at which the owner or operator proposes to reevaluate the area of review;	Section 3, Proposed Reevaluation Cycle
§146.84(b)(2)(ii)	§615.B.2.b.ii	The monitoring and operational conditions that would warrant a reevaluation of the area of review prior to the next scheduled reevaluation as determined by the minimum fixed frequency established in paragraph (b)(2)(i) of this section.	Section 3, Table 2 - Reevaluation Triggers
§146.84(b)(2)(iii)	§615.B.2.b.iii	How monitoring and operational data (e.g., injection rate and pressure) will be used to inform an area of review reevaluation; and	Section 3, Table 2 - Reevaluation Triggers
§146.84(b)(2)(iv)	§615.B.2.b.iv	How corrective action will be conducted to meet the requirements of paragraph (d) of this section, including what corrective action will be performed prior to injection and what, if any, portions of the area of review will have corrective action addressed on a phased basis and how the phasing will be determined; how corrective action will be adjusted if there are changes in the area of review; and how site access will be guaranteed for future corrective action.	N/A
§146.84(c)	§615.B.3	Owners or operators of Class VI wells must perform the following actions to delineate the area of review and identify all wells that require corrective action:	
§146.84(c)(1)	§615.B.3.a	Predict, using existing site characterization, monitoring and operational data, and computational modeling, the projected lateral and vertical migration of the carbon dioxide plume and formation fluids in the subsurface from the commencement of injection activities until the plume movement ceases, until pressure differentials sufficient to cause the movement of injected fluids or formation fluids into a USDW are no longer present, or until the end of a fixed time period as determined by the Director. The model must:	Section 1, Section 2, Section 3
§146.84(c)(1)(i)	§615.B.3.a.i	Be based on detailed geologic data collected to characterize the injection zone(s), confining zone(s) and any additional zones; and anticipated operating data, including injection pressures, rates, and total volumes over the proposed life of the geologic sequestration project;	Section 1, Section 2
§146.84(c)(1)(ii)	§615.B.3.a.ii	Take into account any geologic heterogeneities, other discontinuities, data quality, and their possible impact on model predictions; and	Section 1, Section 2
§146.84(c)(1)(iii)	§615.B.3.a.iii	Consider potential migration through faults, fractures, and artificial penetrations.	None
§146.84(c)(2)	§615.B.3.b	Using methods approved by the Director, identify all penetrations, including active and abandoned wells and underground mines, in the area of review that may penetrate the confining zone(s). Provide a description of each well's type, construction, date drilled, location, depth, record of plugging and/or completion, and any additional information the Director may require; and	None
§146.84(c)(3)	§615.B.3.c	Determine which abandoned wells in the area of review have been plugged in a manner that prevents the movement of carbon dioxide or other fluids that may endanger USDWs, including use of materials compatible with the carbon dioxide stream.	None
§146.84(d)	§615.C.1	Owners or operators of Class VI wells must perform corrective action on all wells in the area of review that are determined to need corrective action, using methods designed to prevent the movement of fluid into or between USDWs, including use of materials compatible with the carbon dioxide stream, where appropriate.	N/A
§146.84(e)	§615.C.2	At the minimum fixed frequency, not to exceed five years, as specified in the area of review and corrective action plan, or when monitoring and operational conditions warrant, owners or operators must:	N/A
§146.84(e)(1)	§615.C.2.a	Reevaluate the area of review in the same manner specified in paragraph (c)(1) of this section	N/A
§146.84(e)(2)	§615.C.2.b	Identify all wells in the reevaluated area of review that require corrective action in the same manner specified in paragraph (c) of this section;	N/A
§146.84(e)(3)	§615.C.2.c	Perform corrective action on wells requiring corrective action in the reevaluated area of review in the same manner specified in paragraph (d) of this section; and	N/A
§146.84(e)(4)	§615.C.2.d	Submit an amended area of review and corrective action plan or demonstrate to the Director through monitoring data and modeling results that no amendment to the area of review and corrective action plan is needed. Any amendments to the area of review and corrective action plan must be approved by the Director, must be incorporated into the permit, and are subject to the permit modification requirements at §§144.39 or 144.41 of this Section, as appropriate.	N/A

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§146.84(f)	§615.C.3	The emergency and remedial response plan (as required by §146.94) and the demonstration of financial responsibility (as described by §146.85) must account for the area of review delineated as specified in paragraph (c)(1) of this section or the most recently evaluated area of review delineated under paragraph (e) of this section, regardless of whether or not corrective action in the area of review is phased.	Section 8, 10
§146.84(g)	§615.C.4	All modeling inputs and data used to support area of review reevaluations under paragraph (e) of this section shall be retained for 10 years.	Section 3
	§609.C.2	The amount of funds available in the financial instrument shall be no less than the amount identified in the cost estimate of the closure plan and any required post-injection site care and site closure, and must be approved by the commissioner	Section 10
	§609.C.3	Any financial instrument filed in satisfaction of the financial responsibility requirements shall be issued by and drawn on a bank or other financial institution authorized under state or federal law to operate in the State of Louisiana.	Section 10
§146.85		**Financial responsibility**	
§146.85(a)	§609.C.1	The owner or operator must demonstrate and maintain financial responsibility as determined by the Director that meets the following conditions:	Section 10
§146.85(a)(1)	§609.C.1.a-e	The financial responsibility instrument(s) used must be from the following list of qualifying instruments: (i) Trust Funds, (ii) Surety Bonds, (iii) Letter of Credit, (iv) Insurance, (v) Self Insurance (i.e., Financial Test and Corporate Guarantee), (vi) Escrow Account, (vii) Any other instrument(s) satisfactory to the Director	Section 10
§146.85(a)(2)	§609.C.4.a	The qualifying instrument(s) must be sufficient to cover the cost of"	Section 10
§146.85(a)(2)(i)	§609.C.4.a.i	Corrective action (that meets the requirements of §146.84);	Section 10
§146.85(a)(2)(ii)	§609.C.4.a.ii	Injection well plugging (that meets the requirements of §146.92);	Section 10
§146.85(a)(2)(iii)	§609.C.4.a.iii	Post injection site care and site closure (that meets the requirements of §146.93); and	Section 10
§146.85(a)(2)(iv)	§609.C.4.a.iv	Emergency and remedial response (that meets the requirements of §146.94).	Section 10
§146.85(a)(3)	§609.C.4.b	The financial responsibility instrument(s) must be sufficient to address endangerment of underground sources of drinking water.	Section 10
§146.85(a)(4)	§609.C.4.c	The qualifying financial responsibility instrument(s) must comprise protective conditions of coverage.	Section 10
§146.85(a)(4)(i)	§609.C.4.c	Protective conditions of coverage must include at a minimum cancellation, renewal, and continuation provisions, specifications on when the provider becomes liable following a notice of cancellation if there is a failure to renew with a new qualifying financial instrument, and requirements for the provider to meet a minimum rating, minimum capitalization, and ability to pass the bond rating when applicable.	Section 10
§146.85(a)(4)(i)(A)	§609.C.4.c.i	Cancellation – for purposes of this part, an owner or operator must provide that their financial mechanism may not cancel, terminate or fail to renew except for failure to pay such financial instrument. If there is a failure to pay the financial instrument, the financial institution may elect to cancel, terminate, or fail to renew the instrument by sending notice by certified mail to the owner or operator and the Director. The cancellation must not be final for 120 days after receipt of cancellation notice	Section 10
§146.85(a)(4)(i)(B)	§609.C.4.c.ii	Renewal – for purposes of this part, owners or operators must renew all financial instruments, if an instrument expires, for the entire term of the geologic sequestration project. The instrument may be automatically renewed as long as the owner or operator has the option of renewal at the face amount of the expiring instrument. The automatic renewal of the instrument must, at a minimum, provide the holder with the option of renewal at the face amount of the expiring financial instrument.	
§146.85(a)(4)(i)(C)	§609.C.4.c.iii	Cancellation, termination, or failure to renew may not occur and the financial instrument will remain in full force and effect in the event that on or before the date of expiration: the Director deems the facility abandoned; or the permit is terminated or revoked or a new permit is denied; or closure is ordered by the Director or a U.S. district court or other court of competent jurisdiction; or the owner or operator is named as debtor in a voluntary or involuntary proceeding under Title 11 (Bankruptcy), U.S. Code; or the amount due is paid.	
§146.85(a)(5)	§609.C.4.d	The qualifying financial responsibility instrument(s) must be approved by the Director.	
§146.85(a)(5)(i)	§609.C.4.d.i	The Director shall consider and approve the financial responsibility demonstration for all the phases of the geologic sequestration project prior to issue a Class VI permit (§146.82).	
§146.85(a)(5)(ii)	§609.C.4.d.ii	The owner or operator must provide any updated information related to their financial responsibility instrument(s) on an annual basis and if there are any changes, the Director must evaluate, within a reasonable time, the financial responsibility demonstration to confirm that the instrument(s) used remain adequate for use. The owner or operator must maintain financial responsibility requirements regardless of the status of the Director's review of the financial responsibility demonstration.	

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§146.85(a)(5)(iii)	§609.C.4.d.iii	The Director may disapprove the use of a financial instrument if he determines that it is not sufficient to meet the requirements of this section.	
§146.85(a)(6)	§609.C.4.e	The owner or operator may demonstrate financial responsibility by using one or multiple qualifying financial instruments for specific phases of the geologic sequestration project.	
§146.85(a)(6)(i)	§609.C.4.e.i	In the event that the owner or operator combines more than one instrument for a specific geologic sequestration phase (e.g., well plugging), such combination must be limited to instruments that are not based on financial strength or performance (i.e., self insurance or performance bond), for example trust funds, surety bonds guaranteeing payment into a trust fund, letters of credit, escrow account, and insurance. In this case, it is the combination of mechanisms, rather than the single mechanism, which must provide financial responsibility for an amount at least equal to the current cost estimate.	
§146.85(a)(6)(ii)		When using a third-party instrument to demonstrate financial responsibility, the owner or operator must provide a proof that the third- party providers either have passed financial strength requirements based on credit ratings; or has met a minimum rating, minimum capitalization, and ability to pass the bond rating when applicable.	
§146.85(a)(6)(iii)		An owner or operator using certain types of third party instruments must establish a standby trust to enable EPA to be party to the financial responsibility agreement without EPA being the beneficiary of any funds. The standby trust fund must be used along with other financial responsibility instruments (e.g., surety bonds, letters of credit, or escrow accounts) to provide a location to place funds if needed	
§146.85(a)(6)(iv)		An owner or operator may deposit money to an escrow account to cover financial responsibility requirements; this account must segregate funds sufficient to cover estimated costs for Class VI (geologic sequestration) financial responsibility from other accounts and uses.	
§146.85(a)(6)(v)		An owner or operator or its guarantor may use self insurance to demonstrate financial responsibility for geologic sequestration projects. In order to satisfy this requirement the owner or operator must meet a Tangible Net Worth of an amount approved by the Director, have a Net working capital and tangible net worth each at least six times the sum of the current well plugging, post injection site care and site closure cost, have assets located in the United States amounting to at least 90 percent of total assets or at least six times the sum of the current well plugging, post injection site care and site closure cost, and must submit a report of its bond rating and financial information annually. In addition the owner or operator must either: have a bond rating test of AAA, AA, A, or BBB as issued by Standard & Poor's or Aaa, Aa, A, or Baa as issued by Moody's; or meet all of the following five financial ratio thresholds: a ratio of total liabilities to net worth less than 2.0; a ratio of current assets to current liabilities greater than 1.5; a ratio of the sum of net income plus depreciation, depletion, and amortization to total liabilities greater than 0.1; a ratio of current assets minus current liabilities to total assets greater than -0.1; and a net profit (revenues minus expenses) greater than 0.	
§146.85(a)(6)(vi)		An owner or operator who is not able to meet corporate financial test criteria may arrange a corporate guarantee by demonstrating that its corporate parent meets the financial test requirements on its behalf. The parent's demonstration that it meets the financial test requirement is insufficient if it has not also guaranteed to fulfill the obligations for the owner or operator.	
§146.85(a)(6)(vii)		An owner or operator may obtain an insurance policy to cover the estimated costs of geologic sequestration activities requiring financial responsibility. This insurance policy must be obtained from a third party provider.	
§146.85(b)		The requirement to maintain adequate financial responsibility and resources is directly enforceable regardless of whether the requirement is a condition of the permit.	
§146.85(b)(1)	§609.C.4.g	The owner or operator must maintain financial responsibility and resources until:	
§146.85(b)(1)(i)	§609.C.4.g.i	The Director receives and approves the completed post-injection site care and site closure plan; and	
§146.85(b)(1)(ii)	§609.C.4.g.ii	The Director approves site closure	
§146.85(b)(2)		The owner or operator may be released from a financial instrument in the following circumstances:	
§146.85(b)(2)(i)		The owner or operator has completed the phase of the geologic sequestration project for which the financial instrument was required and has fulfilled all its financial obligations as determined by the Director, including obtaining financial responsibility for the next phase of the GS project, if required; or	
§146.85(b)(2)(ii)		The owner or operator has submitted a replacement financial instrument and received written approval from the Director accepting the new financial instrument and releasing the owner or operator from the previous financial instrument.	
§146.85(c)	§609.C.4.h	The owner or operator must have a detailed written estimate, in current dollars, of the cost of performing corrective action on wells in the area of review, plugging the injection well(s), post-injection site care and site closure, and emergency and remedial response.	Section 10

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§146.85(c)(1)	§609.C.4.h.i	The cost estimate must be performed for each phase separately and must be based on the costs to the regulatory agency of hiring a third party to perform the required activities. A third party is a party who is not within the corporate structure of the owner or operator.	Section 10
§146.85(c)(2)	§609.C.4.h.ii	During the active life of the geologic sequestration project, the owner or operator must adjust the cost estimate for inflation within 60 days prior to the anniversary date of the establishment of the financial instrument(s) used to comply with paragraph (a) of this section and provide this adjustment to the Director. The owner or operator must also provide to the Director written updates of adjustments to the cost estimate within 60 days of any amendments to the area of review and corrective action plan (§146.84), the injection well plugging plan (§146.92), the post-injection site care and site closure plan (§146.93), and the emergency and remedial response plan (§146.94).	Section 10
§146.85(c)(3)	§609.C.4.h.iii	The Director must approve any decrease or increase to the initial cost estimate. During the active life of the geologic sequestration project, the owner or operator must revise the cost estimate no later than 60 days after the Director has approved the request to modify the area of review and corrective action plan (§146.84), the injection well plugging plan (§146.92), the post-injection site care and site closure plan (§146.93), and the emergency and response plan (§146.94), if the change in the plan increases the cost. If the change to the plans decreases the cost, any withdrawal of funds must be approved by the Director. Any decrease to the value of the financial assurance instrument must first be approved by the Director. The revised cost estimate must be adjusted for inflation as specified at paragraph (c)(2) of this section.	Section 10
§146.85(c)(4)	§609.C.4.h.iv	Whenever the current cost estimate increases to an amount greater than the face amount of a financial instrument currently in use, the owner or operator, within 60 days after the increase, must either cause the face amount to be increased to an amount at least equal to the current cost estimate and submit evidence of such increase to the Director, or obtain other financial responsibility instruments to cover the increase. Whenever the current cost estimate decreases, the face amount of the financial assurance instrument may be reduced to the amount of the current cost estimate only after the owner or operator has received written approval from the Director.	Section 10
§146.85(d)	§609.C.4.i	The owner or operator must notify the Director by certified mail of adverse financial conditions such as bankruptcy that may affect the ability to carry out injection well plugging and post-injection site care and site closure.	
§146.85(d)(1)	§609.C.4.i.i	In the event that the owner or operator or the third party provider of a financial responsibility instrument is going through a bankruptcy, the owner or operator must notify the Director by certified mail of the commencement of a voluntary or involuntary proceeding under Title 11 (Bankruptcy), U.S. Code, naming the owner or operator as debtor, within 10 days after commencement of the proceeding.	
§146.85(d)(2)	§609.C.4.i.ii	A guarantor of a corporate guarantee must make such a notification to the Director if he/she is named as debtor, as required under the terms of the corporate guarantee.	
§146.85(d)(3)		An owner or operator who fulfills the requirements of paragraph (a) of this section by obtaining a trust fund, surety bond, letter of credit, escrow account, or insurance policy will be deemed to be without the required financial assurance in the event of bankruptcy of the trustee or issuing institution, or a suspension or revocation of the authority of the trustee institution to act as trustee of the institution issuing the trust fund, surety bond, letter of credit, escrow account, or insurance policy. The owner or operator must establish other financial assurance within 60 days after such an event.	
§146.85(e)	§609.C.4.j	The owner or operator must provide an adjustment of the cost estimate to the Director within 60 days of notification by the Director, if the Director determines during the annual evaluation of the qualifying financial responsibility instrument(s) that the most recent demonstration is no longer adequate to cover the cost of corrective action (as required by §146.84), injection well plugging (as required by §146.92), post-injection site care and site closure (as required by §146.93), and emergency and remedial response (as required by §146.94)	
§146.85(f)	§609.C.4.k	The Director must approve the use and length of pay-in-periods for trust funds or escrow accounts.	
§146.86	§617	**Injection well construction requirements**	Section 4
§146.86(a)	§617.A.1	General. The owner or operator must ensure that all Class VI wells are constructed and completed to:	Section 4
§146.86(a)(1)	§617.A.1.a	Prevent the movement of fluids into or between USDWs or into any unauthorized zones;	Section 4, General Outline
§146.86(a)(2)	§617.A.1.b	Permit the use of appropriate testing devices and workover tools; and	Section 4
§146.86(a)(3)	§617.A.1.c	Permit continuous monitoring of the annulus space between the injection tubing and long string casing.	Section 4
§146.86(b)	§617.A.2	Casing and Cementing of Class VI Wells	

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§146.86(b)(1)	§617.A.2.a	Casing and cement or other materials used in the construction of each Class VI well must have sufficient structural strength and be designed for the life of the geologic sequestration project. All well materials must be compatible with fluids with which the materials may be expected to come into contact and must meet or exceed standards developed for such materials by the American Petroleum Institute, ASTM International, or comparable standards acceptable to the Director. The casing and cementing program must be designed to prevent the movement of fluids into or between USDWs. In order to allow the Director to determine and specify casing and cementing requirements, the owner or operator must provide the following information:	Section 4, Detailed Well Design; Appendix F; Appendix G
§146.86(b)(1)(i)	§617.A.2.a.i	Depth to the injection zone(s);	Section 4, Detailed Well Design (need to list in addition to schematic)
§146.86(b)(1)(ii)	§617.A.2.a.ii	Injection pressure, external pressure, internal pressure, and axial loading	Section 4
§146.86(b)(1)(iii)	§617.A.2.a.iii	Hole size	Section 4- Schematic
§146.86(b)(1)(iv)	§617.A.2.a.iv	Size and grade of all casing strings (wall thickness, external diameter, nominal weight, length, joint specification, and construction material);	Section 4, Schematic
§146.86(b)(1)(ix)	§617.A.2.a.ix	Quantity, chemical composition, and temperature of the carbon dioxide stream.	Appendix G
§146.86(b)(1)(v)	§617.A.2.a.v	Corrosiveness of the carbon dioxide stream and formation fluids	Appendix G
§146.86(b)(1)(vi)	§617.A.2.a.vi	Down-hole temperatures	Section 4, Detailed Well Design (need to list in addition to schematic)
§146.86(b)(1)(vii)	§617.A.2.a.vii	Lithology of injection and confining zone(s)	Section 1
§146.86(b)(1)(viii)	§617.A.2.a.viii	Type or grade of cement and cement additives; and	Section 4, Appendix F
§146.86(b)(2)	§617.A.2.b	Surface casing must extend through the base of the lowermost USDW and be cemented to the surface through the use of a single or multiple strings of casing and cement.	Section 4
§146.86(b)(3)	§617.A.2.c	At least one long string casing, using a sufficient number of centralizers, must extend to the injection zone and must be cemented by circulating cement to the surface in one or more stages	Section 4
§146.86(b)(4)	§617.A.2.d	Circulation of cement may be accomplished by staging. The Director may approve an alternative method of cementing in cases where the cement cannot be recirculated to the surface, provided the owner or operator can demonstrate by using logs that the cement does not allow fluid movement behind the well bore.	Section 4
§146.86(b)(5)	§617.A.2.e	Cement and cement additives must be compatible with the carbon dioxide stream and formation fluids and of sufficient quality and quantity to maintain integrity over the design life of the geologic sequestration project. The integrity and location of the cement shall be verified using technology capable of evaluating cement quality radially and identifying the location of channels to ensure that USDWs are not endangered.	Section 4
	§617.A.3	Casing and Casing Seat Tests. The owner or operator shall monitor and record the tests using a surface readout pressure gauge and a chart or digital recorder. All instruments shall be calibrated properly and in good working order. If there is a failure of the required tests, the owner or operator shall take necessary corrective action to obtain a passing test.	Appendix F
	§617.A.3.a	Casing. After cementing each casing, but before drilling out the respective casing shoe, all casings shall be hydrostatically pressure tested to verify casing integrity and the absence of leaks. For surface casing, the stablized test pressure applied at the surface shall be aminimum of 500 pounds per square inch gauge (psig). The stabalized test pressure applied at the surface for all other casings shall be a minimum of 1,000 psig. All casing test pressures shall be maintained for one hour after stabilization. Allowable pressure loss is limited to five percent of the test pressure over the stabalized test duration.	Appendix F
	§617.A.3.a.i	Casing test pressures shall never exceed the rated burst or collapse pressures of the respective casings.	Appendix F
	§617.A.3.b	Casing seat. The casing seat and cement of any intermediate and injection casings shall be hydrostatically pressure tested after drilling ou the casing shoe. At least 10 feet of formation below the respective casing shoes shall be dreilled before the test. The test pressure applied at the surface shall be a minimum of 1,000 psig. The test pressure shall be maintained for one hour after pressure stabilization. Allowable pressure loss is limited to five percent of the test pressure over the stabilized test duration.	Appendix F
	§617.A.3.b.i	Casing seat test pressures shall never exceed the rated burst or collapse pressures of the respective casings.	Appendix F
§146.86(c)	§617.A.4	Tubing and packer.	Section 4
§146.86(c)(1)	§617.A.4.a	Tubing and packer materials used in the construction of each Class VI well must be compatible with fluids with which the materials may be expected to come into contact and must meet or exceed standards developed for such materials by the American Petroleum Institute, ASTM International, or comparable standards acceptable to the Director.	Appendix G

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§146.86(c)(2)	§617.A.4.b	All owners or operators of Class VI wells must inject fluids through tubing with a packer set at a depth opposite a cemented interval at the location approved by the Director.	
§146.86(c)(3)	§617.A.4.c	In order for the Director to determine and specify requirements for tubing and packer, the owner or operator must submit the following information:	
§146.86(c)(3)(i)	§617.A.4.c.i	Depth of setting;	Section 4
§146.86(c)(3)(ii)	§617.A.4.c.ii	Characteristics of the carbon dioxide stream (chemical content, corrosiveness, temperature, and density) and formation fluids;	Appendix G
§146.86(c)(3)(iii)	§617.A.4.c.iii	Maximum proposed injection pressure	Section 4
§146.86(c)(3)(iv)	§617.A.4.c.iv	Maximum proposed annular pressure;	Section 4
§146.86(c)(3)(v)	§617.A.4.c.v	Proposed injection rate (intermittent or continuous) and volume and/or mass of the carbon dioxide stream	Section 4
§146.86(c)(3)(vi)	§617.A.4.c.vi	Size of tubing and casing; and	Section 4
§146.86(c)(3)(vii)	§617.A.4.c.vii	Tubing tensile, burst, and collapse strengths.	Section 4
§146.87	§617.B	**Logging, sampling, and testing prior to injection well operation.**	
§146.87(a)	§617.B.1	During the drilling and construction of a Class VI injection well, the owner or operator must run appropriate logs, surveys and tests to determine or verify the depth, thickness, porosity, permeability, and lithology of, and the salinity of any formation fluids in all relevant geologic formations to ensure conformance with the injection well construction requirements under §146.86 and to establish accurate baseline data against which future measurements may be compared. The owner or operator must submit to the Director a descriptive report prepared by a knowledgeable log analyst that includes an interpretation of the results of such logs and tests. At a minimum, such logs and tests must include:	Appendix F
§146.87(a)(1)	§617.B.1.a	Deviation checks during drilling on all holes constructed by drilling a pilot hole which is enlarged by reaming or another method. Such checks must be at sufficiently frequent intervals to determine the location of the borehole and to ensure that vertical avenues for fluid movement in the form of diverging holes are not created during drilling; and	Appendix F
§146.87(a)(2)	§617.B.1.b	Before and upon installation of the surface casing:	Appendix F
§146.87(a)(2)(i)	§617.B.1.b.i	Resistivity, spontaneous potential, and caliper logs before the casing is installed; and	Appendix F
§146.87(a)(2)(ii)	§617.B.1.b.ii	A cement bond and variable density log to evaluate cement quality radially, and a temperature log after the casing is set and cemented.	Appendix F
§146.87(a)(3)	§617.B.1.c	Before and upon installation of the long string casing:	Appendix F
§146.87(a)(3)(i)	§617.B.1.c.i	(i) Resistivity, spontaneous potential, porosity, caliper, gamma ray, fracture finder logs, and any other logs the Director requires for the given geology before the casing is installed; and	Appendix F
§146.87(a)(3)(ii)	§617.B.1.c.ii	A cement bond and variable density log, and a temperature log after the casing is set and cemented.	Appendix F
§146.87(a)(4)	§617.B.1.d	A series of tests designed to demonstrate the internal and external mechanical integrity of injection wells, which may include:	Appendix F
§146.87(a)(4)(i)	§617.B.1.d.i	A pressure test with liquid or gas;	Appendix F
§146.87(a)(4)(ii)	§617.B.1.d.ii	A tracer survey such as oxygen-activation logging;	N/A
§146.87(a)(4)(iii)	§617.B.1.d.iii	A temperature or noise log;	Appendix F
§146.87(a)(4)(iv)	§617.B.1.d.iv	A casing inspection log; and	Appendix F
§146.87(a)(5)	§617.B.1.e	Any alternative methods that provide equivalent or better information and that are required by and/or approved of by the Director.	N/A
§146.87(b)	§617.B.2	The owner or operator must take whole cores or sidewall cores of the injection zone and confining system and formation fluid samples from the injection zone(s), and must submit to the Director a detailed report prepared by a log analyst that includes: well log analyses (including well logs), core analyses, and formation fluid sample information. The Director may accept information on cores from nearby wells if the owner or operator can demonstrate that core retrieval is not possible and that such cores are representative of conditions at the well. The Director may require the owner or operator to core other formations in the borehole.	Appendix F
§146.87(c)	§617.B.3	The owner or operator must record the fluid temperature, pH, conductivity, reservoir pressure, and static fluid level of the injection zone(s).	Appendix F
§146.87(d)	§617.B.4	At a minimum, the owner or operator must determine or calculate the following information concerning the injection and confining zone(s):	
§146.87(d)(1)	§617.B.4.a	Fracture pressure;	Appendix F
§146.87(d)(2)	§617.B.4.b	Other physical and chemical characteristics of the injection and confining zone(s); and	Appendix F
§146.87(d)(3)	§617.B.4.c	Physical and chemical characteristics of the formation fluids in the injection zone(s).	Appendix F

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§146.87(e)	§617.B.5	Upon completion, but prior to operation, the owner or operator must conduct the following tests to verify hydrogeologic characteristics of the injection zone(s):	Appendix F
§146.87(e)(1)	§617.B.5.a	pressure fall-off test; and,	Appendix F, Section 5
§146.87(e)(2)	§617.B.5.b	A pump test; or	Appendix F, Section 5
§146.87(e)(3)	§617.B.5.c	Injectivity tests.	Appendix F, Section 5
§146.87(f)	§617.B.6	The owner or operator must provide the Director with the opportunity to witness all logging and testing by this subpart. The owner or operator must submit a schedule of such activities to the Director 30 days prior to conducting the first test and submit any changes to the schedule 30 days prior to the next scheduled test.	Appendix F
§146.88	§621.A	**Injection well operating requirements**	
§146.88(a)	§621.A.1	Except during stimulation, the owner or operator must ensure that injection pressure does not exceed 90 percent of the fracture pressure of the injection zone(s) so as to ensure that the injection does not initiate new fractures or propagate existing fractures in the injection zone(s). In no case may injection pressure initiate fractures in the confining zone(s) or cause the movement of injection or formation fluids that endangers a USDW. Pursuant to requirements at § 146.82(a)(9), all stimulation programs must be approved by the Director as part of the permit application and incorporated into the permit.	Section 4
§146.88(b)	§621.A.2	Injection between the outermost casing protecting USDWs and the well bore is prohibited.	Section 4
§146.88(c)	§621.A.3	The owner or operator must fill the annulus between the tubing and the long string casing with a non-corrosive fluid approved by the Director. The owner or operator must maintain on the annulus a pressure that exceeds the operating injection pressure, unless the Director determines that such requirement might harm the integrity of the well or endanger USDWs.	Section 4, Appendix F
§146.88(d)	§621.A.4	Other than during periods of well workover (maintenance) approved by the Director in which the sealed tubing casing annulus is disassembled for maintenance or corrective procedures, the owner or operator must maintain mechanical integrity of the injection well at all times.	Section 4, Section 5
§146.88(e)		The owner or operator must install and use:	
§146.88(e)(1)	§621.A.6.a	Continuous recording devices to monitor: The injection pressure; the rate, volume and/or mass, and temperature of the carbon dioxide stream; and the pressure on the annulus between the tubing and the long string casing and annulus fluid volume; and	Section 5
§146.88(e)(2)	§621.A.7.a.i	Alarms and automatic surface shut-off systems or, at the discretion of the Director, down-hole shut-off systems (e.g., automatic shut-off, check valves) for onshore wells or, other mechanical devices that provide equivalent protection; and	Section 5, Plume Monitoring Equipment Review (/Thunder 7.5 Surface Controlled Subsurface Safety Valve)
§146.88(e)(3)	§621.A.7.a.ii	Alarms and automatic down-hole shut-off systems for wells located offshore but within State territorial waters, designed to alert the operator and shut-in the well when operating injection rate, or other parameters diverge beyond permitted ranges and/or gradients specified in the permit	N/A
§146.88(f)	§621.A.6.b	If a shutdown (i.e., down-hole or at the surface) is triggered or a loss of mechanical integrity is discovered, the owner or operator must immediately investigate and identify as expeditiously as possible the cause of the shutoff. If, upon such investigation, the well appears to be lacking mechanical integrity, or if monitoring required under paragraph (e) of this section otherwise indicates that the well may be lacking mechanical integrity, the owner or operator must	Section 8
§146.88(f)(1)	§621.A.6.b.i	Immediately cease injection;	Section 8
§146.88(f)(2)	§621.A.6.b.ii	Take all steps reasonably necessary to determine whether there may have been a release of the injected carbon dioxide stream or formation fluids into any unauthorized zone	Section 8
§146.88(f)(3)	§621.A.6.b.iii	Notify the Director within 24 hours	Section 8
§146.88(f)(4)	§621.A.6.b.iv	Restore and demonstrate mechanical integrity to the satisfaction of the Director prior to resuming injection; and	Section 8
§146.88(f)(5)	§621.A.6.b.v	Notify the Director when injection can be expected to resume	Section 8
§146.89	**§627**	**Mechanical Integrity**	
§146.89(a)	§627.A.1	A Class VI well has mechanical integrity if:	
§146.89(a)(1)	§627.A.1.a	There is no significant leak in the casing, tubing, or packer; and	Section 5
§146.89(a)(1)	§627.A.1.b	There is no significant fluid movement into a USDW through channels adjacent to the injection well bore.	Section 5
§146.89(b)	§627.A.2	To evaluate the absence of significant leaks under paragraph (a)(1) of this section, owners or operators must, following an initial annulus pressure test, continuously monitor injection pressure, rate, injected volumes; pressure on the annulus between tubing and long-string casing; and annulus fluid volume as specified in § 146.88 (e);	Section 5

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§146.89(c)	§627.A.3	At least once per year, the owner or operator must use one of the following methods to determine the absence of significant fluid movement under paragraph (a)(2) of this section:	Section 5
§146.89(c)(1)	§627.A.3.a	An approved tracer survey such as an oxygen-activation log; or	
§146.89(c)(2)	§627.A.3.b	A temperature or noise log.	Section 5
§146.89(d)	§627.A.4	If required by the Director, at a frequency specified in the testing and monitoring plan required at § 146.90, the owner or operator must run a casing inspection log to determine the presence or absence of corrosion in the long string casing.	Section 5
§146.89(e)	§627.A.5.a	The Director may require any other test to evaluate mechanical integrity under paragraphs (a)(1) or (a)(2) of this section. Also, the Director may allow the use of a test to demonstrate mechanical integrity other than those listed above with the written approval of the Administrator. To obtain approval for a new mechanical integrity test, the Director must submit a written request to the Administrator setting forth the proposed test and all technical data supporting its use. The Administrator may approve the request if he or she determines that it will reliably demonstrate the mechanical integrity of wells for which its use is proposed. Any alternate method approved by the Administrator will be published in the Federal Register and may be used in all States in accordance with applicable State law unless its use is restricted at the time of approval by the Administrator.	N/A
§146.89(f)	§627.A.6	In conducting and evaluating the tests enumerated in this section or others to be allowed by the Director, the owner or operator and the Director must apply methods and standards generally accepted in the industry. When the owner or operator reports the results of mechanical integrity tests to the Director, he/she shall include a description of the test(s) and the method(s) used. In making his/her evaluation, the Director must review monitoring and other test data submitted since the previous evaluation.	N/A
§146.89(g)	§627.A.7	The Director may require additional or alternative tests if the results presented by the owner or operator under paragraphs (a) through (d) of this section are not satisfactory to the Director to demonstrate that there is no significant leak in the casing, tubing, or packer, or to demonstrate that there is no significant movement of fluid into a USDW resulting from the injection activity as stated in paragraphs (a)(1) and (2) of this section.	N/A
§146.90	§625.A	**Testing and Monitoring Requirements:** The owner or operator of a Class VI well must prepare, maintain, and comply with a testing and monitoring plan to verify that the geologic sequestration project is operating as permitted and is not endangering USDWs. The requirement to maintain and implement an approved plan is directly enforceable regardless of whether the requirement is a condition of the permit. The testing and monitoring plan must be submitted with the permit application, for Director approval, and must include a description of how the owner or operator will meet the requirements of this section, including accessing sites for all necessary monitoring and testing during the life of the project. Testing and monitoring associated with geologic sequestration projects must, at a minimum, include:	Section 5
§146.90(a)	§625.A.1	Analysis of the carbon dioxide stream with sufficient frequency to yield data representative of its chemical and physical characteristics;	Section 5
§146.90(b)	§625.A.2	Installation and use, except during well workovers as defined in §146.88(d), of continuous recording devices to monitor injection pressure, rate, and volume; the pressure on the annulus between the tubing and the long string casing; and the annulus fluid volume added;	Section 5
§146.90(c)	§625.A.3	Corrosion monitoring of the well materials for loss of mass, thickness, cracking, pitting, and other signs of corrosion, which must be performed on a quarterly basis to ensure that the well components meet the minimum standards for material strength and performance set forth in §146.86(b), by:	Section 5
§146.90(c)(1)	§625.A.3.a	Analyzing coupons of the well construction materials placed in contact with the carbon dioxide stream; or	Section 5
§146.90(c)(2)	§625.A.3.b	Routing the carbon dioxide stream through a loop constructed with the material used in the well and inspecting the materials in the loop; or	Section 5
§146.90(c)(3)	§625.A.3.c	Using an alternative method approved by the Director	Section 5
§146.90(d)	§625.A.4	Periodic monitoring of the ground water quality and geochemical changes above the confining zone(s) that may be a result of carbon dioxide movement through the confining zone(s) or additional identified zones including:	Section 5
§146.90(d)(1)	§625.A.4.a	The location and number of monitoring wells based on specific information about the geologic sequestration project, including injection rate and volume, geology, the presence of artificial penetrations, and other factors; and	Section 5
§146.90(d)(2)	§625.A.4.b	The monitoring frequency and spatial distribution of monitoring wells based on baseline geochemical data that has been collected under §146.82(a)(6) and on any modeling results in the area of review evaluation required by §146.84(c).	Section 5

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§146.90(e)	§625.A.5	A demonstration of external mechanical integrity pursuant to §146.89(c) at least once per year until the injection well is plugged; and, if required by the Director, a casing inspection log pursuant to requirements at §146.89(d) at a frequency established in the testing and monitoring plan;	
§146.90(f)	§625.A.6	A pressure fall-off test at least once every five years unless more frequent testing is required by the Director based on site-specific information	
§146.90(g)	§625.A.7	Testing and monitoring to track the extent of the carbon dioxide plume and the presence or absence of elevated pressure (e.g., the pressure front) by using:	Section 5
§146.90(g)(1)	§625.A.7.a	Direct methods in the injection zone(s); and,	Section 5
§146.90(g)(2)	§625.A.7.b	Indirect methods (e.g., seismic, electrical, gravity, or electromagnetic surveys and/or down-hole carbon dioxide detection tools), unless the Director determines, based on site-specific geology, that such methods are not appropriate;	Section 5
§146.90(h)	§625.A.8	The Director may require surface air monitoring and/or soil gas monitoring to detect movement of carbon dioxide that could endanger a USDW.	N/A: Water bottom
§146.90(h)(1)	§625.A.8.a	Design of Class VI surface air and/or soil gas monitoring must be based on potential risks to USDWs within the area of review;	N/A: Water bottom
§146.90(h)(2)	§625.A.8.b	The monitoring frequency and spatial distribution of surface air monitoring and/or soil gas monitoring must be decided using baseline data, and the monitoring plan must describe how the proposed monitoring will yield useful information on the area of review delineation and/or compliance with standards under § 144.12 of this chapter;	N/A: Water bottom
§146.90(h)(3)	§625.A.8.c	If an owner or operator demonstrates that monitoring employed under §§ 98.440 to 98.449 of this chapter (Clean Air Act, 42 U.S.C. 7401 *et seq.*) accomplishes the goals of paragraphs (h)(1) and (2) of this section, and meets the requirements pursuant to § 146.91(c)(5), a Director that requires surface air/soil gas monitoring must approve the use of monitoring employed under §§ 98.440 to 98.449 of this chapter. Compliance with §§ 98.440 to 98.449 of this chapter pursuant to this provision is considered a condition of the Class VI permit;	N/A: Water bottom
§146.90(i)	§625.A.9	Any additional monitoring, as required by the Director, necessary to support, upgrade, and improve computational modeling of the area of review evaluation required under § 146.84(c) and to determine compliance with standards under § 144.12 of this chapter;	Section 5
§146.90(j)	§625.A.10	The owner or operator shall periodically review the testing and monitoring plan to incorporate monitoring data collected under this subpart, operational data collected under § 146.88, and the most recent area of review reevaluation performed under § 146.84(e). In no case shall the owner or operator review the testing and monitoring plan less often than once every five years. Based on this review, the owner or operator shall submit an amended testing and monitoring plan or demonstrate to the Director that no amendment to the testing and monitoring plan is needed. Any amendments to the testing and monitoring plan must be approved by the Director, must be incorporated into the permit, and are subject to the permit modification requirements at § 144.39 or § 144.41 of this chapter, as appropriate. Amended plans or demonstrations shall be submitted to the Director as follows:	N/A
§146.90(j)(1)	§625.A.10.a	Within one year of an area of review reevaluation;	N/A
§146.90(j)(2)	§625.A.10.b	Following any significant changes to the facility, such as addition of monitoring wells or newly permitted injection wells within the area of review, on a schedule determined by the Director; or	N/A
§146.90(j)(3)	§625.A.10.c	When required by the Director.	N/A
§146.90(k)	§625.A.11	A quality assurance and surveillance plan for all testing and monitoring requirements.	
§146.91	§629.A	**Reporting requirements.** The owner or operator must, at a minimum, provide, as specified in paragraph (e) of this section, the following reports to the Director, for each permitted Class VI well:	
§146.91(a)	§629.A.1	Semi-annual reports containing:	Section 5
§146.91(a)(1)	§629.A.1.a	Any changes to the physical, chemical, and other relevant characteristics of the carbon dioxide stream from the proposed operating data;	Section 5
§146.91(a)(2)	§629.A.1.b	Monthly average, maximum, and minimum values for injection pressure, flow rate and volume, and annular pressure;	Section 5
§146.91(a)(3)	§629.A.1.c	A description of any event that exceeds operating parameters for annulus pressure or injection pressure specified in the permit;	Section 5
§146.91(a)(4)	§629.A.1.d	A description of any event which triggers a shut-off device required pursuant to § 146.88(e) and the response taken;	Section 5
§146.91(a)(5)	§629.A.1.e	The monthly volume and/or mass of the carbon dioxide stream injected over the reporting period and the volume injected cumulatively over the life of the project;	Section 5

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§146.91(a)(6)	§629.A.1.f	Monthly annulus fluid volume added; and	Section 5
§146.91(a)(7)	§629.A.1.g	The results of monitoring prescribed under § 146.90.	Section 5
§146.91(b)	§629.A.2	Report, within 30 days, the results of:	Section 5
§146.91(b)(1)	§629.A.2.a	Periodic tests of mechanical integrity;	Section 5
§146.91(b)(2)	§629.A.2.b	Any well workover; and,	Section 5
§146.91(b)(3)	§629.A.2.c	Any other test of the injection well conducted by the permittee if required by the Director.	Section 5
§146.91(c)	§629.A.3	Report, within 24 hours:	Section 5
§146.91(c)(1)	§629.A.3.a	Any evidence that the injected carbon dioxide stream or associated pressure front may cause an endangerment to a USDW	Section 5
§146.91(c)(2)	§629.A.3.b	Any noncompliance with a permit condition, or malfunction of the injection system, which may cause fluid migration into or between USDWs;	Section 5
§146.91(c)(3)	§629.A.3.c	Any triggering of a shut-off system (*i.e.,* down-hole or at the surface);	Section 5
§146.91(c)(4)	§629.A.3.d	Any failure to maintain mechanical integrity; or.	Section 5
§146.91(c)(5)	§629.A.3.e	Pursuant to compliance with the requirement at § 146.90(h) for surface air/soil gas monitoring or other monitoring technologies, if required by the Director, any release of carbon dioxide to the atmosphere or biosphere.	Section 5
§146.91(d)	§629.A.4	Owners or operators must notify the Director in writing 30 days in advance of:	Section 5
§146.91(d)(1)	§629.A.4	Any planned well workover;	Section 5
§146.91(d)(2)	§629.A.4	Any planned stimulation activities, other than stimulation for formation testing conducted under § 146.82; and	Section 5
§146.91(d)(3)	§629.A.4	Any other planned test of the injection well conducted by the permittee.	Section 5
§146.91(e)	§629.A.5	Regardless of whether a State has primary enforcement responsibility, owners or operators must submit all required reports, submittals, and notifications under subpart H of this part to EPA in an electronic format approved by EPA.	Section 5
§146.91(f)	§629.A.6	Records shall be retained by the owner or operator as follows:	Section 5
§146.91(f)(1)	§629.A.6.a	All data collected under § 146.82 for Class VI permit applications shall be retained throughout the life of the geologic sequestration project and for 10 years following site closure.	Section 5
§146.91(f)(2)	§629.A.6.b	Data on the nature and composition of all injected fluids collected pursuant to § 146.90(a) shall be retained until 10 years after site closure. The Director may require the owner or operator to deliver the records to the Director at the conclusion of the retention period.	Section 5
§146.91(f)(3)	§629.A.6.c	Monitoring data collected pursuant to § 146.90(b) through (i) shall be retained for 10 years after it is collected.	Section 5
§146.91(f)(4)	§629.A.6.d	Well plugging reports, post-injection site care data, including, if appropriate, data and information used to develop the demonstration of the alternative post-injection site care timeframe, and the site closure report collected pursuant to requirements at §§ 146.93(f) and (h) shall be retained for 10 years following site closure.	Section 5
§146.91(f)(5)	§629.A.6.e	The Director has authority to require the owner or operator to retain any records required in this subpart for longer than 10 years after site closure.	
§146.92	§631	**Injection well plugging**	
§146.92(a)	§631.A.2	Prior to the well plugging, the owner or operator must flush each Class VI injection well with a buffer fluid, determine bottomhole reservoir pressure, and perform a final external mechanical integrity test.	Section 6, Appendix H
§146.92(b)	§631.A.3	Well plugging plan. The owner or operator of a Class VI well must prepare, maintain, and comply with a plan that is acceptable to the Director. The requirement to maintain and implement an approved plan is directly enforceable regardless of whether the requirement is a condition of the permit. The well plugging plan must be submitted as part of the permit application and must include the following information:	Section 6, Appendix H
§146.92(b)(1)	§631.A.3.a	Appropriate tests or measures for determining bottomhole reservoir pressure;	Section 6, Appendix H
§146.92(b)(2)	§631.A.3.b	Appropriate testing methods to ensure external mechanical integrity as specified in § 146.89;	Section 6, Appendix H
§146.92(b)(3)	§631.A.3.c	The type and number of plugs to be used;	Section 6, Appendix H
§146.92(b)(4)	§631.A.3.d	The placement of each plug, including the elevation of the top and bottom of each plug;	Section 6, Appendix H
§146.92(b)(5)	§631.A.3.e	The type, grade, and quantity of material to be used in plugging. The material must be compatible with the carbon dioxide stream; and	Section 6, Appendix H
§146.92(b)(6)	§631.A.3.f	The method of placement of the plugs.	Section 6, Appendix H

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§146.92(c)	§631.A.4	Notice of intent to plug. The owner or operator must notify the Director in writing pursuant to § 146.91(e), at least 60 days before plugging of a well. At this time, if any changes have been made to the original well plugging plan, the owner or operator must also provide the revised well plugging plan. The Director may allow for a shorter notice period. Any amendments to the injection well plugging plan must be approved by the Director, must be incorporated into the permit, and are subject to the permit modification requirements at § 144.39 or § 144.41 of this chapter, as appropriate.	Section 6, Appendix H
§146.92(d)	§631.A.5	Plugging report. Within 60 days after plugging, the owner or operator must submit, pursuant to § 146.91(e), a plugging report to the Director. The report must be certified as accurate by the owner or operator and by the person who performed the plugging operation (if other than the owner or operator.) The owner or operator shall retain the well plugging report for 10 years following site closure.	Section 6, Appendix H
§146.93	**§633**	**Post-injection site care and site closure**	
§146.93(a)	§633.A.1	The owner or operator of a Class VI well must prepare, maintain, and comply with a plan for post-injection site care and site closure that meets the requirements of paragraph (a)(2) of this section and is acceptable to the Director. The requirement to maintain and implement an approved plan is directly enforceable regardless of whether the requirement is a condition of the permit.	Section 7
§146.93(a)(1)	§633.A.1.a	The owner or operator must submit the post-injection site care and site closure plan as a part of the permit application to be approved by the Director.	Section 7
§146.93(a)(2)	§633.A.1.b	The post-injection site care and site closure plan must include the following information:	Section 7
§146.93(a)(2)(i)	§633.A.1.b.i	The pressure differential between pre-injection and predicted post-injection pressures in the injection zone(s);	Section 7
§146.93(a)(2)(ii)	§633.A.1.b.ii	The predicted position of the carbon dioxide plume and associated pressure front at site closure as demonstrated in the area of review evaluation required under § 146.84(c)(1);	Section 7
§146.93(a)(2)(iii)	§633.A.1.b.iii	A description of post-injection monitoring location, methods, and proposed frequency;	Section 7
§146.93(a)(2)(iv)	§633.A.1.b.iv	A proposed schedule for submitting post-injection site care monitoring results to the Director pursuant to § 146.91(e); and,	Section 7
§146.93(a)(2)(v)	§633.A.1.b.v	The duration of the post-injection site care timeframe and, if approved by the Director, the demonstration of the alternative post-injection site care timeframe that ensures non-endangerment of USDWs.	Section 7
§146.93(a)(3)	§633.A.1.c	Upon cessation of injection, owners or operators of Class VI wells must either submit an amended post-injection site care and site closure plan or demonstrate to the Director through monitoring data and modeling results that no amendment to the plan is needed. Any amendments to the post-injection site care and site closure plan must be approved by the Director, be incorporated into the permit, and are subject to the permit modification requirements at § 144.39 or § 144.41 of this chapter, as appropriate.	Section 7
§146.93(a)(4)	§633.A.1.d	At any time during the life of the geologic sequestration project, the owner or operator may modify and resubmit the post-injection site care and site closure plan for the Director's approval within 30 days of such change.	
§146.93(b)	§633.A.2	The owner or operator shall monitor the site following the cessation of injection to show the position of the carbon dioxide plume and pressure front and demonstrate that USDWs are not being endangered.	Section 7
§146.93(b)(1)	§633.A.2.a	Following the cessation of injection, the owner or operator shall continue to conduct monitoring as specified in the Director-approved post-injection site care and site closure plan for at least 50 years or for the duration of the alternative timeframe approved by the Director pursuant to requirements in paragraph (c) of this section, unless he/she makes a demonstration under (b)(2) of this section. The monitoring must continue until the geologic sequestration project no longer poses an endangerment to USDWs and the demonstration under (b)(2) of this section is submitted and approved by the Director.	Section 7
§146.93(b)(2)	§633.A.2.b	If the owner or operator can demonstrate to the satisfaction of the Director before 50 years or prior to the end of the approved alternative timeframe based on monitoring and other site-specific data, that the geologic sequestration project no longer poses an endangerment to USDWs, the Director may approve an amendment to the post-injection site care and site closure plan to reduce the frequency of monitoring or may authorize site closure before the end of the 50-year period or prior to the end of the approved alternative timeframe, where he or she has substantial evidence that the geologic sequestration project no longer poses a risk of endangerment to USDWs.	Section 7
§146.93(b)(3)	§633.A.2.c	Prior to authorization for site closure, the owner or operator must submit to the Director for review and approval a demonstration, based on monitoring and other site-specific data, that no additional monitoring is needed to ensure that the geologic sequestration project does not pose an endangerment to USDWs.	Section 7

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§146.93(b)(4)	§633.A.2.d	If the demonstration in paragraph (b)(3) of this section cannot be made (*i.e.,* additional monitoring is needed to ensure that the geologic sequestration project does not pose an endangerment to USDWs) at the end of the 50-year period or at the end of the approved alternative timeframe, or if the Director does not approve the demonstration, the owner or operator must submit to the Director a plan to continue post-injection site care until a demonstration can be made and approved by the Director.	
§146.93(c)	§633.A.3	Demonstration of alternative post-injection site care timeframe. At the Director's discretion, the Director may approve, in consultation with EPA, an alternative post-injection site care timeframe other than the 50 year default, if an owner or operator can demonstrate during the permitting process that an alternative post-injection site care timeframe is appropriate and ensures non-endangerment of USDWs. The demonstration must be based on significant, site-specific data and information including all data and information collected pursuant to §§ 146.82 and 146.83, and must contain substantial evidence that the geologic sequestration project will no longer pose a risk of endangerment to USDWs at the end of the alternative post-injection site care timeframe.	Section 7
§146.93(c)(1)	§633.A.3.a	A demonstration of an alternative post-injection site care timeframe must include consideration and documentation of:	
§146.93(c)(1)(i)	§633.A.3.a.i	The results of computational modeling performed pursuant to delineation of the area of review under § 146.84;	Section 7
§146.93(c)(1)(ii)	§633.A.3.a.ii	The predicted timeframe for pressure decline within the injection zone, and any other zones, such that formation fluids may not be forced into any USDWs; and/or the timeframe for pressure decline to pre-injection pressures;	Section 7
§146.93(c)(1)(iii)	§633.A.3.a.iii	The predicted rate of carbon dioxide plume migration within the injection zone, and the predicted timeframe for the cessation of migration;	Section 2
§146.93(c)(1)(iv)	§633.A.3.a.iv	A description of the site-specific processes that will result in carbon dioxide trapping including immobilization by capillary trapping, dissolution, and mineralization at the site;	Section 2
§146.93(c)(1)(ix)	§633.A.3.a.ix	A description of the well construction and an assessment of the quality of plugs of all abandoned wells within the area of review;	None
§146.93(c)(1)(v)	§633.A.3.a.v	The predicted rate of carbon dioxide trapping in the immobile capillary phase, dissolved phase, and/or mineral phase;	Section 2
§146.93(c)(1)(vi)	§633.A.3.a.vi	The results of laboratory analyses, research studies, and/or field or site-specific studies to verify the information required in paragraphs (iv) and (v) of this section;	Post drilling
§146.93(c)(1)(vii)	§633.A.3.a.vii	A characterization of the confining zone(s) including a demonstration that it is free of transmissive faults, fractures, and micro-fractures and of appropriate thickness, permeability, and integrity to impede fluid (e.g., carbon dioxide, formation fluids) movement;	Section 1
§146.93(c)(1)(viii)	§633.A.3.a.viii	The presence of potential conduits for fluid movement including planned injection wells and project monitoring wells associated with the proposed geologic sequestration project or any other projects in proximity to the predicted/modeled, final extent of the carbon dioxide plume and area of elevated pressure;	N/A
§146.93(c)(1)(x)	§633.A.3.a.x	The distance between the injection zone and the nearest USDWs above and/or below the injection zone; and	Section 1, App B
§146.93(c)(1)(xi)	§633.A.3.a.xi	Any additional site-specific factors required by the Director.	
§146.93(c)(2)	§633.A.3.b	Information submitted to support the demonstration in paragraph (c)(1) of this section must meet the following criteria:	
§146.93(c)(2)(i)	§633.A.3.b.i	All analyses and tests performed to support the demonstration must be accurate, reproducible, and performed in accordance with the established quality assurance standards;	
§146.93(c)(2)(ii)	§633.A.3.b.ii	Estimation techniques must be appropriate and EPA-certified test protocols must be used where available;	
§146.93(c)(2)(iii)	§633.A.3.b.iii	Predictive models must be appropriate and tailored to the site conditions, composition of the carbon dioxide stream and injection and site conditions over the life of the geologic sequestration project;	
§146.93(c)(2)(iv)	§633.A.3.b.iv	Predictive models must be calibrated using existing information (e.g., at Class I, Class II, or Class V experimental technology well sites) where sufficient data are available;	
§146.93(c)(2)(v)	§633.A.3.b.v	Reasonably conservative values and modeling assumptions must be used and disclosed to the Director whenever values are estimated on the basis of known, historical information instead of site-specific measurements;	
§146.93(c)(2)(vi)	§633.A.3.b.vi	An analysis must be performed to identify and assess aspects of the alternative post-injection site care timeframe demonstration that contribute significantly to uncertainty. The owner or operator must conduct sensitivity analyses to determine the effect that significant uncertainty may contribute to the modeling demonstration.	
§146.93(c)(2)(vii)	§633.A.3.b.vii	An approved quality assurance and quality control plan must address all aspects of the demonstration; and,	
§146.93(c)(2)(viii)	§633.A.3.b.viii	Any additional criteria required by the Director.	

EPA 40 CFR	LAC 43:XVII.Chapter 6	Description	Permit Application
§146.93(d)	§633.A.4	Notice of intent for site closure. The owner or operator must notify the Director in writing at least 120 days before site closure. At this time, if any changes have been made to the original post-injection site care and site closure plan, the owner or operator must also provide the revised plan. The Director may allow for a shorter notice period.	Section 7
§146.93(e)	§633.A.5	After the Director has authorized site closure, the owner or operator must plug all monitoring wells in a manner which will not allow movement of injection or formation fluids that endangers a USDW.	Section 7
§146.93(f)	§633.A.6	The owner or operator must submit a site closure report to the Director within 90 days of site closure, which must thereafter be retained at a location designated by the Director for 10 years. The report must include:	Section 7
§146.93(f)(1)	§633.A.6.a	Documentation of appropriate injection and monitoring well plugging as specified in § 146.92 and paragraph (e) of this section. The owner or operator must provide a copy of a survey plat which has been submitted to the local zoning authority designated by the Director. The plat must indicate the location of the injection well relative to permanently surveyed benchmarks. The owner or operator must also submit a copy of the plat to the Regional Administrator of the appropriate EPA Regional Office;	Section 7
§146.93(f)(2)	§633.A.6.b	Documentation of appropriate notification and information to such State, local and Tribal authorities that have authority over drilling activities to enable such State, local, and Tribal authorities to impose appropriate conditions on subsequent drilling activities that may penetrate the injection and confining zone(s); and	Section 7
§146.93(f)(3)	§633.A.6.c	Records reflecting the nature, composition, and volume of the carbon dioxide stream.	Section 7
§146.93(g)	§633.A.7	Each owner or operator of a Class VI injection well must record a notation on the deed to the facility property or any other document that is normally examined during title search that will in perpetuity provide any potential purchaser of the property the following information:	Section 7
§146.93(g)(1)	§633.A.7.a	The fact that land has been used to sequester carbon dioxide;	Section 7
§146.93(g)(2)	§633.A.7.b	The name of the State agency, local authority, and/or Tribe with which the survey plat was filed, as well as the address of the Environmental Protection Agency Regional Office to which it was submitted; and	Section 7
§146.93(g)(3)	§633.A.7.c	The volume of fluid injected, the injection zone or zones into which it was injected, and the period over which injection occurred.	Section 7
§146.93(h)	§633.A.8	The owner or operator must retain for 10 years following site closure, records collected during the post-injection site care period. The owner or operator must deliver the records to the Director at the conclusion of the retention period, and the records must thereafter be retained at a location designated by the Director for that purpose.	Section 7
§146.94	**§623**	**Emergency and remedial response**	
§146.94(a)	§623.A.1	As part of the permit application, the owner or operator must provide the Director with an emergency and remedial response plan that describes actions the owner or operator must take to address movement of the injection or formation fluids that may cause an endangerment to a USDW during construction, operation, and post-injection site care periods. The requirement to maintain and implement an approved plan is directly enforceable regardless of whether the requirement is a condition of the permit.	Section 8
§146.94(b)	§623.A.2	If the owner or operator obtains evidence that the injected carbon dioxide stream and associated pressure front may cause an endangerment to a USDW, the owner or operator must:	Section 8
§146.94(b)(1)	§623.A.2.a	Immediately cease injection;	Section 8
§146.94(b)(1)	§623.A.2.b	Take all steps reasonably necessary to identify and characterize any release;	Section 8
§146.94(b)(1)	§623.A.2.c	Notify the Director within 24 hours; and	Section 8
§146.94(b)(1)	§623.A.2.d	Implement the emergency and remedial response plan approved by the Director.	Section 8
§146.94(c)	§623.A.3	The Director may allow the operator to resume injection prior to remediation if the owner or operator demonstrates that the injection operation will not endanger USDWs.	Section 8
§146.94(d)	§623.A.4	The owner or operator shall periodically review the emergency and remedial response plan developed under paragraph (a) of this section. In no case shall the owner or operator review the emergency and remedial response plan less often than once every five years. Based on this review, the owner or operator shall submit an amended emergency and remedial response plan or demonstrate to the Director that no amendment to the emergency and remedial response plan is needed. Any amendments to the emergency and remedial response plan must be approved by the Director, must be incorporated into the permit, and are subject to the permit modification requirements at § 144.39 or § 144.41 of this chapter, as appropriate. Amended plans or demonstrations shall be submitted to the Director as follows:	Section 8
§146.94(d)(1)	§623.A.4.a	Within one year of an area of review reevaluation;	Section 8
§146.94(d)(2)	§623.A.4.b	Following any significant changes to the facility, such as addition of injection or monitoring wells, on a schedule determined by the Director; or	Section 8
§146.94(d)(3)	§623.A.4.c	When required by the Director.	

EPA 40 CFR	LAC 43:XVII.Chapter 6	Description	Permit Application
§146.95		**Class VI injection depth waiver requirements**. This section sets forth information which an owner or operator seeking a waiver of the Class VI injection depth requirements must submit to the Director; information the Director must consider in consultation with all affected Public Water System Supervision Directors; the procedure for Director—Regional Administrator communication and waiver issuance; and the additional requirements that apply to owners or operators of Class VI wells granted a waiver of the injection depth requirements.	No Waiver Requested

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Underground Injection Control – Class VI Permit Application for Hackberry Carbon Sequestration Well No. 001

Cameron Parish, Louisiana

INTRODUCTION

Prepared for *Hackberry Carbon Sequestration, LLC*
Cameron, LA

By

Lonquist Sequestration, LLC
Austin, TX

August 2021
Revised January 2025

SECTION 0 – INTRODUCTION

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Project Overview

Large scale capture of anthropogenic carbon dioxide (CO_2) is increasingly viewed as critical for the United States and global community to meet ambitious goals for greenhouse gas reductions by companies, states, and national governments. For example, the International Energy Agency (IEA) has highlighted a potential need for CO_2 storage to increase from around 40 million metric tons per year today to more than 5,000 million metric tons per year by mid-century. Today, the United States is the global leader in Carbon Capture, Use, and Sequestration (CCUS), holding more than 60% of current CCUS capacity and half of all global CCUS capacity under development.[1]

To have an impact on global greenhouse gas levels, when carbon, generally in the form of CO_2, is captured from a source, that CO_2 must safely be disposed of in some manner. One of the more common methods of dealing with the captured CO_2 is injection into porous formations below the earth's surface. The United States Gulf Coast has long been viewed as suitable for long-term sequestration of CO_2.[2]

The costs associated with CCUS technologies have historically made carbon injection and sequestration projects uneconomical without substantial governmental assistance or revenue from utilizing the CO_2 in an enhanced oil recovery application. However, expansion of the 26 U.S Code **§45Q** tax credit through the Bipartisan Budget Act of 2018 and implementation of the associated guidance and regulations by the U.S. Department of Treasury has now created a framework where more carbon capture and sequestration projects can be economically feasible.

Hackberry Carbon Sequestration, LLC (HCS) proposes drilling and completing a carbon sequestration well in Cameron Parish, Louisiana. As such, HCS is applying for a Class VI permit to construct and operate the well, which will be located on surface acreage, with CO_2 injected and sequestered into subsurface pore space controlled pursuant to an exclusive option to purchase by HCS. The information contained within this permit application is being submitted in support of this proposed Class VI well.

The application will (i) fully detail and characterize the geology of the proposed well location, evaluate the formation for properties necessary to safely and permanently sequester CO_2, (ii) describe the engineering design and safety considerations for the well, and (iii) discuss the proposed monitoring system which will be utilized to compare and contrast actual injectate plume migration to reservoir modeling and simulation of the anticipated plume. In accordance with all federal and local regulations for Class VI wells, the permit will be updated every five years thereafter during the active injection life of the well.

[1] The world has vast capacity to store CO_2: Net zero means we'll need it – Analysis - IEA
[2] 2010 Carbon Atlas of the United States and Canada, National Energy Technology Laboratory, US Department of Energy

Hackberry Carbon Sequestration, LLC

HCS is an entity formed to support the capture and permanent sequestration of CO_2 emitted from liquefied natural gas (LNG) export terminals as well as other industrial facilities located in the Gulf Coast region. LNG terminals operating and under construction in southwest Louisiana and southeast Texas have enabled the United States to become a global leader in exporting natural gas to foreign customers. Increasingly, these customers are seeking natural gas sourced through lower-carbon processes to meet their energy needs and are looking to US suppliers to supply this cleaner product. Likewise, industrial operators and their customers are seeking to decarbonize their facilities and their products. HCS's commitment to facilitate lower carbon energy and industrial production will help these crucial manufacturers evolve as leaders in the global energy transition.

Hackberry Sequestration Project Overview

The project described in this application ("Hackberry Sequestration Project") is located in Cameron Parish in southwest Louisiana; the location of the Hackberry Sequestration Project is ideal given several essential factors.

These factors include:

1. Project location near operational LNG export facilities and additional Lake Charles area industrial facilities nearby for point-source collection of CO_2 gases

2. Ideal subsurface geologic conditions for the injection and storage of the captured CO_2 gases
    a. Thick sand intervals in the Miocene with high porosities and permeabilities
    b. Satisfactory confining layers of shales and siltstones above and below the sand intervals

3. Single tract surface and pore space interests controlled by HCS for the entirety of the CO_2 plume

4. With regards to any pressure sources, sinks or other critical activities in the confining or injection zones of the region, there are none found within an influential distance of this injection operation. The nearest production is several miles away and found primarily in formations other than those being utilized for this project.

Hackberry Carbon Sequestration Project Positive Attributes

The development of the Hackberry Carbon Sequestration Project will have significant economic and social benefits to the State of Louisiana, specifically to Cameron Parish. The development of the Hackberry Carbon Sequestration Project will employ approximately 310 workers during construction, of which fifteen percent (15%) would be local residents, seventy-five percent (75%) commuters, and ten percent (10%) of whom will temporarily relocate to the area. In addition,

once fully operational, the Hackberry Carbon Sequestration Project will require approximately two full-time employees.

As measured by sales and personal earnings, business activity is expected to increase during the construction of the Hackberry Carbon Sequestration Project. Additionally, there will be an increase in tax revenue to local parishes, positively growing the local tax revenue based on tax revenue projections.

In short, the Hackberry Carbon Sequestration Project will provide significant temporary direct and indirect economic benefits to the state of Louisiana and the local communities of southwest Louisiana during construction of the project and even greater long-term economic benefits during the full operating life of the project.

The environmental benefits of the Hackberry Carbon Sequestration Project impact not just the state and local communities, but the global community as well. The sequestration of up to 2 million metric tons per year (MMT/yr) of CO_2 is equivalent to removing approximately 400,000 passenger cars off the road each year[3]. Further, no permanent wetland impacts are expected to result from the project nor any long-term adverse impacts to environmentally sensitive habitats. In fact, the Hackberry Sequestration Project is expected to create approximately 37 acres of wetland marsh, through the beneficial use of dredge material.

Community Engagement

Sempra Infrastructure has been part of the community in southwest Louisiana and the community of Hackberry for over 20 years. Sempra is dedicated to enhancing the economic prosperity and resilience of the area. Sempra Infrastructure has also contributed to several community emergency preparedness and safety initiatives over the years. This includes contributing to the construction of a new, $6.3 million community center in Hackberry, which serves as the area's local Emergency Operations Center and a shelter for residents.

Additionally, as part of the Stakeholder Engagement Plan (SEP), Sempra Infrastructure's due diligence process includes consultations with stakeholder groups to identify and gain understanding of environmental and social risks. The company strives to mitigate any impacts of our operations and collaborates with the community on ways to contribute to the economic prosperity for all people regardless of race, color, national origin or income with respect to the development, implementation and enforcement of environmental laws, regulations and policies.

HCS and Sempra have developed a stakeholder engagement plan to provide transparent, two-way communication to stakeholder audiences to build trust and credibility. The plan also ensures that there are structures and mechanisms in place for stakeholders to express any comments or concerns that may arise so that they can be addressed and resolved in a timely manner. Outreach and engagement activities are utilized to broaden community knowledge on topics related to the

[3] "Greenhouse Gas Equivalencies Calculator." *EPA*, Environmental Protection Agency, Mar. 2021, www.epa.gov/energy/greenhouse-gas-equivalencies-calculator.

project and its benefits. Feedback from these efforts include identifying any concerns or issues early on and addressing them. These efforts include informational meetings and open houses for the community, development of communication materials regarding the project, participation in regional business advocacy groups, establishment of communication mechanisms for community input, and other tactics outlined in the Stakeholder Engagement Plan included in Section 11 – Environmental Justice.

Agreement Discussion

HCS has entered into a Memorandum of Understanding (MoU) with Cameron LNG, LLC (CLNG) to capture and store CO_2 from the CLNG owned LNG export facility (CLNG Facility).

The CLNG Facility receives natural gas from various pipelines and liquifies the gas into LNG for export, the process of preparing the natural gas for export results in generation of CO_2. CLNG can capture a portion of these resultant emissions and deliver them to the Hackberry Sequestration Project for permanent storage.

Proposed CO_2 Sequestration System Discussion

HCS proposes to construct and operate the Hackberry Sequestration Project facilities to sequester up to 2 MMT/yr of captured carbon via injection into up to three storage wells. This application is for the first of those three wells. The proposed well discussed in this application will be named **"Hackberry Carbon Sequestration Well No. 001"** and will be designed to sequester 2 MMT/yr. The anticipated life of active injection for Hackberry Carbon Sequestration Well No. 001 is projected to be 20 years. The sequestration well and CO_2 plume associated with the Hackberry Sequestration Project will be located on approximately 8,112 acres and will include one storage well and a seismic monitoring system for tracking plume movement within the storage formation. Figure 0-1 provides a conceptual overview of the Hackberry Sequestration Project facilities.

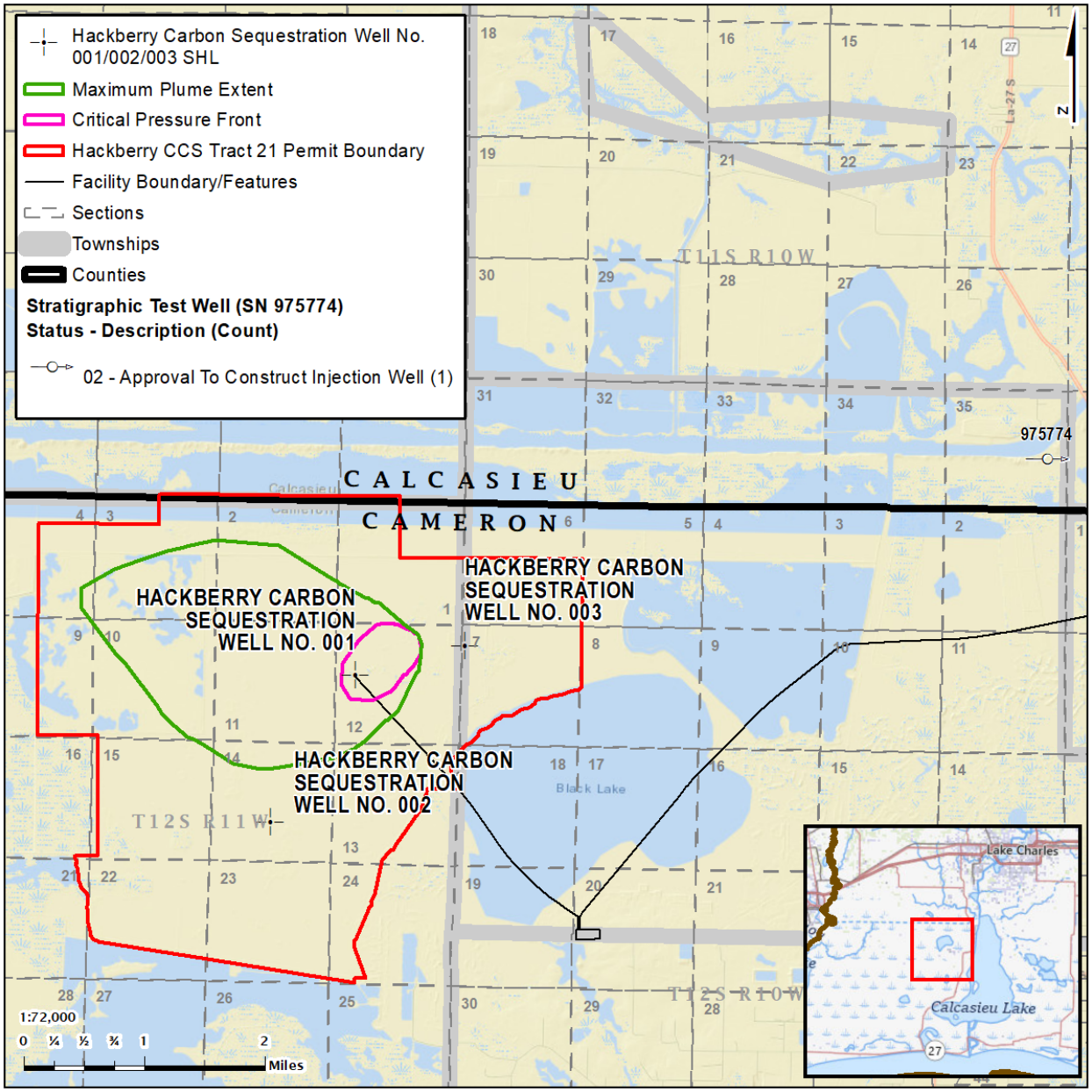

Figure 0-1 – Project Overview

Injection Strategy

The injection strategy for the Hackberry Sequestration Project will entail staged injection intervals spanning over approximately 1,700 net feet of clean, porous, and permeable Miocene sands found in the subsurface of the project site. These injection stages are proposed to be developed at least every five years at the time of permit renewal for the well as required based upon actual sequestration activity.

For the first five years of injection, the lowermost Miocene sands will be targeted and opened via perforations for injection. Then, based on actual injection rates during the five-year period,

and following a plume extent survey, upper injection intervals may be exploited with a well recompletion. This recompletion, if necessary, will be completed in the same manner with each consecutive stage targeting shallower sand packages of Miocene sands until the uppermost limit of the gross injection interval is reached. The final stage of well recompletions is projected to occur in Years 16 through 20.

As each injection stage reaches completion, the lower sands will be plugged and left behind, with only density drift accounting for further plume expansion. While the sand packages will be abandoned beneath an engineered plug, the zones will remain accessible to facilitate the continued monitoring of plume migration and formation conditions. Figure 0-2 provides a graphical depiction of this conceptual completion strategy.

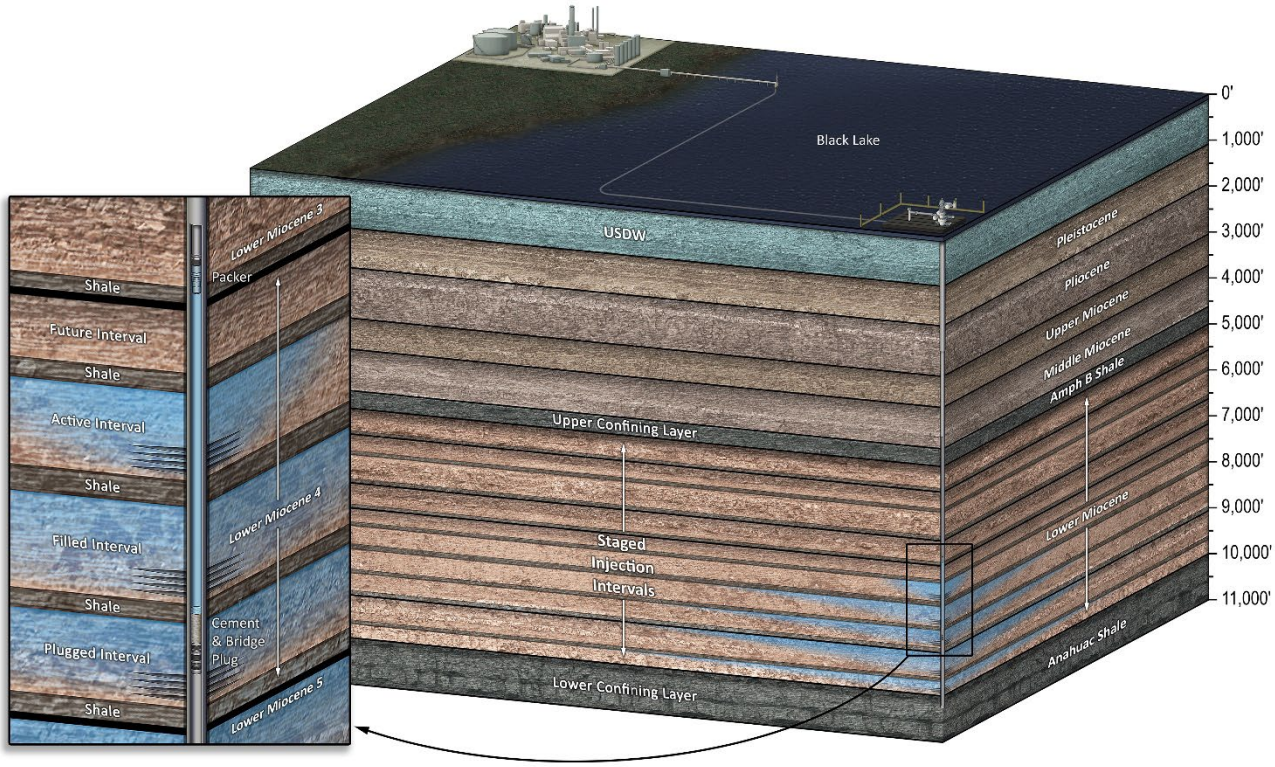

Figure 0-2 – Injection Strategy Concept

HCS Well No. 001 will be completed in this fashion to maximize the utilization of pore space. In doing so, the maximum extent of the plume migration will remain within the boundaries of HCS's controlled surface acreage.

The calculated average or typical anticipated surface operating pressure for the storage well is estimated at 1,700 pounds per square inch gauge (psig). This pressure will be generated at the compressor for injection into the well. The maximum injection pressure is estimated to be 2,000 psig which will be required during the initial injection phase of the well in Year 1. A full discussion of operating and reservoir pressure effects is provided in Section 2 – Plume Model.

Stratigraphic Test Well Discussion

A stratigraphic test well (LA Storage SWD No. 003, SN 975774) was drilled and completed by an affiliate of HCS in the first quarter of 2021 for the specific purpose of preparing this application. HCS has obtained ownership of the data and information associated with that activity. This well was drilled to acquire analogous subsurface detail and characteristics for the proposed injection intervals for HCS Well No. 001. Extensive openhole logging was performed, whole cores and connate fluid samples were obtained, and injectivity tests were performed with respect to the test well. All these variables have been included in the complete site characterization section (Section 1 and Appendix B). Similarly, all the appropriate variables derived from the stratigraphic test well have been applied to the plume modeling efforts associated with this application and are discussed and identified in Section 2.

While the stratigraphic test well was drilled approximately 6 miles from the proposed location of the HCS Well No. 001, Figure 0-3 depicts the anticipated relationship between the stratigraphic test well location and an analog well found approximately 1.2 miles from the HCS Well No. 001 location. Direct correlations were found between the stratigraphic test well and the analog.

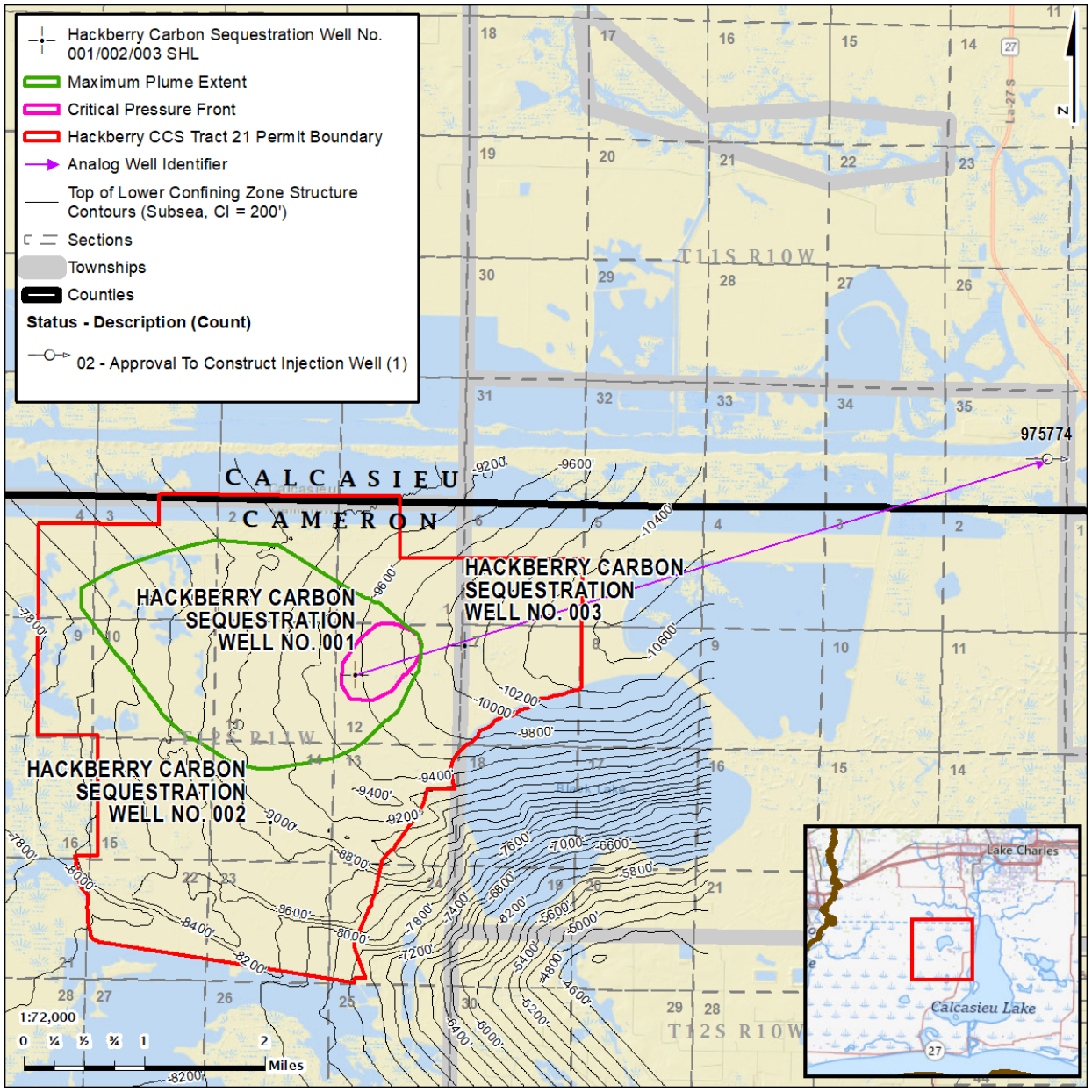

Figure 0-3 – Project Overview – Structure Map

Based on an evaluation of regional geology, it is anticipated that the parameters and variables derived from the stratigraphic test well performed by HCS will be correlative to the actual HCS Well No. 001 location for modeling requirements for this application. These model inputs will be confirmed through sample acquisition during the drilling of Hackberry Carbon Sequestration Well No. 001 and the plume model either verified or updated at that time.

Injectate Information

The HCS Well No. 001 is designed to receive approximately 2.0 MMT/yr of concentrated CO_2 per year.

The primary chemistry of the injectate stream has been determined to consist of:

- ~98% CO_2
- ~2% CH_4

A full description of the injectate composition is discussed in detail in Section 2.2.9.4.

Surface Facilities and Details

The CO_2 will be delivered to the Hackberry Sequestration Project at a typical pressure range of 1,200 to 1,800 pounds per square inch (psi) and at a temperature range of 100°F to 120°F (38°C to 49°C). Under these conditions, the injectate stream will be in a supercritical phase and transported to the Hackberry pump station 6 miles away. The Hackberry pump station will occupy about 10 acres within a 160-acre parcel owned by LA Storage (Figure 0-1). The injectate stream will be compressed to a pressure of approximately 3,000 psig. After compression the injectate stream will be transported to the storage well approximately 3 miles away before being injected into the subsurface strata for sequestration.

Site Suitability

In the process of developing the Hackberry Carbon Sequestration Project and in compliance with regulations, 40 CFR **§146.82(c)(2)**, 40 CFR **§146.83**, and LAC **§3619.A.2** and **§3615.A**, an evaluation of the proposed site, "Site Suitability," was generated and yielded the following:

- The proposed project site is located on private land (non-tribal) in Cameron Parish, Louisiana controlled under an exclusive option to purchase by HCS (Figure 1-1).
- A Phase I Archaeological Survey of the entire proposed project area was performed and identified no archaeological and historic resources within the proposed project survey areas.
- The project area is not located on military installations. No federal installations located near the project site, the nearest federal installation is the Strategic Petroleum Reserve, which is approximately 4 miles away.
- Habitat and wetland surveys of the proposed project area did not find endangered, threatened species or critical habitats.
- The site is located in flood hazard Zone VE as shown in the map on Appendix I-2.
- No existing infrastructure, surface, and subsurface mines or quarries are in the project area.
- No faults or fractures are in the project area based on seismic analysis or geophysical well log characterization.
- No State or Federal subsurface cleanup sites are within the project area.

- No environmental justice issues.
- No artificial penetrations and no freshwater wells were found within the AOR boundaries. The closest freshwater wells to the HCS Well No. 001 surface hole location are over a mile away, with the closest well, 023-5625Z, which is 11,093 feet from the surface hole and approximately 6,961 ft from the outer plume extent of the injectate, and is plugged and abandoned).
- No drinking water wells were found within the AOR boundaries; the closest drinking water well, 023-5444Z, is 20,186 ft away from the HCS Well No. 001 surface hole location and approximately 16,207 ft from the outer plume extent of the injectate and is plugged and abandoned. Please reference Appendix E- Area of Review for detailed maps.

Injection Well Summary and Operational Overview

The proposed HCS Well No. 001 will be located in Section 11, Township 12S, Range 11W at NAD 83 Lat. 30°01'55.08295" N, Long. 93°27'12.07152" W. The well will be vertically drilled to approximately 10,100 ft below ground level (BGL) with a proposed gross injection interval estimated to be between 4,022 ft and 10,026 ft (BGL).

The geology within the gross injection interval consists of Miocene-aged sand packages interbedded with shale layers throughout the entire interval. The net thickness of useable, quality Miocene sands is estimated to be approximately 1,700 ft. These sand packages were selected due to their high porosities and permeabilities, depths desirable for single phase fluid state, and continuous lateral extent.

The upper extent of the gross injection interval is bounded by a shale formation known as the Amphistigina Shale. This upper confining layer is estimated to be approximately 250 ft thick with at least 100 ft of contiguous shale. The basement confining layer has been identified as the Anahuac Shale which is approximately 200 ft thick within the project areal extents. Shale is a proven confinement geology for underground injection control wells. A complete site characterization is detailed in subsequent sections of this application.

HCS Well No. 001 will be operated in such a fashion as to meet the requirements of **§621.A** (*40 CFR* ***§146.88***) with a complete detailing of these operating plans discussed in subsequent sections of this application. It is anticipated that HCS Well No. 001 will operate for 20 years at which time it will be plugged according to **§631** (*40 CFR* ***§146.92***) requirements. Total site closure will occur upon completion of injection into all three injection wells related to the Hackberry Sequestration Project.

A state-of-the-art monitoring and plume verification system will be installed as part of the construction and operation of the project. Monitoring efforts will consist of both a passive seismic monitoring system installed and established above the anticipated extents of the subsurface plume as well as fiber optic equipment and gauges installed within the wellbore itself. The latter will be cemented into place during the setting and cementing of the production casing string.

HCS Well No. 001 has a distinct advantage over most Class VI projects in that there are no artificial penetrations within the simulated plume extent for the well. The proposed monitoring system has been designed to meet the requirements of **§625.A** (*40 CFR* ***§146.90***) with advanced technologies which will allow for the tracking of the injectate plume migration without artificially creating potential pathways for sequestered fluids to escape confinement. A contingency has been included in the proposed monitoring plan in the event that the actual plume migration does not conform to the simulated expectations for subsurface results. Upon review and evaluation of the VSP survey, should the results indicate deficiencies in plume boundary identification, a contingency monitoring program would be considered.

This contingency program, if necessary due to concerns about variances in plume migration, would include the construction of a series of monitoring wells. Artificial penetrations into the confinement geology and alternative pathways out of subsurface should be avoided when possible. The proposed monitoring system and contingency plan will allow for plume variance risk to be mitigated.

A complete detailing of the proposed monitoring system for the Hackberry Sequestration Project is outlined in subsequent sections of this application (Section 5 - Testing and Monitoring Plan).

Summary

This application demonstrates that the HCS Well No. 001 location is ideally situated for the permanent storage of captured CO_2 for several reasons. The most favorable details include:

- Excellent injection intervals of contiguous, thick, high porosity, and high permeability Miocene sand.
- Contiguous upper and basement confining shales and siltstones.
- Contiguous shale formations interbedded with the sand horizons allowing for strategic reservoir management options.
- Favorable geologic depositional formation with no detectable faults or geologic hazards within the modeled plume extents.
- Relatively gentle local and regional structural dip.
- Zero artificial penetrations found within the modeled plume extents.
- Control of pore space occupied by the modeled plume.
- There are no economically recoverable hydrocarbon resources within the gross injection interval of the well.

The proposed well has been designed with the utmost safety in mind. The wellbore construction utilizes recommended metallurgies and acid-resistant cement to protect groundwater resources.

Perhaps one of the most innovative aspects of the Hackberry Carbon Sequestration Project is the plume monitoring technology proposed for use in HCS Well No. 001. The well will be constructed with a permanently installed fiber optic monitoring system. This system will be used to perform vertical seismic profile (VSP) surveys of the plume movement within the storage intervals. Due

to the complex nature of the operational plan for this well, the fiber optic monitoring system offers the ability to survey multiple sand formations during storage operations.

Most importantly, the fiber optic monitoring system allows HCS to monitor the plume movement in real time without additional artificial penetrations into the injection and confining intervals of the well. This system will minimize the risk of sequestered fluids escaping confinement, ensuring that the stored CO_2 remains permanently confined within the Miocene sands.

Appendix A contains details pertaining to the identification of the locations and property boundaries applicable to the Hackberry Sequestration Project. The appendix consists of the following documents:

- Appendix A-1 Project Overview Map
- Appendix A-2 Property Boundary Survey Plat
- Appendix A-3 Well Location Survey Plat
- Appendix A-4 Adjacent Landowner Map

Required Administrative Information

General Application Information

Injection Well Information:

Well Name and Number	Hackberry Carbon Sequestration Well No. 001
Parish	Cameron Parish, Louisiana
Section-Township-Range	11-T12S-R11W
Latitude and Longitude	30°01’55.08295” N, 93°27’12.07152” W

Applicant:

Name	Hackberry Carbon Sequestration, LLC
Address	1500 Post Oak Blvd, Suite 1000 Houston, TX 77056
Facility contacts:	John Koss jkoss@sempraglobal.com (832) 417-3785
Ownership Status	Limited Liability Company
Entity Status	Private

SIC Codes:

4925 – Mixed, Manufactured, or Liquified Petroleum Gas Production and/or Distribution
4953 – Refuse Systems (Nonhazardous waste disposal sites)

This facility is not located on Federal, Indian or State lands.

Additional Permits

Table 0-1 – Permits, Approvals, Consultations & Regulatory Requirements

Agency	Permit & Authorization	Application Date *(anticipated)*	Receipt Date *(anticipated)*	Status
FEDERAL				
Federal Energy Regulatory Commission (FERC)	CLNG Amended Order (CP22-41-000) - Variance Request Approval to locate HCS facilities within CLNG	October 24, 2023	December 2024	Complete
U.S. Army Corps of Engineers (USACE)	Section 404/408/10 Permit	September 1, 2021	March 24, 2023	Complete
U.S. Fish and Wildlife Service (USFWS)	Section 7 Consultation	September 1, 2021	March 24, 2023	Complete
National Oceanic and Atmospheric Administration (NOAA) National Marine Fisheries Service (NMFS)	Section 7 Consultation/EFH	September 1, 2021	February 21, 2022	Complete
STATE				
Louisiana Department of Environmental Quality (LDEQ)	Louisiana Pollutant Discharge Elimination System (LPDES) Permit – Sanitary Wastewater & Stormwater	*(TBD - prior to pump station construction)*	*(TBD - prior to pump station construction)*	*Ongoing*
	Hydrostatic Test Water Discharge General Permit	*(TBD - prior to pipeline construction)*	*(TBD – prior to pipeline construction)*	*Ongoing*
	401 Water Quality Certification	September 1, 2021	September 21, 2022	Complete
	General Construction SWPPP	*(TBD - prior to well construction)*	*(TBD - prior to well construction)*	*Ongoing*
Louisiana Office of Cultural Development	Section 106 Consultation	September 7, 2021	October 11, 2021	Complete
Louisiana Department of Environment and Natural Resources (LDENR)	Class VI Injection Well Permit *(Same as EPA Class VI Permit)*	September 1, 2021	*(March 2025)*	*Ongoing*
	Coastal Use Permit – Office of Coastal Management	September 1, 2021	November 16, 2022	Complete
	Office of Conservation – Pipeline Division	May 31, 2024	*(December 2024)*	*Ongoing*

Louisiana Department of Wildlife and Fisheries (LDWF)	Consultation for state-listed Threatened and Endangered Species and Fish and Wildlife concerns	September 1, 2021	November 16, 2022	Complete
LOCAL				
Cameron Parish Police Jury	Letter of No Objection	NA	January 5, 2022	Complete
CONSULTATION				

APPLNUM 45026

Underground Injection Control – Class VI Permit Application for Hackberry Carbon Sequestration Well No. 001

Cameron Parish, Louisiana

SECTION 1 – SITE CHARACTERIZATION

Prepared for *Hackberry Carbon Sequestration, LLC*
Cameron, LA

By

Lonquist Sequestration, LLC
Austin, TX

August 2021
Revised January 2025

Rev. January 31, 2025

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SECTION 1 – SITE CHARACTERIZATION

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1.1 Introduction

This Site Characterization for Hackberry Carbon Sequestration Well No. 001 was prepared to meet the requirements of SWO 29-N-6 **§607.C.1.b** [40 CFR **§146.82(a)(3)**]. This section describes the regional and site geology for the proposed location.

1.2 Regional Geology, Hydrogeology and Local Structural Geology

Exploratory wells and borings for hydrocarbons, geothermal, storage and groundwater development provide regional geological information across southwest Louisiana. The State of Louisiana Department of Natural Resources (LADNR) provides publicly available documents, well and groundwater information. The United States Geological Survey (USGS) performed a National Assessment of Carbon Dioxide Storage Resources, including a study detailing the U.S. Gulf Coast geologic framework to evaluate possible targets for geologic storage of CO_2. In addition, literature from peer-reviewed journals, dissertations and theses are included in the study of southern Louisiana regional geology.

1.2.1 Regional Geology

The portion of the Gulf of Mexico Basin within the state-waters boundary of the United States covers an area of 148,049,000 acres and spans west to east from the southern coast of Texas to western Florida and reaches as far north as the Mississippi River in southern Missouri, Illinois and Kentucky (Roberts-Ashby et al., 2012). Crustal extension and expansion of the seafloor during the Mesozoic formed the Gulf of Mexico Basin, upon which the thick Jurassic Louann Salt was deposited (Salvador, 1991). Jurassic through Holocene sediment accumulated to as much as 20 kilometers thick in the depocenter located beneath southern Louisiana (Galloway, 2008).

Seafloor spreading during the opening of the Gulf of Mexico Basin was accommodated by NW-SE trending transfer faults which influenced rates of subsidence and salt distribution (Galloway, 2008). Basement structures associated with the Ouachita and Appalachian Mountain ranges and the Llano uplift influenced Louann Salt and subsequent strata deposition. The Balcones, Luling-Mexia-Talco, State Line, and Pickins-Gilberton fault zones are regional structural influences on salt tectonics. The Gulf of Mexico Basin is influenced by sediment loading and salt mobilization expressed as growth-fault related structures, allochthonous salt bodies, salt welds, salt-based detachment faults, salt diapirs, and basin-floor compressional fold belts (Galloway, 2008).

A dip-oriented basin-scale cross section across the general area of the proposed CO_2 storage site illustrates basin structure in Figure 1-1. Figure 1-1(A) plots the path of the cross section from a general North to South direction; the red star approximates the proposed facility location. Figure 1-1(B), modified from Galloway (2008), is a North-South illustrated cross section with generalized stratigraphy, structure, crustal and salt features.

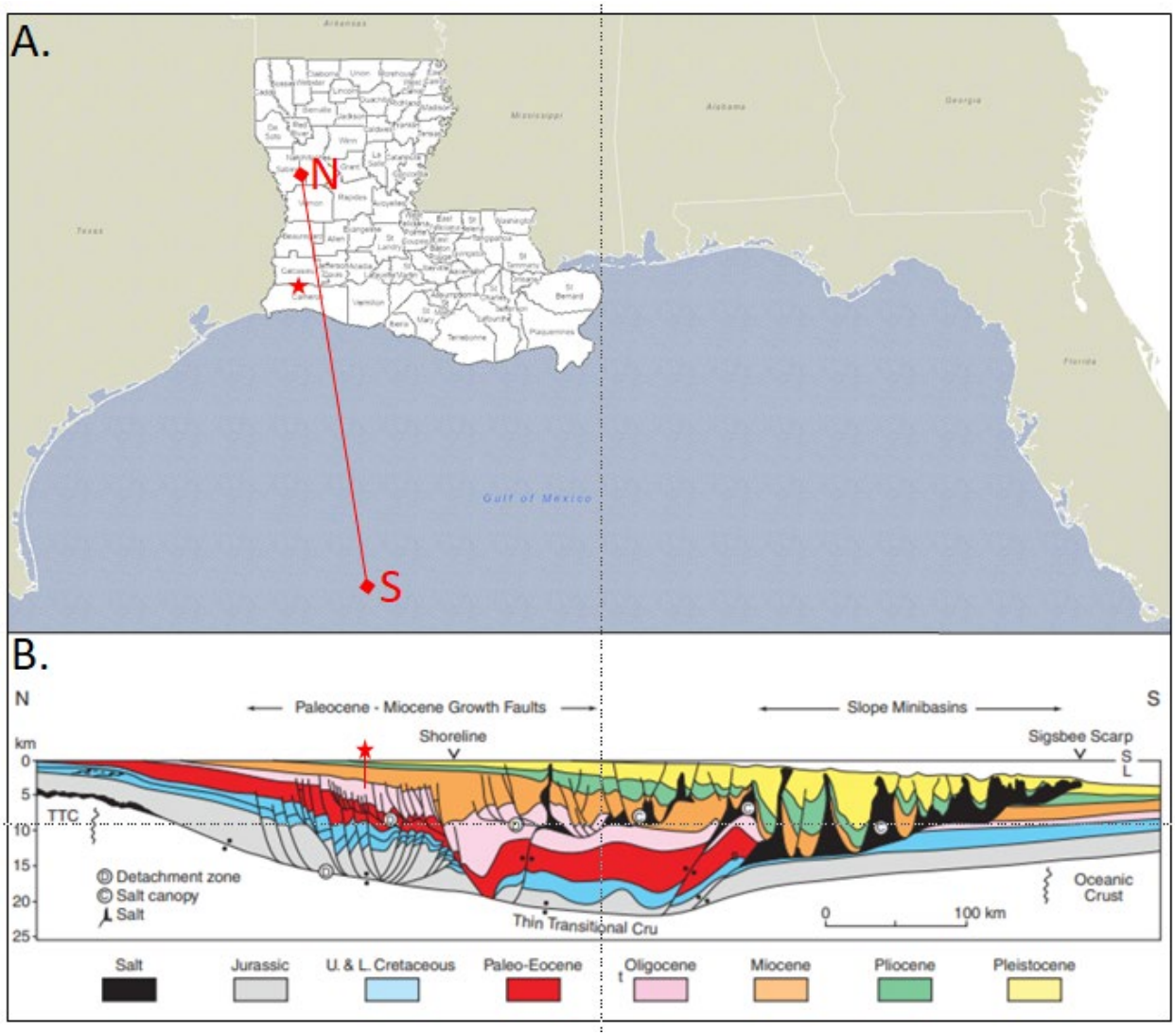

Figure 1-1 – (A) Reference Map and (B) Basin-Scale Cross Section

1.2.2 Major Stratigraphic Units

The Miocene depositional episodes are known as the paleo-Mississippi deposits and are characterized by fluvio-deltaic shale and sandstone sequences separated by regionally extensive shaly units. Miocene strata are divided into three stratigraphic units: the Lower, Middle and Upper Miocene. The Lower Miocene is the stratigraphic interval where CO_2 will be stored over the Hackberry site. In this location, the underlying Oligocene Frio Formation has a lower net-to-gross; therefore, it was not chosen as the injection zone. The Lower Miocene Formation overlays several thousand feet of thick shales within the Anahuac Formation (Oligocene) and is capped by a regionally extensive shaly interval, which corresponds to a regional maximum flooding surface (MFS) induced by a marine transgression over the entire Gulf of Mexico. This shaly unit, acting as the upper confining zone of our storage site, is the MFS 9 zone or Amphistegina B zone (Figure 1-2).

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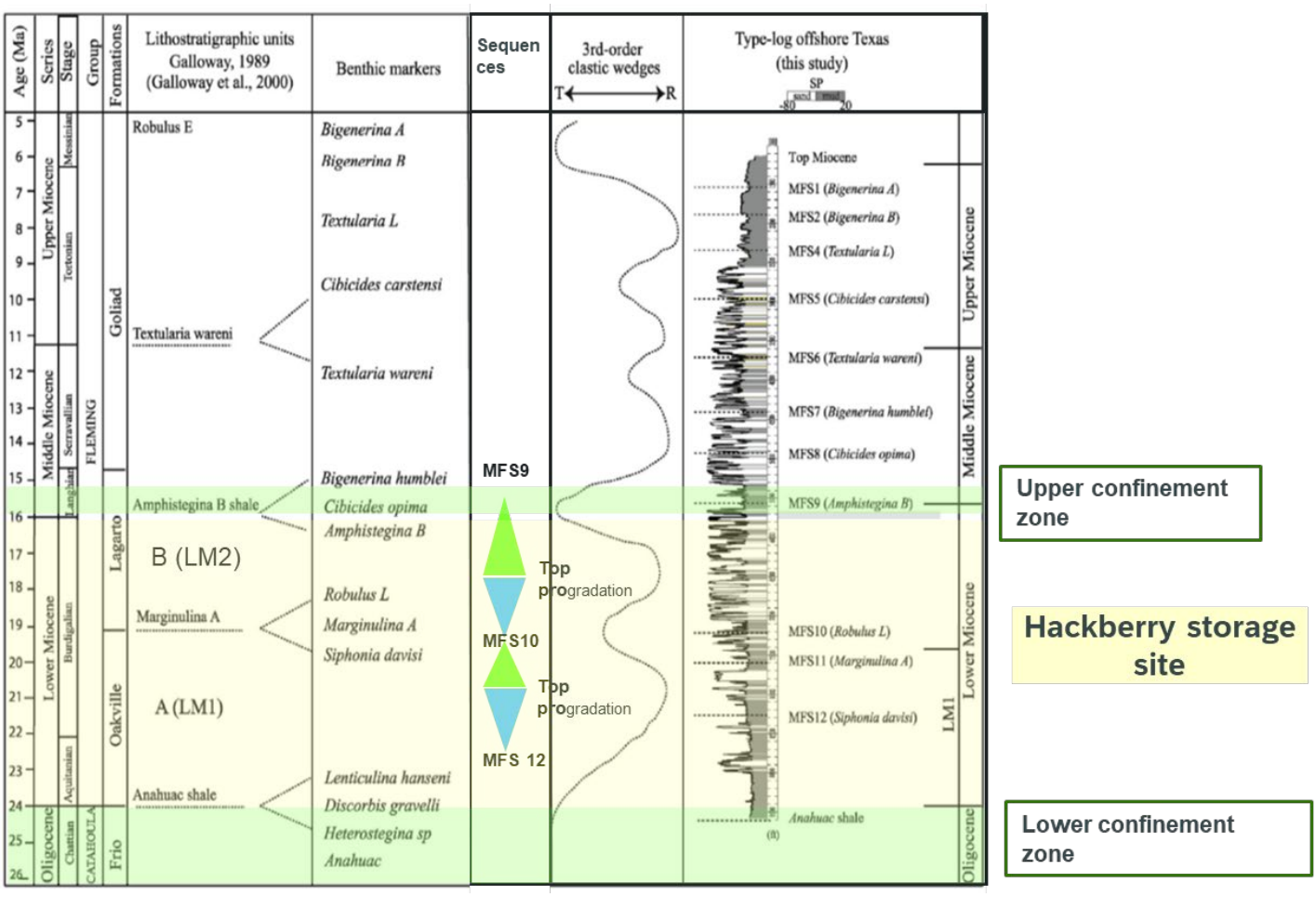

Figure 1-2 – Stratigraphy of the paleo-Mississippi in the Gulf Of Mexico (modified from Galloway et al., 1986, from GCCC) and sequence stratigraphy nomenclature used in this application.

The Lower Miocene is a high sediment supply-rate depositional episode following the end of the Oligocene-age Anahuac transgression (Galloway, 2008). As shown on Figure 1-2, the Lower Miocene is further subdivided into a Lower Miocene I and Lower Miocene II corresponding to two third-order sequences evidenced by Galloway et al. (1986, 2000, 2008). These sequences are defined from landward and seaward stepping phases of the fluvio-deltaic system. They are bound by laterally pervasive MFS with marine influences characterized by shaly deposits. The Lower Miocene I, the first of these sequences, is the basal stratigraphic unit from MFS 12 (Siphonia D.) to *MFS 10 (Robulus L)*. The Lower Miocene II, the second sequence, develops above MFS 10 to MFS 9, regionally known as the *Amphistegina B* zone. The maximum seaward stepping phases of each sequence correspond to maximum progradation events that are referred, in this report, to Tops of Progradation (labeled "Top Progr"). The shale-prone *Amphistegina B* and the Anahuac Shale are known to act as robust regional seals and both the Lower Miocene I and Lower Miocene II reservoirs are noted in the USGS storage assessment as "self-sealed" (Roberts-Ashby et al., 2012). The Lower Miocene I Storage Assessment Unit (SAU), defined by the *Marginulina A* top-seal limit and the State-water boundary, covers an area of 8,432,000 acres. The Lower

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Miocene II SAU, defined by the *Amphistegina B* top-seal limit and State-water boundary, covers an area of 9,924,000 acres (Roberts-Ashby et al., 2012).

Hydrocarbon production in this region from Miocene and Oligocene formations beneath the upper and middle Miocene demonstrate the capability of Miocene and Oligocene clay-rich shales as vertical and laterally sealing units to contain buoyant fluids (oil and natural gas) and prevent vertical migration. Black Bayou Field, west of the proposed storage site, has produced over 12 million barrels of oil and 10 million cubic feet of gas from Miocene and Oligocene sands, trapped beneath Miocene and Oligocene shales.

Figure 1-2 illustrates the regional stratigraphic column at the Hackberry site as encountered in the LA Storage SWD No. 003 (SN 975774) stratigraphic well east of the proposed storage site.

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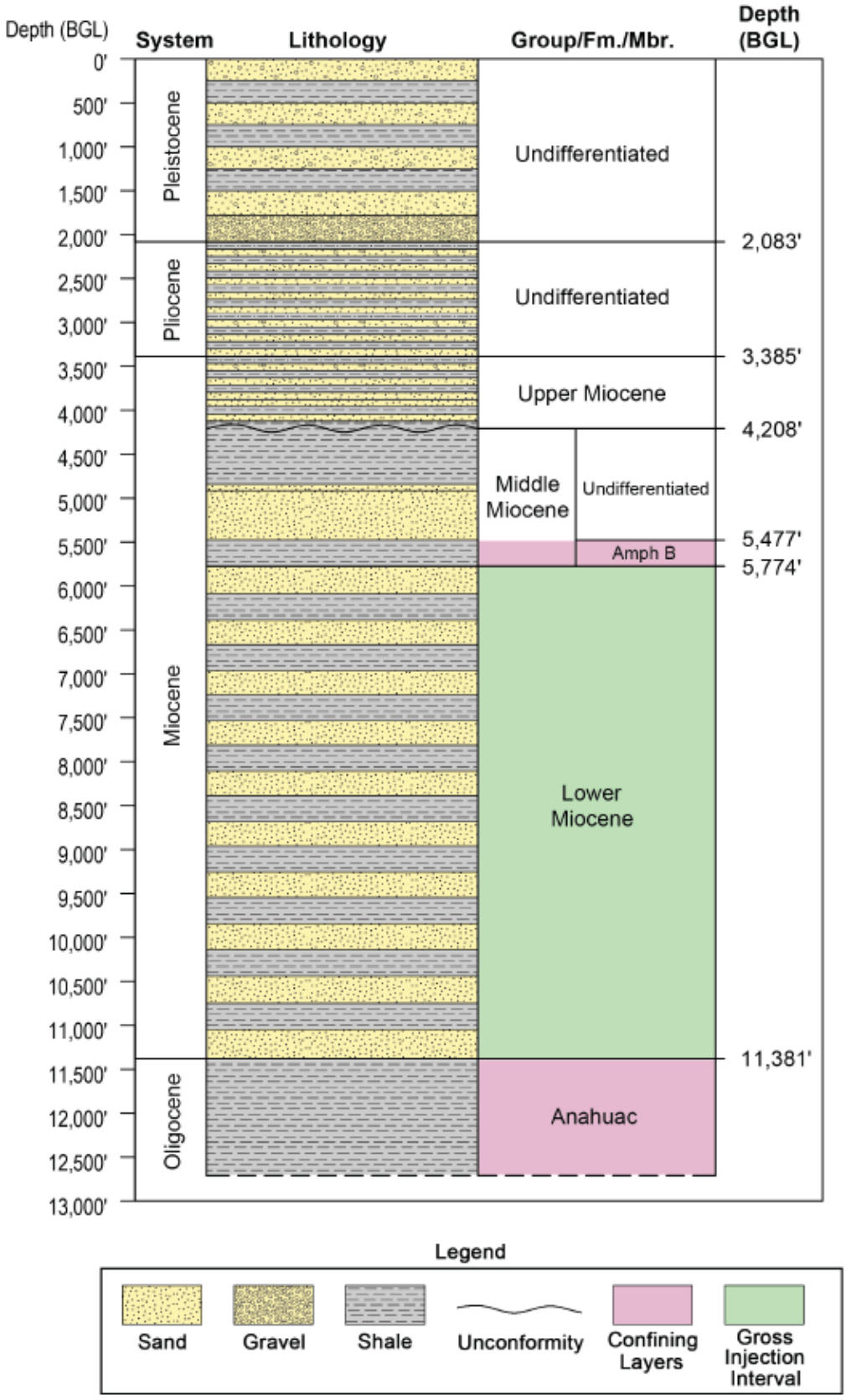

Figure 1-3 – Stratigraphic Column of the LA Storage SWD No. 003 (SN 975774) Well

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1.2.2.1 Lower Confining Zone: Anahuac Shale

The Anahuac is a regionally thick transgressive shale deposited conformably on top of the blanket sands of the Oligocene-age Frio Formation. Regional lithology of the Anahuac Shale is calcareous marine shale with localized, lenticular, micritic limestone typical of open-shelf environments (BEG study). Marine shales are fine-grained sedimentary rock formed from mud deposited in a marine environment. The mud is composed of clay minerals and silt-sized particles; the large percentage of calcite categorizes this shale as calcareous. Shales are effective top seals because they have low permeabilities and are usually laterally continuous.

The Anahuac Shale was deposited across the extent of the Gulf margin, 75 miles inland from the current coastline at the Texas-Louisiana border (Galloway, 2008). From this inland depositional limit, the Anahuac Shale thickens basinward to nearly 2,000 ft.

1.2.2.2 Injection Zone: Lower Miocene Sandstones

Lower Miocene sandstones in southwest Louisiana are fluvial-dominated deltaic deposits which prograded the continental margin 65-80 km basinward (Galloway, 2008). Gross sandstone thickness averages 3,100 ± 800 ft, with an average net sandstone thickness of 1,150 ± 500 ft (Robert-Ashby et al., 2012). Regional reservoir porosity gathered from a production database of 432 petroleum-reservoir-averaged porosity measurements by Nehring Associates, Inc. (2010) was analyzed by the Texas Bureau of Economic Geology and found to be 28 ±4% (Roberts-Ashby et al., 2012). Regional permeability measurements in the production database averaged 500 mD (Nehring Associates, Inc., 2010).

1.2.2.3 Upper Confining Zone: Amphistegina B

The Lower Miocene depositional episode terminates with the maximum flooding surface within the widespread *Amphistegina B* (Amph B) calcareous marine shale (Galloway, 2008). This regional, transgressive shale can reach thicknesses of 820 ft and is chosen as the primary sealing interval in the Offshore CO_2 Storage Resource Assessment by the U.S. Department of Energy National Energy Technology Laboratory (Trevino and Meckel, 2019).

1.3 Site Geology

No wellbores exist in the area of review (AOR) for Hackberry Carbon Sequestration (HCS) Well No. 001. Well logs of the closest offset wells and LA Storage SWD No. 003 (SN 975774), the stratigraphic test well, are submitted in Appendix B along with wells included in all cross sections, as shown in Figure 1-4.

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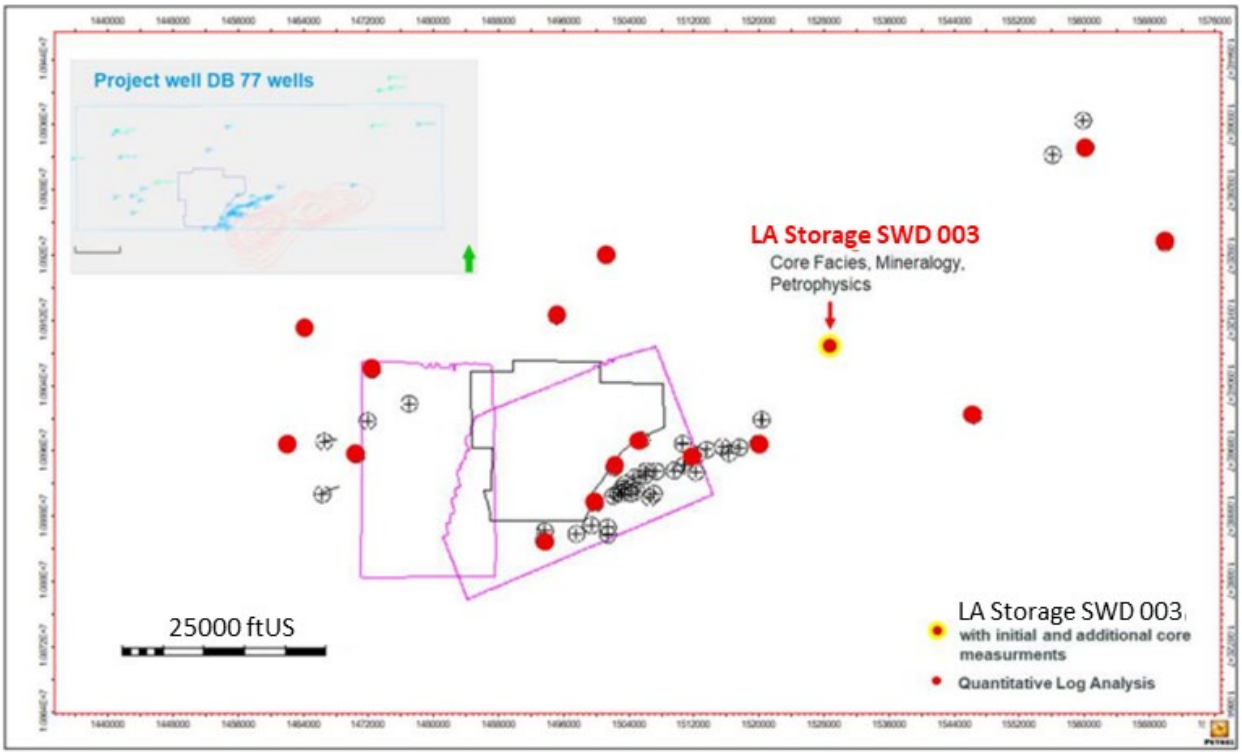

Figure 1-4 – Location of Well Logs Used for Geological Model. The purple outline indicates the 3D seismic used in this evaluation.

HCS Well No. 001 is located approximately 7.5 miles to the northwest of Hackberry, Louisiana (roughly 20 miles southwest of Lake Charles, Louisiana) and northwest of the West Hackberry Salt Dome margin. This location can be seen in Figure 1-5. The stratigraphic test well, LA Storage SWD No. 003 (SN 975774) was drilled, logged, and cored to assist in determining the geologic suitability of the proposed storage zone to both receive injected CO_2 into the proposed Hackberry Carbon Sequestration Well No. 001 well and to provide adequate long-term storage of the injected volumes. The LA Storage SWD No. 003 (SN 975774) well was drilled approximately 6.5 miles east of the proposed storage site. The stratigraphic well is located off the northern flank of the West Hackberry Salt Dome at Latitude: 30.058382, Longitude: -93.3531850 (NAD83). Data collected from the stratigraphic well was integrated into the larger data set to improve the geologic interpretations in this site-specific geology and hydrology document.

The LA Storage SWD No. 003 (SN 975774) was drilled to a total depth of 11,503 ft, which is 122 ft into the top of the Anahuac Shale formation. Formation tops are determined from correlations from offset well logs and publications written on the region. Formation tops as encountered in the stratigraphic well are represented in the stratigraphic column (Figure 1-3). The Lower Miocene section top is encountered in the stratigraphic well at 5,774 ft, the base is reached at 11,381 ft, total Lower Miocene thickness is 5,607 ft.

Extensive data collected during the LA Storage SWD No. 003 (SN 975774) drilling process includes openhole geophysical logs, fluid samples, cutting samples, and conventional cores. This data,

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along with offset correlated data, is the source for the model developed. The geophysical logged intervals are listed in Table 1-1.

Recovered conventional core, totaling 114 ft, sampled the three zones of interest: the Amphistegina B (upper confining zone), the Lower Miocene (storage zone), and the Anahuac shale (lower confining zone). The core depth intervals are listed in Table 1-2. Core recovery was limited in the Anahuac shale, resulting in one foot of recovery. Due to the lack of data on the upper confining zone's mineral content prior to drilling, smectite clays were encountered within the upper confining zone. These clays swelled when encountered by drilling fluids, which allowed for the core to produce artificially inflated results. Proper processes will be taken to adhere to smectite content found within the upper confining zone in future drilling procedures.

Formation tops and depths to the upper confining zone, injection zone, and lower confining zone are provided in Table 1-3. Photographs of slabbed cores from the Amphistegina B and Lower Miocene are shown in Figure 1-6.

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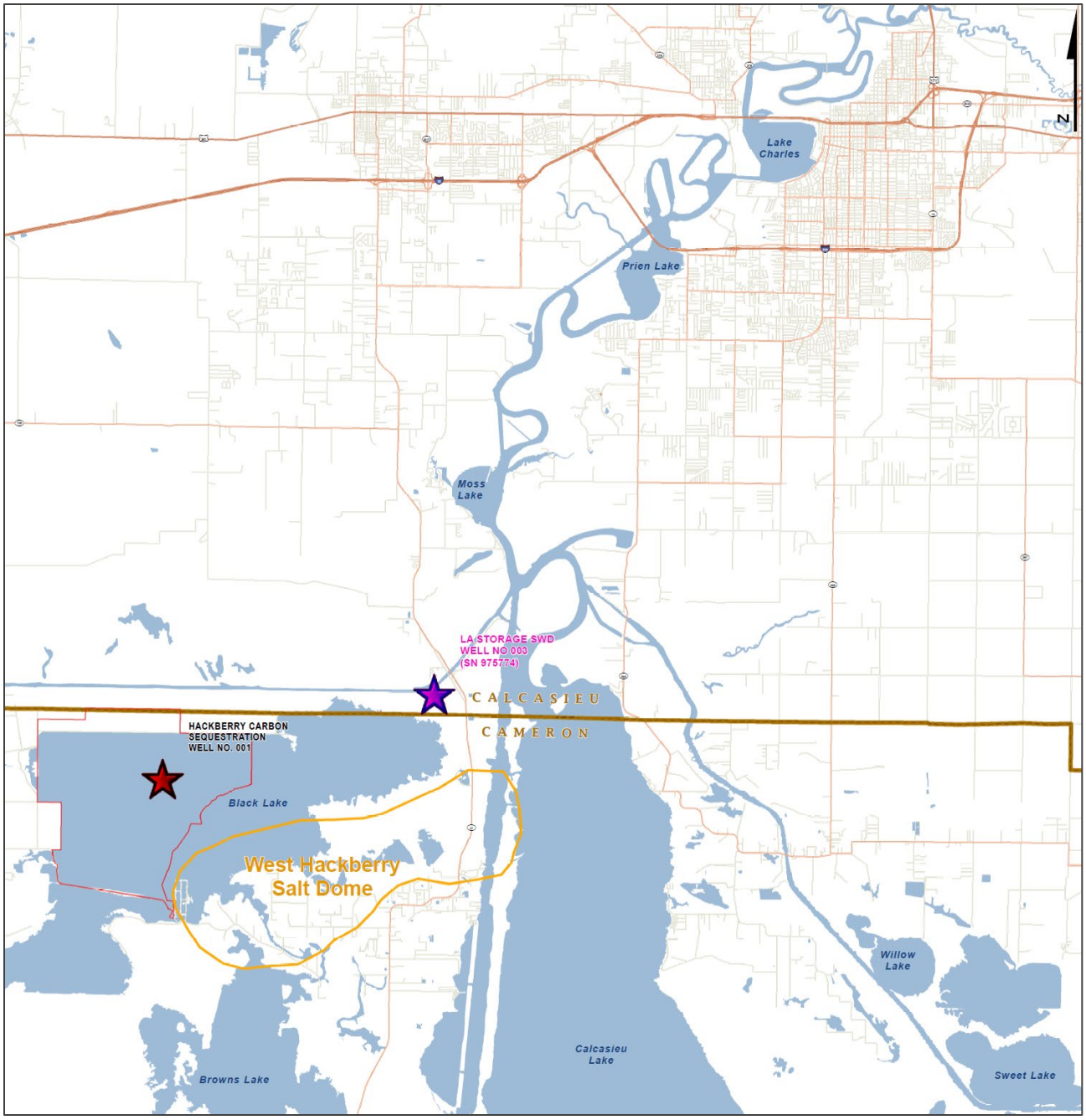

Figure 1-5 – Overview Map of Project Area

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Table 1-1 – Geophysical Wireline Logged Intervals from LA Storage SWD No. 003 (SN 975774)

Geophysical Log Type	Log Interval Top (ft)	Log Interval Bottom (ft)	Use
Spontaneous Potential	185.5	11,494.5	Lithology
Gamma Ray	147.5	11,443	Lithology
Neutron Porosity	166	11,495.5	Porosity
Bulk Density/Density Porosity	168.5	11,506	Porosity
Resistivity	259.5	11,493.25	Fluid Properties
Sonic	164	11,461	Geomechanical/ Lithology/Porosity
Photo Electric	167.5	11,505.5	Lithology
Stripped Potassium-Thorium	2,480	11,441.5	Lithology/Fluid Properties

Table 1-2 – Whole Cored Intervals from LA Storage SWD No. 003 (SN 975774)

Core No.	Interval Top (ft)	Interval Bottom (ft)	Stratigraphic Unit	Zone
1	5,693	5,705	Amphistegina B	Upper Confining
2	5,714	5,752	Amphistegina B	Upper Confining
3	7,612	7,627	Lower Miocene	Injection
4	7,628	7,675	Lower Miocene	Injection
5	11,487	11,488	Anahuac Shale	Lower Confining

Table 1-3 – Injection and Confining Zones as Encountered in LA Storage SWD No. 003 (SN 975774)

System	Group/Formation Name	Injection/Confining Zone	Formation Top-Formation Bottom (ft)	Thickness (ft)
Miocene	Amphistegina B (Amph B)	Upper Confining	5,477 – 5,774	297
Miocene	Lower Miocene	Injection Interval	5,774-11,381	5,607
Oligocene	Anahuac Shale	Lower Confining	11,381-Did not reach	Projected 160

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Figure 1-6 – Whole Core Photographs of the Amphistegina B, Lower Miocene Sands, and Anahuac Shale from LA Storage SWD No. 003 (SN 975774)

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1.3.1 Injection Zone

1.3.1.1 Structure, Sedimentology, and Sequence Stratigraphy

The Lower Miocene is primarily composed of fluvio-deltaic sandstones with interbedded shales and siltstones. The sand intervals within the Lower Miocene (injection zone) are the target reservoir for CO_2 storage. These unconsolidated sands, as described from cores and cuttings in LA Storage SWD No. 003 (SN 975774), are very fine to fine-grained, rounded and moderately sorted.

The structure of the injection site, also described in Section 1.4.3, is illustrated by the top structure map of MFS 9 (Amphistegina B), as seen in Figure 1-7B. It consists of a broad syncline to the west of the site with a ramp shallowing up to the east and northeast of Hackberry Carbon Sequestration (HCS) site. In Figure 1-7B, the salt dome, around which many legacy wells are drilled, is observed to the south of the seismic survey. The continuous growth of this salt dome has impacted the thickness of the Miocene series in the surrounding area. The salt dome activity has also triggered growth faults developing to the west of the area.

All correlation schemes presented here after are based on the stratigraphic framework of Figure 1-2.

Figure 1-7A seismic cross section highlights some of the regionally picked seismic horizons, all calibrated with the available wells. The Miocene fluvio-deltaic series start above the Anahuac shales with the picking of a continuous peak (black) calibrated as MFS 12. Most of the overlying major surfaces are easily recognized on the 3D seismic data and are laterally continuous over the 3D seismic area. In general, the peaks correspond with true shaly MFS.

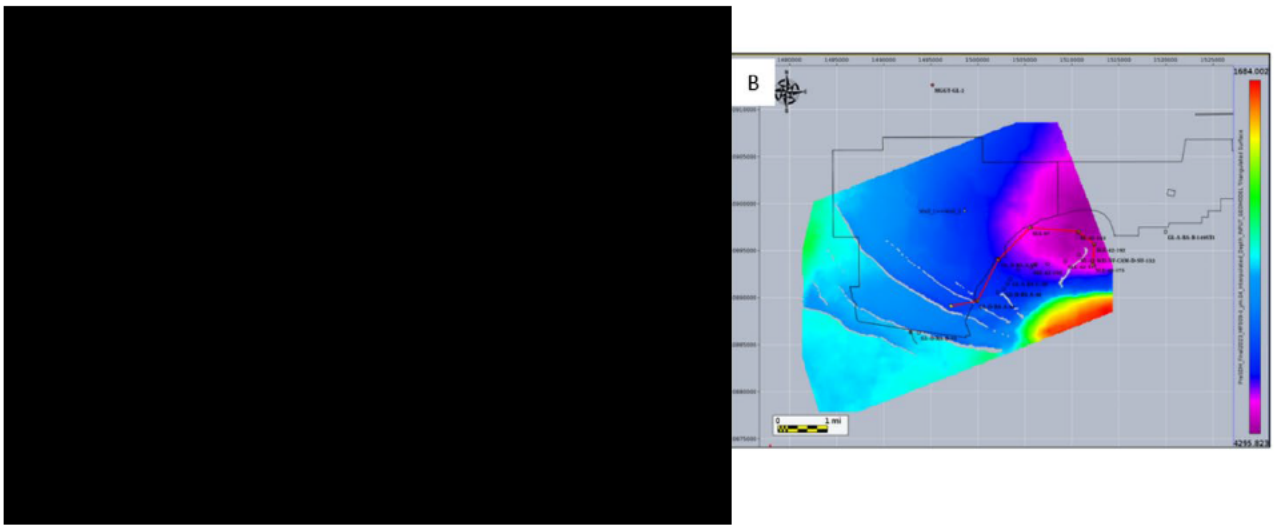

Figure 1-7 – (A) Seismic cross section running to the south of HCS, calibrated by well logs. Only some of the major stratigraphic surfaces are reported. (B) The structure map, with location of the seismic cross section line, is on top of MFS 9 or Amphistegina B.

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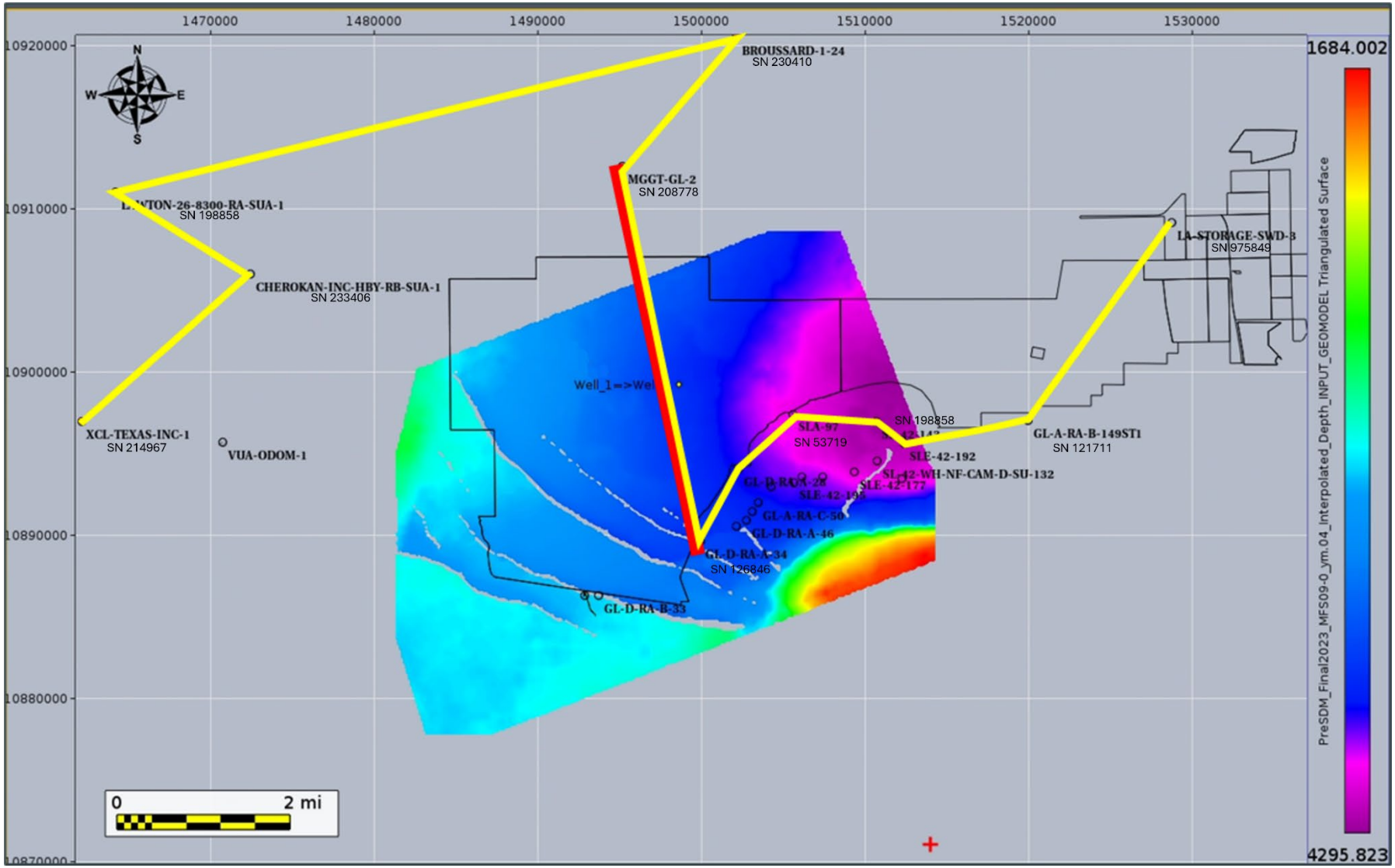

Figure 1-8 – Structural Map of MFS 9 and wells with available logs (even partially over the Lower Miocene) around the injection site and location of the cross section line of Figure 1-7.

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Not all available wells with logs (wells in black on the map of Figure 1-8) comprise full set of logs from the base to top of the Lower Miocene. Only a few could be used for correlation purposes. In the absence of biostratigraphic markers, the MFS 12 was picked on the first shale layer below the first Lower Miocene sandstones. In the LA-SWD-003 well, MFS 12 is identified by biostratigraphy and dated Early Aquitanian to Chattian. As in Figure 1-2, the correlations of the successive MFS were used to build a stratigraphic framework, prompted on the 3D seismic reference (Figure 1-7). This framework illustrates the succession of prograding and retrograding fluvio-deltaic sequences punctuated by regionally correlatable shaly zones. For figure clarity, not all picked MFS are displayed on Figure 1-7 but are included in Figure 1-10). The first maximum prograding event, Top Progr 10, is characterized by the top of thickening up sandstone packages of nearly 1,000 ft. The top of the following retrograding stage is MFS 10 with several tens ft thick shales. The second third-order progradation is calibrated with Top Progr 9, also on top of thickening up sand packages. The last retrogration stage ends up with MFS 9 zone or Amphistegina B.

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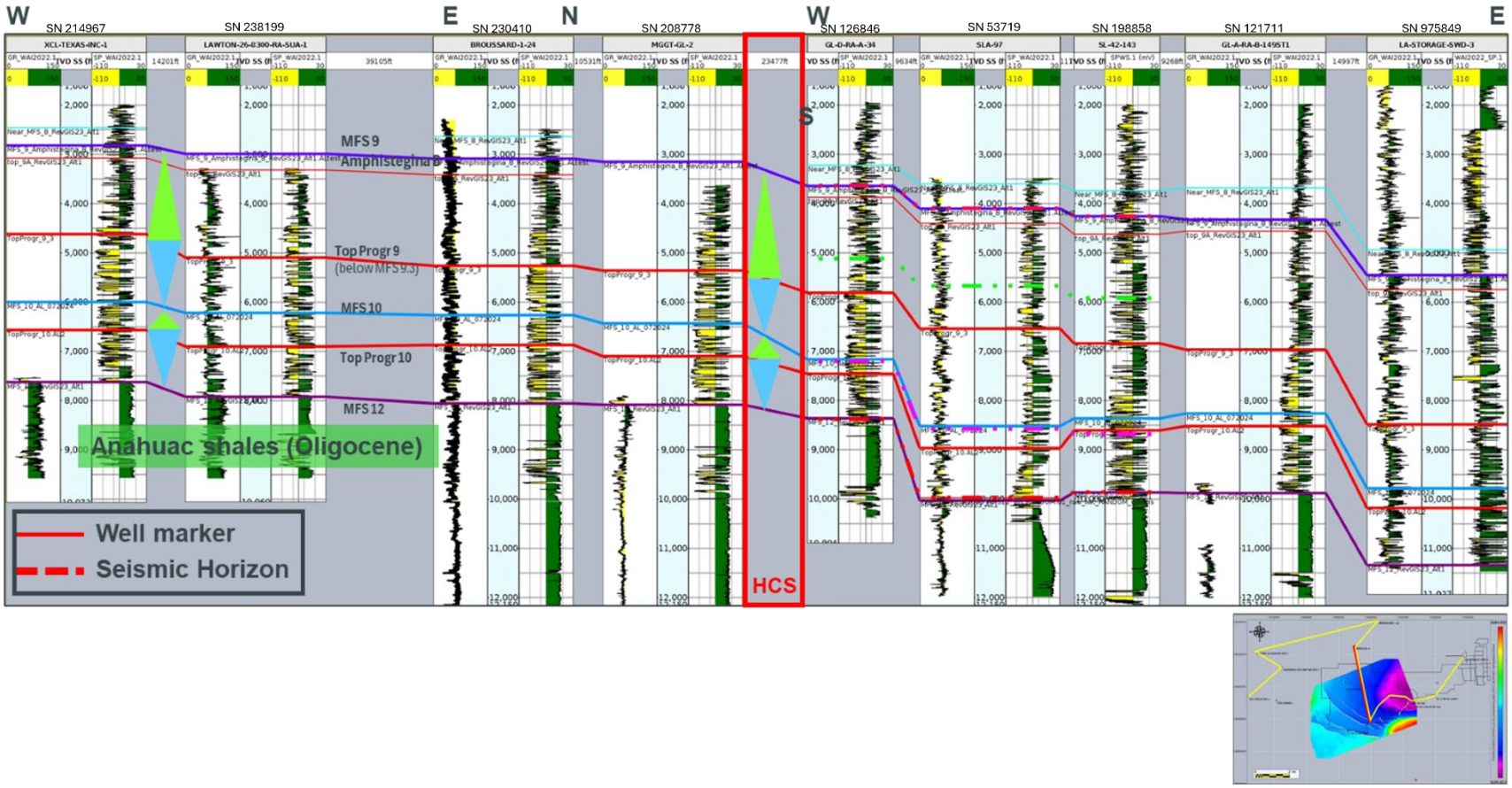

Figure 1-9 – Correlations based on sequence stratigraphy between wells with usable logs over the Lower Miocene interval around HCS site.

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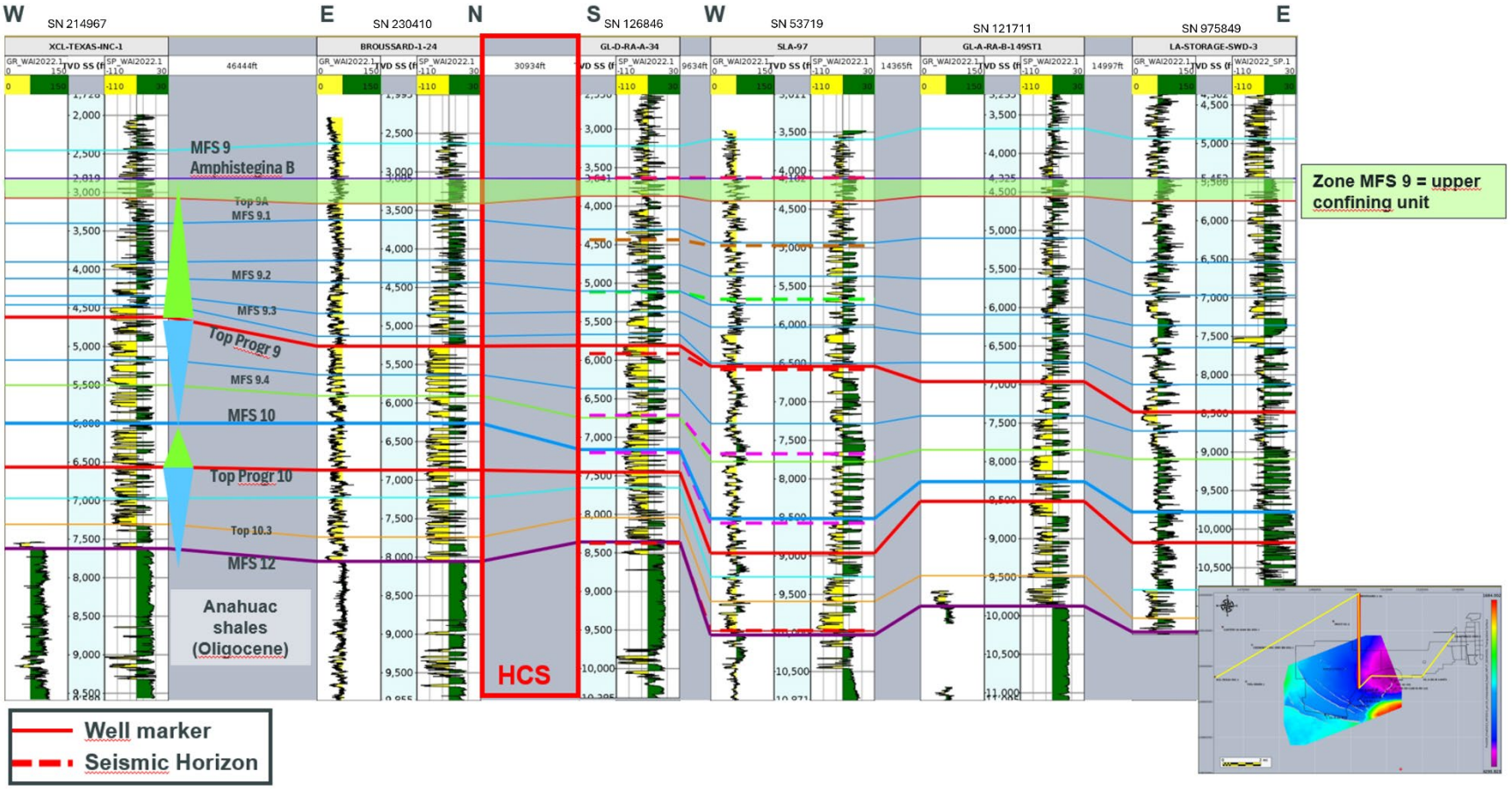

Figure 1-10 – Close-up of correlation scheme with emphasis on underlying and overlying confining units (the correlation is flattened on top of Amphistegina B).

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Figure 1-10 illustrates this stratigraphic framework with higher resolution sequences. At least 12 sequences are identified and correlated across all wells, capped by extensive, correlatable shaly zones. All these MFS may constitute intermediate sealing units for the CO_2 vertical migration. One surface, Top 9A, is the top of a higher resolution fluvio-deltaic progradation and marks the shaly development of MFS 9 zone during a transgressive event.

Figure 1-11, a composite log of LA Storage SWD No. 003 displays, from left to right: Gamma-ray (GR), Spontaneous Potential (SP), True Vertical Depth (TVD), and in the right track, the Shale Volume fraction displaying the Effective Porosity (Shale in Green, Sandstones in yellow and PHIE in blue). The injection zone (between Amph B and MFS 12) in the LA Storage SWD No. 003 (SN 975774) is 5,886 ft thick with 1,227 ft of net sand (sand with greater than 25% effective porosity).

The cored intervals in the upper confining, injection, and lower confining zones are depicted by red rectangles. A close-up view over the cored area illustrates that Cores 1 and 2 are cut over 52 ft at the base of the transgressive event of MFS 9 zone in an area characterized by alternations of shales and very fine sandstones. Cores 3 and 4 are cut over 63 ft at the base of the retrograding stage above "Top Progradation 9". Cored facies are very fine to fine channel sandstones.

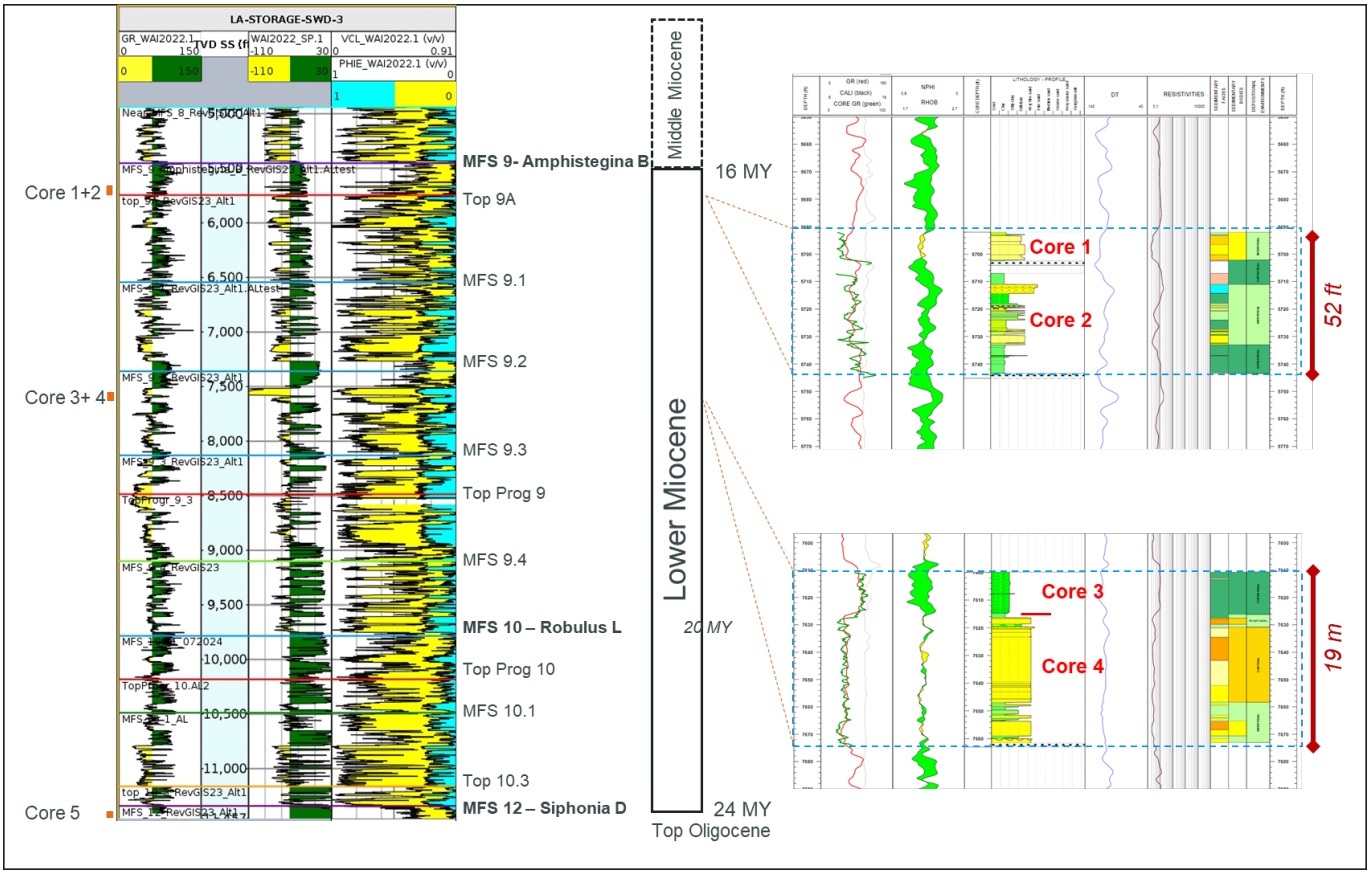

Figure 1-11 – Composite Log LA Storage SWD No. 003 (SN 975774) with Core Location and Description

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Mineralogy

The whole rock mineralogy of Cores 3 and 4 (Table 1-4), characteristics of this section of the injection zone, indicates that sandstones are dominated by quartz (~50-80%), feldspars (~7-18%), calcite (0-1%) and with a clay fraction dominated by smectite and/or interstratified illite/smectite (2-20% of the whole rock). The shale sample contains close to 60% clay and is also dominated by Smectite.

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Table 1-4 – Whole rock quantitative mineralogical composition of Injection Interval samples of Cores 3 and 4 from LA Storage SWD No. 003 (SN 975774).

		WHOLE ROCK MINERALOGICAL COMPOSITION BY REFERENCE MINEVAL QM METHOD													
		Quartz, Silica	Feldspars		Carbonates		Evaporites	Clay Minerals and Micas			Other minerals	Organic Matter	Total (Clays + micas) Sum	Swelling clays interpretation	
Depth	Facies	Quartz	Microcline	Albite	Calcite	Ankerite	Halite	Fe-Kaolinite	Illite and/or I/S R1	Smectite and/or illite-smectite R0		IOM		%Smectite in I/S R1	%Smectite in I/S R0
CEC		0,0	0,0	0,0	0,0	0,0	0,0	10,0	40,0	105,0		0,0			
Mineral Density		2,647	2,570	2,619	2,711	3,110	2,164	2,590	2,750	2,730		1,200			
(feet MD/RT)		(mass%)	(mass%)	(mass%)	(mass%)	(mass%)	(mass%)	(mass%)	(mass%)	(mass%)	(mass%)	(mass%)	(mass%)	(%)	(%)
7611,80	Grey claystone	19,56	2,93	3,84	12,26	1,00	0,18	5,87	4,76	48,03	1,26	0,30	58,66	30-40	No I/S R0
7617,30	Clean fine sdst	79,98	8,88	6,81	0,00	0,00	0,08	0,84	1,18	1,46	0,65	0,12	3,48		
7639,90	Hetrolithic VF	51,54	8,41	7,47	0,59	0,00	1,12	5,36	2,74	21,75	0,92	0,11	29,85	30-40	>85
7655,00	Clean fine sdst	76,11	9,35	8,17	0,72	0,00	0,31	1,41	1,37	1,70	0,73	0,12	4,48	No IS R1	No I/S R0

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1.3.2 Upper Confining Zone

The Amphistegina B (Amph B) unit of the Middle Miocene forms the primary upper confining zone for the Lower Miocene injection zone. At least four higher resolution shale sequences are identified within the upper confining zone from well data (Figure 1-12). The log character of each sequence shows upward coarsening and thickening trends that may correspond to mouth bars capped by transgressive marine deposits. Starting from Top 9A, which is a transgressive surface, the first continuous shale is deposited above and below a high frequency MFS that is referred to as HF MFS 1. This first shale unit that is approximately 30-50 ft thick is not the thickest of the four shales but can be defined as the first confining shale. Shale 3 is the thickest shale unit within the global MFS 9/Amphistegina B zone. From the available log set, these shale units exist on the wells located to the north and south of the HCS site (Broussard 1-24 and GL-D-RA-A-28). Shale 4 is thinner, also continuous and constitutes the top of MFS 9 zone overlaid by fining up sand packages interpreted as channels form the Middle Miocene.

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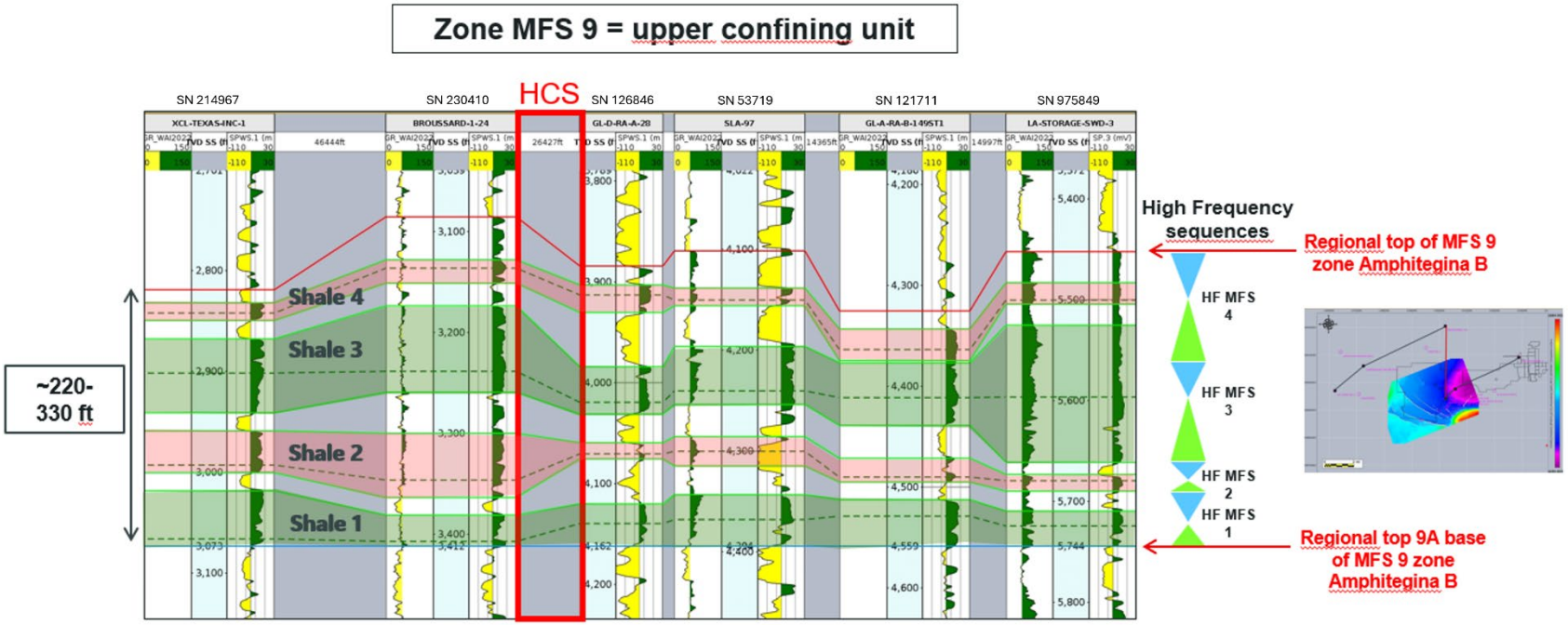

Figure 1-12 – High resolution correlation of the upper confining unit around Amphistegina B zone (MFS 9). Same correlation line as on Figure 1-10.

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Figure 1-13 displays the available well logs in the MFS 9 interval (dashed red rectangles) with gross thickness as point sets. This illustration highlights the spatial variation of the interval of interest. The wells show the lateral continuity of the shaly zone, except for one well, GL-D-RA-A-34, drilled through a growth fault and not representative of the entire zone of interest. From the logs and plotted thickness, no directional trend can be regionally evidenced. The thickness varies from a minimum of 229 ft to 327 ft. The estimated thickness from the base case model at the HCS location (Section 2.3.10) is 256 ft.

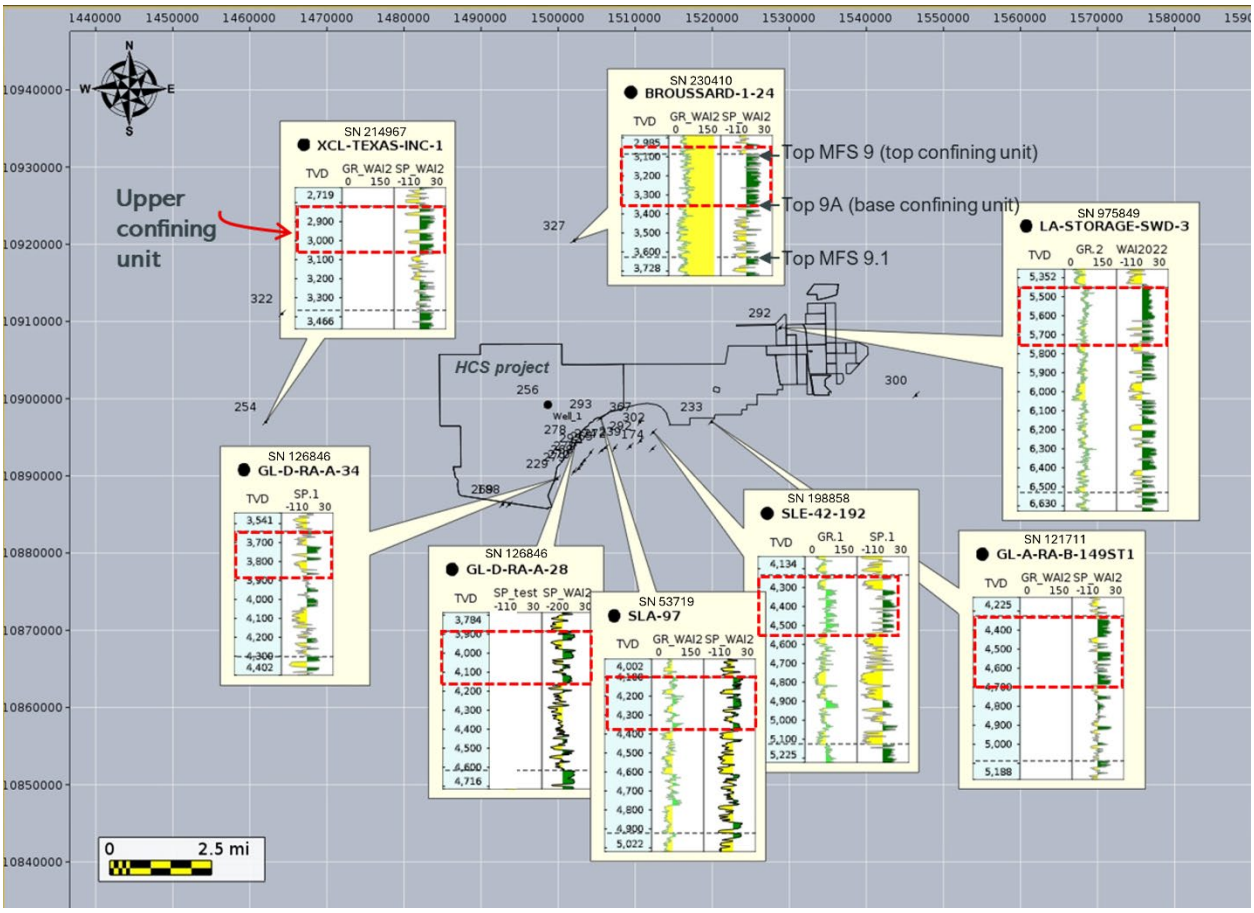

Figure 1-13 – Maps illustrating the log character and continuity of the upper confining unit (Top 9A to MFS 9) with its gross thickness (ft).

An isopach map (Figure 1-14b) of the upper confining zone was also developed from 3D seismic data over Hackberry injection site. The top of MFS 9 zone or Amphistegina B zone could reliably be picked throughout the entire 3D survey. However, the base of the sealing unit, namely Top 9A, a transgressive surface on top of sandstone packages, could not be picked with confidence; therefore, a shallower horizon on a peak in the middle of the confining zone was consistently picked. This peak is near to the middle of Shale 3 as defined from the wells (Figure 1-12). This horizon was shifted down by 160 ft to match the base of the upper confining zone (Figure 1-14b). The upper horizon, MFS 9, constructed on a peak, is affected by erosive features interpreted by

the erosion of channels from the overlying Middle Miocene. These features explain why the isopach (Figure 1-14a) highlights a slightly thinner northwest-to-southeast trend, around 260 ft thick (in green on the map), that represents the erosion from this overlying channel belt. The thickest gross shale unit is around 300 ft to the northeast and southwest of the future injector well. These values agree with the well data surrounding the injection site (Figure 1-13).

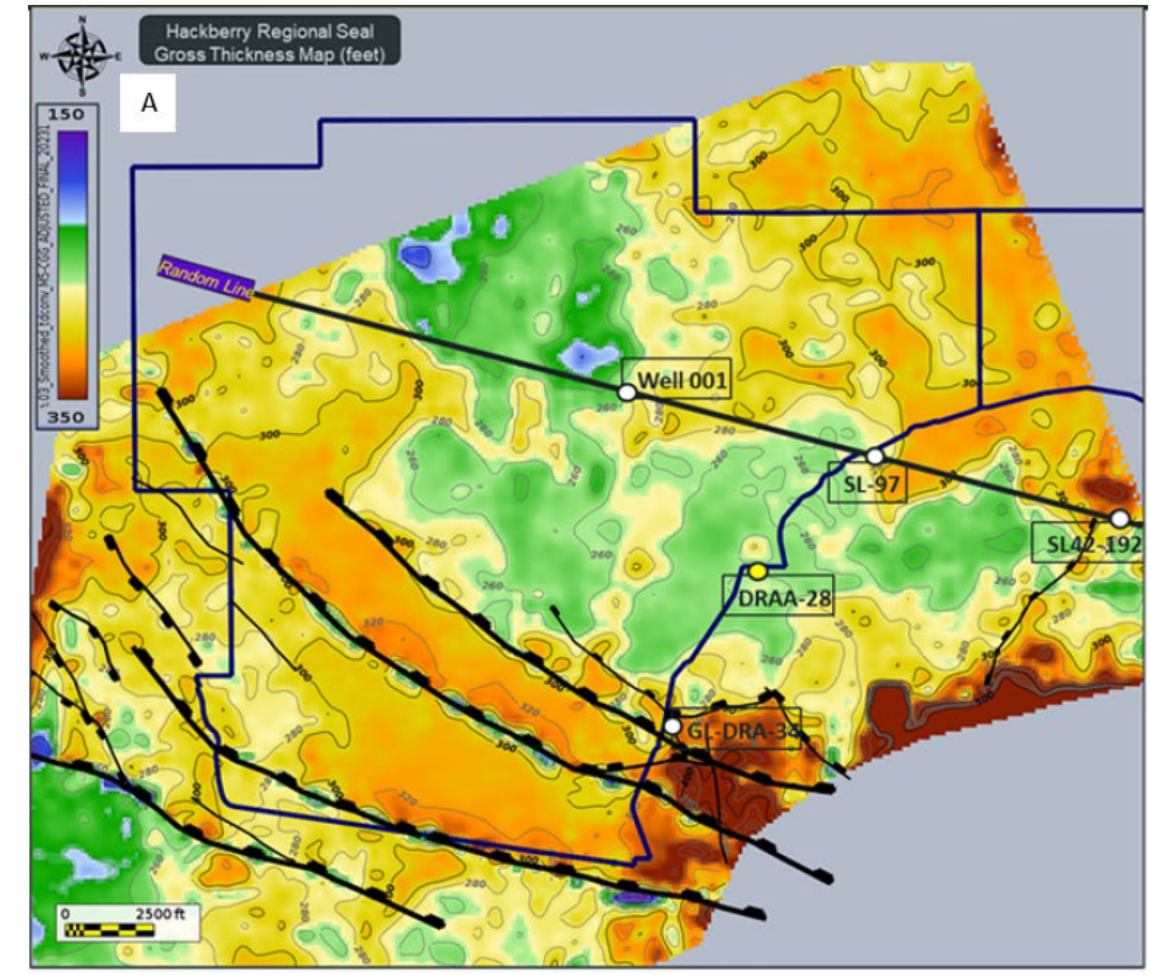

Figure 1-14 – At top (Figure 1-14a), the 3D seismic derived gross thickness map of the upper confining unit computed between Top MFS 9 and the base seal horizon close to Top 9A (Figure 1-14b).

Figure 1-15 highlights Shale 3 with a thickness that varies from at least 39 ft (still on the anomalous well GL-D-RA-A-34) to a maximum of 136 ft on LA-SWD No. 001 and 86 ft to the closest well (Broussard 1-24) to the north of the HCS site. In the vicinity of the injection site, the Shale 3 thickness is approximately 50 ft. Figure 1-16 highlights Shale 1, which is considered as the first confining shale, although a little bit thinner than the main one, Shale 3. On the wells surrounding HCS, Shale 1 has a net thickness varying from 31 ft to 55 ft.

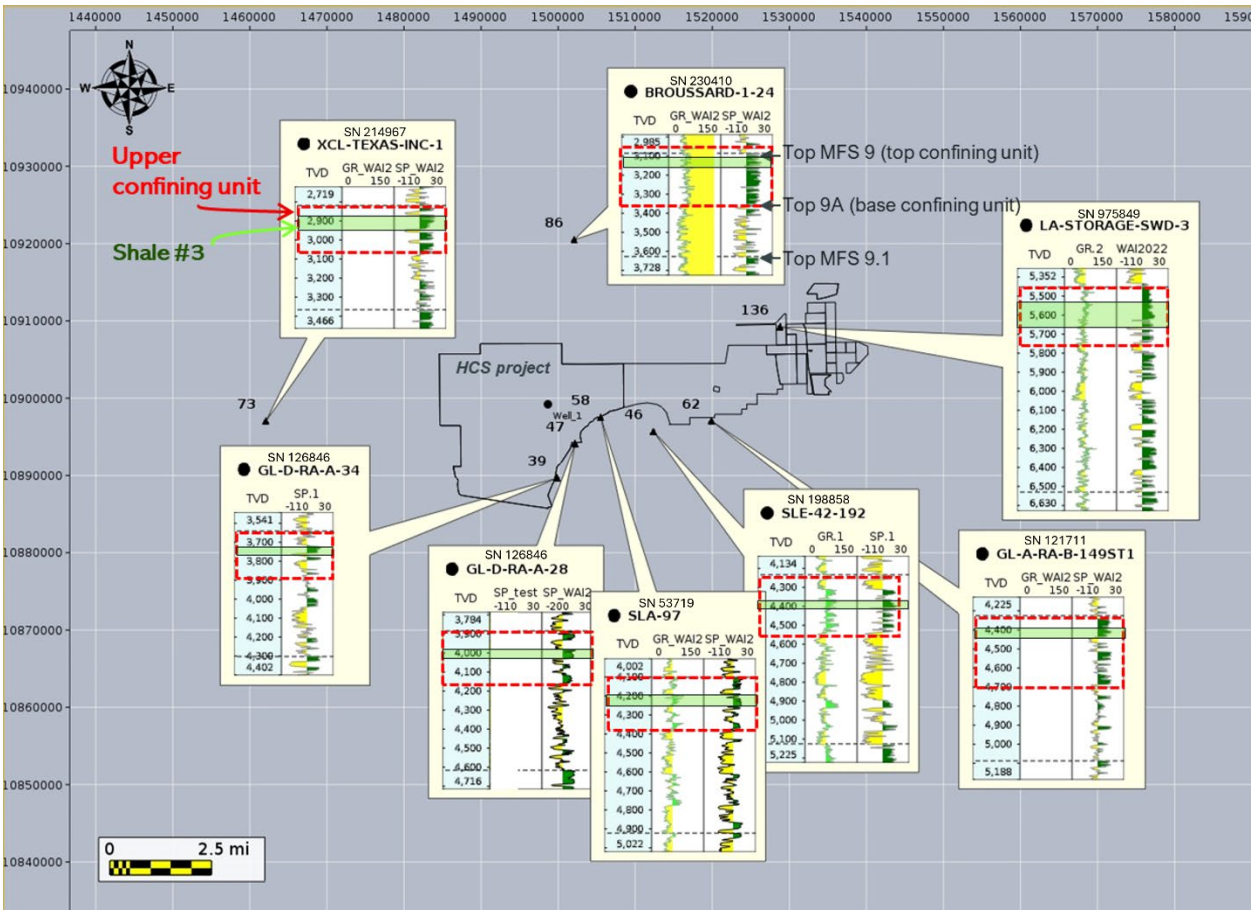

Figure 1-15 – Maps illustrating the continuity of Shale 3 of the upper confining zone (significant wells with logs) with its gross thickness (ft) as point sets.

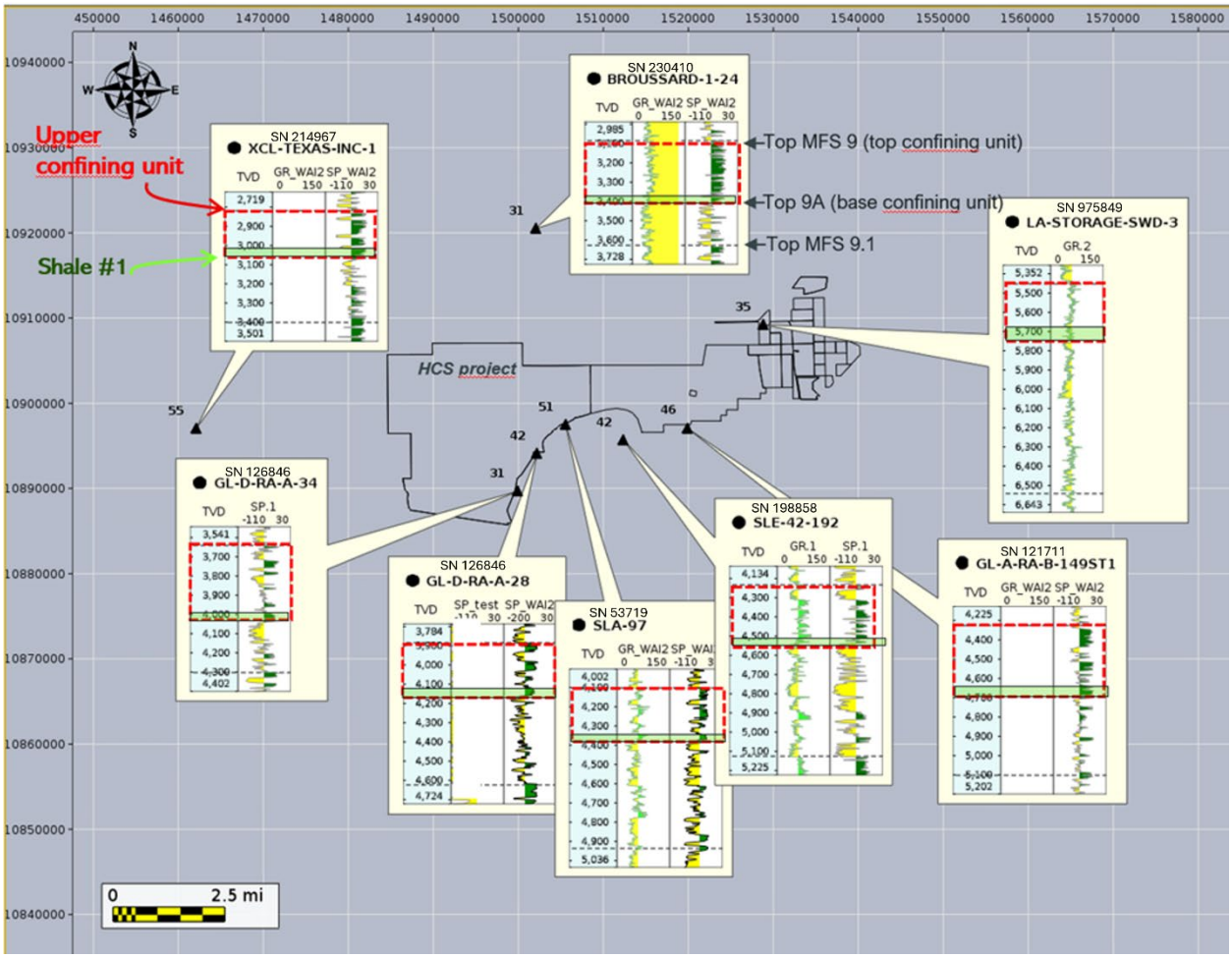

Figure 1-16 – Maps illustrating the continuity of Shale 1 of the upper confining zone (significant wells with logs) with its gross thickness (ft) as point sets.

On the LA Storage SWD No. 003 (SN 975774) stratigraphic test well (Figure 1-17), the Amph B unit is 297 ft thick. Cores 1 and 2 were cut in the upper confining unit attempting at acquiring pure shale facies. However, due to core jamming, only interbedded shales and very fine sandstones were cut (Figure 1-17) at the top of the transgressive surface Top 9A. Drill cuttings from Amph B indicate light gray to red-orange shale with arenitic and calcareous silt particles. The quantitative mineralogical composition of five samples from Cores 1 and 2 are displayed in Table 1-5. The Amph B will be further cored and data received from the proposed HCS Well No. 001.

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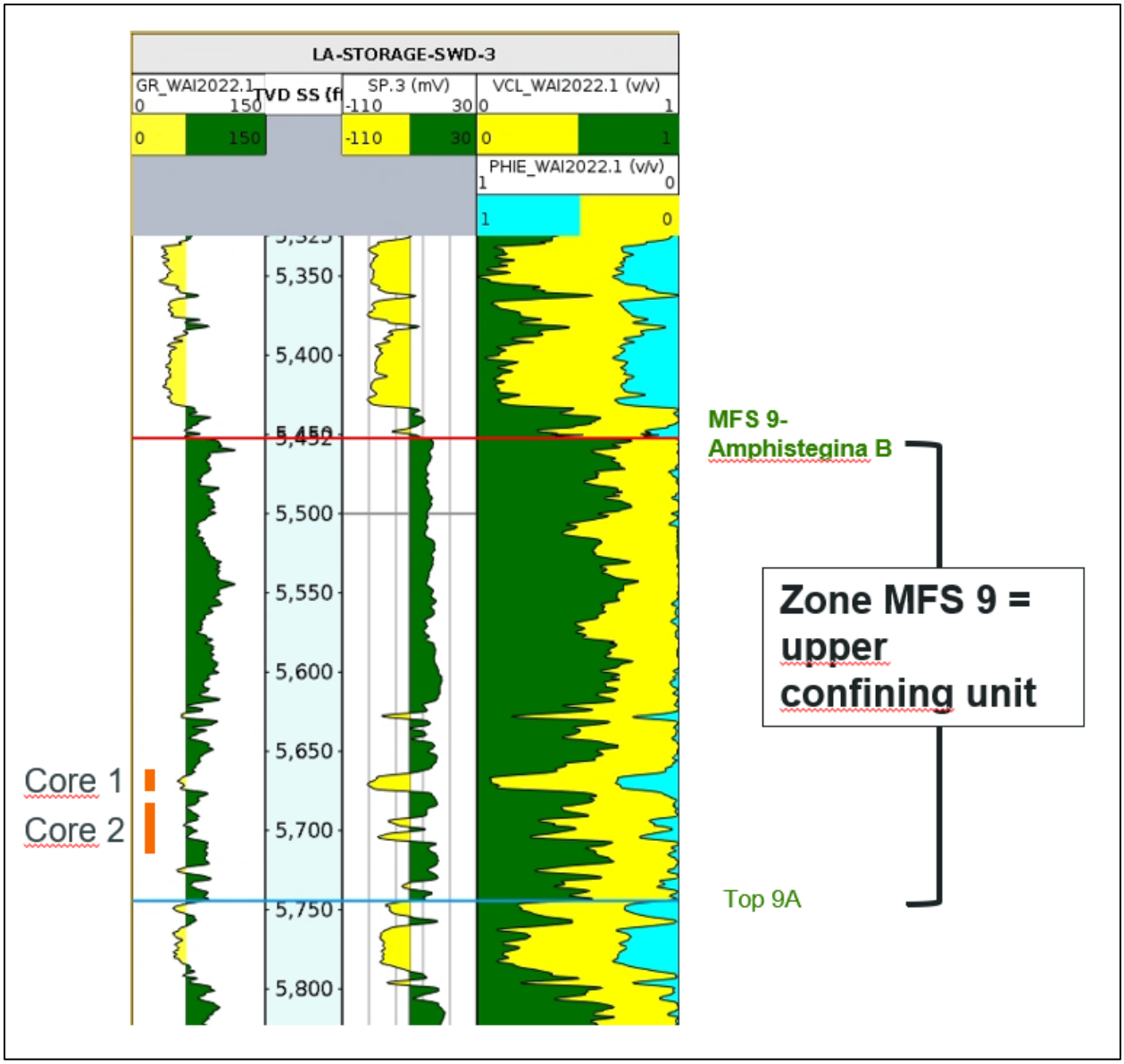

Figure 1-17 – Composite Log of Upper Confining Zone from LA Storage SWD No. 003 (SN 975774)

Figure 1-17 depicts from left to right: the openhole GR, TVDSS depth, SP log and, shale and sand fraction with the effective porosity. The cored section is indicated by the red boxes found on the left side of tracks. Cores 1 and 2 display both the primary shale lithology and interbedded sands characterizing a portion of the 297 ft thick upper confining interval.

Considering the composition of the claystones, the three analyzed shaly samples have variable clay content, from 21 to 45%, all largely dominated by smectite (up to 35%). Smectites are "swelling clays" which indicate these clay minerals readily swell in the presence of water. This property of smectite clays is relevant to many environmental and industrial processes including limiting hazardous contaminant transport in the subsurface and in engineered barriers in nuclear waste repositories (Teich-McGoldrick et al., 2015). In smectite and kaolinite clays, vertical

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permeability decreases logarithmically as vertical effective stress increases. Laboratory experiments of smectite-kaolinite mixtures show a logarithmic reduction in measured vertical permeability as a function of increasing smectite clay content, the curves plotted in Mondol, Bjorlykke and Jahren (2008) are used to estimate anticipated vertical permeability in pure shales of the upper confining zone. Following the smectite (80%) to kaolinite (20%) ratio curve comparable to the LA Storage SWD No. 003 (SN 975774) XRD mineralogy analysis, the vertical permeability of a brine saturated pure shale is expected to range from 0.0002 to 0.0003 millidarcies.

As smectite is a swelling clay, the permeabilities of the confining interval shales are lower than lab result values after the drying process performed prior to analysis. At reservoir conditions, smectite clays occlude the pore throats and, when dried, show amplified permeabilities in laboratory analysis compared to in situ reservoir conditions. Laboratory desiccation effects on permeability within the marine shale samples result in the variability of Core 2 permeability values. Core plugs that retain the smectite clay display permeabilities as low as 0.291 mD, plugs that lost clay volume from desiccation showed permeability values of 60 mD. Coring programs for the proposed HCS No. 001 well will consider the smectite content now known to comprise these layers and follow laboratory procedures to preserve the clay content within the cores. Details on the core evaluated in the upper confining zone are in Section 1.6.

Table 1-5 – Whole rock mineral composition of Cores 1 and 2 samples acquired at the base of the upper confining zone from LA Storage SWD No. 003 (SN 975774).

		WHOLE ROCK MINERALOGICAL COMPOSITION BY REFERENCE MINEVAL QM METHOD												Swelling clays interpretation	
		Quartz, Silica	Feldspars		Carbonates		Evaporites	Clay Minerals and Micas			Other minerals	Organic Matter	Total (Clays + micas) Sum	% Smectite in I/S R1	% Smectite in I/S R0
Depth	Facies	Quartz	Microcline	Albite	Calcite	Ankerite	Halite	Fe-Kaolinite	Illite and/or I/S R1	Smectite and/or illite-smectite R0		IOM			
CEC		0 0	0 0	0 0	0 0	0 0	0 0	10 0	40 0	105 0		0 0			
Mineral Density		2 647	2 570	2 619	2 711	3 110	2 164	2 590	2 750	2 730		1 200			
(feet MD/RT)		(mass%)	(mass%)	(mass%)	(mass%)	(mass%)	(mass%)	(mass%)	(mass%)	(mass%)	(mass%)	(mass%)	(mass%)	(%)	(%)
5708,90	Red Claystone	41,75	4,08	3,82	4,08	0,00	0,14	6,80	2,98	35,24	0,99	0,11	45,02	No IS R1	>75
5712,10	Hetrolithic VF	40,37	4,30	4,30	39,46	0,00	0,45	2,87	2,03	5,52	0,62	0,07	10,42	15-25	>75
5726,00	Grey claystone	43,52	7,09	6,43	16,05	4,08	0,15	4,06	4,43	13,07	1,02	0,10	21,56	15-25	>75
5730,80	Clean fine sdst	63,55	8,91	9,40	4,11	6,58	0,55	2,10	2,00	1,90	0,80	0,11	6,00		
5738,50	Grey claystone	50,65	4,98	5,26	10,71	1,46	0,22	6,66	4,61	13,07	2,26	0,10	24,34	10-20	>70

1.3.3 Lower Confining Zone

The Anahuac shale of the Oligocene epoch is the primary lower confining zone. In the LA Storage SWD No. 003 (SN 975774) stratigraphic test well, 122 ft of the Anahuac shale was drilled; the base of the Anahuac shale was not encountered. Drill cuttings from the LA Storage SWD No. 003 (SN 975774) in the Anahuac shale are primarily green to gray shale, platy, slightly firm to soft, smooth, with a clay luster and some calcareous grains. Challenges during rotary coring operations of the Anahuac shale included low rates of penetration and minimum core recovery. One foot of Anahuac shale core was deemed to have sufficient quality for analysis. Mineralogy of the lower confining zone determined by XRD is displayed in Table 1-6. The composite log in

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Figure 1-18 displays from left to right: the openhole GR, TVDSS depth, SP log, and shale sand fraction with the effective porosity.

Similar to the upper confining layer, the Anahuac shale clay fraction is dominated by smectite with 44.1%, as seen in Table 1-6. As stated in the Section 1.3.2, smectite clay's nature to swell and dry out results in higher measured permeabilities than in situ reservoir conditions within the shale intervals. Smectite clay that occludes pore throats may dissolve out under laboratory processes and result in higher permeabilities than actual reservoir conditions. A detailed discussion of porosity and permeability is found in Section 1.6.

Table 1-6 – Mineralogy of Lower Confining Zone from LA Storage SWD No. 003 (SN 975774)

Lonquist
LA Storage SWD3

Mineralogy Determined by X-ray Diffraction

File: 2100406G

	Whole Rock Mineralogy (Weight %)							Clay (Phyllosilicate) Mineralogy (Weight %)				
Depth	Quartz	K-Feldspar	Plagioclase	Calcite	Dolomite & Fe-Dolomite	Pyrite	Total Clay	Smectite	Illite & Mica	Kaolinite	% Halite Removed	% Barite Removed
11487.00	24.5	2.3	8.1	5.7	0.0	0.0	59.4	44.1	10.6	4.7	0.0	9.6

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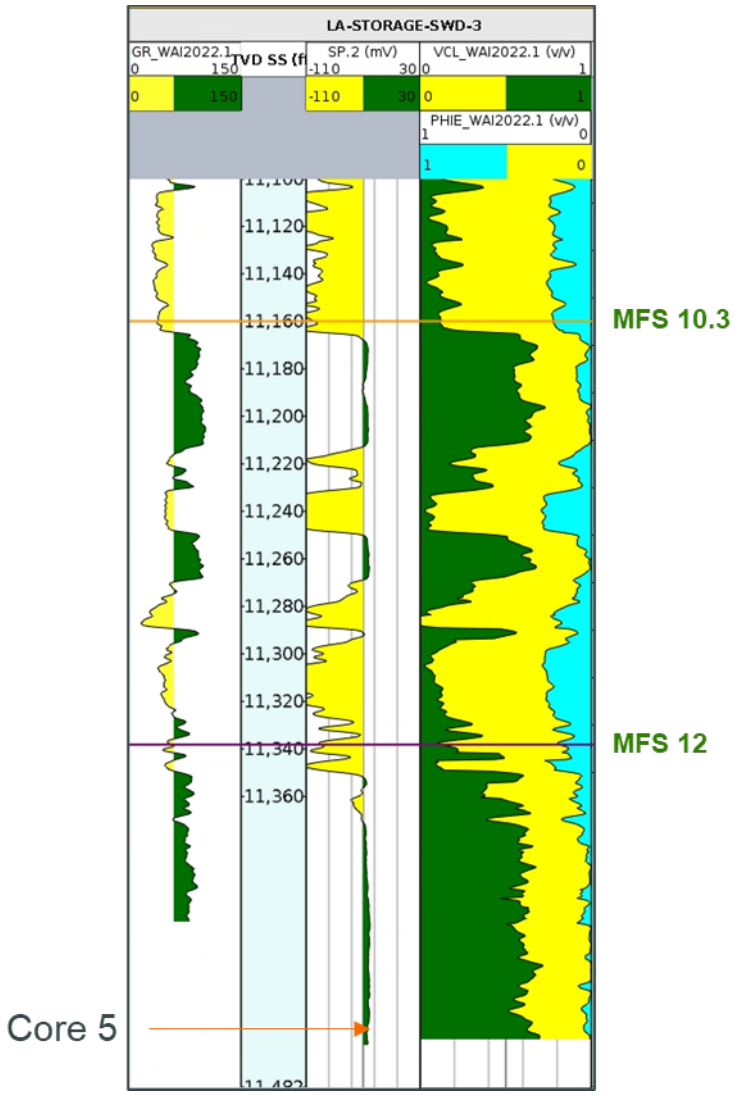

Figure 1-18 – Composite Log of the Lower Confining Zone from LA Storage SWD No. 003 (SN 975774)

With a thickness greater than 2,000 ft and with pervasive presence over the Hackberry site, the Anahuac shales constitute an excellent lower confining zone for HCS storage (Figure 1-19). The Anahuac shales were deposited during a major transgressive event on top of the Oligocene associated with a marine influx that flooded the whole area. Dated Early Aquitanian to Chattian, the biostratigraphic analyses of the sample of Core 5 confirm the open marine conditions at 11,487 ft (K#5), with a strong planktonic presence and the increase in diversity of the calcareous benthic with genera like Buliminella/Nonion/Pleurostomella/Bolivina, point to a predominance of outer neritic to bathyal conditions.

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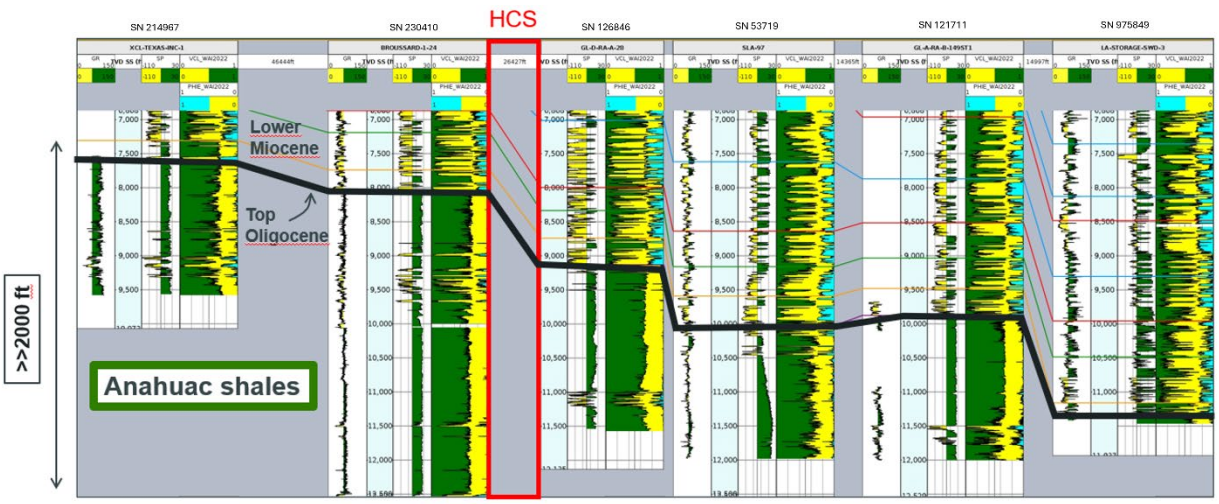

Figure 1-19 – Close-up on the top Oligocene sections showing the thickness of the lower confining unit with the Anahuac Shales.

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1.3.4 Injection Zone Water Chemistry

Injection zone water samples of the LA Storage SWD No. 003 (SN 975774) well were acquired by Halliburton. A fluid pump-out analysis of the operation is included as Appendix B-19. Two formation fluid samples are analyzed for total dissolved solids (TDS) from the LA Storage SWD No. 003 (SN 975774) stratigraphic well at the depths of 7,588 ft and 7,654 ft. Report is included as Appendix B-20. The TDS recorded in these samples are 114,339 mg/L and 106,866 mg/L, respectively. Results from the TDS analyses indicate the in situ reservoir fluid has an order of magnitude higher TDS concentration than the minimum saline aquifer classification (>10,000 mg/L).

A full analysis was run on the 7,654 ft sample. Table 1-7 lists the metals and acid digestion analysis report of the 7,654 ft sample.

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Table 1-7 – Injection Zone Water Chemistry – All Metals/Acid Digestion Analysis from LA Storage SWD No. 003 (SN 975774)

Complete Water Analysis with All Metals / Acid digestion

RFS ID No. 202100683-06

Sample date : February 6, 2021

LA Storage SWD No. 3 - RDT 0890 - 7,653.5 Ft. MD

Cations		Test Method	(mg/l)	MW	Valence	Meq/l
Barium	Ba^{+2}	ICP	69	137.34	2.0	1.01
Cadmium	Cd^{+2}	ICP	<0.006	112.40	2.0	0.00
Calcium	Ca^{+2}	ICP	1,910	40.08	2.0	95.36
Chromium	Cr^{+3}	ICP	0.03	51.99	3.0	0.00
Cobalt	Co^{+2}	ICP	0.08	58.93	2.0	0.00
Copper	Cu^{+2}	ICP	0.49	63.55	2.0	0.02
Iron (dissolved)	Fe^{+2}	ICP	0.98	55.85	2.0	0.04
Iron (total)	Fe^{+2}	ICP	19	55.85	2.0	0.69
Lead	Pb^{+2}	ICP	<2.2	207.20	2.0	0.00
Lithium	Li^{+}	ICP	3.7	6.94	1.0	0.54
Magnesium	Mg^{+2}	ICP	665	24.31	2.0	54.64
Manganese	Mn^{+2}	ICP	0.54	54.94	2.0	0.02
Molybdenum	Mo^{+6}	ICP	<0.044	95.94	6.0	0.00
Nickel	Ni^{+2}	ICP	1.5	58.69	2.0	0.05
Phosphorus	P^{+3}	ICP	<0.17	30.97	3.0	0.00
Potassium	K^{+}	ICP	110	39.10	1.0	2.87
Silicon	Si^{+4}	ICP	9.1	28.09	4.0	1.30
Sodium	Na^{+}	ICP	38,700	22.99	1.0	1,683.36
Strontium	Sr^{+2}	ICP	115	87.62	2.0	2.65
Vanadium	V^{+2}	ICP	<0.01	50.94	2.0	0.00
Zinc	Zn^{+2}	ICP	0.04	65.39	2.0	0.00

Anions		Test Method	(mg/l)	MW	Valence	Meq/l
Alkalinity (as Bicarbonate)	HCO_3^-	Titration	195	61.02	1.0	3.21
Borate	$B(OH)_4^-$	ICP	16	78.84	1.0	0.20
Bromide	Br^-	Titration / IC	74	79.90	1.0	0.93
Carbonate	CO_3^{-2}	Titration	0.0	60.01	2.0	0.00
Chloride	Cl^-	Titration / IC	64,940	35.45	1.0	1,831.75
Fluoride	F^-	IC	<10	19.00	1.0	0.00
Iodide	I^-	Titration / IC	<10	126.90	1.0	0.00
Nitrate	NO_3^{-2}	IC	<10	62.00	2.0	0.00
Nitrite	NO_2^-	IC	<10	46.01	1.0	0.00
Phosphate	PO_4^{-3}	IC	<10	94.97	3.0	0.00
Sulfate	SO_4^{-2}	IC	37	96.06	2.0	0.77
Sulfide	S^{-2}	IC	0.0	32.06	2.0	0.00

Total Cation Meq's	1,842
Total Anion Meq's	1,837
TDS (mg/l)	106,866
TDS (ppm)	99,781
Ion Balance	0.002

pH	7.06
Resistivity (Ohm-Meter) at 77 °F	0.07
Conductivity, microSiemens/cm	141,000
Specific Gravity 60 / 60 °F	1.0721

Stability Index at 100 °F	-1.11
Stability Index at 200 °F	0.76
% Deviation in Meq. Bal.	0.15
% Deviation in TDS	0.06

QA/QC Run ID's

ICP	3172021
IC - Anions	3172021
IC - Organic Acids	NA
Titration - Bicarbonates and Chloride	3172021

1.4 Geologic Structure

At depth, the proposed storage site is in a syncline on the northern flank of the West Hackberry salt ridge. Near surface, the site is overlain by the Chenier Plain, "a low profile, storm-dominated, microtidal coast, downdrift, and west of the Mississippi River deltaic plain" (O'Leary and Gottardi, 2020).

1.4.1 Site Geologic Structure

The proposed CO_2 storage site lies on the northern margin of the Gulf of Mexico. Conditions were favorable during Middle Jurassic for the deposition of the thick Louann Salt in the Gulf of Mexico. Deposition of large quantities of sediment on top of this layer-initiated salt flow, forming salt structures including the southeast-plunging West Hackberry salt ridge (O'Leary and Gottardi, 2020). The West Hackberry salt ridge is the principal geologic structure proximal to the proposed CO_2 storage site.

1.4.2 2D Seismic Evaluation

1.4.2.1 Reflection Seismic Profiles

Four two-dimensional (2D) surface seismic lines with acquisition vintages ranging from 1968 to 1983 were licensed and included in this interpretation, Figure 1-20.

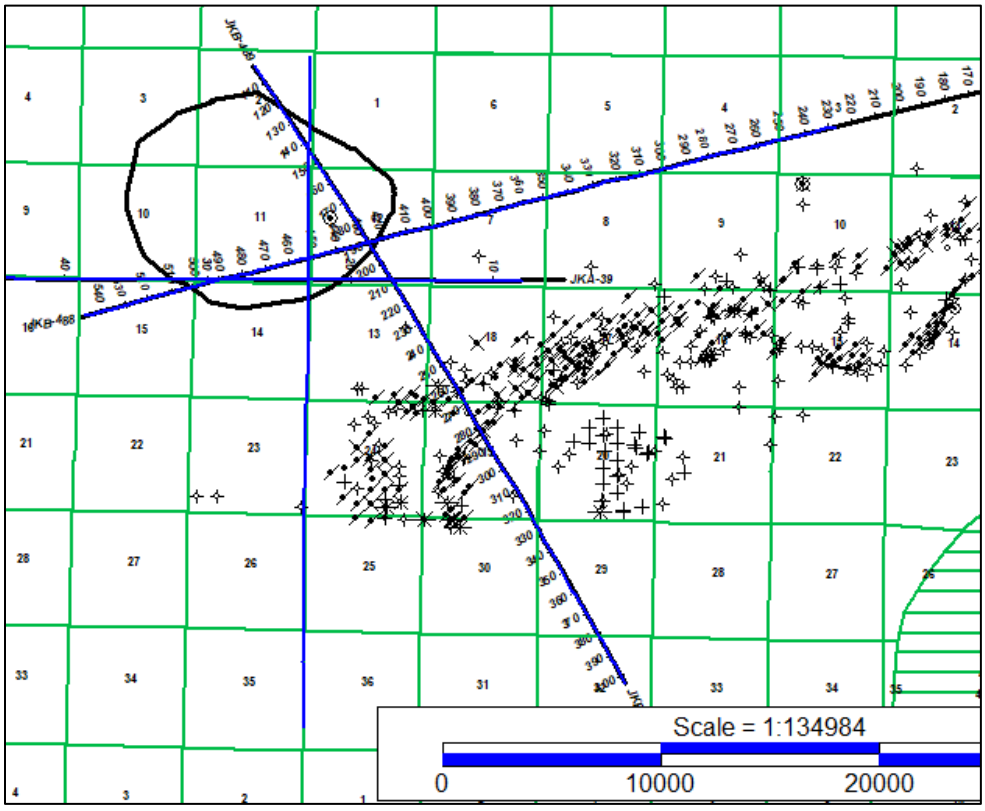

Figure 1-20 – 2D Seismic Line Locations

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The four lines (highlighted in blue) were reprocessed using Pre-Stack Time Migration prior to interpretation.

The resulting 2D seismic reflection profiles, which image the subsurface based on density and velocity contrasts, were combined with subsurface well control (geologic formation tops) to map the proposed injection and confining intervals. These interpretations were incorporated with the 3D seismic data to develop the final maps in Appendix B. These maps illustrate formation depths, thicknesses, and any discontinuities, such as faults. The attachments found within this appendix include structure maps on the tops and bases of confining intervals, the Lower Miocene and four other sub-Lower Miocene sand packages, and isopach/isochore maps of confining and injection intervals.

The primary structural trend of the formations shown in these maps is updip to the west and downdip to the east. The interruption of this southeastern dip is a structural feature on the southern edge of the study area, the West Hackberry salt dome. Radial faulting occurs closer to the dome and out of the anticipated plume extent of the injected fluids. The four profiles indicate a thick sequence of Miocene-aged rocks, approximately 5,175 ft thick. Two of the seismic lines (JKA-39, JKB-173) were originally recorded in the late 1960s and are of lower fold (quality) in comparison to lines (JKB-488, JKB-489) which were both recorded in 1983 with higher fold. Both "higher fold" lines intersect the proposed CO_2 storage area and do not indicate the presence of obvious faults or large changes in thickness of the injection or confining zones.

Adjacent radial faults were interpreted from the 2D lines as depicted in Figure 1-21. Figure 1-22 represents a southwest-northeast trending 2D line with no faulting or major thickness changes seen. Additional refinement and confirmation of these faults trends is discussed in Section 1.4.3, with the incorporation of 3D seismic.

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Figure 1-21 – Location of the 2D Seismic Survey line JKB-489 Traversing the Proposed CO_2 Storage Area

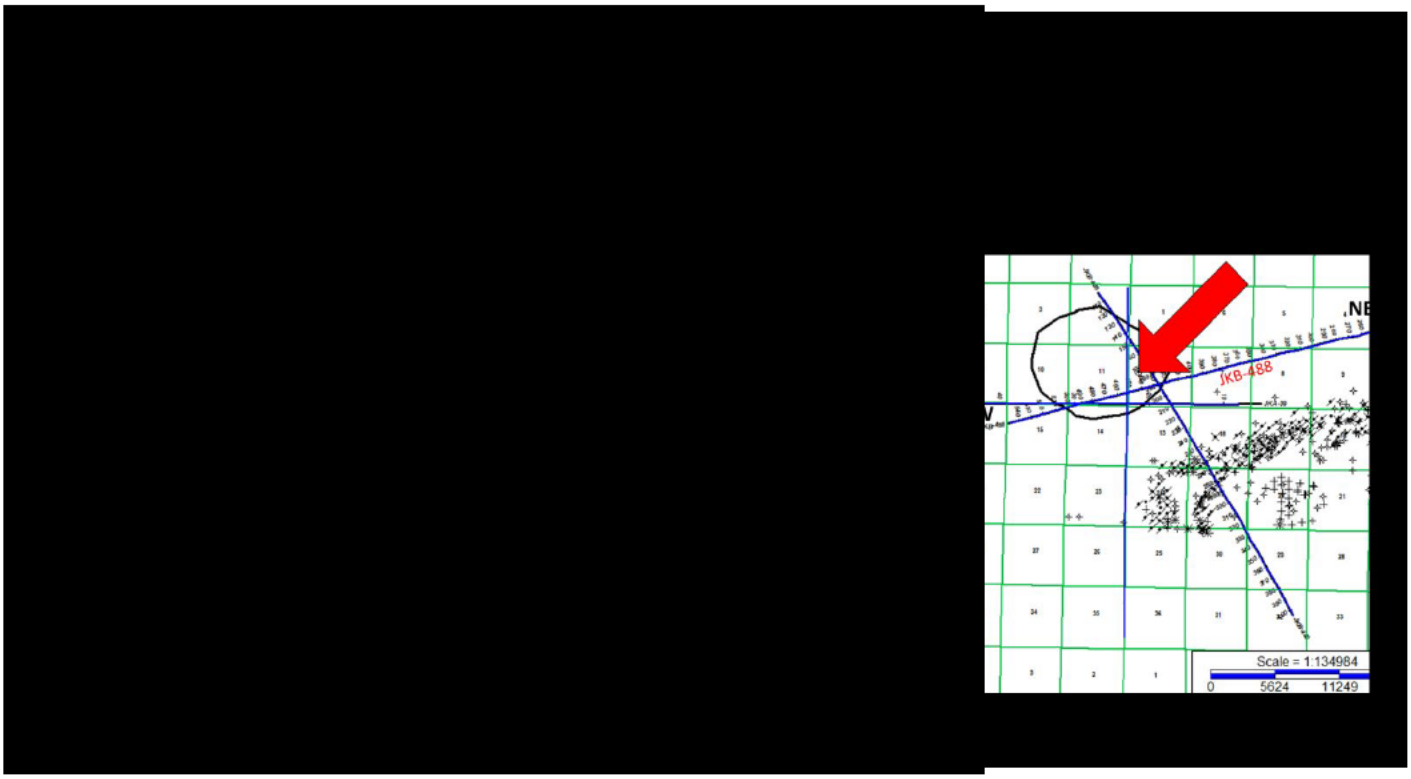

Figure 1-22 – Location of 2D Seismic Survey Line JKB-488

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1.4.2.2 Gravity Data

A publicly available data set of gravity station measurements from USGS across the states of Louisiana and Arkansas covers the proposed storage site (Figure 1-23 and Figure 1-24). Although this survey is based on a relatively wide-spaced grid (approximately one data point every nine miles) the two captioned grids below confirm the regional geologic setting of large quantities of sediment on top of the less dense salt structures.

The original data was extracted from the 1999 version of a gravity database maintained by the National Geophysical Data Center. Observed gravity measurements relative to the IGSN–71 datum was reduced to the Bouguer anomaly using the 1967 gravity formula (Cordell and others, 1982) and a reduction density of 2.67 g/cc. Terrain corrections were calculated radially outward from each station to a distance of 167 km (100 mi) using a method developed by Plouff (1977).

Figure 1-23 presents a regional view of the Bouguer Gravity Anomaly Map surrounding the proposed storage site. Following the rule of thumb that gravity minimum highlights subsurface salt structures the minimum closed contours approximate the location of the Vinton and West Hackberry salt structures flanking the proposed storage site.

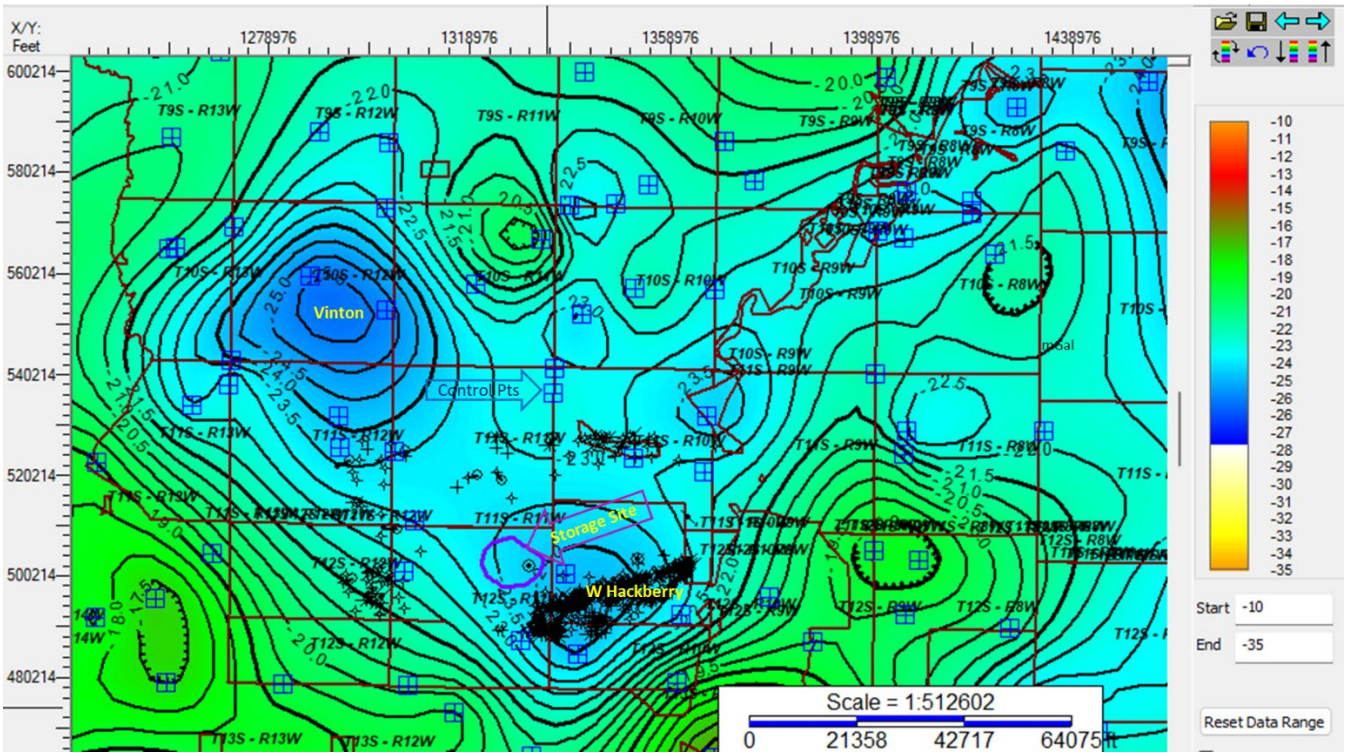

Figure 1-23 – Bouguer Gravity Anomaly Map

Figure 1-24 represents an isostatic gravity anomaly map utilizing the same data point spacing as the previous figure. The isostatic residual gravity map reflects variations in the Earth's gravity field caused by density variations in the rocks composing the upper part of the Earth's crust. The Isostatic residual gravity grid was derived from the Bouguer gravity anomaly data by removing the gravitational effect of the compensating mass that supports topographic loads. The thickness

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of this compensating mass was calculated using averaged digital topography by assuming a crustal thickness for sea level topography of 30 km (18 mi), a crustal density of 2.67 g/cc, and a density contrast between the crust and upper mantle of 0.40 g/cc.

Positive value trends delineate rocks denser than the Bouguer reduction density of 2.67 g/cc, whereas a negative closure such as the 27.0 mGal contour in Figure 1-24 result from rocks of lower density (West Hackberry salt structure). Due to the relatively sparse distribution of data points, the West Hackberry salt structure is only approximately outlined, however the contours reflect the proposed storage site is on the northern flank of the structure, consistent with interpretation of afore mentioned well control and 2D and 3D seismic reflection data.

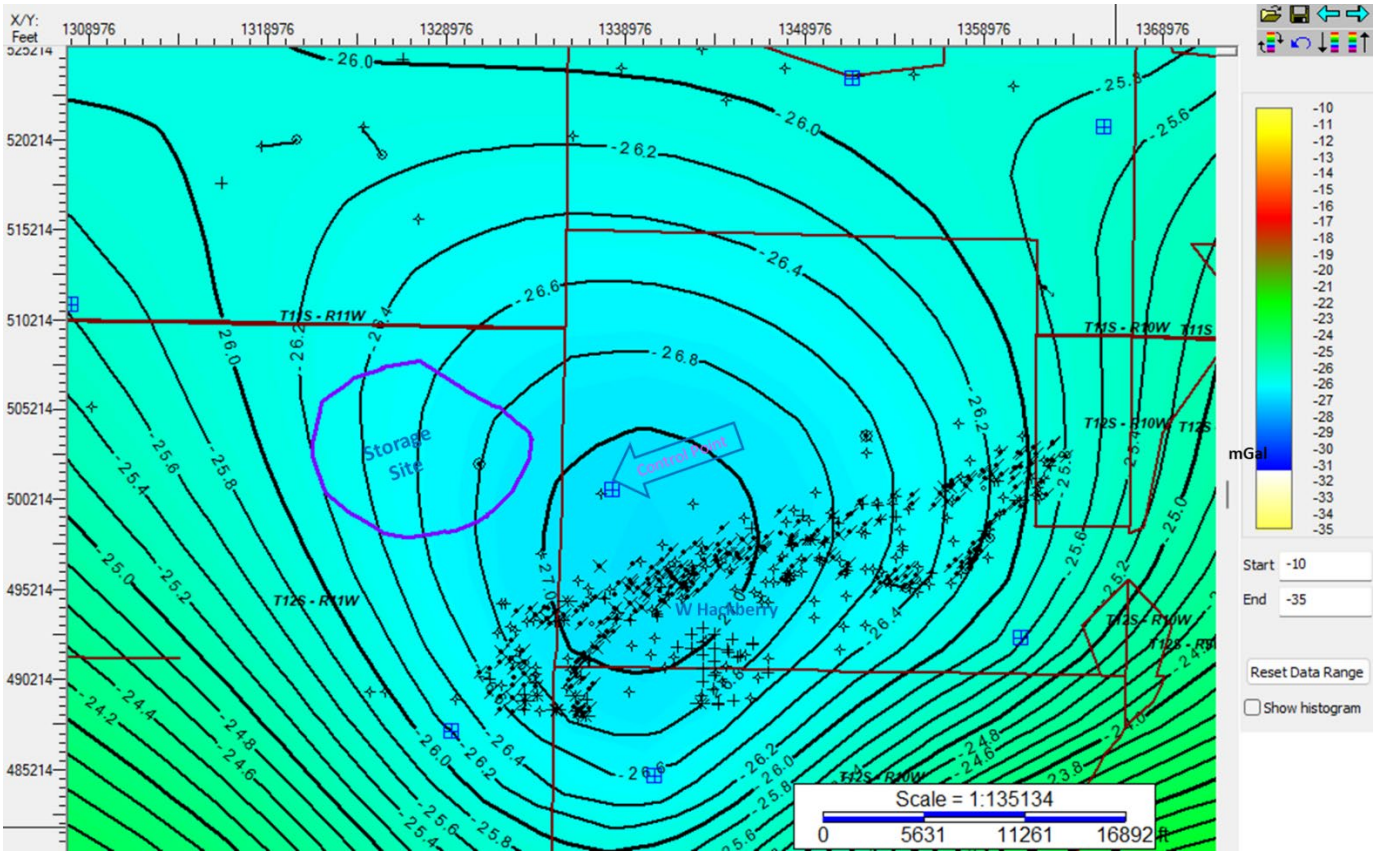

Figure 1-24 – Isostatic Gravity Anomaly Map

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1.4.3 3D Seismic Data

Two 3D seismic volumes were licensed by the HCS in the Hackberry Sequestration Project area. First, to the east, the "Hackberry" volume of the SEI Alligator Cove was used, as shown in Figure 1-25. To the west, the "Seitel Black Bayou" seismic volume was used as shown in Figure 1-26. The two surveys slightly overlap. These two primary volumes were used for 3D seismic interpretation in this study.

The years of Seitel Black Bayou seismic acquisition and processing are not clear. The SEI Hackberry 3D survey was acquired by GRANT Geophysical Corp. between August and October 1995. The parameters and layout are described in Figure 1-27. Given the very shallow water environment, the seismic source was dynamite with holes drilled down to 120 ft to position the seismic energy below the mud and weather layers.

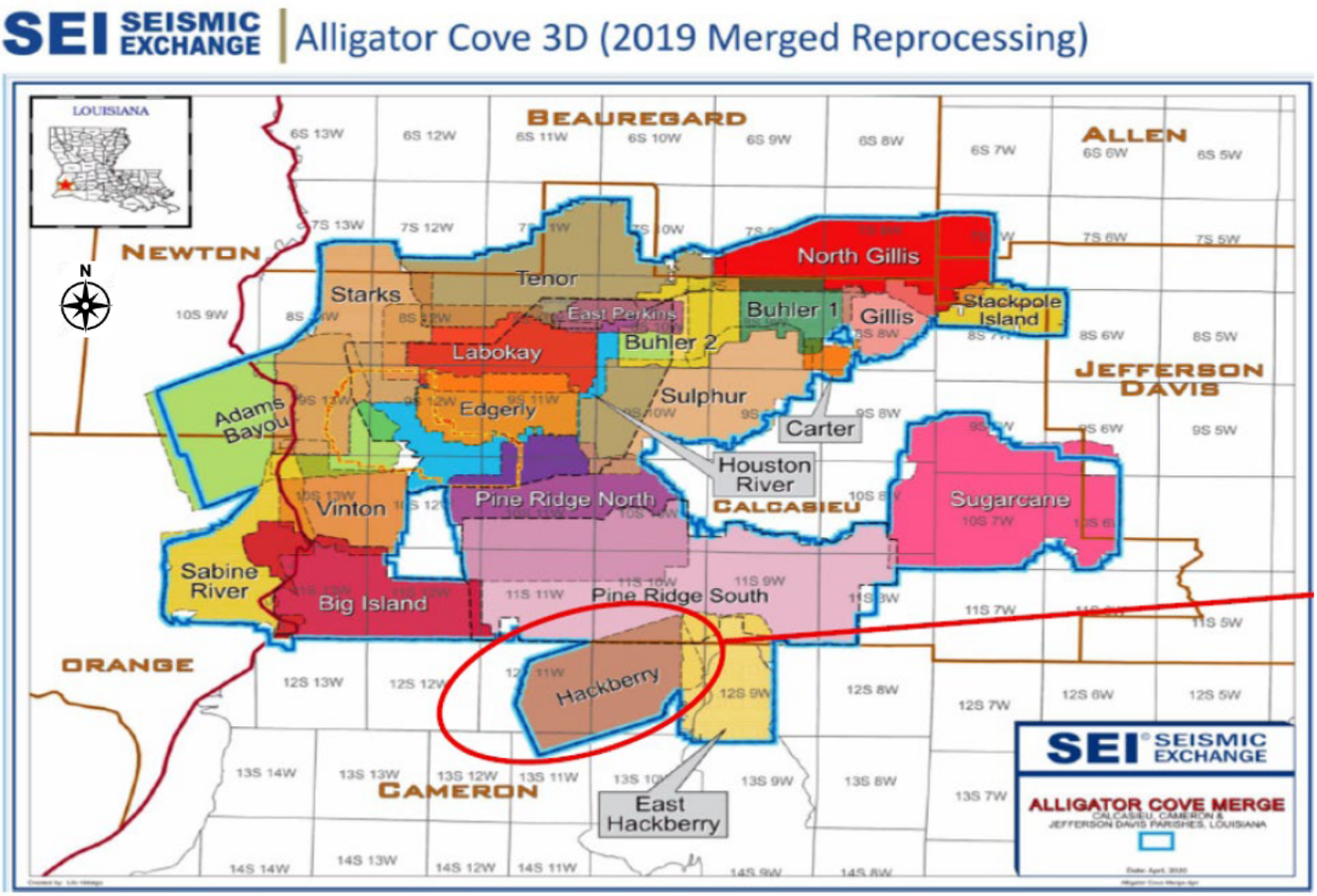

Figure 1-25 – The location of the Hackberry portion of the greater SEI Alligator Cove merge 3D seismic surveys.

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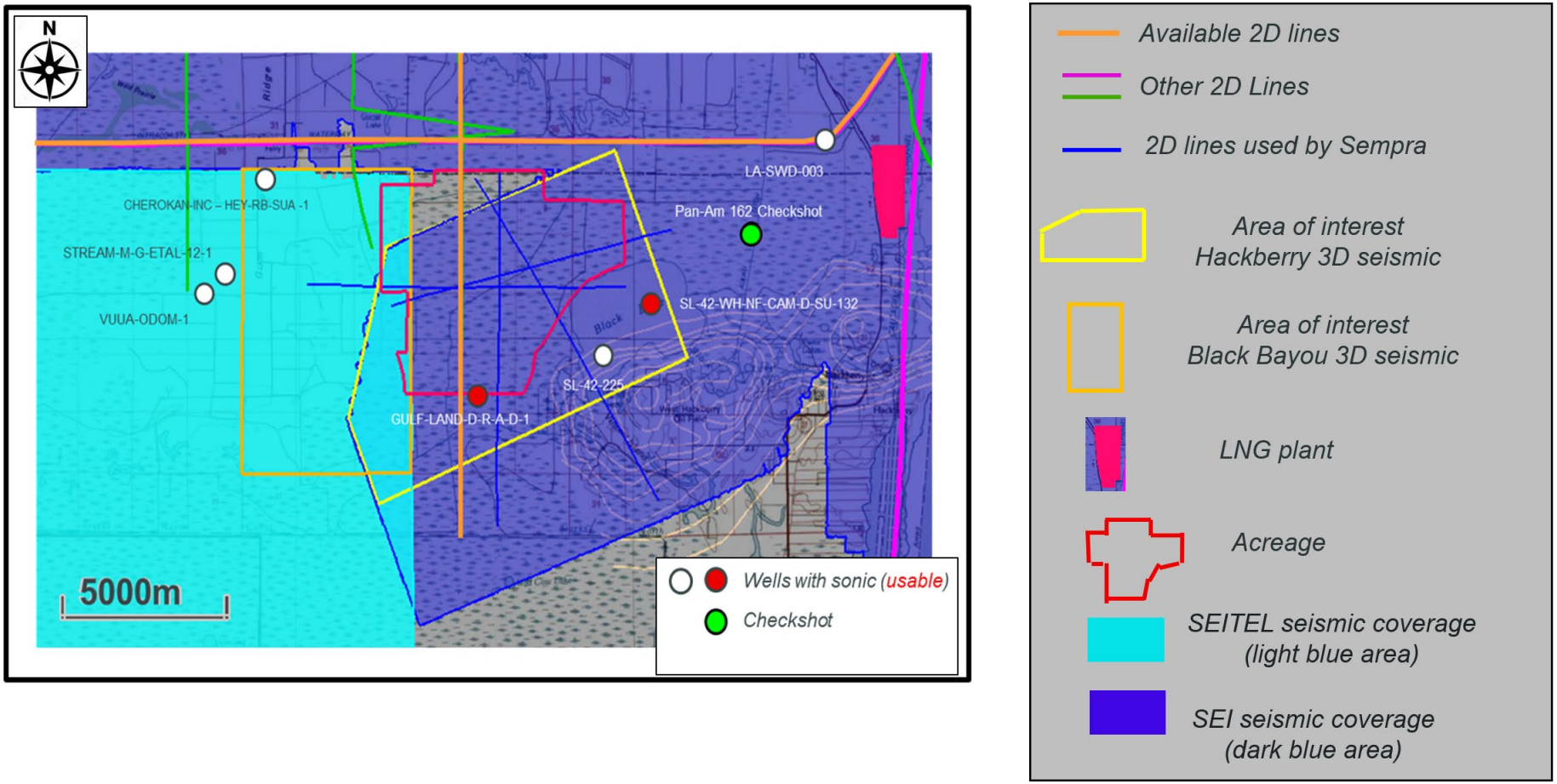

Figure 1-26 – The relative locations of the SEI Alligator Cove survey (yellow box), the Seitel Black Bayou survey (orange box), and the Sempra acreage (red outline). The licensed portions of data are smaller than their associated master surveys (cyan and dark blue).

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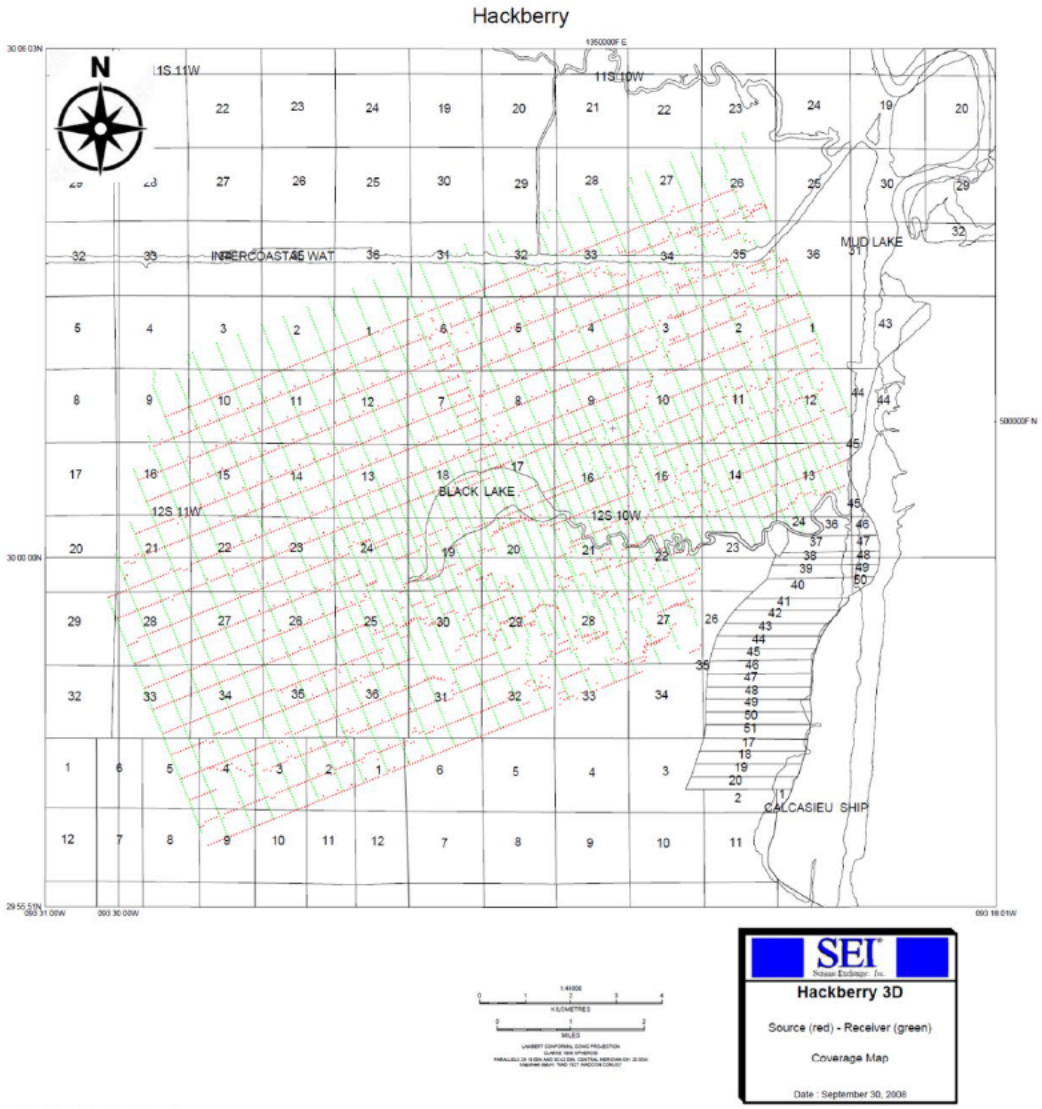

HACKBERRY 3D
HIGH LAND ACQUISITION SUMMARY

CONTRACTOR:	Grant Geophysical Corp.	**PROGRAM DATES:**	06AUG95 - 31OCT95
FOLD:	30	**PROGRAM SQ. MI.:**	59.2579
MAX FAR OFFSET:	30976 (ft.)	**SOURCE LINE ORIENT:**	SW - NE
BIN DIMENSIONS:	110 x 110 (ft.)	**RECEIVER LINE ORIENT:**	SE - NW

ENERGY SOURCE DESCRIPTION

TYPE	:	Pentolite
SOURCE INTERVAL (ft.)	:	220
LINE SPACING (ft.)	:	1760
CHARGE SIZE (lbs.)	:	11
DEPTH (ft.)	:	120
SOURCE PATTERN	:	Cross-Line
ARRAY DESCRIPTION	:	1 charge per shot point. 8 SPs per rack.

RECEIVER DESCRIPTION

TYPE	:	Geophone
STATION INTERVAL (ft.)	:	220
LINE SPACING (ft.)	:	1760
LINE LENGTH (ft.)	:	29700
NUMBER OF LINES	:	10
NUMBER OF STATIONS PER LINE	:	192
ARRAY DESCRIPTION	:	6 geophones bunched

RECORDER DESCRIPTION

TYPE	:	SGR
SAMPLE RATE (ms.)	:	2
RECORD LENGTH (sec.)	:	12
TOTAL SEISMIC CHANNELS RECORDED	:	1920
LO-CUT FILTER (Hz.)	:	8
HI-CUT FILTER (Hz.)	:	200 Hz
TAPE FORMAT	:	SEG-Y

POSITIONING DESCRIPTION

METHOD	:	DGPS
PROJECTION	:	StatePlane Louisiana South FIPS 1702
DATUM	:	NAD 1927

Figure 1-27 – SEITEL Black Bayou seismic acquisition layout and parameters.

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The received seismic volumes were reprocessed in 2019 using a PreStack Time Migration (PSTM) workflow. For PSTM, the data are considered good quality with the ability to clearly see most faults and the reflections are generally continuous and coherent. The amplitude spectrum is in the 10 to 20 hertz (Hz) part of the frequency band for both surveys.

1.4.3.1 Well to Seismic Calibration and Depth Prediction

No publicly available checkshots or VSP surveys are known to exist in the seismic survey area. The Pan Am 162 well (Serial No. 124348) checkshot was purchased and is the only checkshot in the vicinity of the SEI Alligator Cove seismic survey (Figure 1-28). The Pan Am 162 well is approximately 1.8 miles to the east of the eastern edge of the SEI seismic survey. The checkshot was used for two purposes: 1) the checkshot was compared with PSTM stacking velocities and deemed similar and 2) the checkshot was used as a time-depth relationship, from which a velocity cube was created to depth convert the SEI and Seitel seismic cubes. Because there is only one well that can be used for depth conversion, a simple, pragmatic approach was used. This approach used the velocity values at each depth of the checkshot and projected the values out in 3D, thus creating an entire cube of checkshot-derived values (3D velocity cube that covers the areas of both SEI and Seitel surveys) as shown in Figure 1-28.

Continuous, total-well-length sonic and density logs were not available in the well log data set purchased from TGS to make acoustic impedance logs for synthetic generation. Spontaneous Potential (SP) and Gamma Ray (GR) logs were used as proxies or pseudo-acoustic impedance logs. These pseudo-impedance logs were convolved with a ricker wavelet, producing a synthetic seismogram. The wells used for tying the synthetics are Gulf Land DRAB-1 (SN 102295), Gulf Land DRAA-28 (SN 102295), and SL-42-175 (SN 175290). Synthetic seismograms proved moderately helpful in tying the wells to seismic, but displaying the SP and GR curves over the seismic improved the tie. The matching of the visual seismic packages with the SP and GR curves was ultimately used to tie, as close as possible, the seismic reflections and the well markers picked on lithology events

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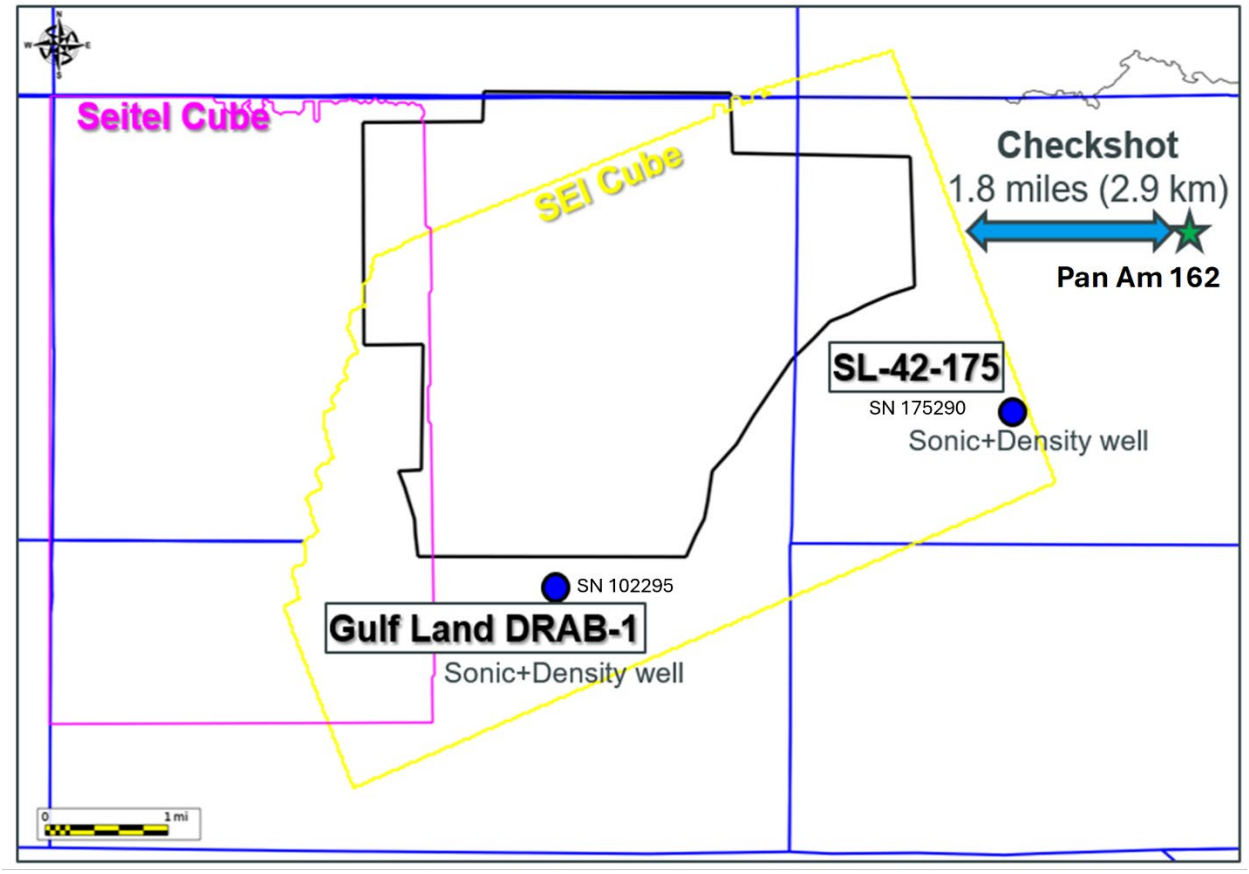

Figure 1-28 – The Pan Am 162 checkshot well (shown as green star) with respect to the two seismic surveys.

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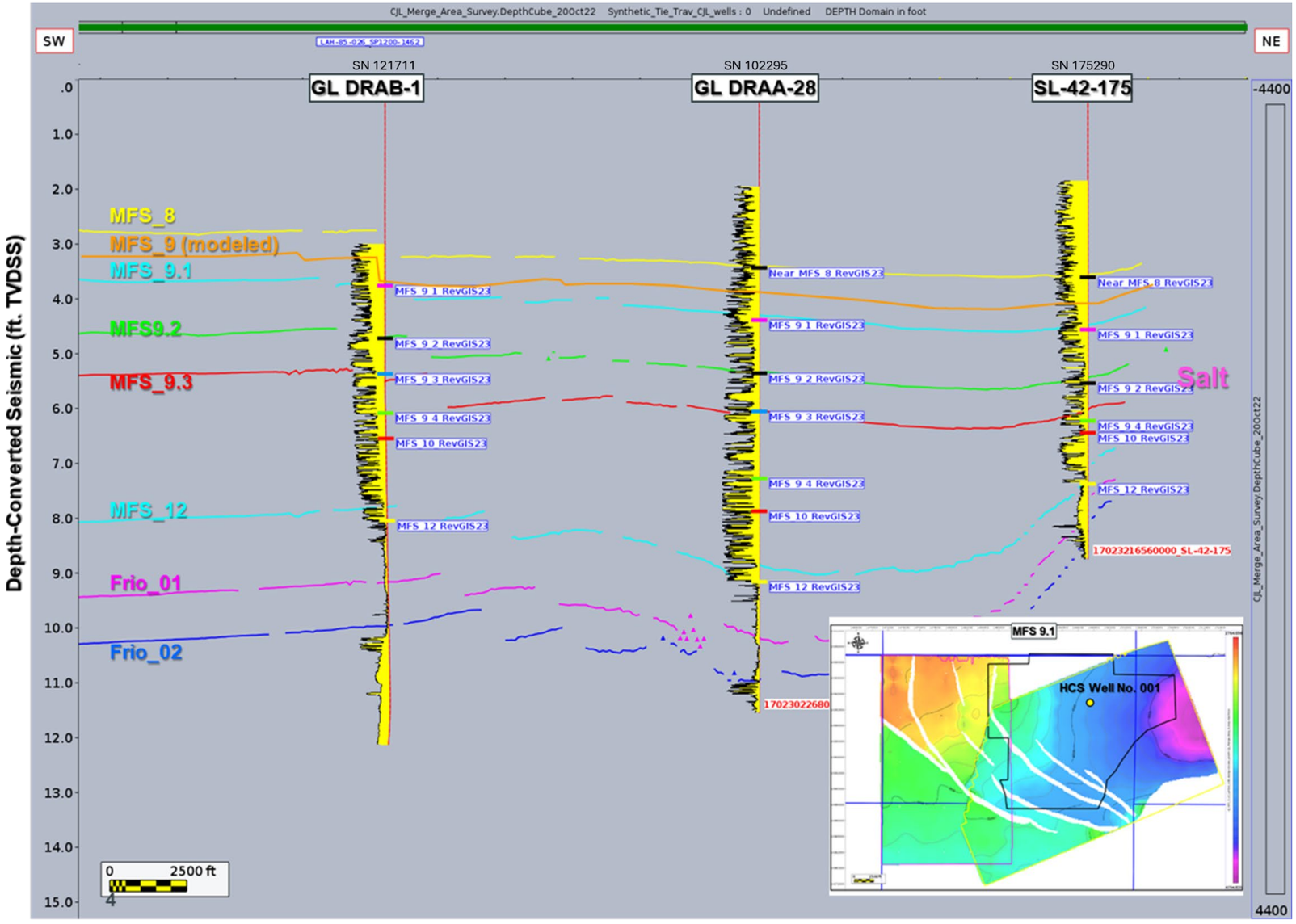

Figure 1-29 – Depth-converted seismic traverse between key wells. GR and SP curves match major seismic reflection events, supporting the robustness of the time-depth conversion method used.

1.4.3.2 Seismic Interpretation

Interpretation Software

Total Energy's proprietary seismic interpretation software, called Sismage, was used to interpret both faults and horizons on the previously described 3D seismic volumes.

Fault Interpretation

The most well-imaged aspect of both seismic cubes is the faults. A dominant signal of faulting was interpreted with a combination of inline-crossline, time slice, and horizon-local extraction-based interpretations (Figure 1-30). Additionally, fault edge detection seismic attributes were used to detect faults in the map-view.

Once the faults were interpreted, maps were created at key intervals that showed the fault gap for those intervals (Figures 1-31 and 1-32). Fault throws varied from roughly 50 to 650 ft, depending on the fault. Most faults strike northwest to southeast, and their development is interpreted to be directly induced by the local Hackberry salt diapir movements. The faults form a graben structure, rooted in the deep salt, and dip both northeast and southwest. The fault throws decrease from the MFS12 up to the MFS9 and above, which shows that fault activity is decreasing with time (syntectonic fault system). To the northeast of the SEI survey, faults are non-existent (Figure 1-33, C-C').

The 3D evaluation better defined the faults originally identified in the 2D survey to the south-southwest of the HCS property. The 3D interpretation provides clear affirmation that faults do not exist across the AOR.

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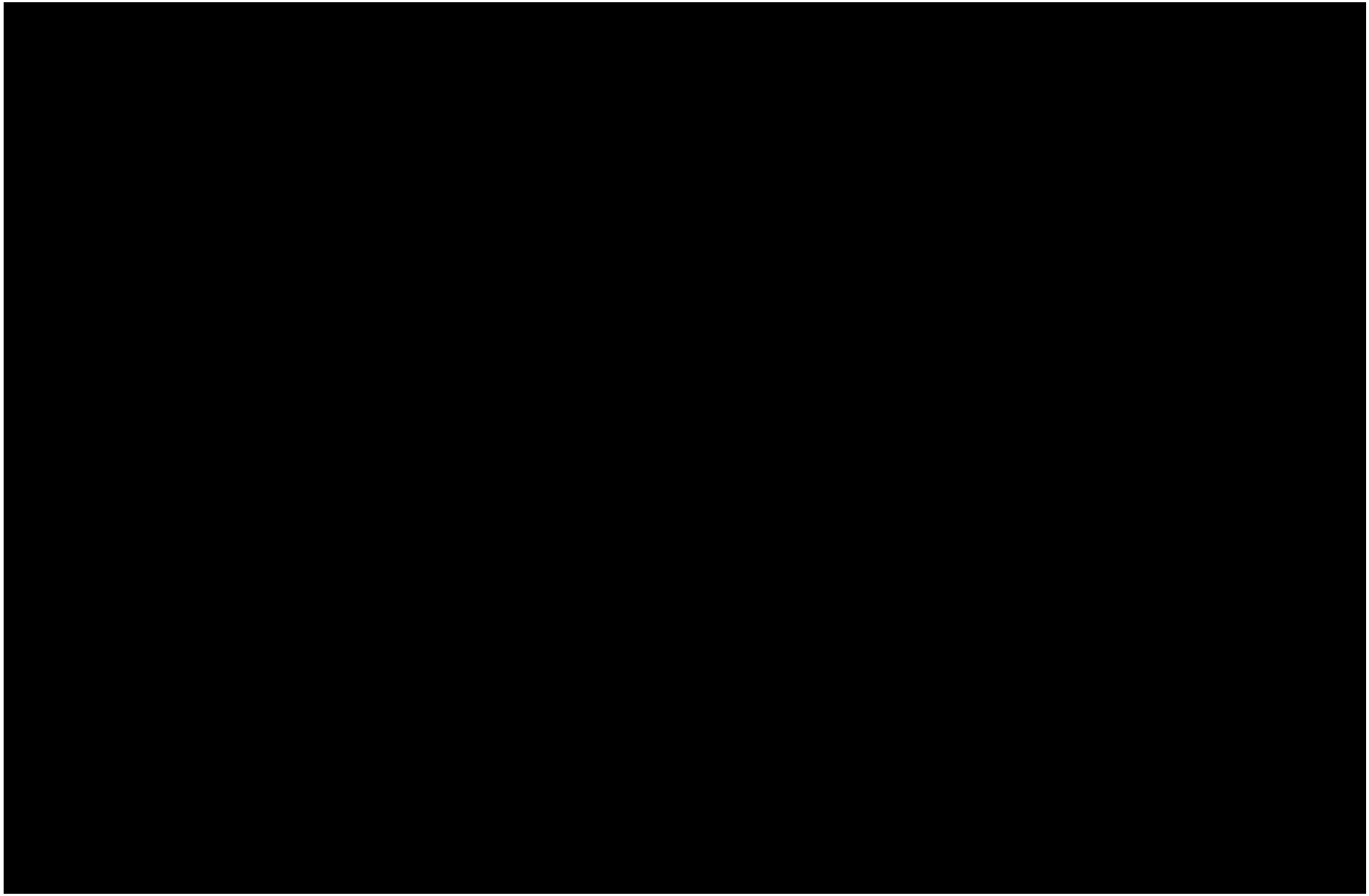

Figure 1-30 – Fault edge detection maps at varying intervals in the Hackberry Project area.

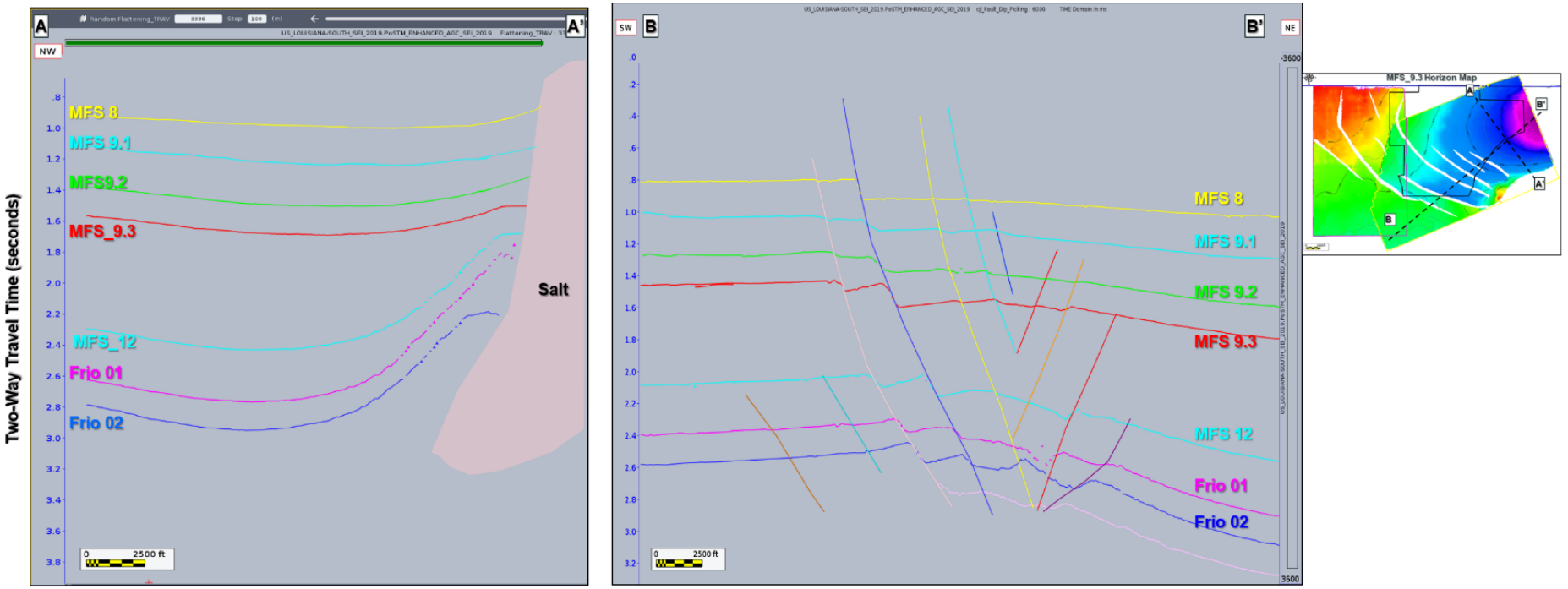

Figure 1-31 – Two cross sections of the subsurface structure. A-A' shows a southeast-trending traverse with little faulting, but the salt body can be seen. B-B' is a northeast-trending traverse across all the major faults in the area, showing the extensional, salt-derive.

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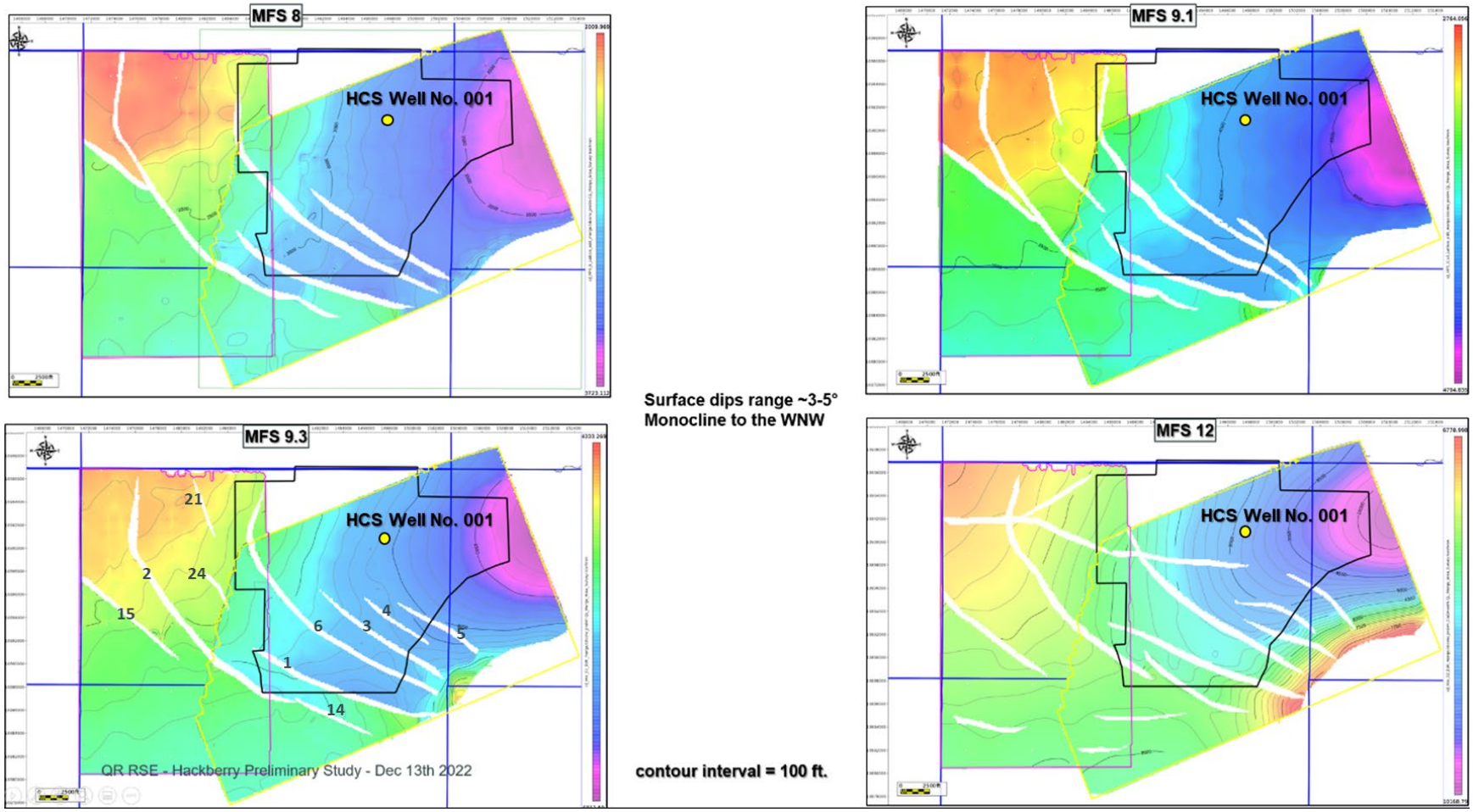

Figure 1-32 – Maps of faulting at key stratigraphic intervals. The fault numbers are also shown as an example on the MFS 9.3 map.

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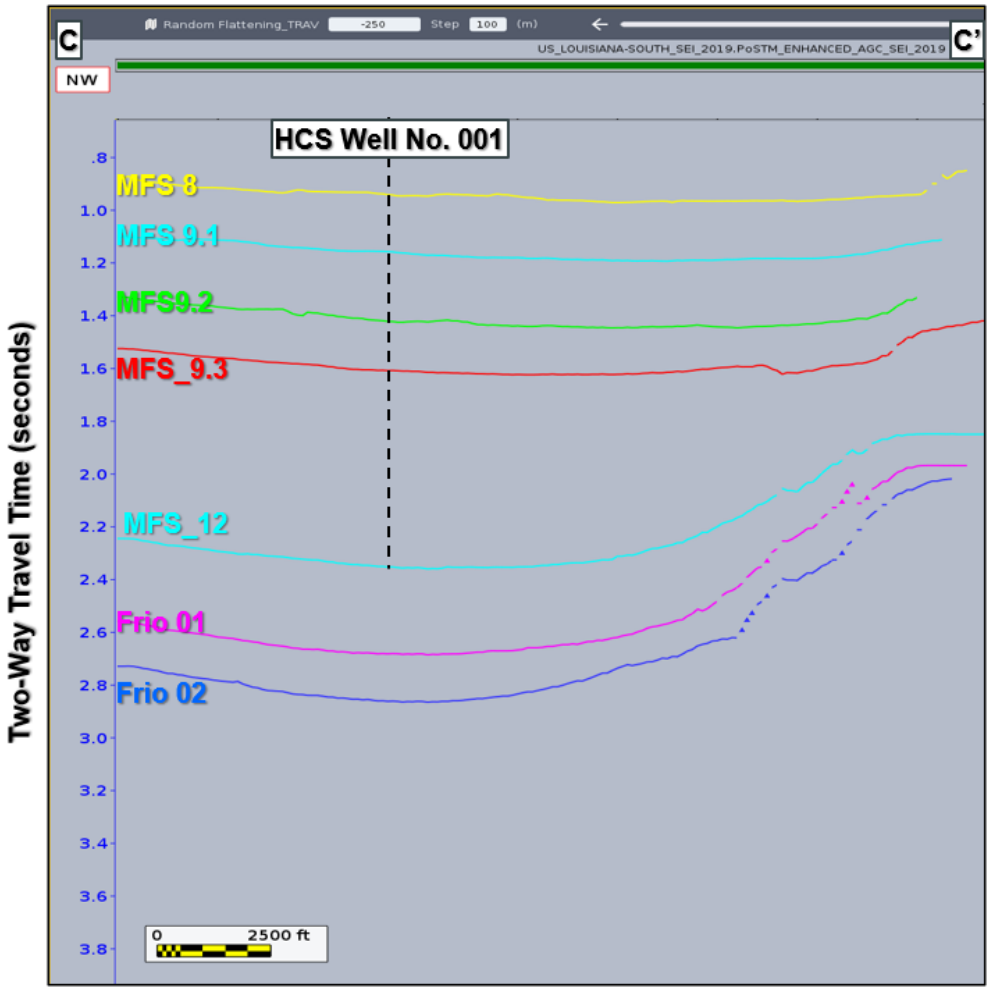

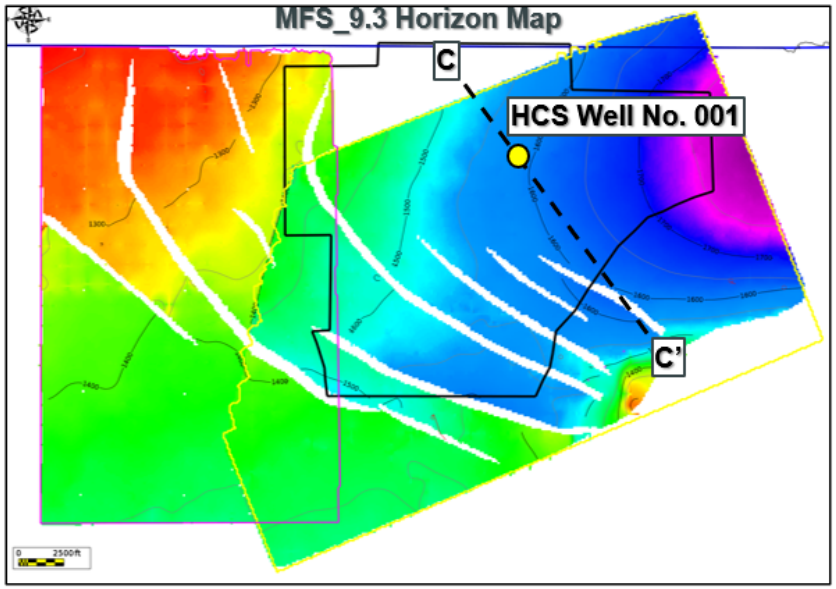

Figure 1-33 – A structural cross section C-C' that shows the notional area of the HCS Well No. 001 injection well. Note the lack of faulting in this area.

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Horizon Interpretation

Structural interpretation of seismic reflections differentiating layers of sedimentary rock was generally straight forward and considered to be of high confidence especially regarding the section from MFS 8 TO MFS 12. Just below the MFS 12 is the Anahuac shale, which has a distinctive seismic signature characterized by fewer seismic reflection cycles. The PSTM seismic quality is not high enough to confidently discern lateral sand continuity of the injection layers, nor differentiate between shale and sand layers, for much of the potential injection zone. Horizons interpreted for this study were:

- MFS 8
- MFS 9 (Amphistegina B) – a surface created/modeled between MFS 8 and MFS 9.1
- MFS 9.1
- MFS 9.2
- MFS 9.3
- MFS 12 (Anahuac Shale top)
- Two sub-MFS 12 horizons (Frio_1 and Frio_2)

The deeper horizons such as the Frio, MFS 12, and MFS 9.3 are the most seismically visible and easiest to interpret, especially because of their continuity. Shallower horizons were more difficult because there was no diagnostic seismic character (no clear seismic packages). The SEI and Seitel seismic surveys were acquired/processed independently and with different processing sequences and thus, a depth-offset seam is present between the surveys. This offset introduces some uncertainty into the horizon interpretation. These horizons were input for the geologic model but were not used directly. The horizons were bulk shifted slightly up or down to match the interpreted well log markers. Once in alignment, these new shifted surfaces were used as the geologic model input surfaces. An update of the horizons will likely be completed after HCS Well No. 001 is drilled and the well-to-seismic tie completed with new sonic and density logs, along with a potential vertical seismic profile (VSP) survey. At that time, a detailed interpretation update of the key maximum flooding surfaces and base of sand reservoirs will be performed.

A seismic attribute study was conducted from the top of the cubes (very shallow) to MFS 12 to attempt to see evidence for sedimentological features, such as channels, lobes, deltas, and shorefaces. Conventional amplitude extraction, time slices, and spectral decomposition techniques were used to visualize these features. After extensive searching, only sinuous channel features (Figure 1-34) were visible like the one in the MFS 9.2 interval. These features allow an estimation of fairway direction that was used in the geologic model.

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Figure 1-34 – Spectral decomposition attribute at the MFS 9.2 surface showing a sinuous feature in the northeastern portion of the SEI Alligator Cove seismic cube.

During the evaluation and interpretation of the PSTM seismic data, a Pre-Stack Depth Migration (PSDM) reprocessing project was launched for a portion of the licensed data with the contractor CGG. Although the PSDM data was not incorporated into this interpretation, the goal is for learnings from this effort be utilized to improve the seismic image, making faults more visible and increasing the regularization of the ultra-shallow section (see better reflection continuity above MFS 8). This reprocessing project took place from July 2022 to March 2023. Key seismic processing flow steps were:

- Elevation statics
- 5D regularization to densify the ultra-shallow section
- Velocity model building
- Tomography / gather flattening
- Demultiple
- Post-processing denoise techniques

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For the purposes of this project, due to the regional structural dip of the Miocene sands in the project area of approximately 3 degrees (at the top of the injection interval at HCS No. 001), the difference between an isopach and isochore thickness of the geologic horizons is approximately 99.7% of core thicknesses. As such, the maps generated were labeled as isopach maps and were determined from vertical openhole log details for thicknesses. Negligible differences exist between the isopach and isochore map.

3D Seismic Survey Summary

The 3D seismic survey efforts confirmed the interpretations of the geological structure from the original 2D evaluation. The evaluation provided a better understanding of the location of offset faults and proved that faulting does not exist in the project area. No other significant features were identified that would indicate that the interpretation of the lateral continuity of the injection and confining zones has changed.

1.5 Geomechanics

1.5.1 Local Stress Conditions

Local stress conditions are incalculable from either data collected within the LA Storage SWD No. 003 (SN 975774) stratigraphic well by the X-Dipole openhole geophysical log or brine injection step-rate test in the injection interval. The X-Dipole log shows the two Flexural Shear Slowness curves (XX and YY) to overlap throughout the injection zone, indicating minimum anisotropy or borehole breakout. This indication supports the interpretation that the injection interval has low shear strength due to the lithology found within the interval (Zerwer, 1997). From the brine injection step-rate test, no observation of fracture initiation within the injection stages was made; therefore, fracture orientations were unable to be determined.

Technical publications on the regional stress conditions in the Gulf of Mexico Basin indicate the orientation of maximum horizontal stress (S_{Hmax}) is largely parallel to the strike of the progradational clastic sedimentary wedge, in a general northeast-southwest direction (Zerwer, 1997). As the data provided in the stratigraphic well was inconclusive, the assumed S_{Hmax} orientation at the proposed HCS location is parallel to the coastline.

1.5.1.1 Determination of Vertical Stress (S_v) from Density Measurements

The vertical stress can be characterized by the pressure exerted on a formation at a given depth due to the total weight of the rocks and fluids above that depth (Aird, 2019). Vertical stress is calculated with the density data logged in the openhole section of the LA Storage SWD No. 003 (SN 975774). The overburden gradient, vertical stress, and average densities of the upper confining, injection and lower confining zones from LA Storage SWD No. 003 (SN 975774) stratigraphic well are in Table 1-8 below. Densities from the openhole log used to calculate these gradients excluded portions of the log where borehole washout had occurred based on caliper readings. Density tools can be highly affected by increased borehole size which would result in incorrect data. Density values are only valid where the caliper is in gauge.

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Table 1-8 – Calculated Vertical Stresses in LA Storage SWD No. 003 (SN 975774)

Formation	Depth (ft)	Avg Density (g/cm^3)	Avg Density (lb/ft^3)	Vertical Stress (psi)	Gradient (psi/ft)
Amph B	5,477	2.228	139.1	5,289	0.97
Lower Miocene	5,774	2.230	139.2	5,582	0.97
Anahuac	11,381	2.232	139.3	11,012	0.97

1.5.2 Elastic Moduli and Fracture Gradient

Elastic moduli and fracture gradients were determined from laboratory analysis of core samples where available. Triaxial tests were performed on two samples recovered from the LA Storage SWD No. 003 (SN 975774). The core samples are referred to as sample numbers 2-1V and 4-2V and were recovered from the upper confining zone and the injection zone, respectively. Tests were performed on two-inch diameter vertical plugs from each core.

Results for geophysical properties of sample 2-1V were not within the range of expected values for the rock type. After further investigation, the tests for sample 2-1V were determined inconclusive due to improper preparation and handling of the sample. Key results from core analyses are listed below in Table 1-9.

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Table 1-9 – Triaxial Compressive Strength Test Results in the LA Storage SWD No. 003 (SN 975774)

Sample Number	Depth (ft)	Zone	Member	Confining Pressure (psi)	Compressive Strength (psi)	Young's Modulus (10^6 psi)	Poisson's Ratio
2-1V	5,737.90	Upper Confining	Amph B	Inconclusive	Inconclusive	Inconclusive	Inconclusive
4-2V	7,628.35	Injection	Lower Miocene	2,400	6,406	0.37	0.28

1.5.3 Injection Zone Fracture Gradient

A step-rate test was performed on the injection zone at the LA Storage SWD No. 003 (SN 975774) in an attempt to identify the fracture gradient. During the test, brine was injected into the Lower Miocene through perforations from 8,195 ft to 8,255 ft. Rates were increased until a safe maximum injection pressure and tubing fluid velocity were reached at a final rate of approximately 36,000 bbl/day. Stabilized bottomhole pressures for each rate step are plotted below in Figure 1-35. This chart shows a single linear trend and no indication of fracturing during the test up to the maximum gradient of 0.72 psi/ft. Because a fracture gradient was not identified, this test was deemed inconclusive. The fracture gradient was estimated to be 0.66 psi/ft using results from the core analysis as inputs for Eaton's equation. These values are listed in Table 1-10. The friable sand of the injection formation at this location is too unconsolidated to produce a fracture gradient under the conditions of this test.

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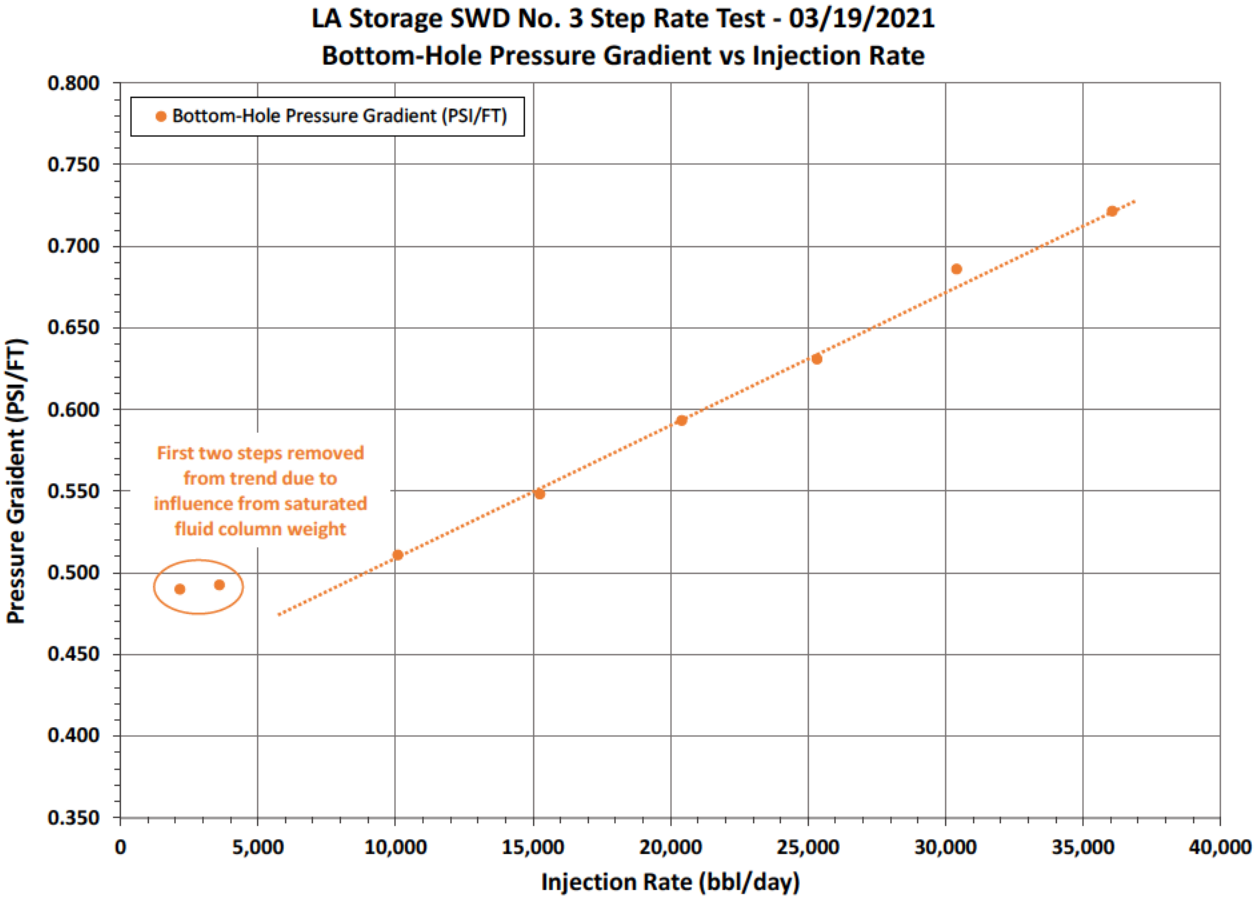

Figure 1-35 – Step Rate Test Results from LA Storage SWD No. 003 (SN 975774)

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Table 1-10 – Fracture Gradient Calculation Inputs and Results

Sample Number	Depth (ft)	Zone	Member	Overburden Stress (psi)	Pore Pressure (psi)	Poisson's Ratio	Fracture Gradient (psi/ft)
4-2V	7,628.35	Injection	Lower Miocene	7,652	3,558	0.28	0.66

According to [40 CFR **§146.88(a)**], the maximum allowable pressure based on the step-rate test results is 0.65 psi/ft, 90% of the assumed minimum fracture gradient of 0.72 psi/ft.

The fracture gradient was also calculated from core analysis results and estimated to be 0.66 psi/ft using Eaton's equation. This estimate is a conservative value, as the fracture gradient could not be determined during the step-rate test, which exceeded the calculated estimate. The conservative maximum allowable pressure, based on the core analysis, is 0.60 psi/ft, which is 90% of the estimated 0.66 psi/ft.

Following 20 years of injection, the injectivity model determined a maximum bottomhole pressure gradient of 0.54 psi/ft. This value is less than both the Eaton-calculated core analysis estimate and the step-rate test-determined minimum fracture gradient.

1.5.4 Confining Zone Fracture Gradient

Injection tests were not performed on the upper or lower confining zones. Fracture gradients were estimated using Eaton's equation as shown in Table 1-11. Core samples were not recovered from the lower confining zone and the triaxial tests for the upper confining zone were deemed inconclusive. For these reasons, values for Poisson's ratio were chosen based on the lithology observed in openhole logs and XRD testing. These zones consist of large uninterrupted shale deposits. Shales are known to have a Poisson's Ratio greater than 0.3, according to the National Engineering Handbook. This value is used as a conservative estimate to calculate the fracture gradients.

Table 1-11 – Upper Confining Zone Fracture Gradient Calculated using Triaxial Test Results and Eaton's Equation

Sample Number	Depth (ft)	Zone	Member	Overburden Stress (psi)	Pore Pressure (psi)	Poisson's Ratio	Fracture Gradient (psi/ft)
2-1V	5,738	Upper Confining	Amph B	5,829	2,711	0.30	0.701
N/A	11,381	Lower Confining	Anahuac	11,075	5,300	0.30	0.683

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Additional rock mechanics data, including ductility and rock strength, will be added after is collected during the drilling and completion of HCS Well No. 001 and analyzed.

1.6 Porosity and Permeability

In the following sections, the porosity described is effective porosity. Due to the irreducible bound water in the clay matrix, total porosity is not representative of the pore space that can be occupied by mobile fluids within the sealing units. As addressed in the site geology section, measured total porosity in the smectite clay is higher than kaolinite clay though the permeability in smectite clay is much lower than permeability measured in higher kaolinite clay shales. However, when determining permeability within the injection sands, total porosity was used when the facies was deemed as a sandstone or clay-rich sandstone. This approach is defined in Section 2.2.8.3.

Effective porosity is described as the porosity of a rock or sediment available to contribute to fluid flow through the rock. The effective porosity is calculated by determining the Vshale of the interval:

$$Vshale = \frac{(SP - SPsand)}{(SPshale - SPsand)}$$

The Vshale is incorporated into the effective porosity (ϕ_{eff}) equation:

$$\emptyset_{eff} = \emptyset * (1 - Vshale)$$

1.6.1 Upper Confining Zone

1.6.1.1 Porosity

Openhole log data through the Amphistegina B confining interval in the LA Storage SWD No. 003 (SN 975774) stratigraphic test well indicate an average effective porosity of 4.9%. Figure 1-36, an openhole log of the stratigraphic test well, displays (from left to right) the SP curve (lithology indicator), permeability, effective porosity, and a standard crossplot of total porosity. The red boxes shown in the leftmost track indicate the location of cores extracted from the section.

Based on the SP curve (lithology indicator), the upper confining layer was cored in interbedded sands and shales. This means the upper confining layer core will have sand lithologies represented within the shale intervals, which primarily have higher porosities, within the core data. The shale layer from the top of Amph B to 5,645 ft will act as the primary confining lithology. Cored total porosities in the upper confining shale interval average 19.4%. The average effective porosity of the upper 168 ft of confining shale interval is 1.0%.

A nuclear magnetic resonance (NMR) test run on a core plug from 5,738 ft measured the porosity at 17.8%. The effective porosity was determined to be 1.0%, as shown in Table 1-12. Multiple zones in the upper confining zone measure an effective porosity of 0.0%, as shown in Table 1-12.

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In Figure 1-37, a relationship between the Effective Porosity (PHIE) curve and the Spontaneous Potential curve (SP) was determined in LA Storage SWD No. 003 and applied to ascertain the effective porosity in the closest offset well (SN 102295) to the proposed HCS No. 001 well location. Using this equation, an effective porosity was determined which yielded an average of 0.0% PHIE of the confining shale in the bottom 100 ft of the Amph B interval in the closest offset well (SN 102295) as seen in Figure 1-38.

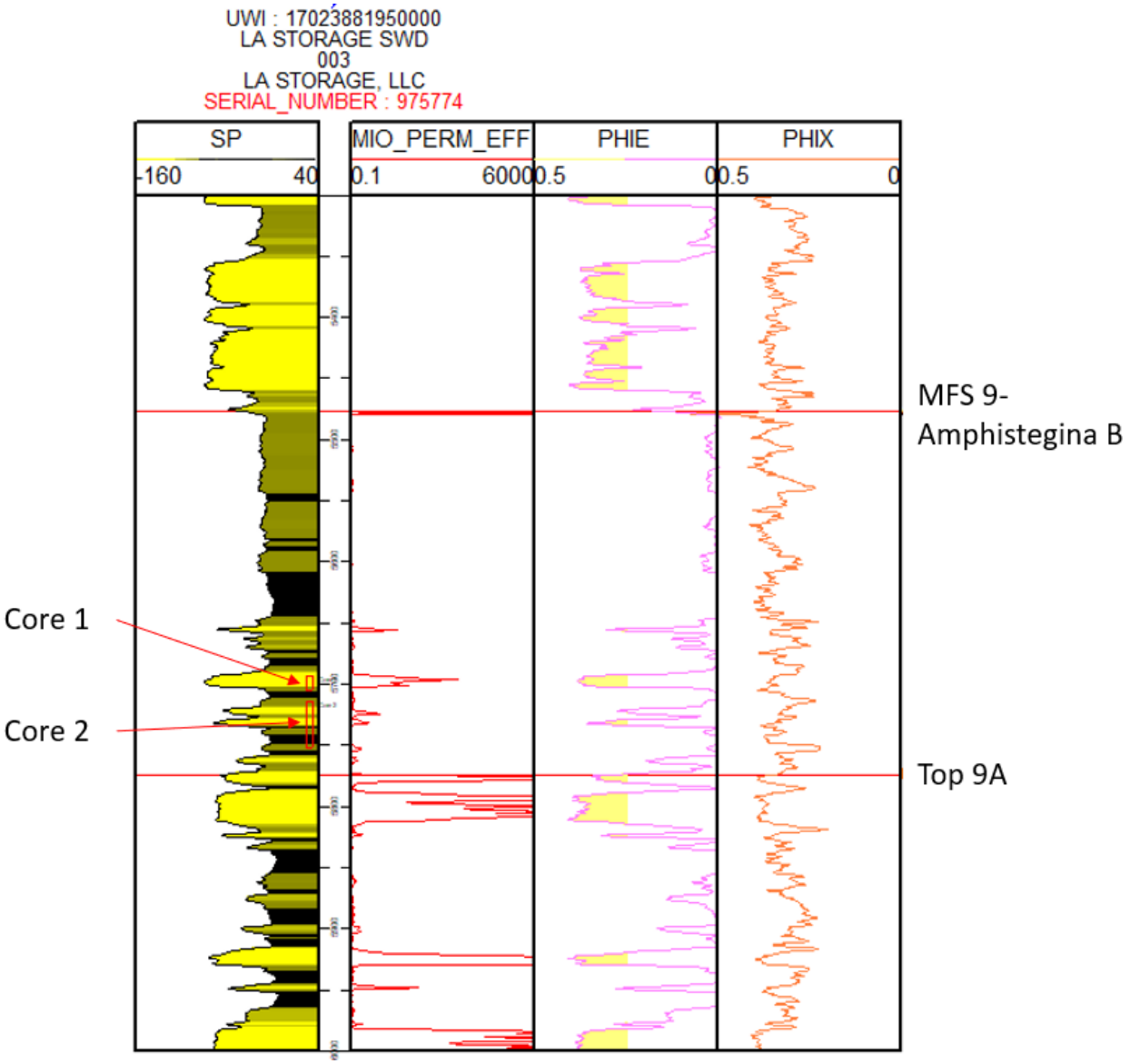

Figure 1-36 – Openhole Log Display of LA Storage SWD No. 003 (SN 975774) Upper Confining Zone

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Table 1-12 – Core Porosity and NMR Effective Porosity from Sample within Upper Confining Zone

		Core Analysis Data			NMR Data		
					100% Brine Saturation		
Sample ID	Depth (ft)	NCS (psi)	Porosity (%)	Kair Permeability (md)	Porosity (%)	Effective Porosity (%)	T_2 Log Mean (ms)
2-16H	5737.95	800	17.4	0.945	17.8	1.0	0.7

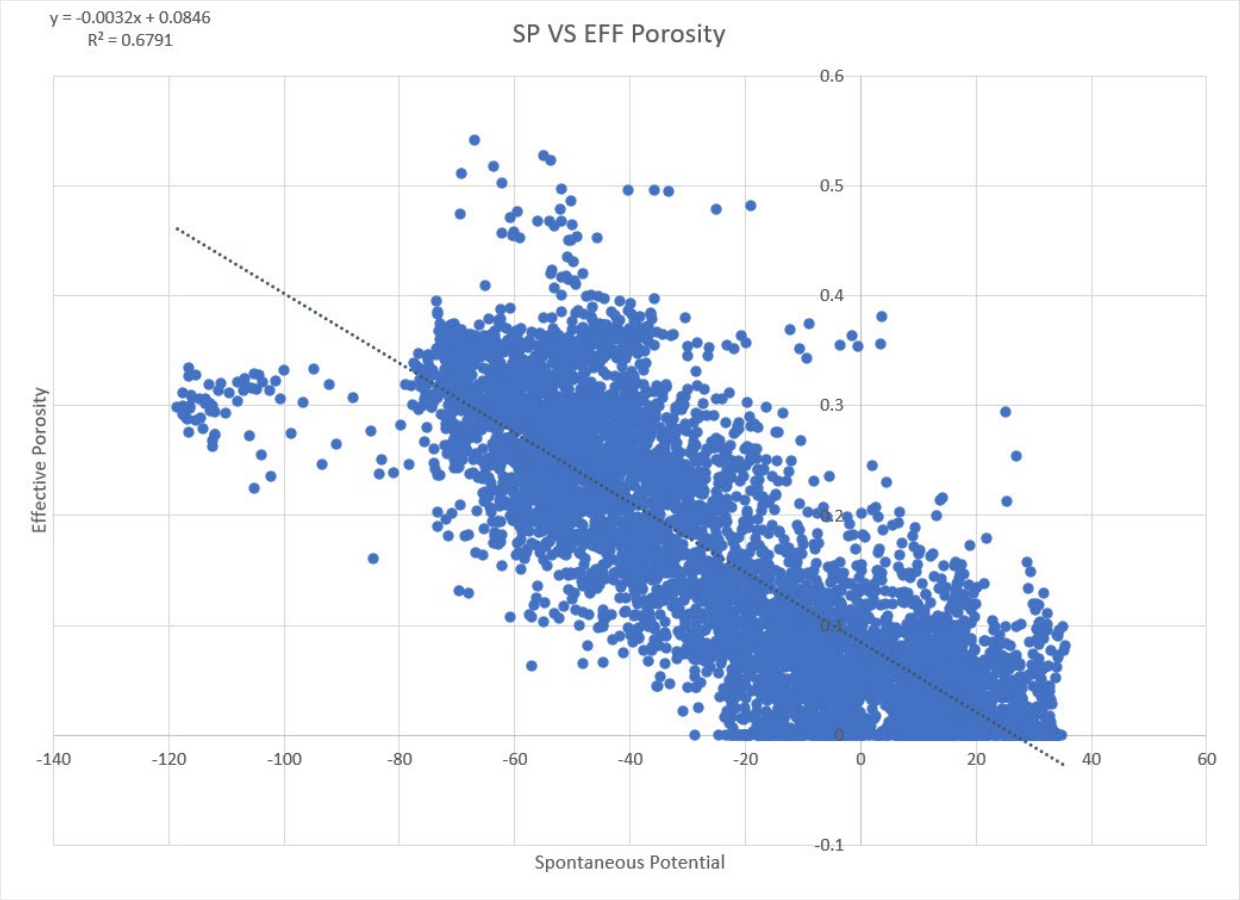

Figure 1-37 – Scatter Plot of Effective Porosity vs. SP in the LA Storage SWD No. 003 (SN 975774)

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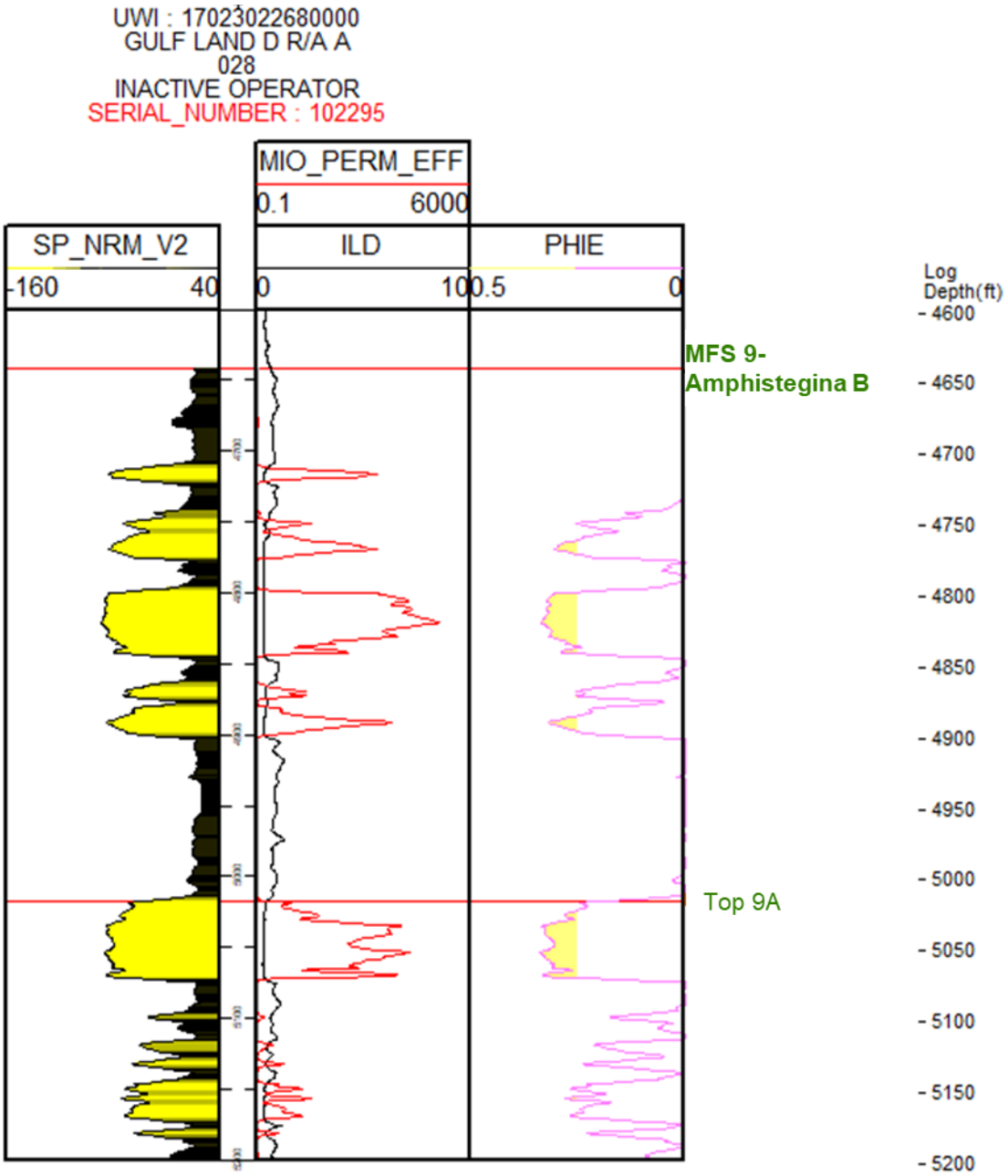

Figure 1-38 – Openhole Log Display of SN 102295 Upper Confining Zone

1.6.1.2 Permeability

Permeabilities found in the core taken from the LA Storage SWD No. 003 (SN 975774) upper confining zone had a range of 0.291 mD to 21.9 mD. Table 1-13 shows the tabular results from the core taken from the upper confining zone. As mentioned in Section 1.3, mineralogy determined by the X-Ray Diffraction (XRD) test shows a high concentration of smectite. This clay mineral was physically altered during the coring process due to the use of water-based drilling mud and a lack of sediment stability in the handling of the cores. These two factors combined to cause shrinkage of the smectite in the formation from the well to the lab. The smectite shrinkage

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will produce artificially elevated permeability lab results within the marine shales when compared to in situ formation conditions. Therefore, permeabilities within facies determined as "clay/non-reservoir", as described in *Section 2 – Plume Model* (2.2.8.2), were assumed to have no ability to transmit injectate.

Table 1-13 – Core Results from LA Storage SWD No. 003 (SN 975774) Upper Confining Zone

Lonquist & CO. LLC
LA Storage SWD #3
Cameron Parish, Louisiana

CL File No: 202100406
Date: 28-Apr-2021
Analyst(s): SM

CONVENTIONAL PLUG ANALYSIS

Sample Number	Depth (ft)	Net Confining Stress (psig)	Porosity (%)	Permeability Kair (md)	Saturation Oil % Pore Volume	Saturation Water % Pore Volume	Grain Density (g/cm3)	Footnote
2-4H	5713.50	1780	18.23	3.85	NA	NA	2.706	(1)
2-5H	5715.50	1780	22.85	21.9	NA	NA	2.725	(1)
2-10H	5725.50	1780	19.87	10.6	NA	NA	2.718	(1)
2-15H	5737.60	1780	18.77	.291	NA	NA	2.711	
2-16H	5737.90	1780	17.2	0.406	NA	NA	2.670	

Footnotes :

(1) : Encapsulated sample. Permeability measured using steady-state method.

1.6.2 Injection Zone

1.6.2.1 Porosity

Figure 1-39 is an openhole log in the Lower Miocene of the LA Storage SWD No. 003 (SN 975774) injection zone with an SP curve in Track 1 (lithology indicator), permeability curve in Track 2, effective porosity in Track 3, and standard crossplot porosity in Track 4. Also indicated is the depth at which Core 3 and Core 4 were taken in the openhole section. Core 4 represents the most accurate example of the reservoir properties within the proposed injection intervals. The sand intervals, indicated with a yellow shade in Track 1, will be the targeted injection sands within the injection zone. The average effective porosity found within these sands is 27.1%. The average cored porosity within the injection zone is 31%. The calculated average effective porosity of the injection zone of the SN 102295 well is 27%.

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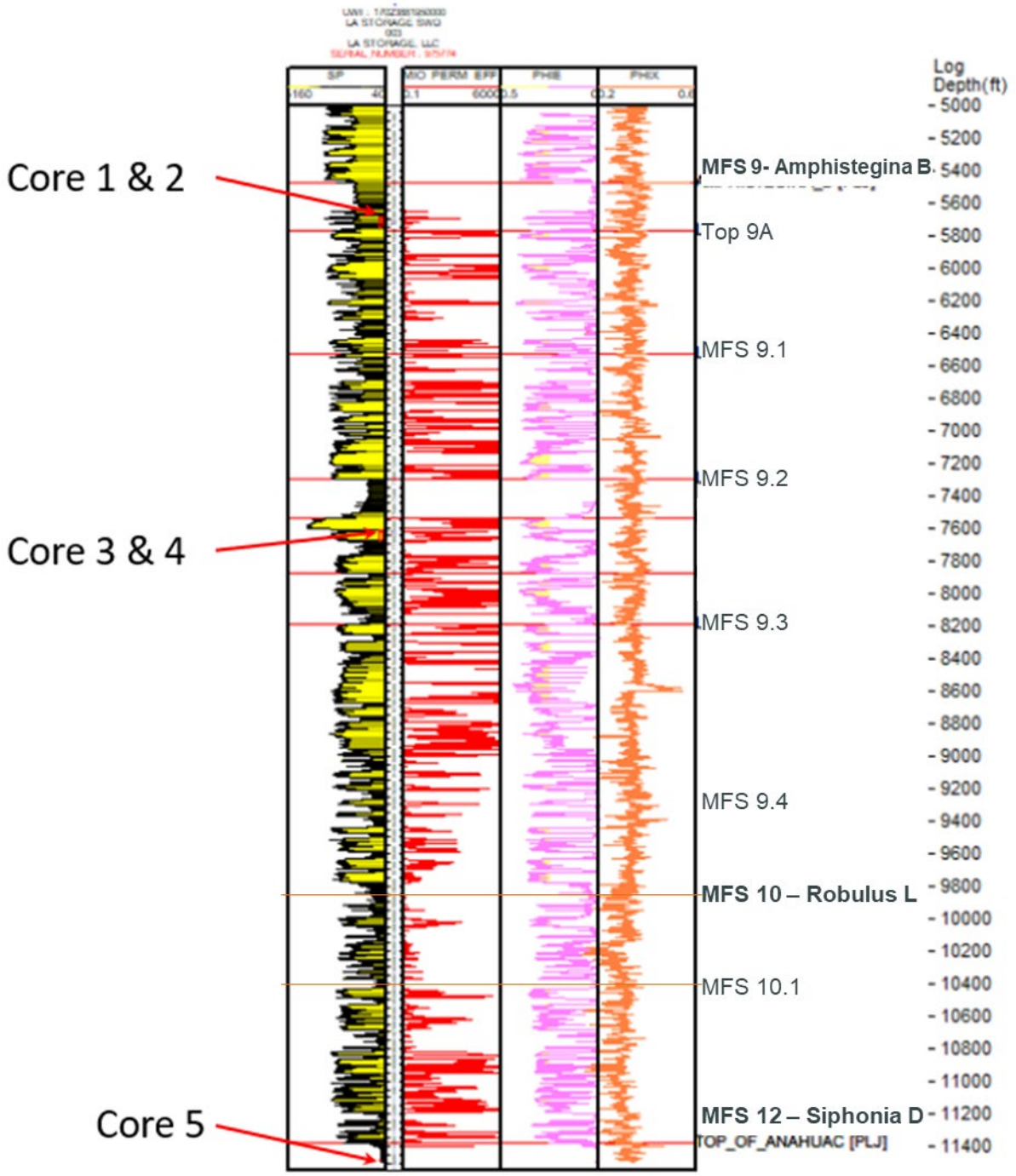

Figure 1-39 – Openhole Log Display of LA Storage SWD No. 003 (SN 975774) Injection Zone

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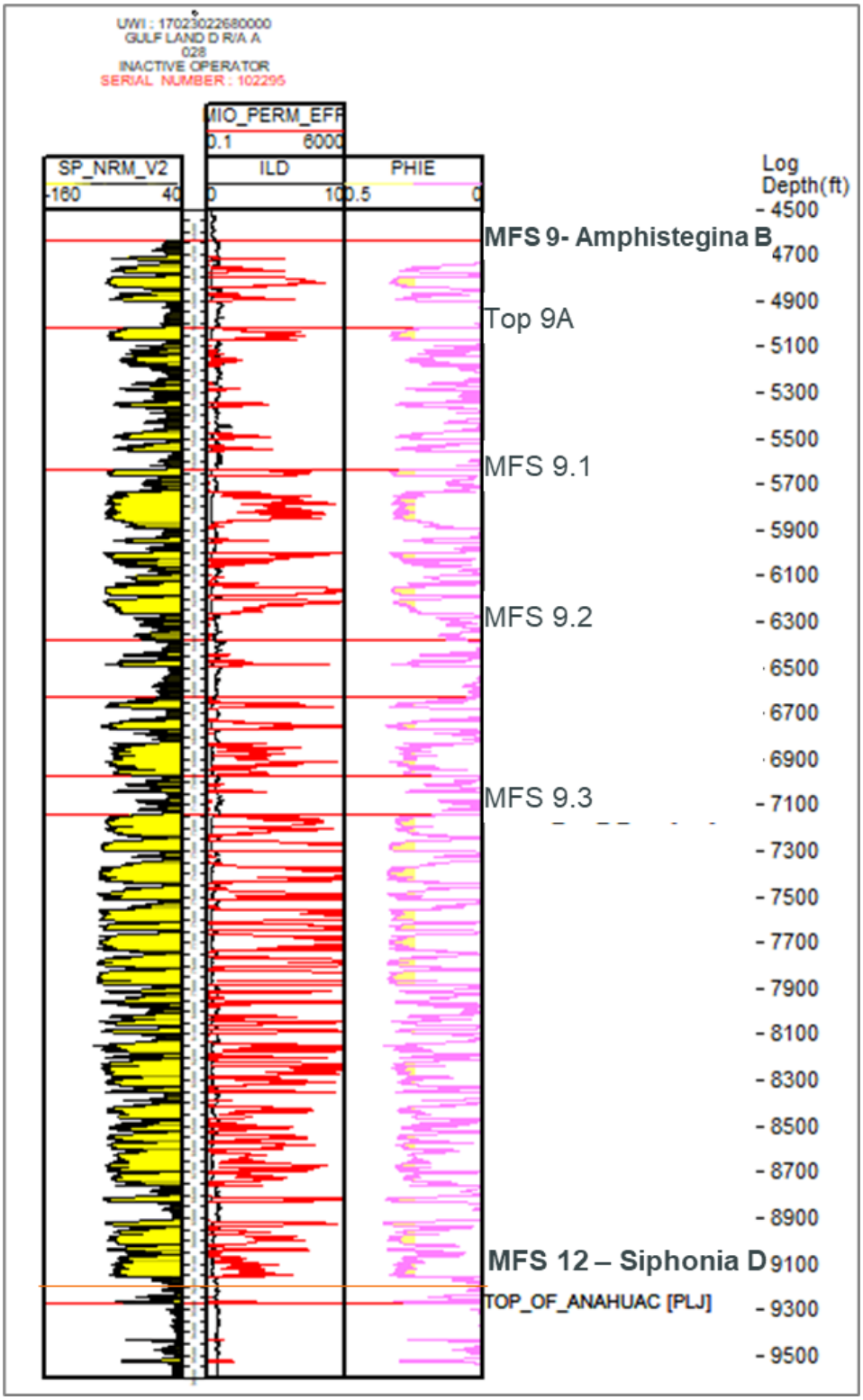

Figure 1-40 – Openhole Log Display of SN 102295 Injection Zone

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1.6.2.2 Permeability

Table 1-14 displays the results of the analysis of Core 4 plugs taken from one of the sands within the injection zone encountered in LA Storage SWD No. 003 (SN 975774). The core permeabilities ranged from 374 mD to 7,750 mD with an average of 4,095 mD. These data points are used to determine the relationship between porosity and permeability as described in Figure 1-41. The relationship was extrapolated throughout the injection interval based on facies determination better described in Section 2.2.8.3. The average permeability calculated across the injection interval is 3,334 mD. The vertical/horizontal permeability ratio determined in the injection sands from the core samples is 0.91, though the lab reported the sand recovered from the cores were friable and unstable which can cause inflated horizontal and vertical permeability measurements. Further discussion on the vertical/horizontal permeability ratios is in Section 2.3.1.

Figure 1-41 is a scatter plot displaying the relationship between core-derived permeabilities and total porosities calculated from the openhole logs. The relationship was used to extrapolate a permeability curve from the total porosity curve for the facies identified as reservoir facies containing predominately sandstone and sandstones with clay. This facies determination can be better described in Section 2.2.8.2. The equation used for determining permeability within these facies is:

$$Coates\ K = 9.951\,\mathrm{E} + 9 \ * \ \mathrm{PHIT}^{12.008}$$

Where:

Coates K = Permeability in mD
PHIT = Total porosity v/v
SwIrr = Irreducible water saturation v/v

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Table 1-14 – Core Results from Lower Miocene Sand within LA Storage SWD No. 003 (SN 975774)

Lonquist & CO. LLC
LA Storage SWD #3
Cameron Parish, Louisiana

CL File No: 202100406
Date: 28-Apr-2021
Analyst(s): SM

CONVENTIONAL PLUG ANALYSIS

Sample Number	Depth (ft)	Net Confining Stress (psig)	Porosity (%)	Permeability Kair (md)	Saturation Oil (% Pore Volume)	Saturation Water (% Pore Volume)	Grain Density (g/cm3)	Footnote
4-3H	7617.50	2380	31.59	4900	NA	NA	2.644	(1)
4-4H	7618.50	2380	32.83	5370	2.4	94.1	2.646	(1)
4-5H	7619.70	2380	26.90	374	NA	NA	2.726	(1)
4-6H	7620.50	2380	26.50	2300	2.0	95.2	2.659	(1)
4-7H	7621.70	2380	25.72	1960	NA	NA	2.681	(1)
4-8H	7622.50	2380	27.66	1040	1.9	88.7	2.668	(1)
4-9H	7623.50	2380	32.52	3260	NA	NA	2.646	(1)
4-10H	7624.50	2380	30.17	3360	2.6	85.6	2.643	(1)
4-11H	7625.50	2380	32.20	4370	NA	NA	2.643	(1)
4-12H	7626.70	2380	33.27	4390	2.1	90.2	2.642	(1)
4-13H	7627.50	2380	32.77	3170	NA	NA	2.646	(1)
4-14H	7628.50	2380	32.17	4550	1.9	86.2	2.639	(1)
4-15H	7629.50	2380	30.13	3550	NA	NA	2.644	(1)
4-16H	7630.70	2380	32.07	4380	1.2	94.5	2.635	(1)
4-17H	7631.50	2380	32.11	4010	NA	NA	2.640	(1)
4-18H	7632.50	2380	32.98	5000	2.0	89.2	2.655	(1)
4-19H	7633.50	2380	33.04	4630	NA	NA	2.642	(1)
4-20H	7634.50	2380	26.91	1220	3.0	94.4	2.651	(1)
4-21H	7635.50	2380	30.62	4240	NA	NA	2.644	(1)
4-22H	7636.50	2380	29.09	3490	3.9	89.3	2.660	(1)
4-23H	7637.50	2380	30.21	4400	NA	NA	2.646	(1)
4-26H	7640.70	2380	26.22	1170	3.0	92.4	2.671	(1)
4-27H	7641.50	2380	33.84	5360	NA	NA	2.641	(1)
4-28H	7642.50	2380	33.96	5730	1.5	89.0	2.651	(1)
4-29H	7643.50	2380	32.63	4820	NA	NA	2.642	(1)
4-30H	7644.50	2380	34.77	5660	1.6	90.2	2.664	(1)
4-31H	7645.50	2380	34.50	5040	NA	NA	2.657	(1)
4-32H	7646.50	2380	34.39	3870	1.8	95.2	2.653	(1)
4-33H	7648.50	2380	30.57	5590	NA	NA	2.663	(1)
4-37H	7654.50	2380	31.25	4110	NA	NA	2.648	(1)
4-38H	7655.50	2380	32.76	4900	1.4	95.5	2.651	(1)
4-39H	7656.50	2380	31.37	5520	NA	NA	2.644	(1)
4-40H	7657.70	2380	30.90	7750	2.1	94.6	2.655	(1)
4-41H	7658.50	2380	30.75	5760	NA	NA	2.645	(1)

Footnotes :

(1) : Encapsulated sample. Permeability measured using steady-state method.

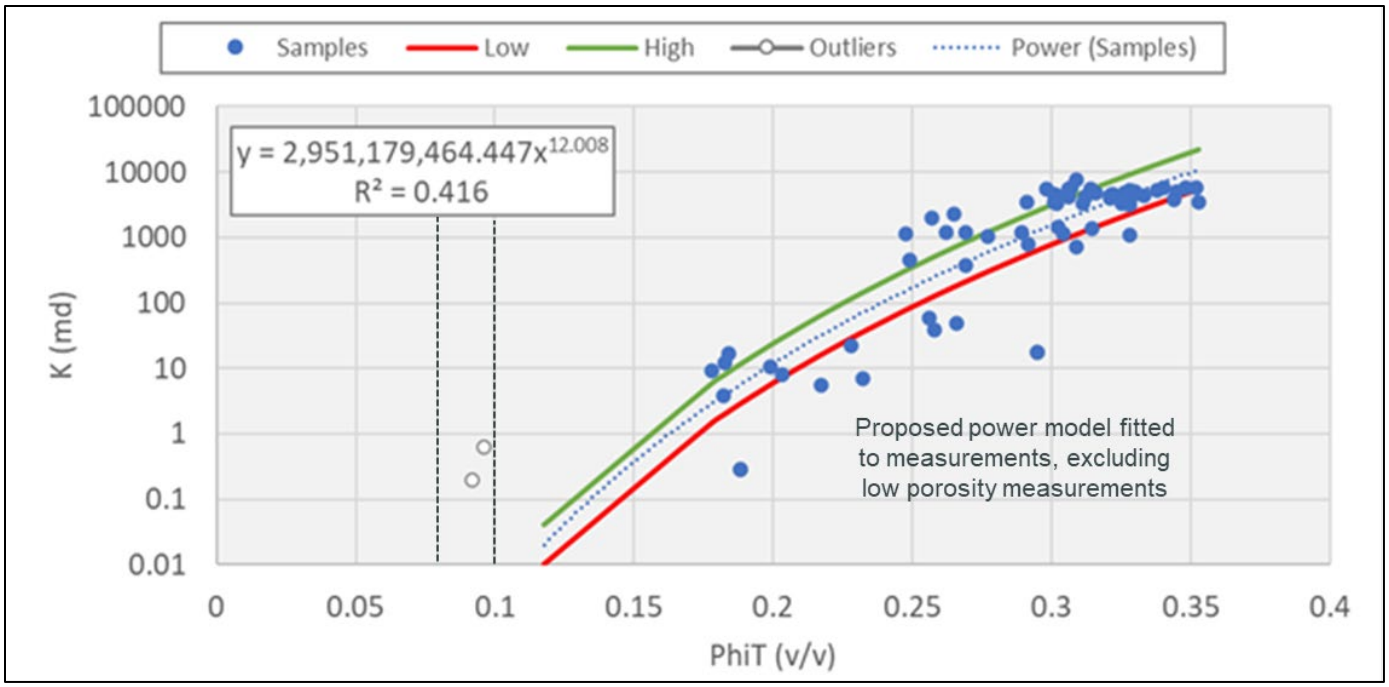

Figure 1-41 – Scatter Plot of Permeability and Effective Porosity in the LA Storage SWD No. 003 (SN 975774)

1.6.3 Lower Confining Zone

1.6.3.1 Porosity

Figure 1-42 is an openhole log section showing the top of Anahuac shale (lower confining zone) with an SP curve in Track 1 (lithology indicator), a permeability curve in Track 2, an effective porosity in Track 3, and crossplot porosity in Track 4. The 1-ft of core recovered in this section is represented by a red box in Track 1. The average effective porosity in the Anahuac shale section is 1.1%. Similar to the upper confining Amph B section, the Anahuac shale mineralogy analysis recorded a 44.1% concentration of smectite. The smectite concentration is found in Table 1-6. The average effective porosity in the upper 100 ft of Anahuac shale formation in SN 102295 well is 0.00%.

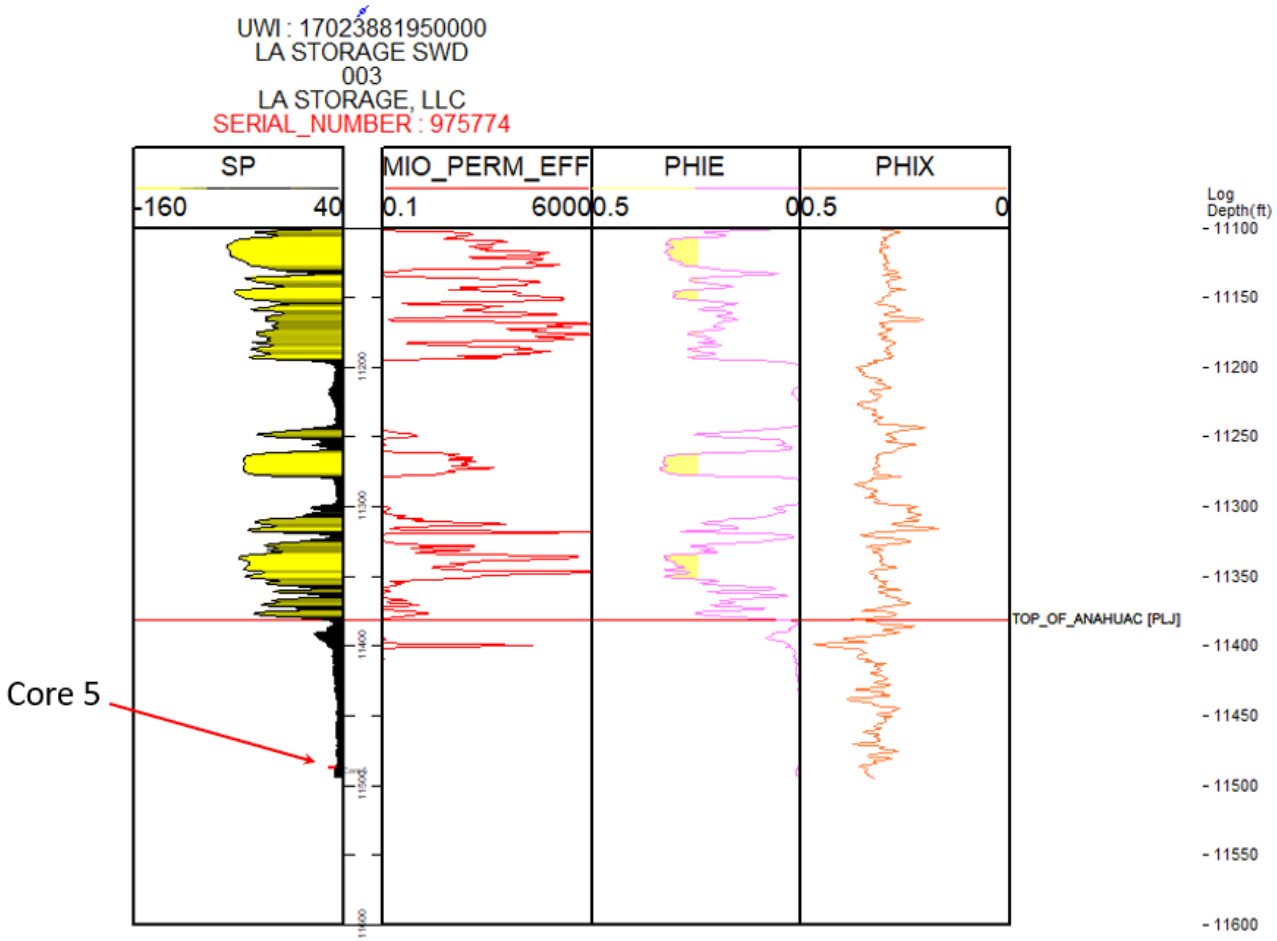

Figure 1-42 – Openhole Log Display of LA Storage SWD No. 003 (SN 975774) Lower Confining Zone

1.6.3.2 Permeability

Permeabilities within facies determined as “clay/non-reservoir”, as described in Section 2.2.8.2, were assumed to have no ability to transmit injectate. The openhole log of the SN 102295 well is displayed in Figure 1-43.

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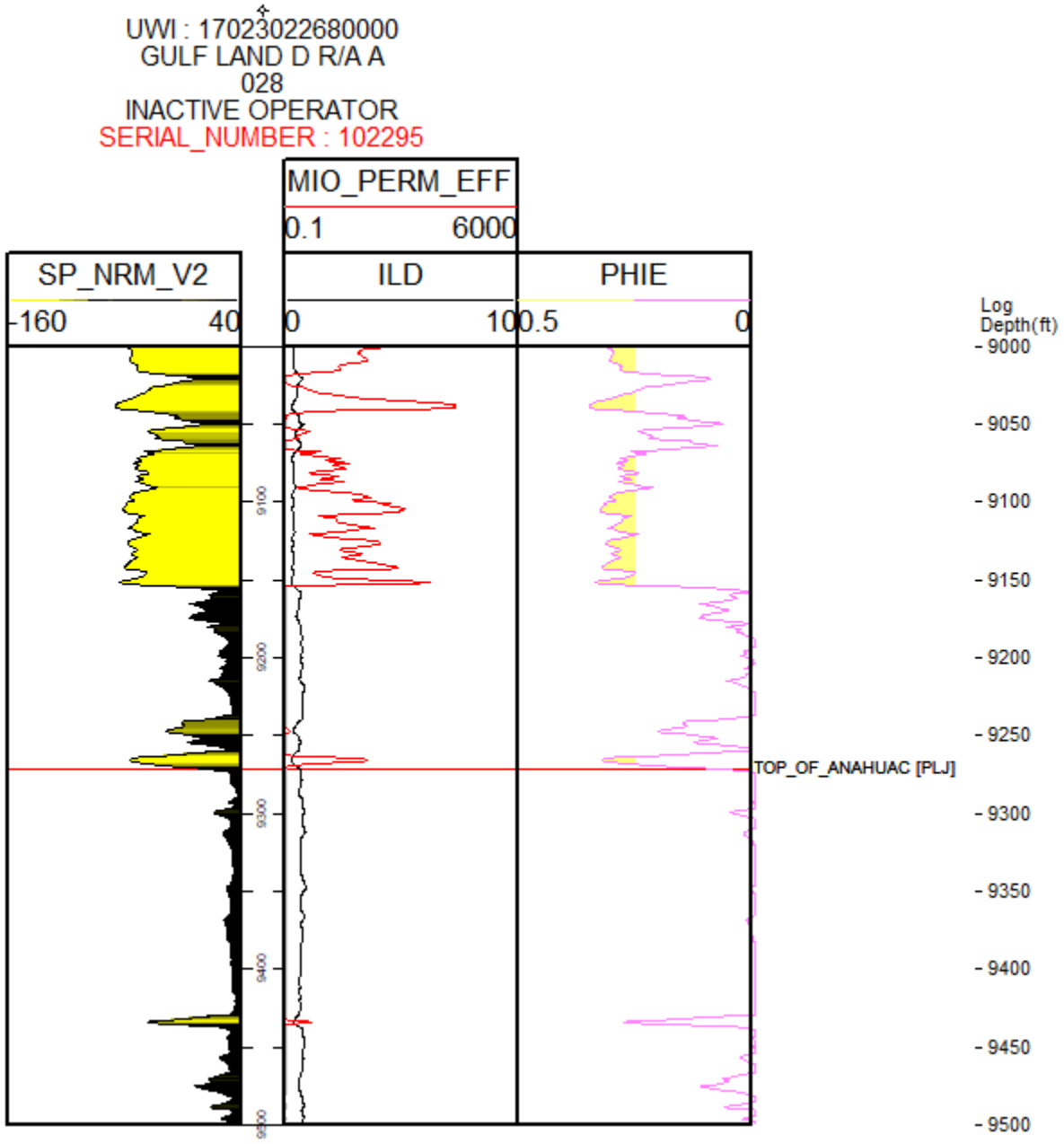

Figure 1-43 – Openhole Log Display of SN 102295 Lower Confining Zone

1.7 Geochemical Evaluation of the CO_2 Storage at Hackberry

1.7.1 Context, Objectives, and Result Summary

The planned injection temperatures and pressures of the CO_2-rich gas mixture are above the critical values resulting in a phase that is lighter than formation brine. The lower-density injected CO_2 will mix with the reservoir brine, rise buoyantly to the top of the aquifer formation and accumulate underneath the seal rock (Lindeberg and Wessel-Berg, 1997). The CO_2 brine will partially dissolve into the upper confining zone formation water and may diffuse upward into the seal rock, an extremely slow process in low-permeability seal rocks. Any CO_2 that may diffuse upward will likely react with minerals present in the seal rock (Hildenbrand et al., 2002). To simulate the potential slow diffusion, geochemical interactions at the interface between the surface of the seal rock minerals, seal rock fluid and injected CO_2-rich gas solution are modeled.

One of the technical elements to support a CO_2 storage project is the assessment of the chemical impacts of the stored CO_2 on the storage formation. This assessment is primarily based on a quantitative mineralogy evaluation performed on nine samples from well LA Storage SWD No. 003 (SN 975774). These samples come from Cores 1 to 4, acquired in the injection zones. No samples are deemed representative of the upper and lower confining zones. The main impact of the CO_2 is expected to be partial- to total-dissolution of illite and smectite, releasing Mg and Fe(II) ions in the brine and enabling mineralization of CO_2 as siderite and dolomite. This process leads to a decrease of porosity which enhances CO_2 sequestration. As the long-term dissolution of albite remains uncertain, a scenario is performed allowing albite dissolution which does not modify the main results.

The modeling scenarios presented in this section consider two cases: one where the albite is excluded from the modeling and a second where albite is included. The modeling included in this section is thermodynamic equilibrium based, meaning that calculations assess maximum conversion of minerals under the simulation conditions, but do not assess timing of reactions using kinetic parameters. Since reaction rates (kinetics) for albite are slow, model Case 1 without albite is expected to most accurately represent the net change in minerals under reservoir conditions. Case 2, model case with albite, is included to thoroughly explore geologic time-scale reactions.

1.7.2 Input Data

The mineralogical input comes from a full quantitative mineralogical composition performed on nine samples from the four cores of well LA Storage SWD No. 003 (SN 975774) in the Miocene succession.

Conditions at reference depth of 8,262 ft TDVSS include a reservoir pressure of 3,842 psi and temperature of 133°F. The salinity is 110,000 mg/l. The porosity is 30% and water saturation is estimated at 20%. This work shall be updated once core material and water samples are available from the HCS Well No. 001.

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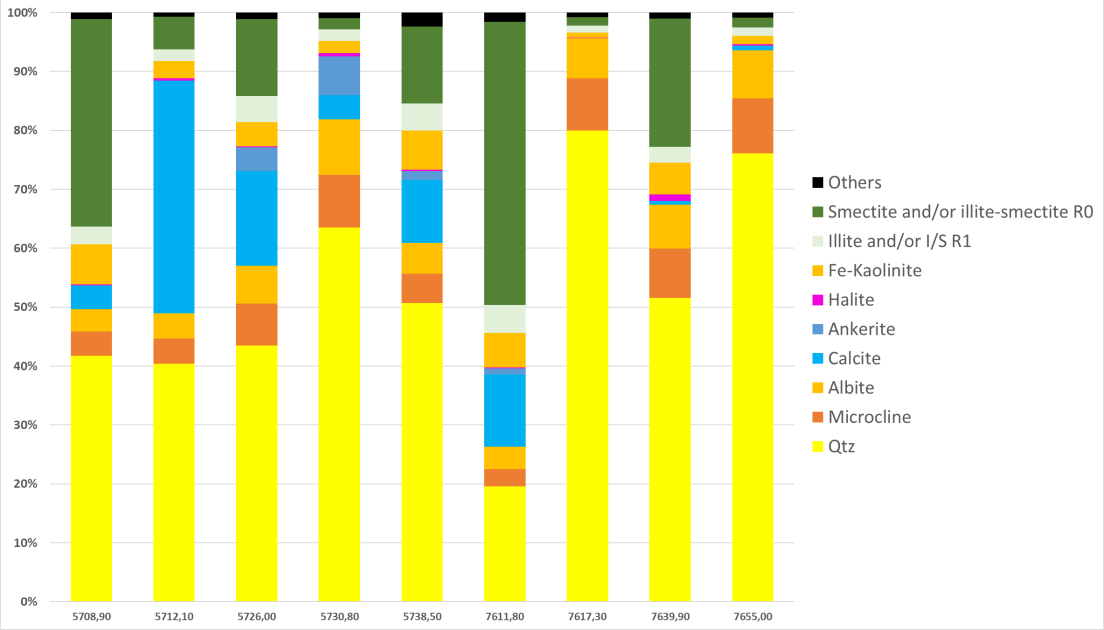

Figure 1-44 – Quantitative Mineralogical Composition of Nine Samples from Cores 1 to 4

1.7.3 Modeling Assumptions – Aquifer

The mineral database used is Thermoddem - Databases | Thermoddem (brgm.fr). PHREEQC™ software is used, version 3.6.2.15100. The salinity is based on primarily NaCl salts, corresponding to a molality of 1.88 molal.

The mineral assemblage is built based on the following assumptions:

- Halite precipitation is not modeled in the included scenarios because the brine is not salt-saturated.
- Ankerite mineralogy was quantified as Ca 1.0/Mg 0.4/Fe 0.6. As this mineral is not available in databases, 1 mole of Ankerite is modeled as 0.6 mole of dolomite, 0.4 mole of calcite and 0.6 mole of siderite.
- Iron-kaolonite is not available in the database and is modeled as kaolinite
- Smectite and magnesium illite are modeled as smectite (MX80) and illite (FeII) to ensure thermodynamical stability of the assemblage
- Albite is modeled as albite(low). As kinectic models expect very low reactivity of the albite (compared to CO_2 dissolution and mixing with aquifer formation water), the base case modeling scenario removes the albite from the list of reactive minerals and is inferred top be the representative set of rock-mineral-brine interactions during injection time and the following thousands of years. An alternative scenario assumes albite will indeed react with CO_2. This scenario represents likely reactons during deep, geologic time.

The following mineralogical assemblage is used in PHREEQC for the sandstone, consisting of the average mass fraction of the five samples with cay minerals below 20%.

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Table 1-15 – Mineralogical assemblage used in Phreeqc for the sandstone (average mass fraction of five samples with clay minerals below 20%).

Mineral in PHREEQC Assemblage	Mineral Mass Fraction in Sandstone	Molality for 30% Porosity and 100% Water Saturation	Molality for 30% Porosity and 20% Water Saturation
Albite (low)	6.7%	1.61	8.1
Dolomite	(from Ankerite)	0.28	1.4
Calcite	11.8%	7.84	39.2
Siderite	(from Ankerite)	0.41	2.1
Illite (Fell)	2.6%	0.41	2.0
Kaolinite	3.0%	0.73	3.6
Microcline	7.3%	1.64	8.2
Quartz	59.0%	61.7	308.5
Smectite (MX80)	6.1%	1.02	5.1

1.7.4 Modeling Steps – Aquifer

The interaction between the gas injectate and reservoir rock/brine is modeled through PHREEQC batch reaction. The reservoir brine sample is assumed to be in equilibrium with the reservoir rock. Feed stream gas molecules with an anticipated mole percentage greater than 1.0% (CO_2, H_20 and CH_4) are included in the model at formation mid-perf temperature and pressure (215 °F, 3,750 psi). The model assumes a 1 cubic meter rock and brine sample injected with 100 liters of gas. The results of the reservoir brine and injected gas model are in Table 1-18. The pH scale is logarithmic and inversely indicates the concentration of hydrogen ions in solution. The decrease in pH of the reservoir brine and gas model is due to the mixture of CO_2 with water of the brine, which dissociates the water and increases the concentration of hydrogen ions. The mass increase of 0.5 kg is owed to the weight of the gas injected into the closed system. The modeled reservoir brine and gas solution is referred to as "gas solution" in this narrative.

Three consecutive steps are followed:

- Equilibrate the mineralogical assemblage (at 100% water saturation) with the NaCl brine at the aquifer temperature and pressure to evaluate the chemically equilibrated brine.
- Perform a second equilibration with the previously equilibrated brine and the mineralogical assemblage, the base case including albite and an alternative scenario including albite.
- Model the CO_2 storage:
    - Start with the chemically equilibrated brine
    - Use the mineral molalities corresponding to a water saturation of 20%

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- Assume no change of pressure and temperature (assuming temperature and pressure perturbation are rather short term and largely localized around injection well)
- Use a pressure of pure CO_2 of 3,842 psi, corresponding to a total (free phase and dissolved) CO_2 of 67 molal.

All modeling assumes thermodynamic equilibrium, i.e., neglecting any kinetic consideration.

1.7.5 Results in Aquifer – Base Case Without Albite

The following mineralogical changes are a consequence of CO_2 injection.

Table 1-16 – Mineralogical modifications and impact on porosity, base case. Smectite partly dissolves, releasing both Mg and Fe ions. Mg ions recombine with Ca ions resulting from calcite dissolution and bicarbonates to form dolomite.

Mineral	Initial Molality	Final Molality	Delta Molality	Delta Mineral Volume cm^3/khH_20	Delta Porosity
Calcite	39.20	38.45	-0.75	-27.8	0.17%
Dolomite	1.40	2.19	0.79	50.8	-0.31%
Illite (Fell)	2.10	0.00	-2.10	-295.4	1.77%
Kaolinite	3.60	8.61	5.01	498.1	-2.99%
Microcline	8.20	9.96	1.76	190.9	-1.15%
Quartz (alpha)	308.30	313.90	5.61	127.2	-0.76%
Siderite	2.10	2.75	0.65	19.2	-0.12%
Smectite (MX80)	5.10	1.42	-3.68	-496.8	2.98%
Sum				66.3	-0.4%

Illite is fully dissolved, releasing Fe ions to the brine that recombine with bicarbonates to form siderite. Albite and siderite, resulting from the dissolution of these minerals, re-equilibrate through the precipitation of kaolinite, microcline and quartz. As illustrated in Table 1-16, the incorporation of the bicarbonates into carbonate minerals lead to an increase of the mineral volume and, therefore, a reduction of the pore volume.

The CO_2 balance consists of:

- 67 molal available CO_2 prior to any dissolution / mineralisation
- 2.55 molal are dissolved as $(CO_2)g$ and 2.51 as other ions (bicarbonates and other ions)
- 0.65 molal is mineralized as siderite
- 0.83 molal is mineralized as the net result of calcite dissolution and dolomite precipitation

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Over hundreds of years, CO_2 will fully dissolve in the brine through convective mixing, further enhancing this dissolution and mineralization processes.

The interaction of gas solution, seal rock and seal brine is modeled through PHREEQC batch reaction. This case builds from the previous model to simulate a 1:1 mixture of gas solution and modeled in situ brine. The model assumes a 1 cubic meter rock and brine sample flushed with 50% gas solution. A comparison of the modeled in situ seal brine (the initial rock-brine condition) and results of the simulated seal rock, seal brine and gas solution mixture are in Table 1-19. Compared to the gas solution, the pH of the seal rock/brine and gas solution mixture has increased, due to the mixture of higher pH seal and a buffering of the solution by the seal rock.

The masses of both the seal brine and the gas solution are greater than the resulting seal rock/brine and gas solution mixture, the 6% reduction in expected mass indicates precipitation of minerals from the brine. Modeled saturation indices indicate kaolinite-serpentine and carbonate mineral groups to be the primary precipitants, including chrysotile, dolomite, huntite, strontianite, witherite, and hydromagnesite. Other minor precipitants include copper oxide and copper iron oxide minerals. The modeled net precipitation of minerals suggests pore occluding processes will occur as the CO_2-rich brine diffuses into the upper seal rock, further lowering permeability and obstructing potential CO_2 pathways.

1.7.6 Results in Aquifer – Alternative Scenario with Albite

Table 1-17 shows the mineralogical changes caused by CO_2 injection.

Table 1-17 – Mineralogical Modifications and Impact on Porosity

Mineral	Initial Molality	Final Molality	Delta Molality	Delta Mineral Volume cm^3/khH_20	Delta Porosity
Albite (low)	8.10	1.67	-6.44	-644.0	3.86%
Calcite	39.20	39.19	-0.01	-0.3	0.00%
Dolomite	1.40	1.41	0.01	0.5	0.00%
Illite (Fell)	2.10	0.00	-2.10	-295.4	1.77%
Kaolinite	3.60	8.43	4.83	479.8	-2.88%
Microcline	8.20	9.98	1.78	193.1	-1.16%
Quartz (alpha)	308.30	319.90	11.59	263.0	-1.58%
Siderite	2.10	2.63	0.53	15.5	-0.09%
Smectite (MX80)	5.10	5.06	-0.04	-4.8	0.03%
Sum				7.42	-0.04%

Other alterations include:

- Partial dissolution of smectite, releasing both Mg and Fe ions. Mg ions recombine with Calcite ions resulting from calcite dissolution and bicarbonates to form dolomite.

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- Full dissolution of illite, releasing Fe ions to the brine that recombine with bicarbonates to form siderite.
- Re-equilibration of Al and Si resulting from the dissolution of these minerals through the precipitation of kaolinite, microcline and quartz.
- As shown in Table 1-16, the incorporation of the bicarbonates into carbonate minerals leads to an increase of the mineral volume and as a consequence a reduction of the pore volume.

Dissolution of albite would result in forming $NaH(CO_3)$ ions, enhancing further CO_2 dissolution and reducing bicarbonate availability for mineralization into dolomite and siderite carbonates.

The CO_2 balance consists of:

- 67 molal available CO_2 prior to any dissolution / mineralisation
- 2.0 molal are dissolved as $(CO_2)g$ and 8.0 as other ions (primarily $NaH(CO_3)$ ions)
- 0.53 molal is mineralized as siderite
- Lower quantities result from the dissolution of calcite and precipitation of dolomite.

1.7.6.1 Geochemical impact of CO_2 on shales

With the available samples from LA STORAGE SWD No. 003, the same reactive pathway is expected to occur in shales bounding the storage (i.e., dissolution of smectite and illite, CO_2 mineralisation into dolomite and siderite), leading to a net reduction of shale porosity.

1.7.6.2 Summary of Rock-Brine-CO_2 Interactions

In aggregate, the modeling results indicate that reaction of CO_2 with brine and the minerals in the study area support long term storage of CO_2. Dissolution, precipitation and alteration of the mineral matrix will lead to a net reduction in permeability and increase seal capacity at the seal-reservoir interface.

1.8 Hydrology

Beneath the Prairie Formation is a sequence of Pleistocene deposits that collectively form what is known as the Chicot aquifer. Based on the depths of similar deposits in the Lake Charles area, the aquifer is comprised of three sand units referred to as the "200-Foot Sand", "500-Foot Sand" and "700-Foot Sand." However, these sand units occur at varying depths across southwest Louisiana influenced by subsurface structures, such as the West Hackberry Salt Dome. The nomenclature of "200-Foot Sand," etc. refers to the analogous sand body and not the actual depth and is used herein for consistency. The "200-Foot Sand" and "500-Foot Sand" are primary sources of fresh groundwater in southwest Louisiana, including Hackberry, Louisiana. The "700-Foot Sand" is utilized as a source of fresh groundwater in areas generally to the north of the Hackberry, Louisiana area. The sand and gravel deposits that comprise the Chicot aquifer thicken along their southern dip and are coarser at their base. In the proposed HCS project area, the three sand units are separated by confining clays. The confining clays were deposited in lagoonal and flood plain environments and vary in thickness and extent. For a general depiction of

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subsurface groundwater flow direction within the Chicot aquifer, please refer to Appendix C-8. As illustrated in the attached appendix, groundwater flow trends south to north at the proposed HCS project area.

1.8.1.1 "200-Foot Sand"

The "200-Foot Sand" generally consists of fine to medium sand with coarse-grained sand and occasionally gravel at its base in areas where the zone is thickest. This layer dips generally southward at a gradient of approximately 10 vertical feet per mile. The 200-Foot Sand occurs 200 to 300 feet below the surface across the proposed HCS project area and is approximately 160 feet thick. The 200-foot Sand is depicted in the attached north-south and west-east cross sections (Appendix C-2, C-3). Regionally, the 200-Foot Sand supplies water for irrigation, industrial, public supply, and domestic purposes. Locally, the 200-Foot Sand provides water to some domestic wells, although many of the rural users in the area obtain groundwater from the Cameron Parish Water Works Districts 2 or 11. Water samples from the 200-Foot Sand indicate a total dissolved solid (TDS) content greater than 1,000 mg/l. For a more detailed report, please reference the water report in Appendix C-7, submitted by Liberty Gas to the LADNR for an offset project near the proposed HCS No. 001.

1.8.1.2 "500-Foot Sand"

The "500-Foot Sand" is a heavily used aquifer in the region, particularly to the north toward Lake Charles, supplying the bulk of the groundwater used for irrigation, public supply, and some industrial needs. The 500-Foot Sand is utilized as a municipal drinking water source for the town of Hackberry, Louisiana. In the vicinity of the proposed HCS Well No. 001, water in the 500-Foot Sand is moderately hard with TDS in the range of 1,000 to 1,500 mg/l. In the Hackberry, LA area and to the east, the water in the 500-Foot Sand has lower TDS, ranging from 600 to 850 mg/l. The 500-Foot Sand is composed of fine to coarse grain sand fining upward and grades to deltaic deposits (Whiting, 1980).

The 500-Foot Sand at the proposed HCS Well No. 001 site occurs at a depth of approximately 570 ft to 800 ft below surface and is hydraulically separated from the 200-Foot Sand by approximately 200 ft of predominately clay material. This material serves as a barrier to groundwater flow migration between the two sand bodies. The 500-Foot Sand is shown in the attached north-south and west-east cross sections (Appendix C-2, C-3). For a more detailed report, please reference the water report in Appendix C-7, submitted by Liberty Gas for an offset project near the proposed HCS Well No. 001.

1.8.1.3 "700-Foot Sand"

The "700-Foot Sand" is the deepest of the groundwater bearing sands in the Chicot aquifer. At the proposed HCS Well No. 001 location, the 700-Foot Sand occurs in the depth interval from approximately 945 to 1,025 feet below surface and is separated from the 500-Foot Sand by approximately 145 feet of clay that serves as a barrier to groundwater flow between these two sand bodies. Calculated from offset well logs, TDS content of the 700-Foot Sand beneath the proposed HCS Well No. 001 ranges from 10,000 to 15,000 mg/l, rendering it unsuitable for municipal supply or irrigation. No known wells utilizing the 700-Foot Sand were identified near

the proposed HCS Well No. 001. The 700-Foot Sand is depicted in the attached north-south and west-east cross sections (Appendix C-2, C-3). For a more detailed report, please reference the water report in Appendix C-7, submitted by Liberty Gas for an offset project near the proposed HCS Well No. 001. Based on the cross sections in Appendix C-2 and C-3, the lower most USDW is estimated to be 1,090 ft below ground surface at the proposed HCS Well No. 001 location. Appendix C-5 and C-6 depict cross sections indicating the stratigraphic separation between the base of the USDW and the top of proposed injection interval. An estimated 3,758 ft of vertical separation exists between the top of injection interval and base of USDW, with 1,030 net ft of impermeable, interbedded shale intervals that will prevent migration of the injectate to the protected water table.

1.9 Site Evaluation of Mineral Resources

Other subsurface geochemical considerations include the potential for mineral or hydrocarbon resources beneath the proposed CO_2 storage site. In closest proximity to the HCS Well No. 001 are the West Hackberry Salt Dome and Oil Field. West Hackberry Dome was discovered in 1902 followed by the discovery of the bordering Oil Field in 1928.

West Hackberry Dome is currently used for emergency crude oil storage by the U.S. Strategic Petroleum Reserve. West Hackberry Dome currently has 21 storage caverns, an authorized storage capacity of 220.4 million barrels and a cavern inventory of 192.3 million barrels.

West Hackberry Oil Field is primarily productive out of the Pliocene, Fleming and Anahuac formations. More than 800 wells have been drilled though only 18 of those wells are still active today. To date, the field has produced about 152 MMbbls of oil and 19 Bcf of gas. In February 2021, the field produced 5.3 Mbbls of oil and 1.9 MMcf of gas.

As shown in Figure 1-45 below, the HCS Well No. 001 is about 1.7 miles from the northwestern extent of West Hackberry Oil Field and even further from active cavern crude oil storage operations. The HCS Well No. 001 plume extent is about 1.1 miles from the northwestern extent of the West Hackberry Oil Field at its closest point and generally drifts away from the oil field. Currently, there are no active Miocene producers within 5 miles of HCS Well No. 001. The closest active oil and gas wells are producing from the Oligocene; therefore, no offset production will affect the migration of the CO_2 plume.

Other oil and gas fields in the region include the Gun Grove Oil and Gas Field (about 5 miles west of HCS Well No. 001), the Bayou Choupique Oil and Gas Field (about 5.1 miles northeast of HCS Well No. 001), and the South Black Bayou Oil Field (about 6.5 miles southwest of HCS Well No. 001).

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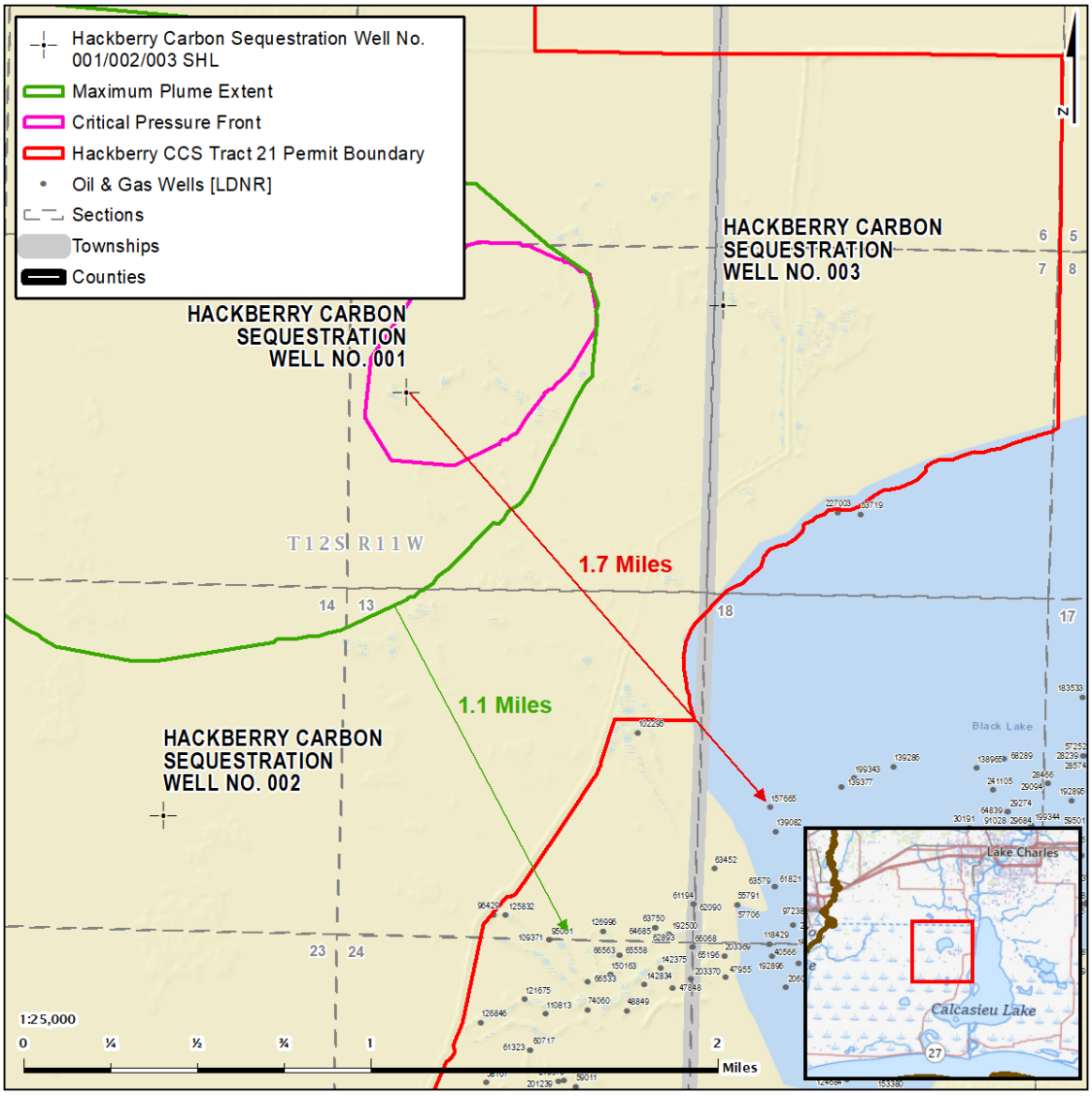

Figure 1-45 – Closest Offset Production Map

1.10 Seismic History

An important consideration in the design and development of all new injection well projects is the determination for the potential of injection activities to induce a seismic event. This effort is comprised of a three-step approach. These three steps include:

1. Identification of historical seismic events within proximity to the project
2. Determination of operational influences on nearby faults
3. Performance of a fault-slip potential (FSP) simulation model

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Identification of Historical Seismic Events

For the first step, an investigation for seismic review surrounding the project location is conducted. The area of investigation for this review is defined as a 9.08-kilometer radius or an 100-square mile area surrounding the project. If any recorded events are discovered, an FSP model may be run.

According to the USGS database, no seismic events were recorded within the 9.08-kilometer radius of HCS Well No. 001. The search included all seismic events greater than 2.0 magnitude, as shown in Figures 1-46 and 1-47.

Influencing of Nearby Faults

EPA regulations require that a complete understanding of the extent and location of the resultant injection plume be determined and identified. Should the final plume extent encounter a nearby fault, an FSP model would be run. The results discussed in Section 2.3.6 of this application indicate that no faults are encountered during the injection operations for HCS Well No. 001.

Fault-Slip Potential Model

As no faults are encountered within the anticipated plume extent and no records of historical seismic activity within the area of review were found, no seismic risk has been associated with this project. Hence, no FSP model was performed.

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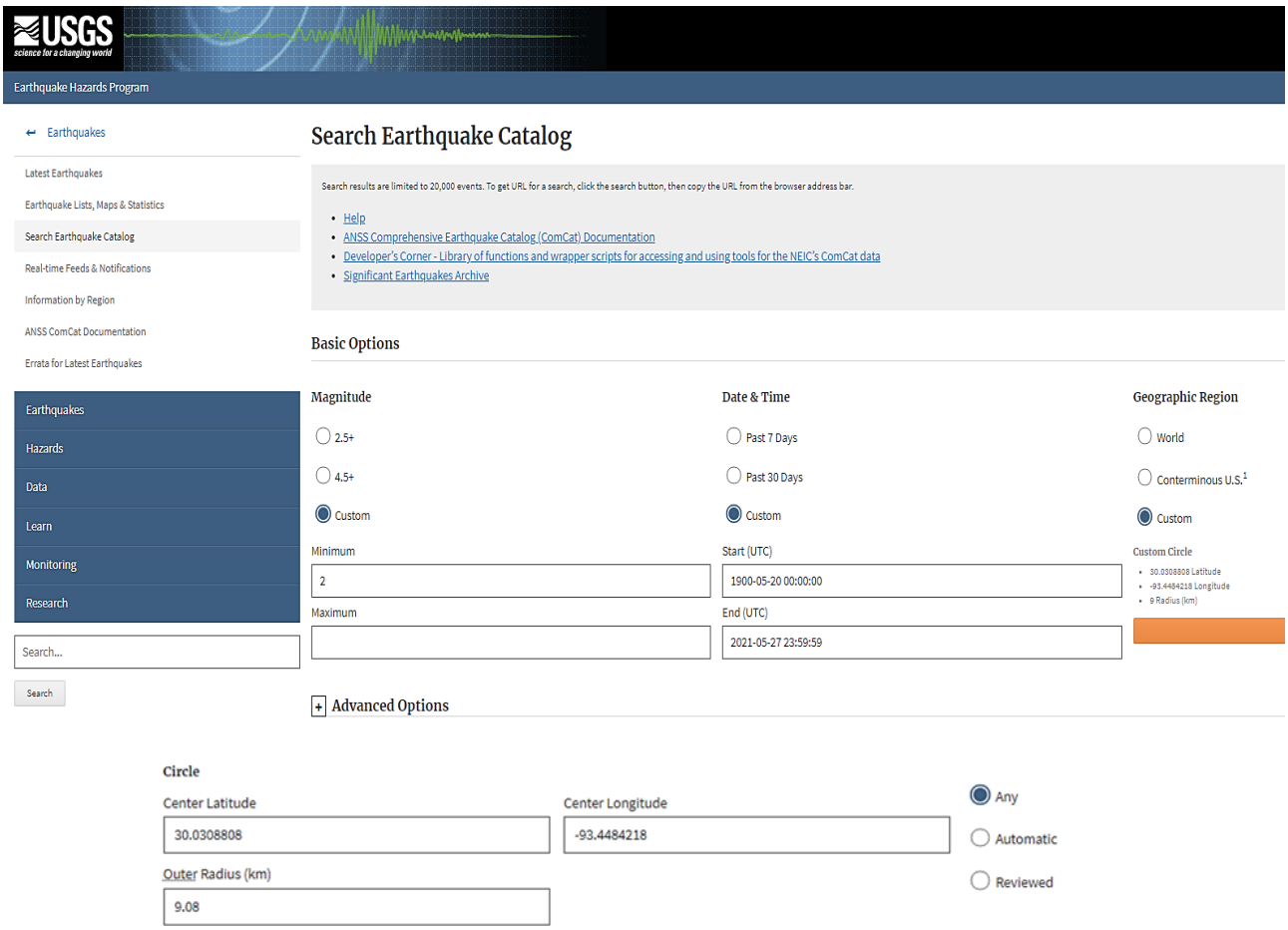

Figure 1-46 – Earthquake Search Parameters from USGS Website

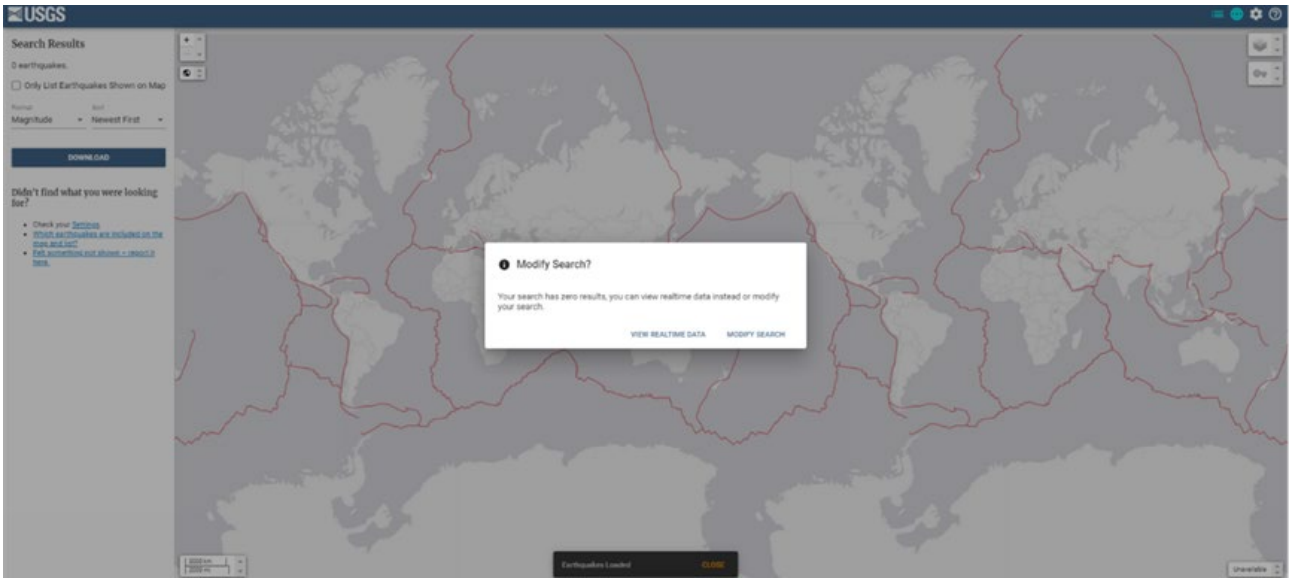

Figure 1-47 – Earthquake Search Results from USGS Website

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1.11 Conclusion

Geological site characterization of the proposed HCS Well No. 001 location indicates the lower Miocene sandstone has sufficient porosity, permeability and lateral continuity and is of sufficient depth and thickness to store the proposed 2 MMT/yr of CO_2. The Amphistegina B shale at the site has low permeability, plus sufficient thickness and lateral continuity to serve as the primary upper confining zone. At the site, the Anahuac shale has low permeability, plus sufficient thickness and lateral continuity to serve as the primary lower confining zone. No potential CO_2 migration pathways from the lower Miocene injection zones are identified at the proposed storage site. No wellbores are present within the AOR. No faults or fractures are identified based on seismic analysis or geophysical well log characterization. Minimum wellbore geometric anisotropy in openhole geophysical logs and a lack of induced fractures in the LA Storage SWD No. 003 (SN 975774) well during a brine injection step rate test combined with study of published regional stress data indicates the well is not situated near normal faults that may be close to failure.

Higher resolution maps of the site area are included in Appendix B and contain the following:

- Appendix B-1 Top of Upper Confining Zone Structure Map
- Appendix B-2 Upper Confining Zone Isopach Map
- Appendix B-3 Top of Injection Zone Structure Map
- Appendix B-4 Injection Zone Isopach map
- Appendix B-5 Top of Lower Confining Zone Structure Map
- Appendix B-6 Lower Confining Zone Isopach Map
- Appendix B-7 Cross Section Reference Map
- Appendix B-8 North-South Structural Cross Section
- Appendix B-9 West-East Structural Cross Section
- Appendix B-10 North-South Stratigraphic Cross Section
- Appendix B-11 West-East Stratigraphic Cross Section
- Appendix B-12 Formation Top Control Wells Spreadsheet
- Appendix B-13 Fluid Pump-out Analysis
- Appendix B-14 Water Analyses, LA Storage SWD No. 003
- Appendix B-15 Injectivity Test Results, LA Storage SWD No. 003
- Appendix B-16 Step-rate Test Results, LA Storage SWD No. 003
- Appendix B-17 Core Photos, LA Storage SWD No. 003

The following maps and paper related to the hydrology are found in Appendix C and contain the following:

- Appendix C-1 Base USDW Map
- Appendix C-2 North-South USDW Cross Section
- Appendix C-3 West-East USDW Cross Section

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- Appendix C-4 USDW to Injection Cross Section Reference Map
- Appendix C-5 North-South USDW to Injection Interval Cross Section
- Appendix C-6 West-East USDW to Injection Interval Cross Section
- Appendix C-7 Chicot Aquifer Report
- Appendix C-8 Groundwater Potentiometric Map

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Underground Injection Control – Class VI Permit Application for Hackberry Carbon Sequestration Well No. 001

Cameron Parish, Louisiana

SECTION 2 – PLUME MODEL

Prepared for *Hackberry Carbon Sequestration, LLC*
Cameron, LA

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August 2021
Revised January 2025

SECTION 2 – PLUME MODEL

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2.1 Introduction

This plume model discussion for Hackberry Carbon Sequestration (HCS) Well No. 001 was prepared to meet the requirements of SWO 29-N-6, **§615.31** [40 CFR **§146.84**]. This section describes the process of building the plume model from static modeling through dynamic simulations. The plume model simulates the plume growth over time and assesses the area of review (AOR) for the well. The plume model, calibrated with dynamic data, helps to visualize and anticipate the plume extent.

A 3D seismic survey acquired and processed in 2022, along with core data obtained from LA Storage SWD No. 003 (SN 975774) and available well data around the Hackberry Carbon Sequestration (HCS) site were used to generate a geocellular model built with Petrel™ software, the basis of a reservoir model used in the INTERSECT™ reservoir simulation framework. INTERSECT™ has developed technically sound reservoir simulation software packages for conventional, unconventional, and secondary recovery. As with other simulation packages, it utilizes equation-of-state (EOS) algorithms along with some of the most advanced computational methods to evaluate compositional, chemical, and geochemical processes and characteristics to produce highly reliable simulation models for carbon sequestration.

INTERSECT™ utilizes the compositional methods described above along with equations specific to CO_2 to effectively model and simulate plume behavior within the injection intervals.

2.2 Geocellular Modeling

2.2.1 Data Sources

The geological evaluation and modeling used 3D seismic data and available well data from 77 regional wells. Sixteen wells had logs available and were selected for quantitative analysis (Figure 2-1) and constituted the main input for the static modeling.

Core analysis was available from the stratigraphic test well, LA Storage SWD No. 003 (SN 975774). In this analysis, the cores were described and sampled for additional conventional core analysis (CCA), lithological compositional analysis (X-ray diffraction analysis [XRD]) and special core analysis (SCAL). Subsurface fluid samples were also obtained in this well and used for calibration of the log evaluation. Public databases and literature were reviewed and incorporated in the interpretation of data, in well correlation and for analogues in support of the geocellular modeling.

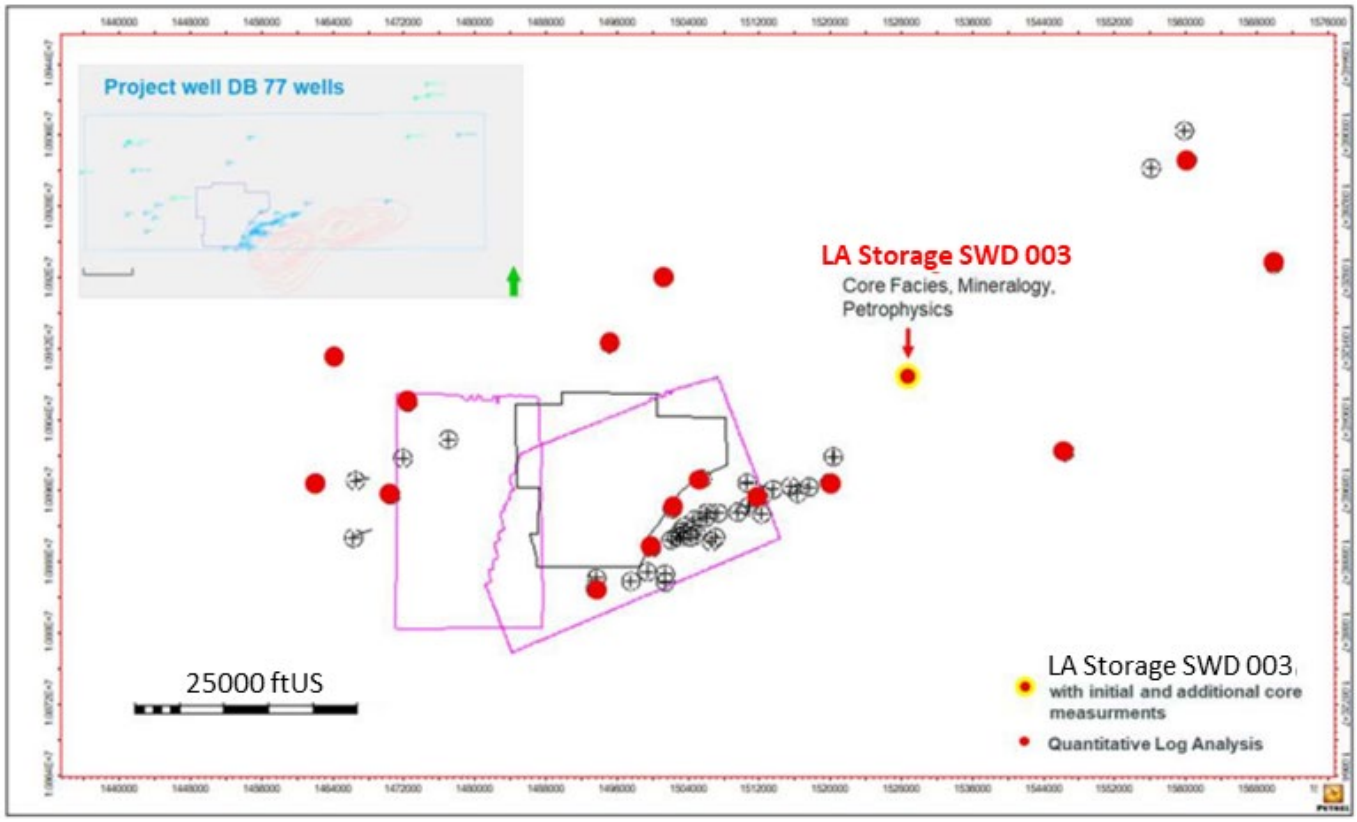
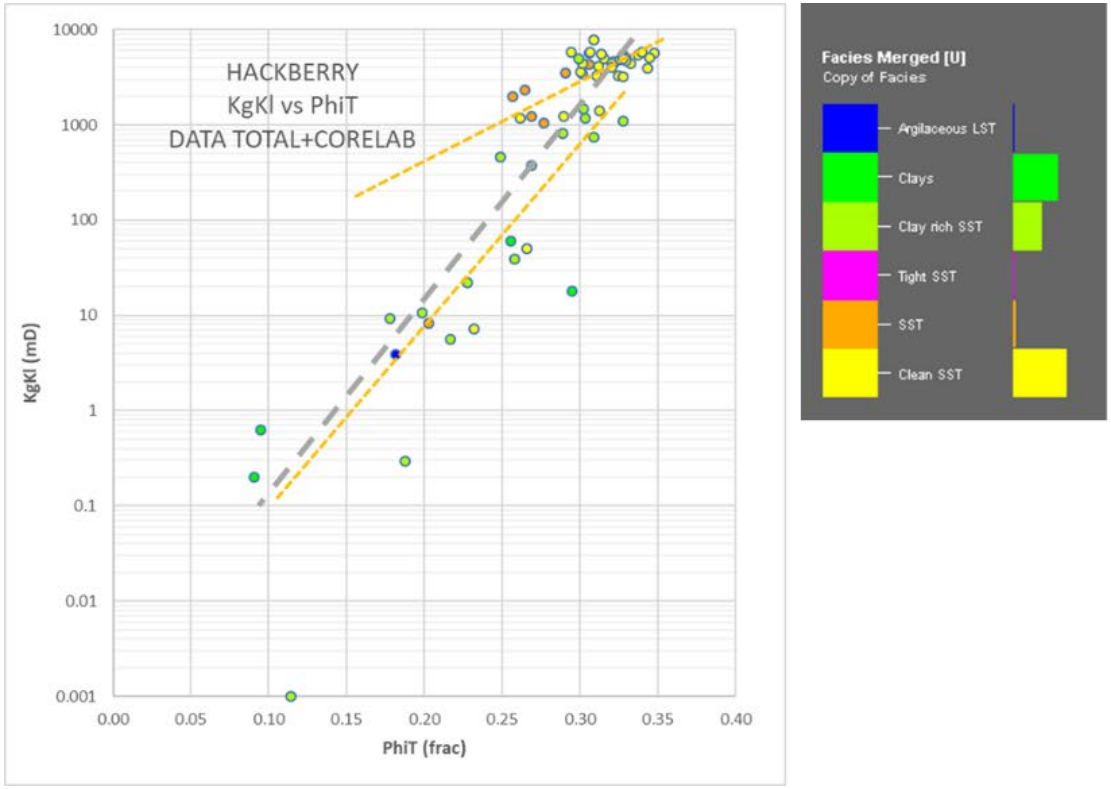


Figure 2-1 – Well map of 77 wells used in geocellular model. Quantitative analysis was performed for 16 wells (red). Pink outlines show the 3D seismic coverage of the Hackberry CCS acreage (black outline).

2.2.2 Petrophysical Measurements

As a part of the evaluation of LA Storage SWD No. 003 (SN 975774), existing petrophysical measurements were available for the modeling exercise. In addition to the CCA available from Corelab, TotalEnergies's internal laboratory carried out complementary studies of minerology, granulometry and CCA to support the log analysis and geological modeling.

The unconsolidated nature of the formation and previous sampling made plugging the core challenging. Nevertheless, seven suitable plugs were cut for CCA, which, with existing data, establishes the relationship between total porosity (PhiT) and Klinkenberg permeability as shown in Figure 2-2. The challenge to obtain measurements in the degraded facies and argillaceous sands can be observed from the sparse data in those facies. There is a poorly established dependency for specific facies (or rock type (RT)) to Phi/K.



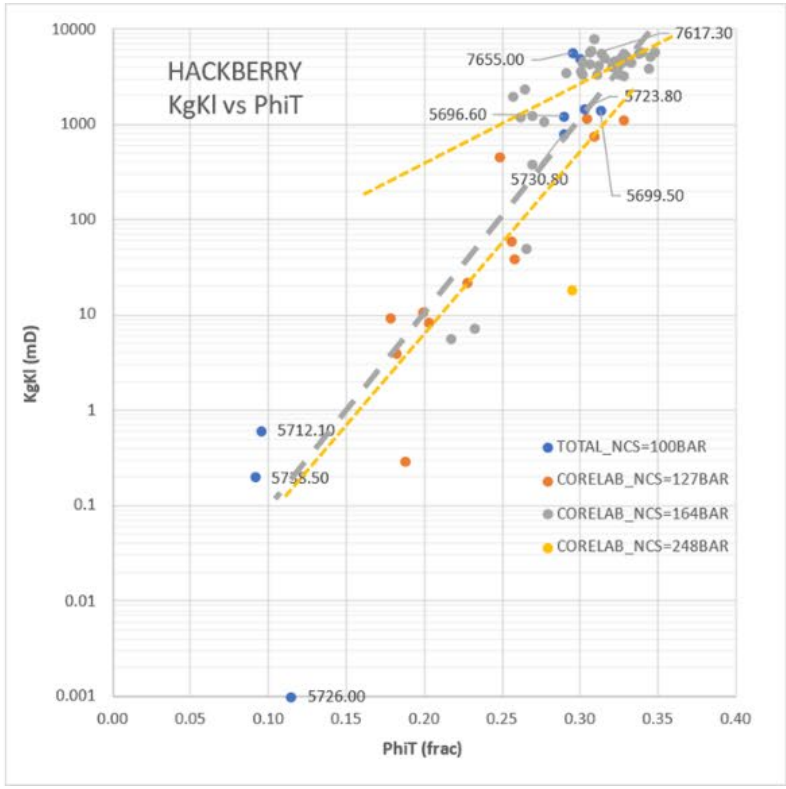


Figure 2-2 – PhiT versus KgKl of all available measurements by facies (left) and laboratory (right).

2.2.3 Quantitative Log Evaluation

In support of the modeling and simulation study, quantitative log analysis was conducted on 16 wells in the project vicinity. The aim of the study was to provide composite logs, to carry out quantitative interpretation with the Petrolan™ software by incorporating all available data (logs, cores, plugs, samples), carry out pre-processing and normalization of logs and to provide electrofacies, calibrated on core facies. Petrolan is an integrated log interpretation module in Geolog6 software program, a Paradigm® Formation Evaluation product.

For the 16 wells utilized, all wells have spontaneous potential (SP) and deep resistivity (RES) logs, two do not have Gamma Ray (GR), most have Neutron logs but with overlying reduced intervals. Six wells have Neutron/Density logs and five have sonic (DT) logs. All the calibration laboratory data (water samples, m parameter, plugs PhiK and XRD) come from LA Storage SWD No. 003 (SN 975774), as it provided the most comprehensive suite of logs. A summary of available data is seen in Table 2-1. To build appropriate interpretations on these wells, different trends such as RHOB_CL, VCL/PHIE relation or PHIE_CLEAN were defined from the wells considered as most reliable (the six wells with neutron/density logs) to populate the different parameters.

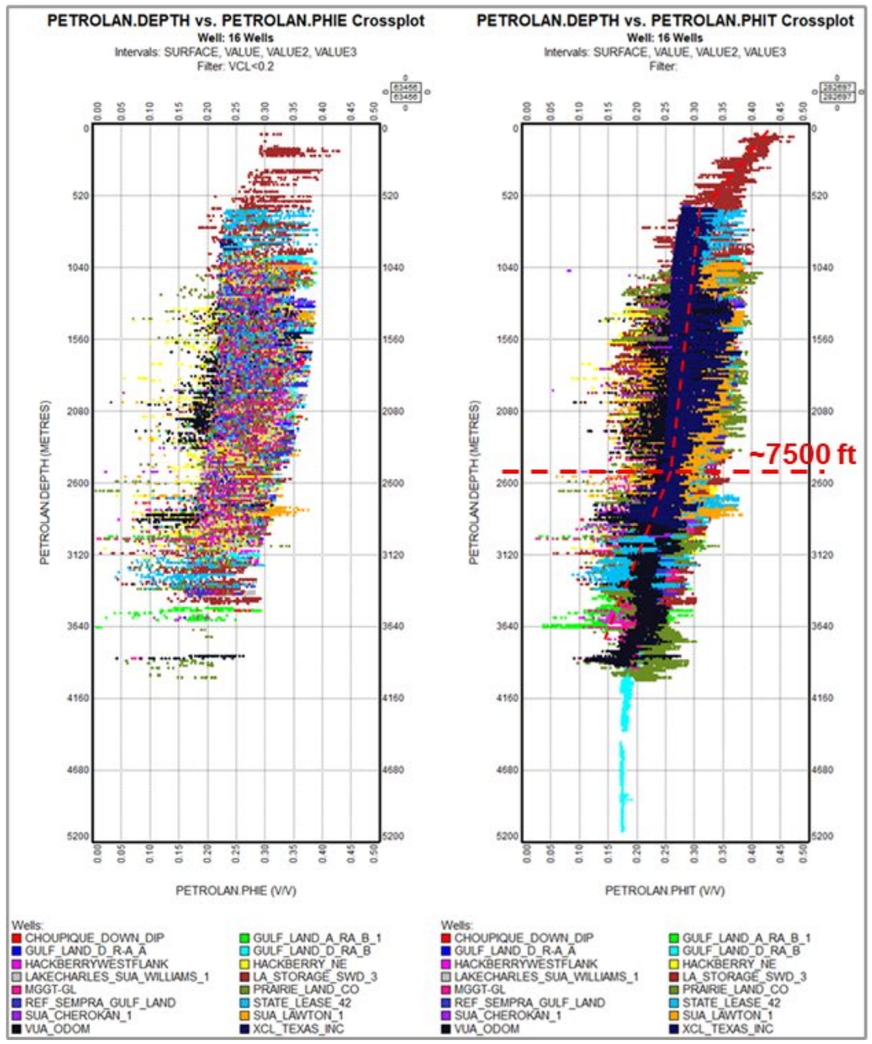
The data from all wells were consistent with no outliers and no strong regional variations (Figure 2-3). The analysis demonstrated a strong porosity trend of decreasing porosity with depth and no major lateral porosity variations among the 16 wells. The mean effective porosity (PhiE) is 26% and mean total porosity (PhiT) is 26%.

Table 2-1 – Logs and Data Available for the Quantitative Log Evaluation

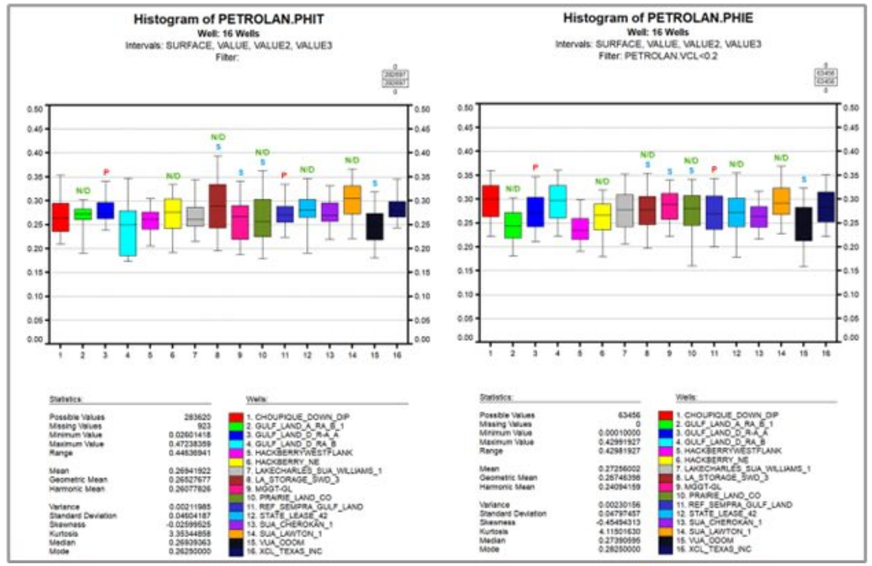
API Well Name	SN	GR	CaLiper	Density	Neutron	Resistivity	SP	Sonic	Porosity	SWE	Vcl
17023881950000_LA-STORAGE-SWD-3	975849										
17019210450000_PRAIRIE-LAND-1	179035										
17019215790000_MGGT-GL-2	208778										
17019220310000_BROUSSARD-1-24	230410										
17019223130000_WILLIAMS-HBY-RG-SUA-1	246607										
17023001830000_STATE-LAND-97	53719										
17023022680000_GULF-LAND-D-R-A-A-28	102295										
17023201190100_GULF-LAND-A-R-A-B-149ST1	121711										
17023202690000_GULF-LAND-D-R-A-A-34	126846										
17023221590000_SL-42-192	198858										
17023225770000_XCL-TEXAS-INC-1	214967										
17023227530000_GULF-LAND-D-R-A-B-1	222408										
17023228120000_VUA-ODOM-1	226073										
17023229420000_CHEROKAN-INC-HBY-RB-SUA-1	233406										
17023229830000_SL-50-147	235770										

Available over the entire Lower Miocene
Not available over the entire Lower Miocene
Absent over the Lower Miocene

PHIE & PHIT vs Depth



PHIT & PHIE



VCL & DCL

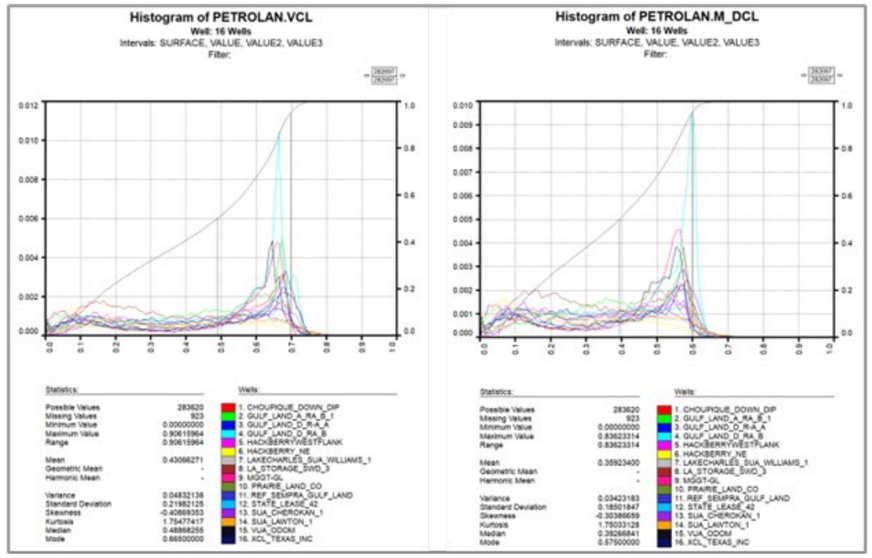


Figure 2-3 – Results of Quantitative Log Analysis of 16 Offset Wells. The ~7,500 ft line represents a change in the porosity-depth trend and is also reflected in the model. These well locations are shown on Figure 2-1. No directional or spatial trend was observed. Note that the histograms of PHIT and PHIE (top right) are made over the entire well intervals and not only over the reservoir sections. Histograms of VCL and DCL (bottom right) are computed over the entire logged well intervals and not only over the Lower Miocene.

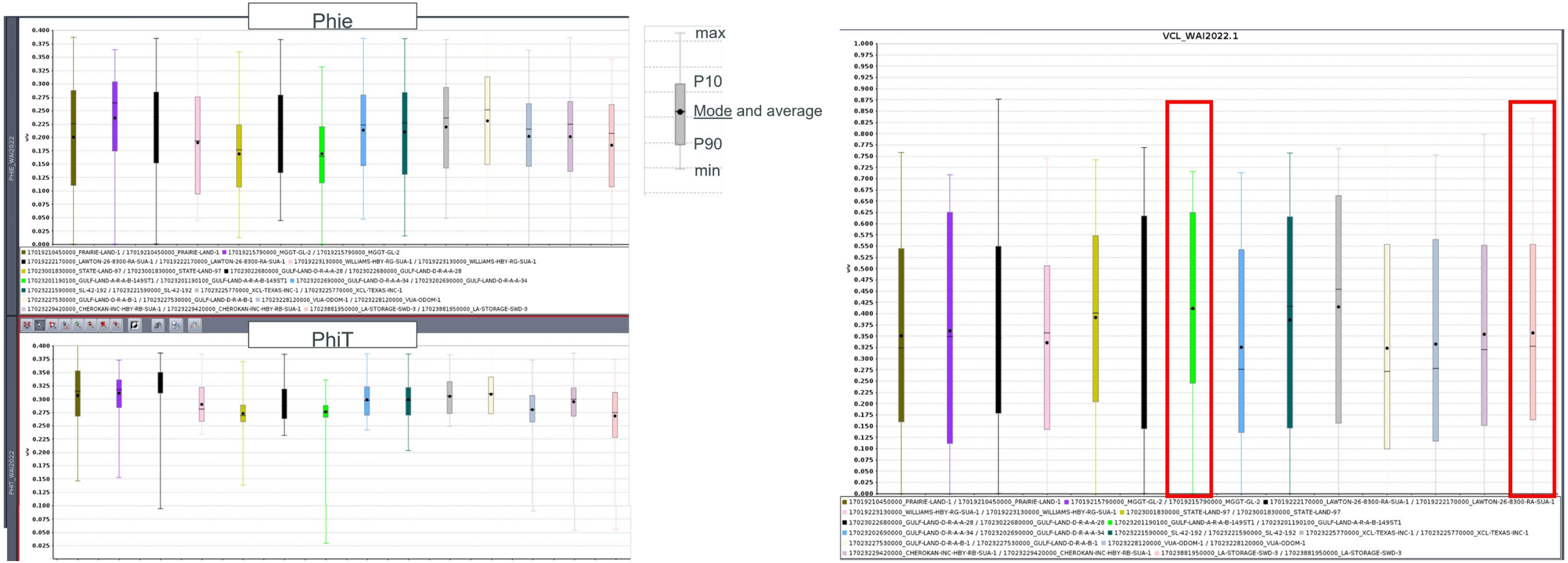


Figure 2-4 – Phie and PhiT Histograms over reservoir interval. The two plots on the left are histograms (box plots) for Phie and PhiT (similar to Figure 2-3) but computed only over the reservoir interval based on a cutoff of 50% Vcl (values over the net intervals): net Phie is systematically lower than net PhiT. The box plot on the right is the Vcl statistics per well over the Lower Miocene interval. The two wells highlighted in red are the Gulf Land ARAB 149 ST1 and LA Storage SWD 3 which appear to be outliers in the Figure 2-3 due to the data source being over the entire well and not just over the reservoir interval.

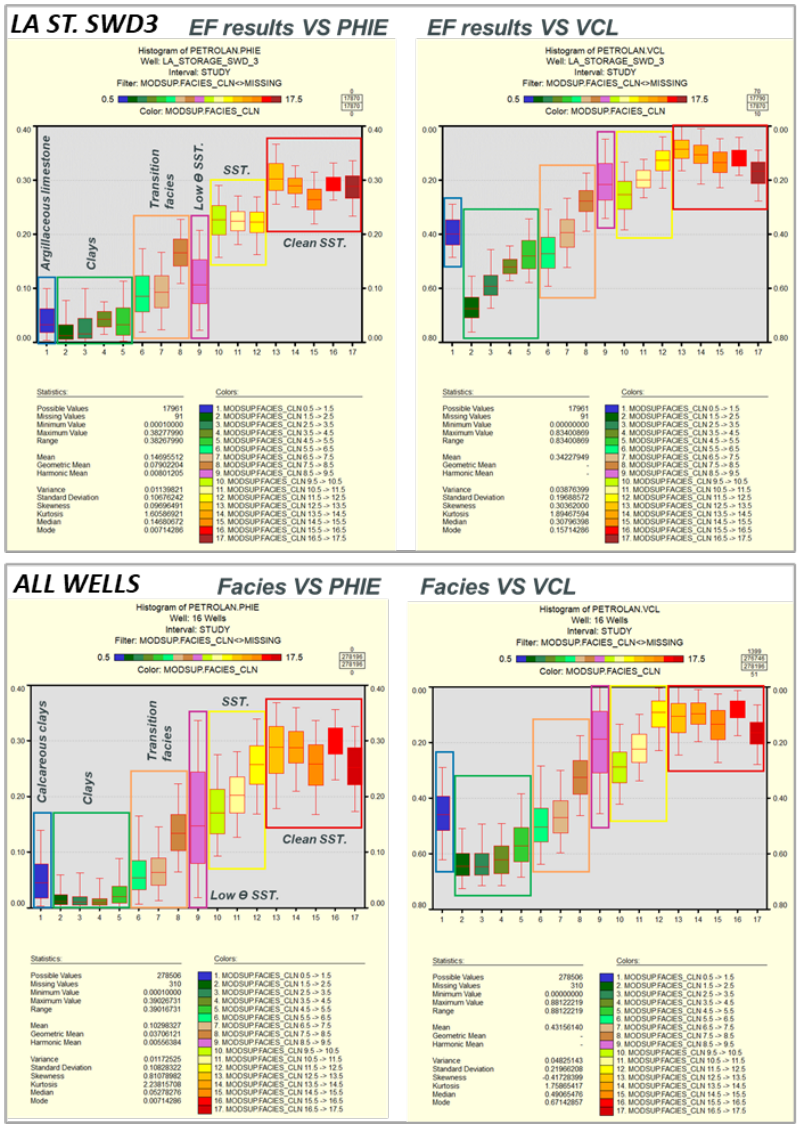
A consistent and coherent composite and evaluated log database is the foundation for the identification of electrofacies (Efacies). Efacies modeling is primarily intended to extrapolate core data (geological facies, petrophysical classifications, lithological characterization, etc.) to unsampled zones by using log data to facilitate the facies modeling and populate the geomodel.

The methodology relies on an algorithm built from a training set comprised of a selection of logs and core data to be combined into categories. The model requires a prior analysis, including log pre-processing (fluid correction, compaction trend correction) and normalization as well as core depth matching, to be carried out. This prior analysis is done on the full dataset to establish associated log responses. The feasibility analysis includes log value crossplots and distributions and coloring for facies or categories (learning set) to determine if data can be discriminated and which logs and which zones within the training set well(s) are the most suitable for this.

The zones selected for the training set must meet the following criteria:

- All the logs chosen as modeling support are present and of good quality
- All shoulder effects are avoided, as well as anything which could be sampling or scale change biases (with respect to the vertical resolution of the logs)
- The quantity of samples per facies must be globally balanced over the whole of the learning interval

After reviewing two methodologies to identify Efacies for the geocellular modeling effort, the model was selected that identified 27 clusters (Efacies types). These clusters were then reduced to 17 to represent the ones identified on the cores. A model to further reduce the number of facies groups to six rock types (RT) was also prepared (Figure 2-5). The guided model has a sufficient facies distribution versus the VCL and PHIE from the quantitative interpretation to allow adequate analysis and general consistency compared to the cores in LA Storage SWD No. 003 (SN 975774).



17 Efacies merged into 6 Efacies

E-Facies Results		FE merge suggestion	Core facies equivalent
Descriptive	FACIES_CLN	FACIES_MERGE	SF
Argillaceous limestone	1	1	5
Clay 1	2	2	6a
Clay 2	3		6b
Clay 3	4		
Clay 4	5		
Clay/Sand transition 1	6	3	4
Clay/Sand transition 2	7		
Clay/Sand transition 3	8		
Tight to low poro SST	9	4	n/a
Sandstone 1	10	5	2a
Sandstone 2	11		2b
Sandstone 3	12		2c
Clean Sandstone 1	13	6	1
Clean Sandstone 2	14		
Clean Sandstone 3	15		
Clean Sandstone 4	16		
Clean Sandstone 5	17		

Core facies descriptions

Facies

- 1-Fine/very fine sandstone. rare bioturbation. Low mud content
- 2a-Very fine clayey sandstone with ripples and mud lenses
- 2b-Very fine sandstone with planar laminations or mud drapes
- 2c-Very fine sandstone with abundant mud clasts
- 3-Calcareous cemented sandstone layers
- 4-Thin alternations of claystones/very fine sandstones (mudclasts, drapes)
- 5-Oyster lumachelle
- 6a-Reddish bioturbated claystone
- 6b-Greyish bioturbated claystone

**Core mineralogy not included*

Figure 2-5 – Electrofacies results versus quantitative interpretation (left). The original 17 Efacies were merged into 6 Efacies shown with equivalent core description facies to the right.

2.2.4 Well Correlation

The correlation rationales and scheme used in Texas and Louisiana, as promoted by the GCCC (Gulf Coast Carbon Center) at the University of Austin in Texas, act as the reference for further high-resolution well correlation of the fluvio-deltaic Miocene succession (Bump and Hovorka, 2023). The reservoir is characterized by fluvio-deltaic meandering environment and fluvial delta front (mouth bars), with varying sand body connectivity, both horizontally and vertically. In the Hackberry Project region, several key maximum flooding surfaces (MFS) are regionally correlated within the Upper Oligocene to Miocene strata, which enables the identification of vertical stratigraphic sequences or units (Figure 2-6). Each sequence is characterized by lateral facies changes, from mouth bars to meandering channels and shaly coastal plain deposits, with spatial varying sand body connectivity. The Miocene sands are underlain by up to 2,000 ft thick and continuous shales of the Anahuac formation.

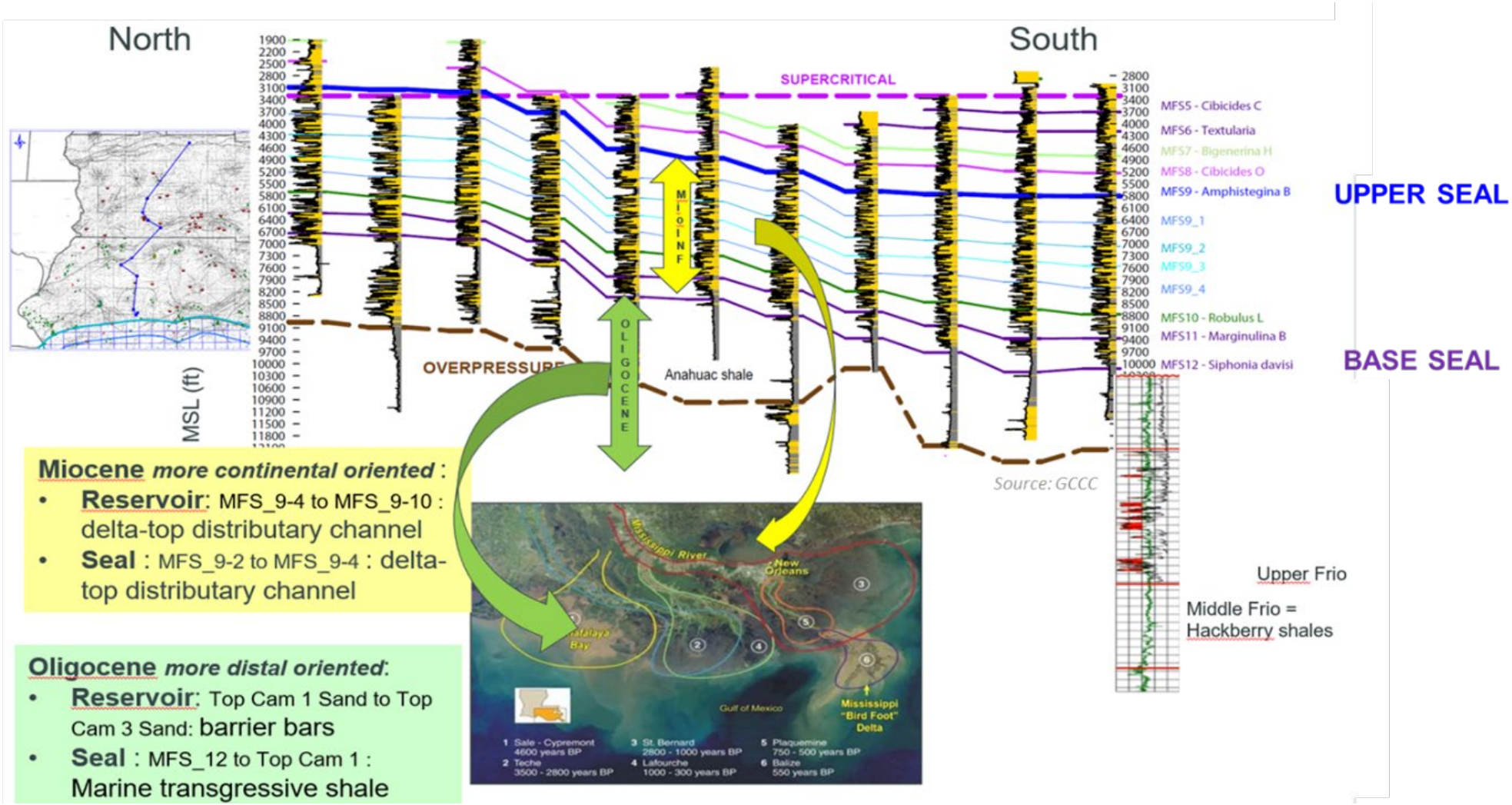


Figure 2-6 – Stratigraphic units and framework for the high-resolution correlation (modified after GCCC).

A high-resolution stratigraphic correlation was carried out from the 16 wells with evaluated logs and an additional 34 regional wells to provide structural depth control, assess changes in layer thickness and to aid in the geological modeling while overall providing a clearer understanding of the targeted stratigraphy.

Correlations, based on VCL logs, SP and GR logs, are supported by the key seismic markers, some of these show strong continuity. The correlation has identified packages of aggradational and mainly upwards-fining sequences. A total of 18 well markers were correlated from MFS 12 to MFS 8 (Figure 2-7). The correlation confirms that there is no significant syn-depositional tectonic evolution of the basin. However, some moderate thinning is observed towards the diapir flanks, limited to the lower reservoir intervals.

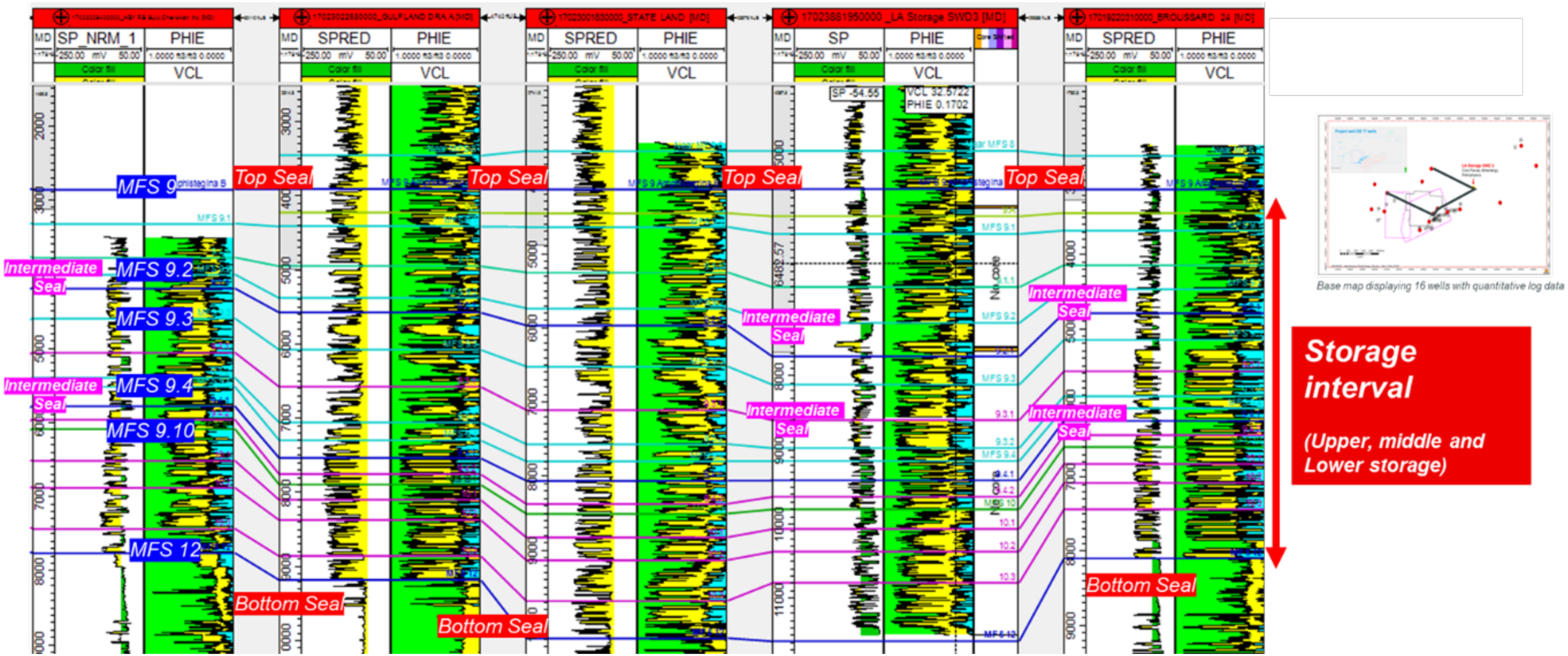


Figure 2-7 – Example of High-Resolution Correlation

2.2.5 Sedimentological Analysis of the Cores from LA Storage SWD No. 003 (SN 975774)

Four cores (35m) from the LA Storage SWD No. 003 (SN 975774) in the Miocene succession (Figure 2-8), were described and analyzed in TotalEnergies Scientific Center located in Pau, France. The objectives of the sedimentology study were to:

- Describe the sedimentary microfacies.
- Classify and characterize the facies with grain size analysis.
- Integrate mineralogical results.
- Identify sedimentary bodies and depositional environments in the cores.
- Depth-match the cores with wireline logs.

Nine sedimentary facies were described (breakout based on both core description, grain size and thin sections mineralogy), ranging from homolithic clean fine sand to bioturbated claystone. Biostratigraphical results were integrated for paleoenvironment determination. The results show evidence of both freshwater and marine influences, but the marine elements are interpreted as transported by tidal currents. Biostratigraphical results are compatible with the following environments of deposition represented in the cores:

- **Deltaic environment**, dominated by major fluvial and minor tidal influence (K4)
- **Tidal lower coastal plain** (K1 to 3). This environment comprises the characteristic tidal flats (sand flat, mixed flat or mud flat).

Four types of sedimentary bodies, (or facies associations), were interpreted on the cored intervals (Figure 2-9):

- **Distributary channel**, the best reservoir encountered throughout the cores. The thickest cored sand is a 9 m-thick complex of distributary channels.
- **Sand flat**, a reservoir facies association mainly composed of very fine sand.
- **Mixed flat**, a heterogeneous facies association composed of claystone and very fine sand.
- **Mud flat**, a non-reservoir facies association.

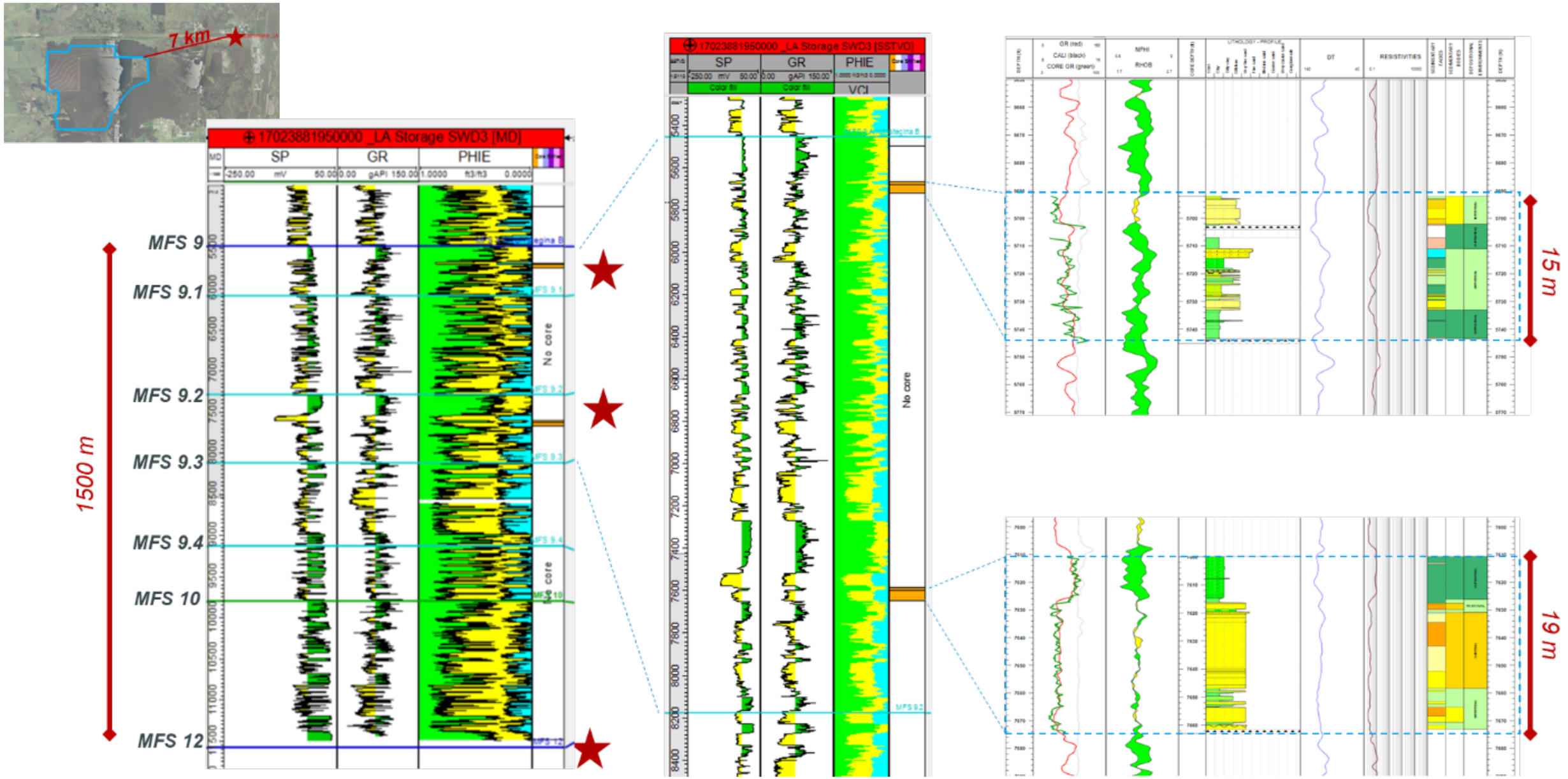


Figure 2-8 – LA Storage SWD No. 003 (SN 975774) Core Intervals

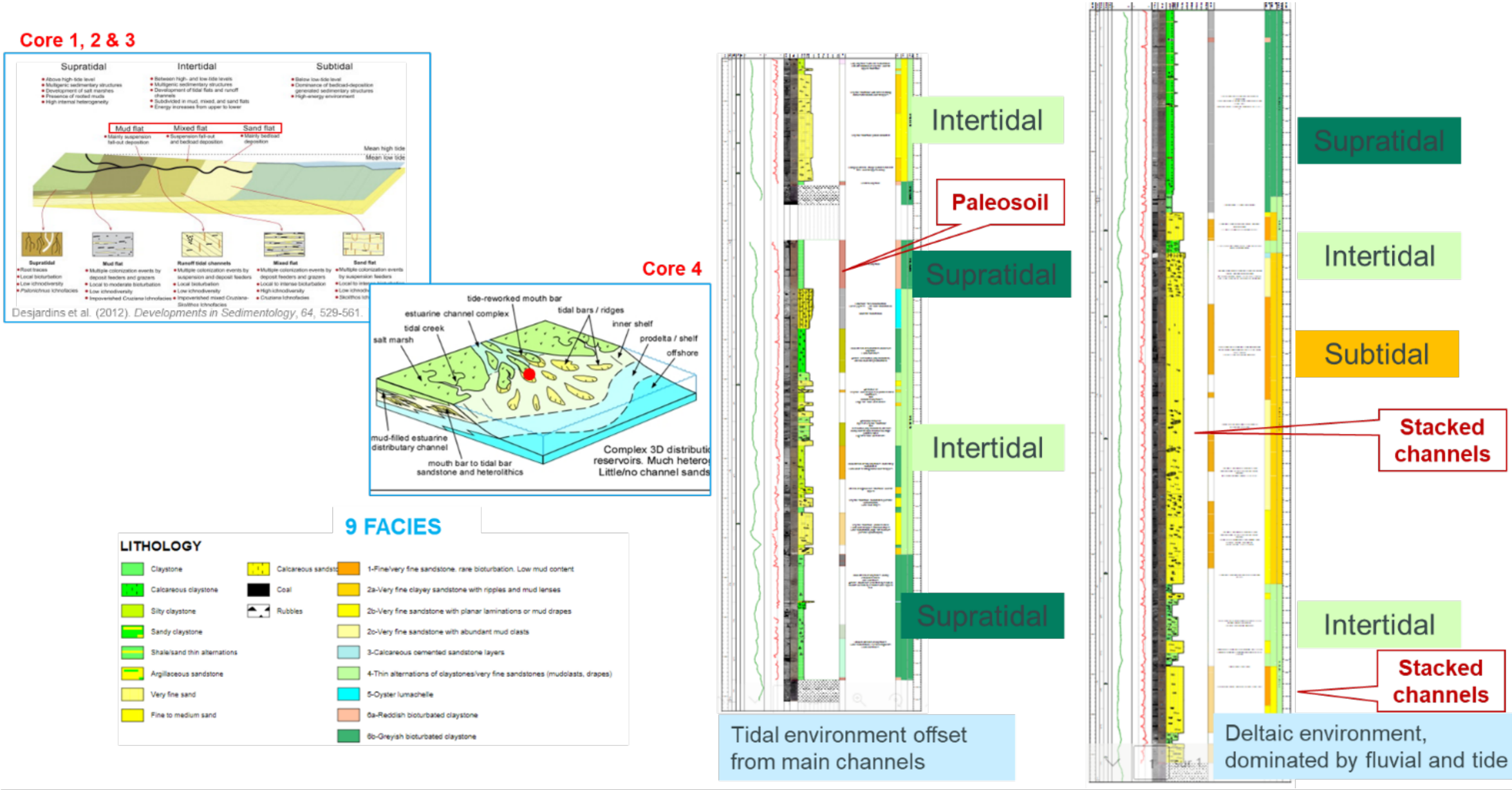


Figure 2-9 – LA Storage SWD No. 003 (SN 975774) Core Description

2.2.6 Depositional Model

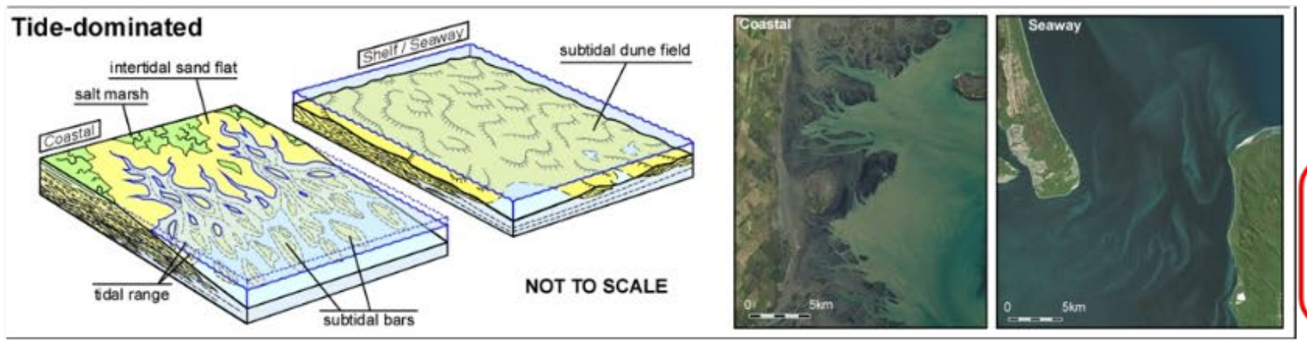
The well correlations, seismic interpretation, and core observations correspond with the regional stratigraphic context of a stacked, isopachous, and laterally extensive sand and shale succession of a fluvio-deltaic to tidal domain. Reservoir characteristics of the unconsolidated sands are generally very good (35% porosity and up to 8,000 mD permeability).

Two main depositional environments are evidenced on these Miocene cored intervals:

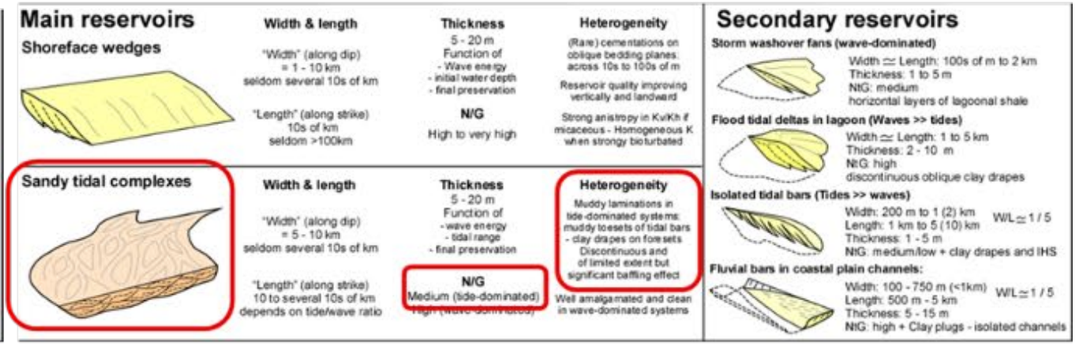
- Tidal dominated environment (lower coastal plain)
- Deltaic environment dominated by fluvial channels: sand bodies are either individual or stacked meandering fluvial channels to distributary channels in delta plain, little proportion of mouth bars (less than 10 or 20% and coarsening)

The depositional architecture relating to those two environments is given in Figure 2-10 together with indications of the internal level of heterogeneity and relation of width and length supported by TotalEnergies' global analog database. The dominant meandering fluvial system is illustrated in Figure 2-11.

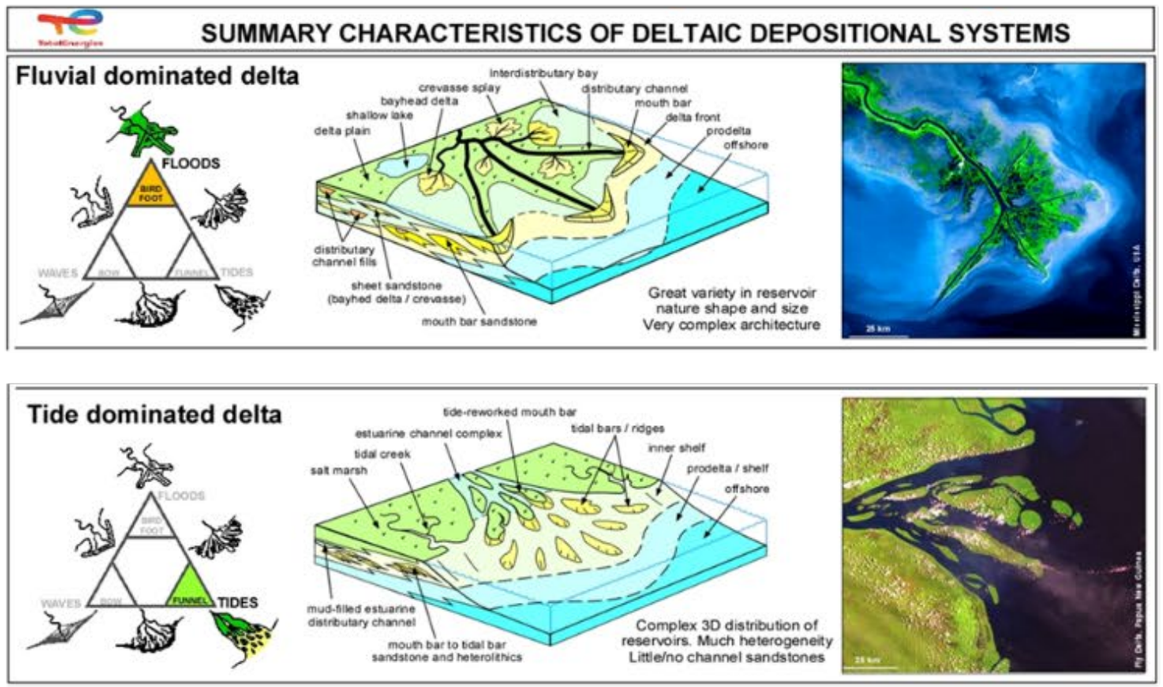
Cores 1, 2 & 3: *Tidal environment offset from main channels*



Depositional Architecture



Core 4: *Deltaic environment, dominated by fluvial and tide*



Depositional Architecture

K4: channel but in more distal position

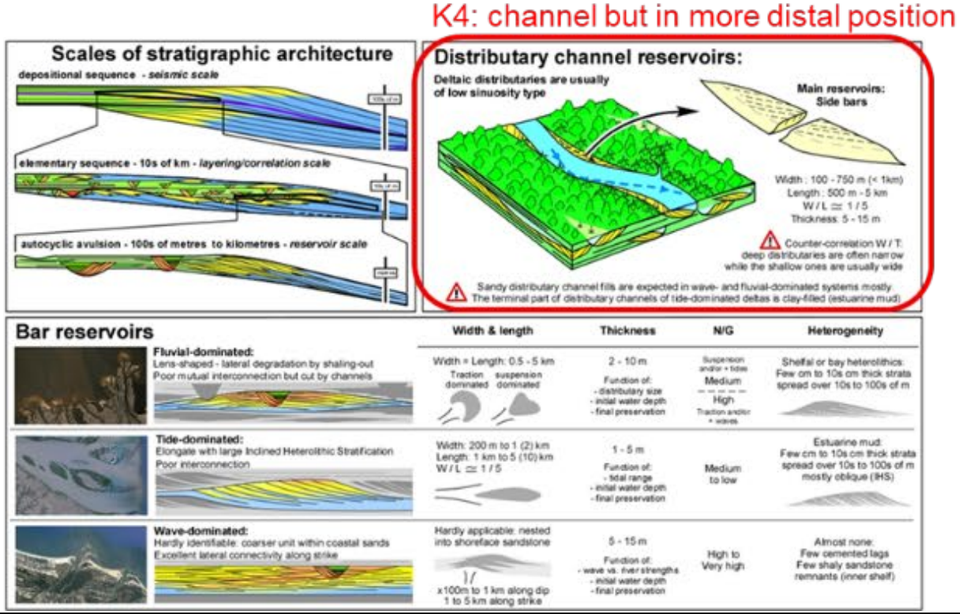


Figure 2-10 – Depositional Models. Depositional architecture observed in core circled in red.

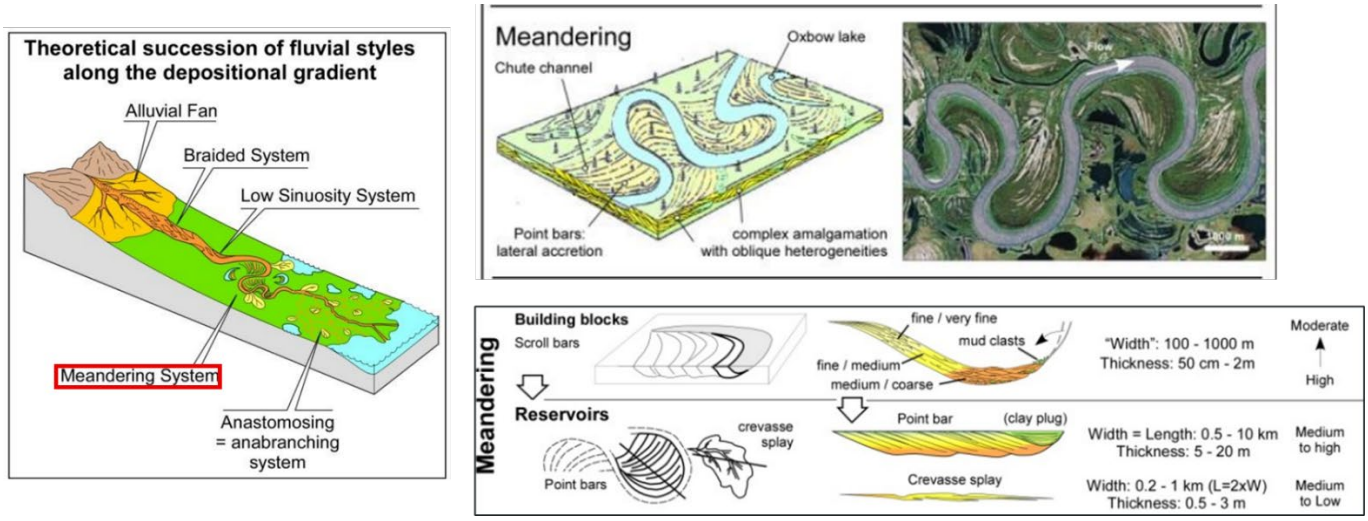


Figure 2-11 – Fluvial depositional model prevailing outside the cored areas of LA Storage SWD No. 003 (SN 975774).

2.2.7 Static Modeling

The geological, petrophysical and geophysical data were combined in a geocellular model of the reservoir built in Schlumberger's Petrel™ Software. This industry standard software combines information from logs and seismic data to build a 3D representation of the underground reservoir with respect to depth of the reservoir layers and of the distribution of lithological facies and the associated porosity and permeability properties.

The uncertainty related to quantification and distribution of these parameters has been considered through the construction of models representing multiple scenarios: together with the base case model as the mid case, two static uncertainty scenarios were submitted to represent a low and a high case in the simulation.

The geologic model is referenced to the North American Datum of 1927 (NAD27) and projected in UTM Zone 15N.

2.2.8 Structural Framework

The geocellular grid is contained by a structural framework. The framework ties together the depth horizons and faults resulting from the seismic evaluation and further ties the horizons to the geological well markers. The structural framework was built covering an area of 76,600 acres (72,000 ft by 46,000 ft). The area is partially covered by 3D seismic and the depth converted seismic surfaces were extrapolated to include the wells outside the seismic coverage. Figure 2-12 shows the workflow which combines 18 correlated well markers, 6 depth-converted seismic surfaces, and 15 faults into a 3D structural framework. The final tied horizons (subset of eight horizons displayed as transparent grid in the figure) and faults (full color fill in figure) are shown to the right. In addition to the six seismically derived maps, 12 horizons are extrapolated from the well markers keeping a proportional relation between the seismic surfaces.

The structural modeling incorporated multiple steps to ensure a perfect tie at the wells for the optimal upscaling of the logs, as well as some smoothing to avoid mis-ties in the northwestern area between the two 3D surveys and a final QC of mis-ties between the input surfaces and the final grid surfaces. Some mis-ties, especially related to the bulk shifted MFS 9 surface, are observed and are, in addition to the bulk shift, explained by the presence of faults along the salt structure as well as closely spaced wells.

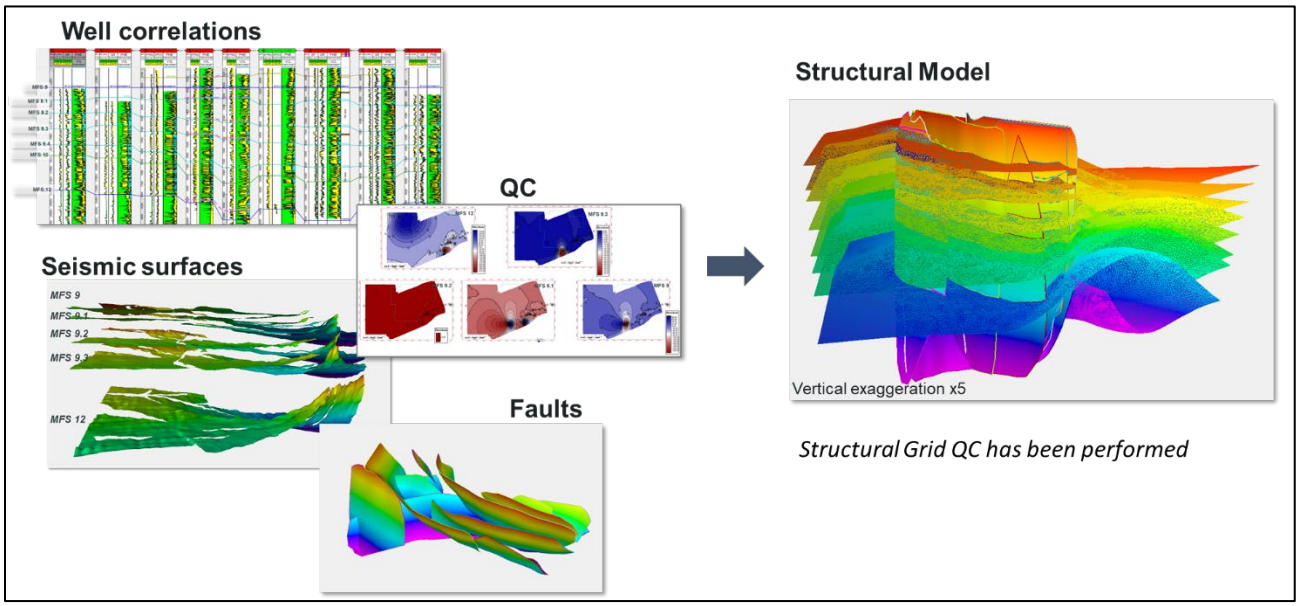


Figure 2-12 – Workflow to create the structural framework of the large grid.

2.2.8.1 Layering and Geocellular Grid

The structural framework consisting of 17 zones was converted into a geocellular grid for property distribution. This step includes stair-stepping of the faults in the structural framework and retains the 18 constraining horizons from the high-resolution well correlation incorporated during the structural modeling. A layering strategy was applied that gives a vertical cell size preserving the thickness and heterogeneity of sand and shale packages within each zone.

Two static grids were created: 1) a large grid for the purpose of investigating pressure dissipation in the extended area and for providing the means to upscale all the available logs and 2) a small grid to provide a grid suitable for simulation of the plume migration and sweep efficiency. The large grid contains all the evaluated wells and covers an area of 76,600 acres. The small grid has an extent of 13,600 acres, covering the facility (Figure 2-13). Both grids have cell sizes of 100 ft by 100 ft by approximately 18 ft (cell height varies), corresponding to 111.8 million and 20.7 million grid cells for the large and small grid, respectively, leaving the large grid unsuitable for simulation due to size. The grids have the same division of 307 layers. The number of layers per zone is shown in the table in Figure 2-14.

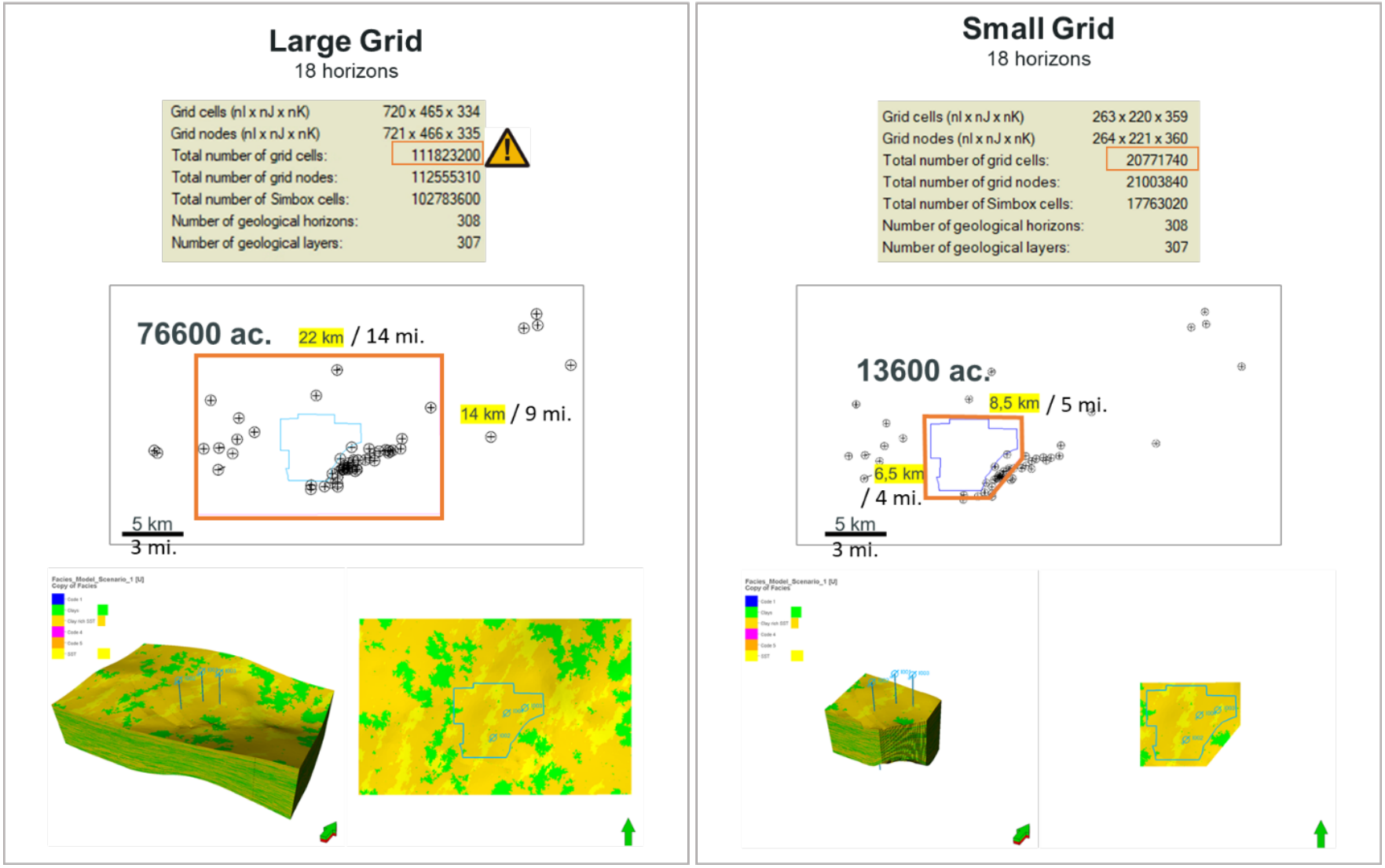


Figure 2-13 – The large grid covering 310 sq.km (76,600 acres) incorporates all the 16 evaluated wells. The small grid covers 55 sq.km (13,600 acres). Grid extent is shown as red polygon in map.

Near MFS 8-MFS 9 Amphistegina B	31
MFS 9 Amphistegina B-9.A	19
9.A-MFS 9.1	24
MFS 9.1-9.1.1	27
9.1.1-MFS 9.2	19
MFS 9.2-9.2.1	25
9.2.1-Horizon MFS 9.3	29
Horizon MFS 9.3-9.3.1	21
9.3.1-9.3.2	15
9.3.2-MFS 9.4	7
MFS 9.4-9.4.1	23
9.4.1-9.4.2	11
9.4.2-MFS 10	6
MFS 10-10.1	11
10.1-10.2	8
10.2-10.3	15
10.3-MFS 12	16

Figure 2-14 – Table of the 17 static model zones with number of layers per zone.

2.2.8.2 Lithofacies Distribution

The Efacies interpretation from 14 wells form the basis for the lithofacies modeling. At the log scale, the Efacies that were determined during the evaluation were merged into six facies groups based on a similarity index (Figure 2-15 left) and then further grouped into the three Rock Types (RT) sandstone, clay-rich sandstone, and clay/non-reservoir (Figure 2-15). The RT logs were then upscaled to the large model using the "most of" algorithm. From the upscaled RT facies, a vertical probability curve (VPC) of the relative facies contribution per stratigraphic layer was made. The VPC is shown in Figure 2-16, which compares the upscaled facies to the log scale and demonstrates that the upscaling has not changed the vertical distribution making the VPC adequate for facies distribution. The VPC illustrates the lateral variability of the facies and thus provides evidence that MFS intervals are not made of shales only. Therefore, they should be referred to as baffles and not barriers to flow.

In this study, distribution of facies was carried out using the sequential indicator simulation (SIS) geostatistical methodology. This methodology is suitable for modeling the depositional facies in the case where purely deterministic modeling based on detailed sedimentological maps (as derived from reliable seismic attributes for example) is not possible.

The simulation distributes the three facies with the proportions for each layer given by the VPC with the relation of the facies provided by variograms. Based on the depositional model (Figure 2-16), the sandstone (SST) facies was modeled as elongated north-northeast to south-southwest features (channel or bar-like) while the inter-channel facies of clay-rich SST and clays were modelled as unidirectional features, the clay-rich SST about one-third the size of the clay. The parameters of the variograms are shown in Figure 2-17.

The simulated lithofacies of the large grid is shown in Figure 2-18 where it is observed that the vertical heterogeneity from the upscaled wells is preserved, and that the global facies proportion is preserved.

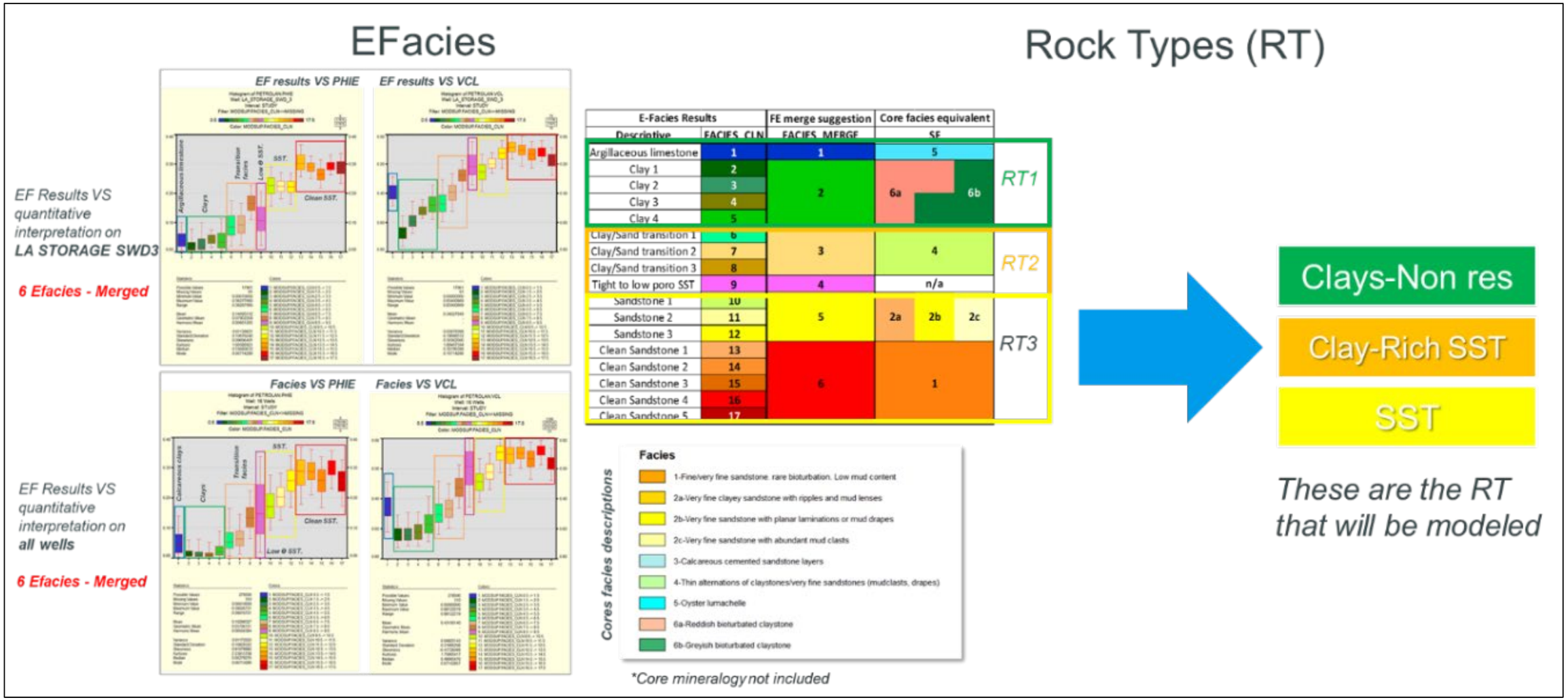


Figure 2-15 – Efacies identified in quantitative log analysis are merged and grouped into three rock types for lithofacies modeling.

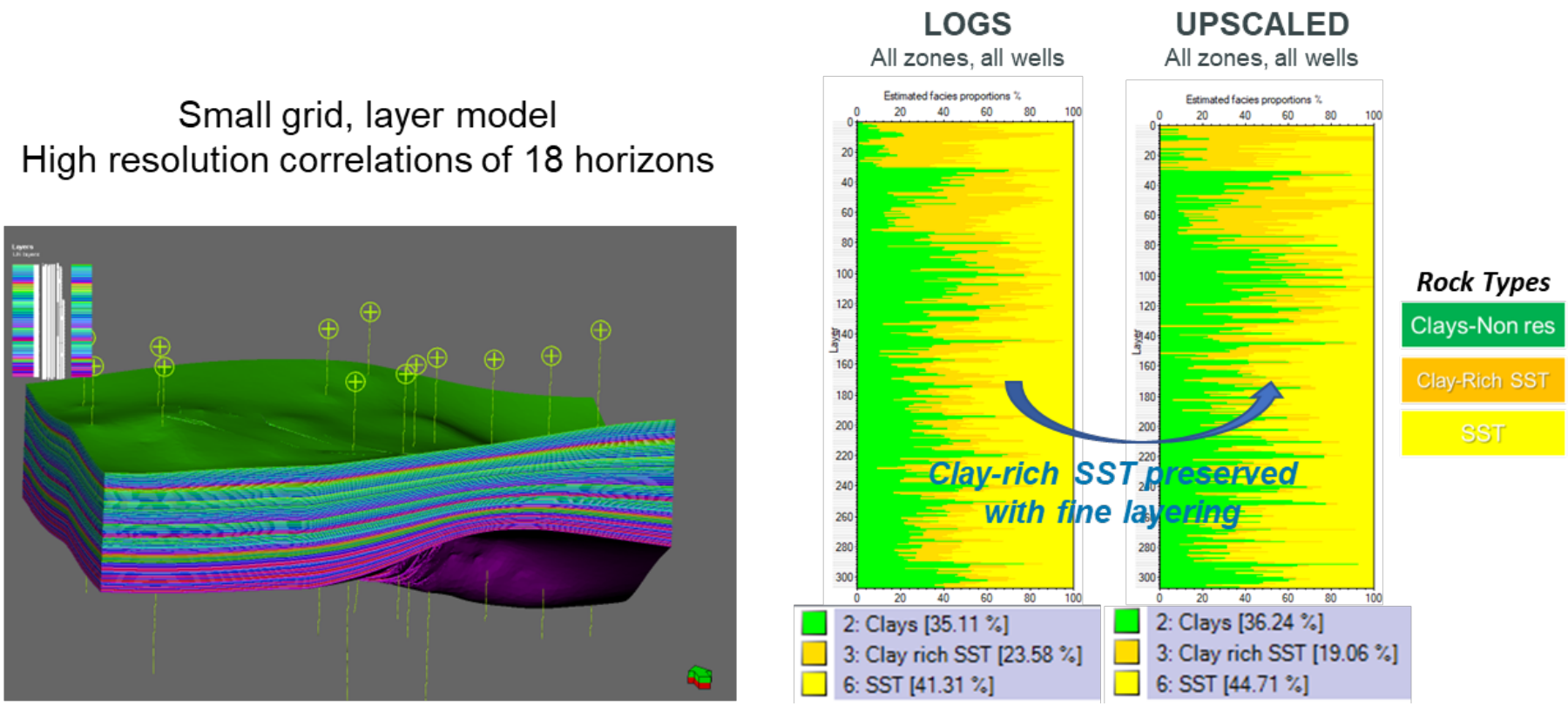
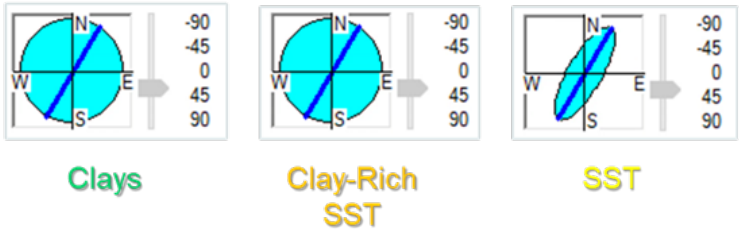


Figure 2-16 – Vertical probability curves (VPC) of using log from 14 evaluated wells (left) and upscaled to the model (right). The layering as shown to the far left adequately preserves the clay-rich SST rock type during the upscaling.

Varyogram Inputs	Clays	Clay-Rich SST	SST
Type	Exponetial	Exponetial	Exponetial
Nugget	0	0	0
Sill	1	1	1
Major Range	9800	3200	9800
Minor Range	9800	3200	3200
Vertical Range	60	40	60



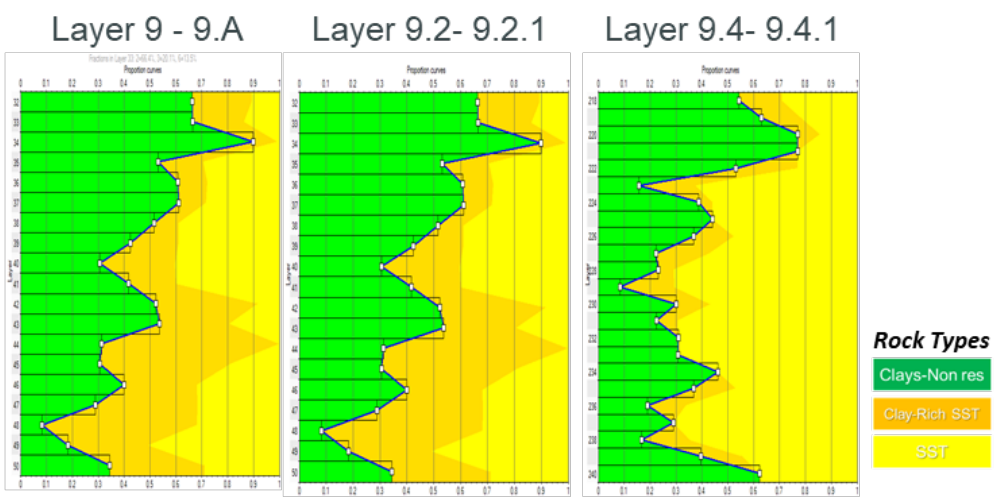
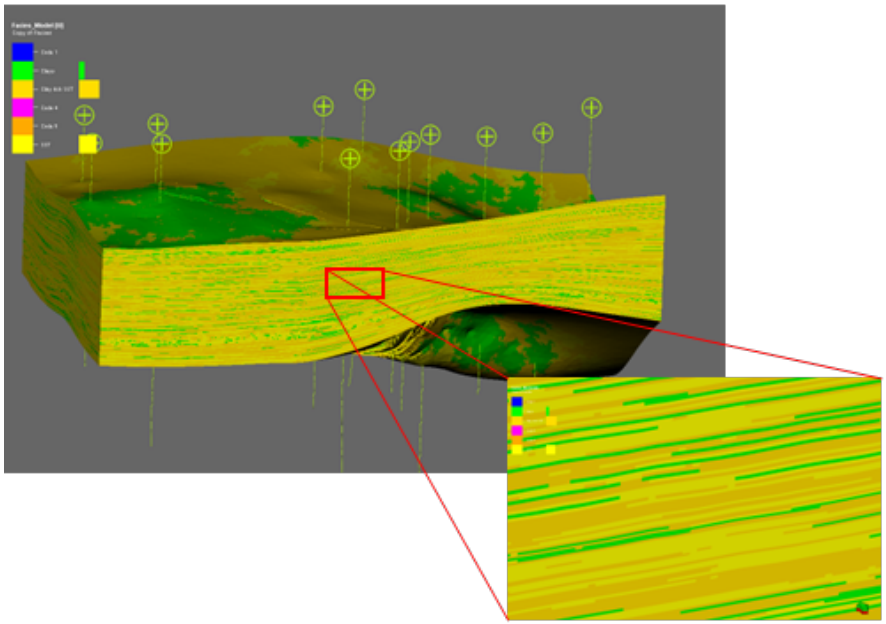
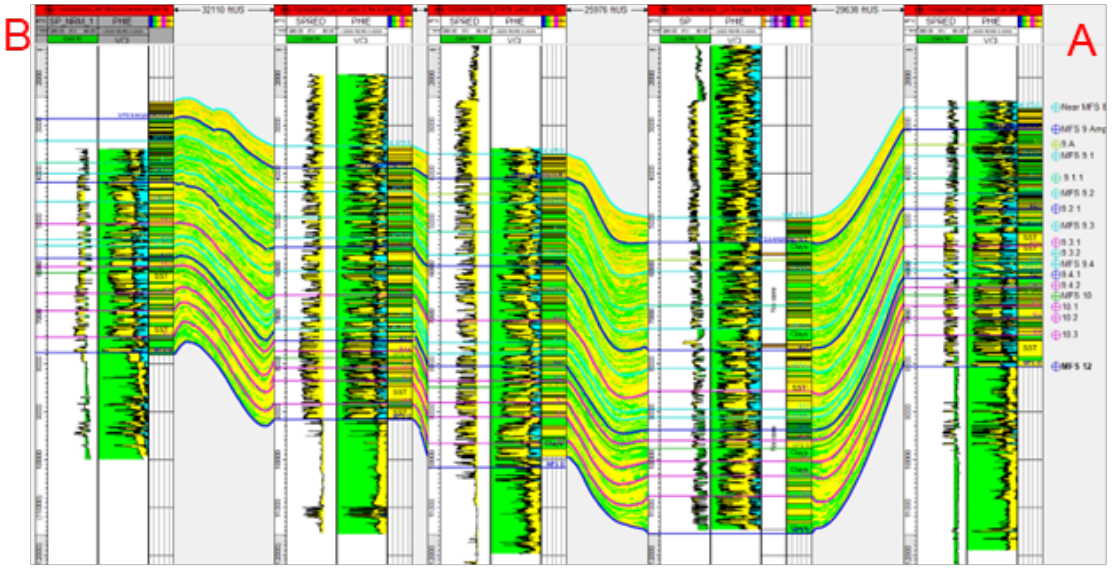


Figure 2-17 – Variogram Input and Zoomed Vertical Probability Curves





3 Rock Types (Model Scenario1)
Clays- 36%
Clay-Rich SST-19%
SST - 45%

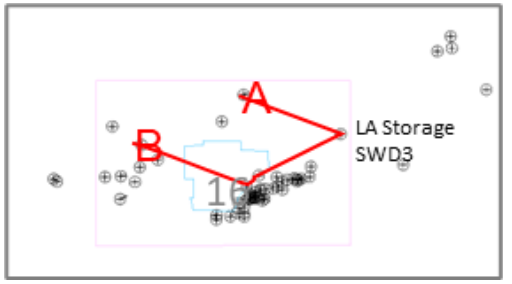


Figure 2-18 – Base case lithofacies model (large grid) in 3D and compared to wells.

The modeled representation of the main seal around MFS 9 is illustrated in Figure 2-19. This seal interval is represented by the lumping of multiple clay-rich units (16 layers) from MFS 9 to the top of the injection interval at zone 9A. The thickness of the top sealing zone is expected to be 260 to 300 ft within the acreage (200 to 360 ft beyond the limit of the permit). After removing the interbedded sandstone, the net thickness is from 60 to 180 ft with a varied distribution across the site (lower left in Figure 2-19).

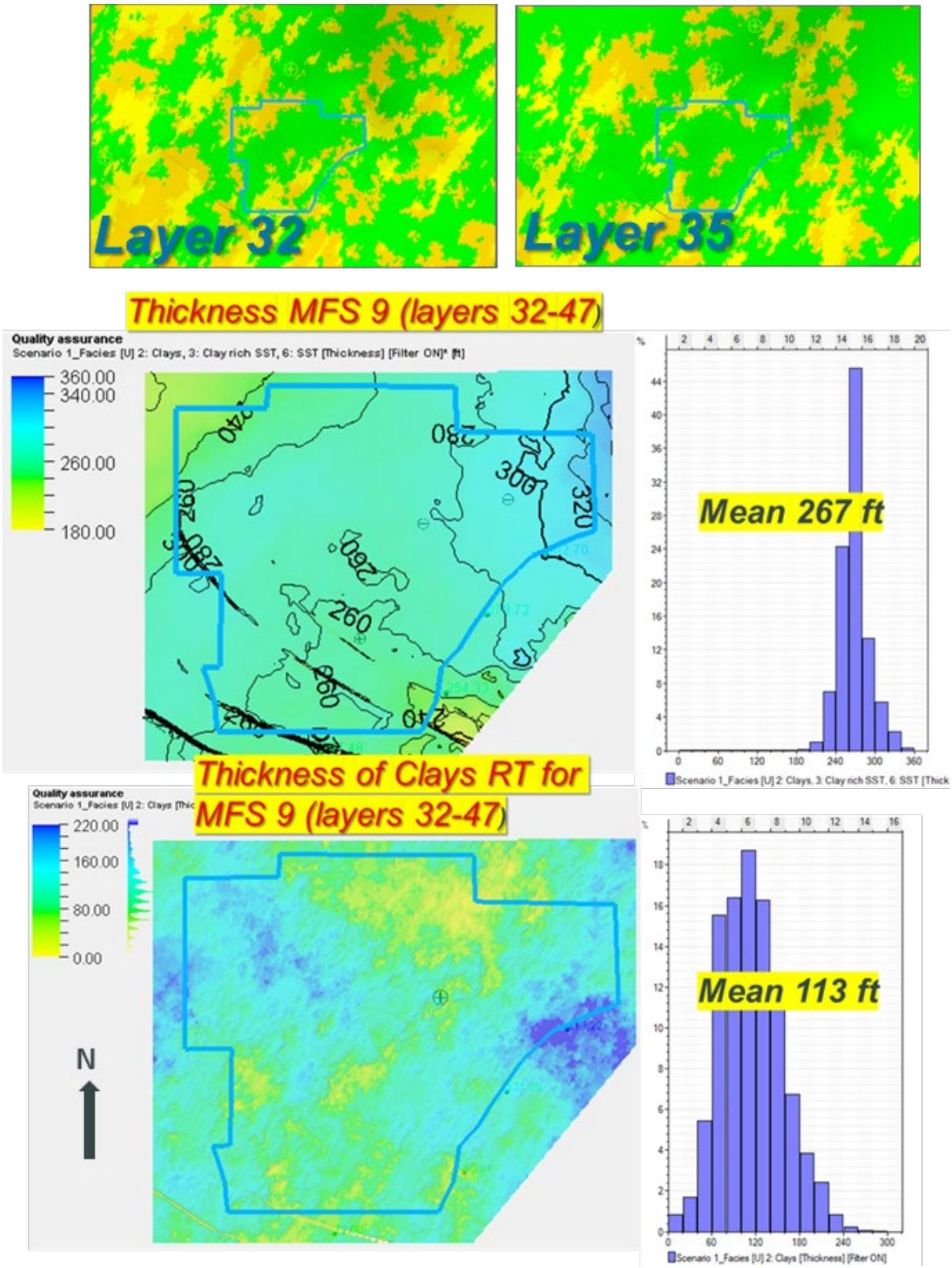


Figure 2-19 – Top Seal (MFS 9) consists of multiple layers. The seismic resolution (25-100 ft) is sufficient to accurately measure the thickness of the seal greater than seismic resolution.

2.2.8.3 Petrophysical Modeling

For this study, distribution petrophysical properties were carried out using a Sequential Gaussian Simulation (SGS) geostatistical methodology. The modeling is performed per facies and for all zones together and considers the burial trend and interdependency of the parameters.

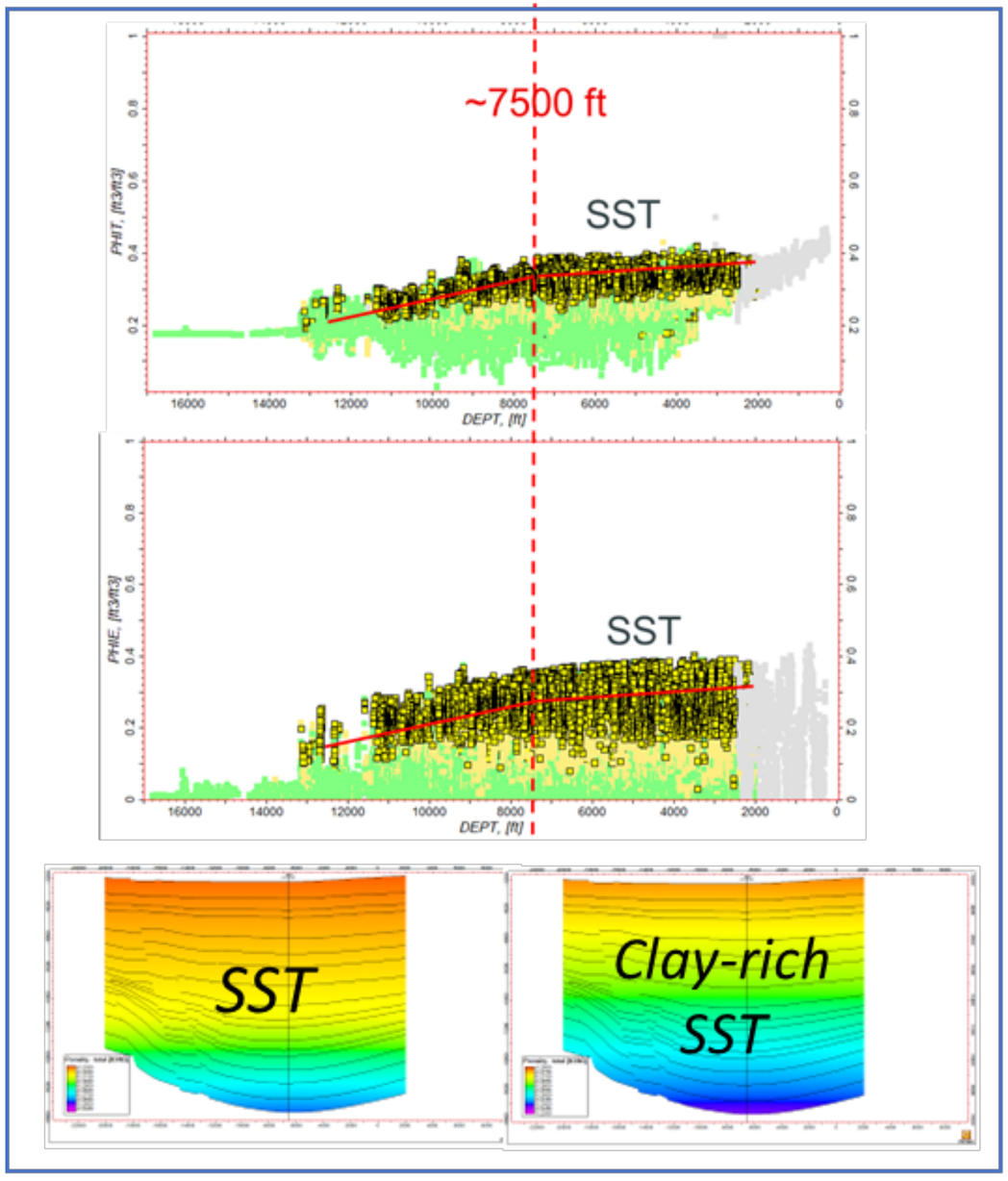
The prerequisite is the upscaled properties from the evaluated well logs of net-to-gross (NTG), total porosity (PHIT) and effective porosity (PHIE). The NTG blocking is derived from a net flag created at well log scale using cutoffs of PHIE ≥ 8% and VCL ≤ 40%. The PHIE-log was upscaled for the full log and for the net sand equivalent of the PHIE.

A normal distribution was used for transforming porosities and a beta function for the transformation of NTG. The interdependency of the facies and petrophysical parameters was ensured by linked variables. At the first simulation step, which is the PHIT modeling, the property is normalized for the compaction trend that was observed for the porosity during the quantitative evaluation (Figure 2-3) however, the main impact of the trend is ultimately on the permeability. Trends were established for the PHIT of SST and clay-rich SST vs. depth (Figure 2-20 left) and implemented as a local varying mean. Subsequent properties of PHIE, NTG and PHIE of the net were simulated with cokriging to give an intermediate to high degree of correlation between the petrophysical property cubes as shown in Figure 2-20.

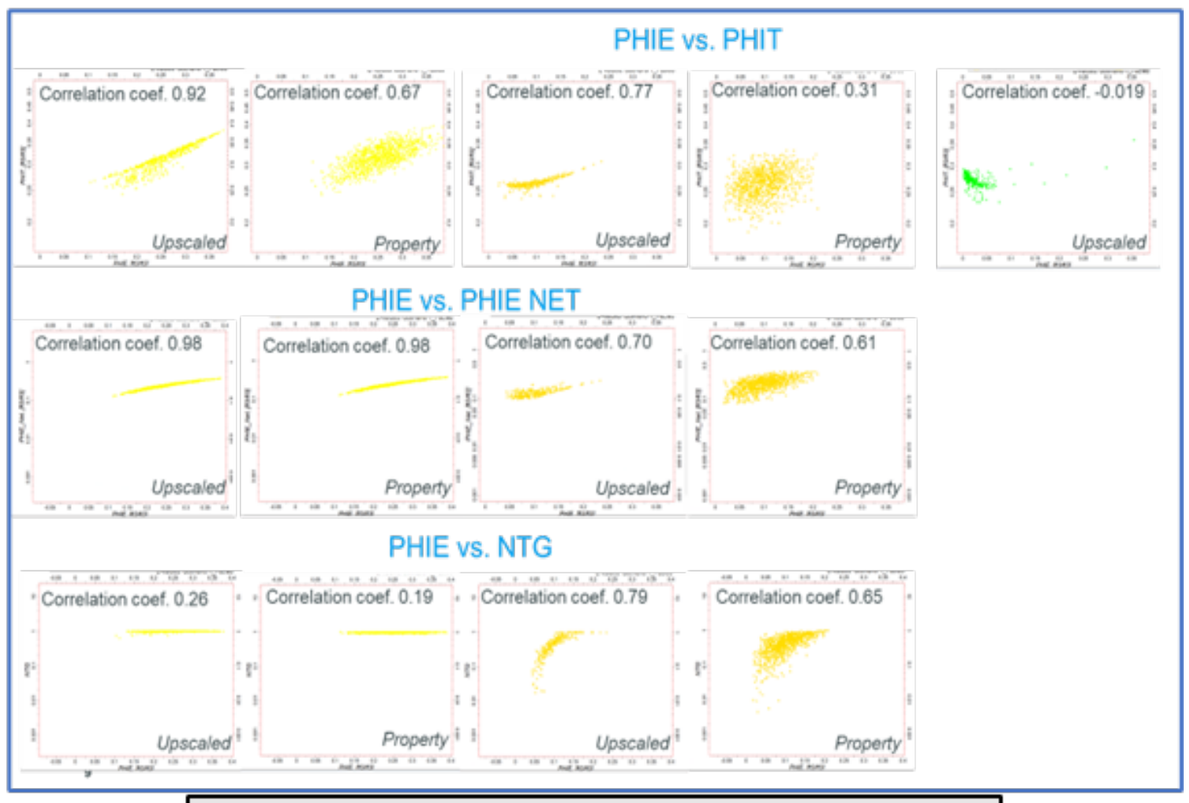
Permeability is populated from the relationship of $K = 9.951\ E{+}9 * PHIT^{12.008}$ (Figure 2-21). The power model is derived from core analysis (CCA). Permeability was constrained at 8,000 mD and post-processed with a cloud transform.

The final distribution of the lithofacies and petrophysical properties is seen for the base case (Scenario 1) in cross sections in Figure 2-22 and is characterized by intercalated sandstone and clay with an elevated level of vertical heterogeneity and variable lateral continuity of the properties.

Depth Trend



Correlation of Variables



Variogram Input (scenario 1)

Varyogram Inputs	Clays	Clay-Rich SST	SST
Type	Exponetial	Exponetial	Exponetial
Nugget	0	0	0
Sill	1	1	1
Major Range	3200	1000	3200
Minor Range	3200	1000	1000
Vertical Range	40	40	40
Method	SGS	SGS	SGS

Figure 2-20 – Inputs for property modeling. Left: compaction trend. Upper right: Post-simulation correlation per facies and property. Lower right: Variogram ranges per facies.

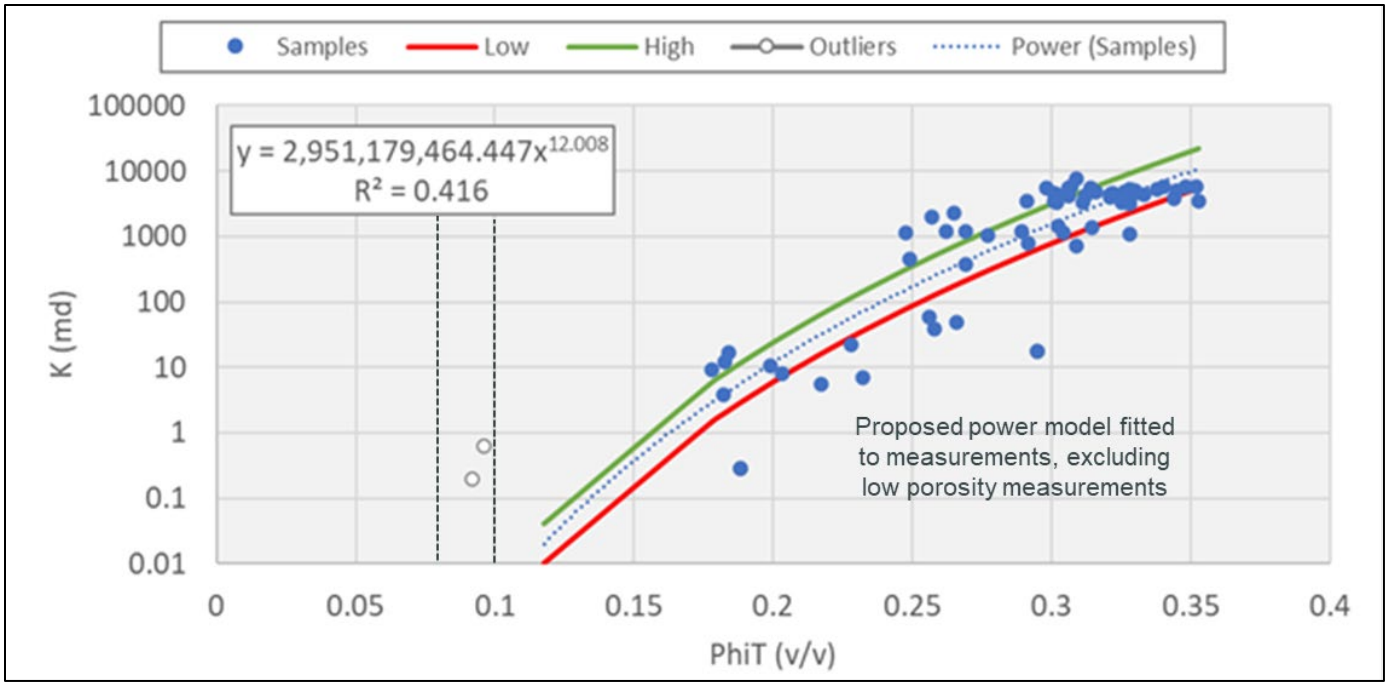


Figure 2-21 – Porosity-permeability relationship for model. Data and power model.

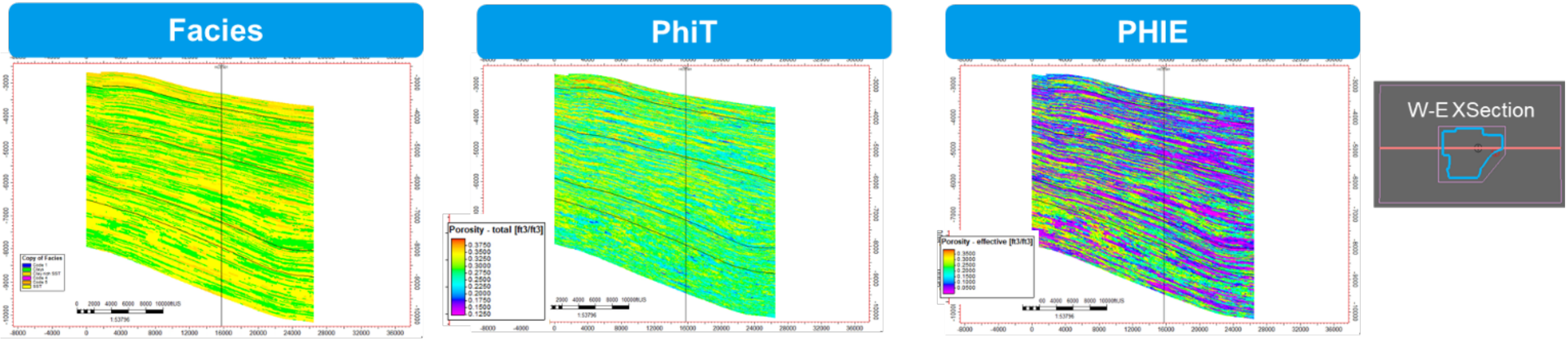


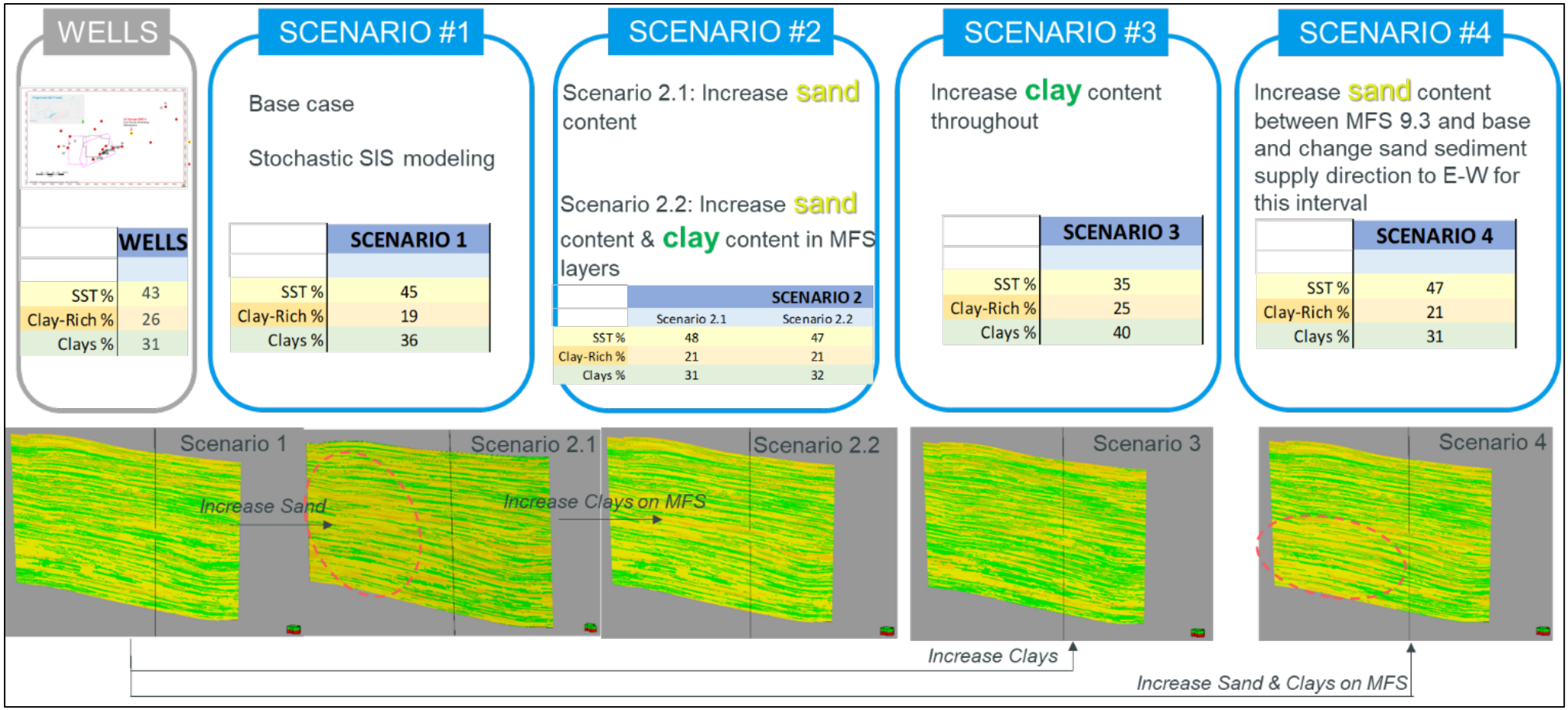
Figure 2-22 – West-east model sections of the static model properties at the planned HCS No. 001.

2.2.8.4 Uncertainty Management

The uncertainties associated with the geological characterization of the subsurface were characterized though the implementation of multiple scenarios that covers the range of uncertainties and variability in the geological parameters within this relatively well-constrained environment. The purpose of making multiple deterministic models is mainly to provide distinctly different cases to be tested in dynamic simulation.

Four different geological scenarios were constructed, consistent with regional observations on wells and are summarized in Figure 2-23. Four observations were considered:

1. The depositional characterization from core and logs provides a limited room for strongly diverging models at the acreage scale, however variation is possible vertically.
2. Uncertainty exists on the continuity of shales.
3. Sand content is variable. Additional distributary channels could be present.
4. Orientation of the sand bodies in each layer is uncertain.



	WELLS
SST %	43
Clay-Rich %	26
Clays %	31

	SCENARIO 1
SST %	45
Clay-Rich %	19
Clays %	36

	SCENARIO 2	
	Scenario 2.1	Scenario 2.2
SST %	48	47
Clay-Rich %	21	21
Clays %	31	32

	SCENARIO 3
SST %	35
Clay-Rich %	25
Clays %	40

	SCENARIO 4
SST %	47
Clay-Rich %	21
Clays %	31

Figure 2-23 – Facies and Property Modeling Scenarios

Scenario 2 has an increased sand content, reflecting a high case, and incorporating observations (1) and (3). A global increase of shale will significantly deteriorate the internal seal/baffles thus causing the volumetric high case to become a dynamic low case. Therefore, a Scenario 2.2 case was built by increasing the clay content in the flooding zones, while still observing the global clay content as seen in the calibration wells.

Scenario 3 is a low-case scenario where the global clay content is increased to 40% compared to 31% as observed by wells. Scenario 4 is another high case which increases the sand content in the lower interval and changes the variogram direction to east-west to model an alternative sediment supply.

The lithofacies scenarios for uncertainty were built in the small grid using the same SIS distribution methodology as in the static base case and followed by case specific petrophysical property SGS simulation, also as per the static base case. The scenarios chosen to represent the static low, mid, and high cases are:

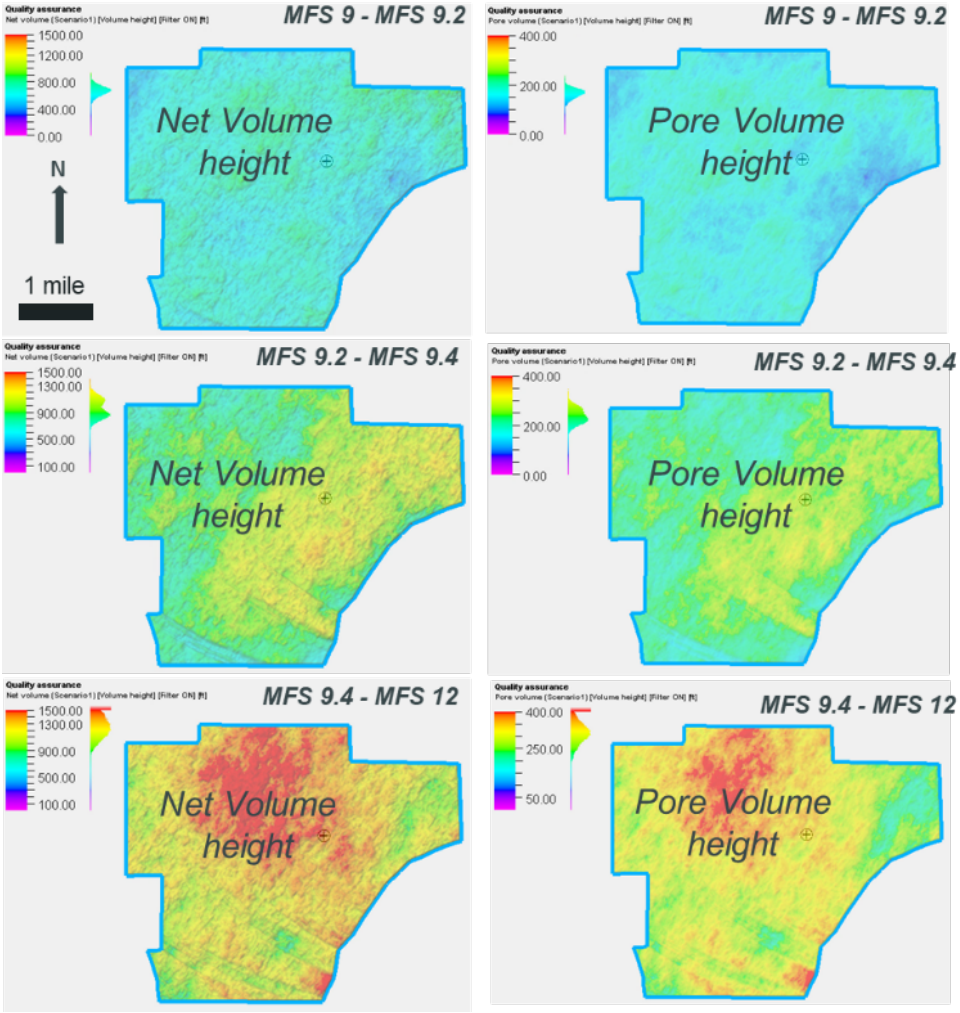
- Low case: increased clay content (Scenario 3),
- Mid case: static base case (Scenario 1)
- High case: Scenario 2.2 with increased content of sand .

2.2.8.5 Static Volumetrics

In the base case (Scenario 1), a total of 47,200 million reservoir barrels were assessed for the full vertical extent of the geocellular model, and 43,361 million reservoir barrels for the zones excluding the near MFS 8-MFS 9 Amphistegina B zone, which is not considered for carbon dioxide injection. A breakdown of the volumetrics is seen in Figure 2-24, together with net and pore volume foot maps of the upper, middle, and lower reservoir interval, respectively.

The pore volume relative to the bulk container size is higher in the thicker lower reservoir unit between MFS 9.4 and MFS 12 and decreases upwards through the middle (MFS 9.2 to MFS 9.4) and top the upper reservoir interval from MFS 9- MFS 9.2.

In comparison, the alternative scenarios represent a range of -12% to +13% pore volume compared to the total pore volume of the static base case. Pore volume feet maps comparing the scenarios are shown in Figure 2-25 and the model total pore volumes are listed in Table 2-2.



	Bulk volume [*10^6 ft3]	Net volume [*10^6 ft3]	Pore volume [*10^6 RB]
PV_Scenario_1	1963990	1070031	**47200**
Zones			
Near MFS 8-MFS 9 Amphistegina B	148674	89411	3839
MFS 9 Amphistegina B-9.A	101793	45340	1991
9.A-MFS 9.1	65236	35348	1548
MFS 9.1-9.1.1	184302	86428	3831
9.1.1-MFS 9.2	133787	60486	2681
MFS 9 - MFS 9.2	***485118***	***227602***	***10051***
MFS 9.2-9.2.1	115606	51040	2254
9.2.1-Horizon MFS 9.3	159238	94897	4203
Horizon MFS 9.3-9.3.1	161944	86929	3862
9.3.1-9.3.2	107168	64298	2830
9.3.2-MFS 9.4	60171	27665	1221
MFS 9.2 - MFS 9.4	***604127***	***324829***	***14370***
MFS 9.4-9.4.1	101097	52896	2330
9.4.1-9.4.2	75740	37761	1669
9.4.2-MFS 10	51101	30084	1315
MFS 10-10.1	118897	73517	3273
10.1-10.2	115284	75318	3317
10.2-10.3	142784	96892	4273
10.3-MFS 12	121169	61723	2763
MFS 9.4 - MFS 12	**726072**	**428191**	**18940**

Figure 2-24 – Pore volume foot maps per main reservoir zones (left) with calculated porous volume of the base case – Scenario 1 (right).

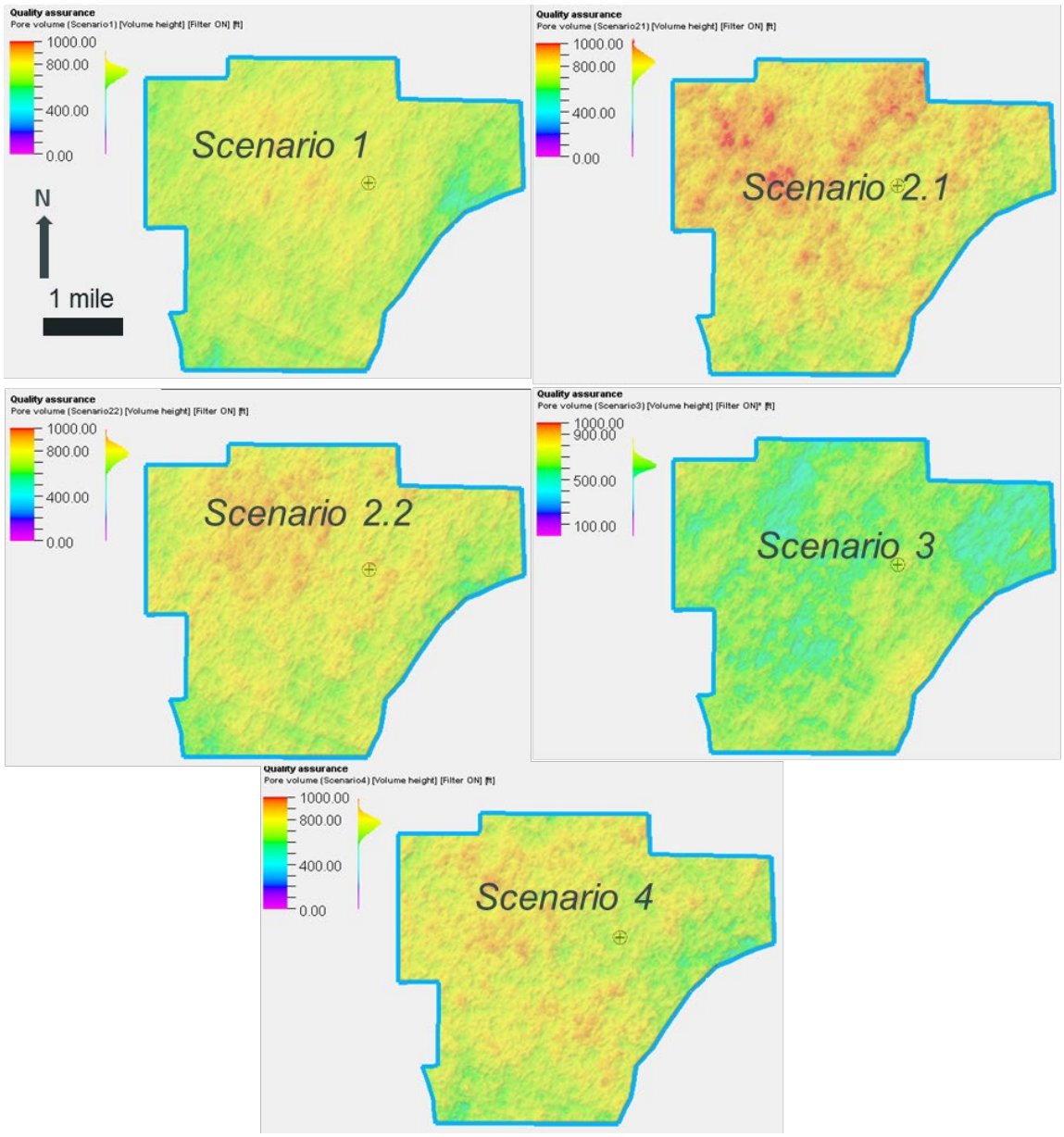


Figure 2-25 – Pore Volume Height Maps (ft) – All Scenarios

Table 2-2 – Total Pore Volume Per Geological Scenario

Case	Bulk volume[*10^6 ft3]	Net volume[*10^6 ft3]	Pore volume[*10^6 RB]
Scenario1	1963990	1070031	**47200**
Scenario2.1	1963990	1172823	**53447**
Scenario2.2	1963990	1105826	**50268**
Scenario3	1963990	923107	**41752**
Scenario4	1963990	1096436	**49738**

2.3 Dynamic Modeling

A simulation model based on the previously described static model was built to study the process of injection into the Miocene injection zone. This model is designed to assess the impact of a wide range of static and dynamic parameters on the lateral and vertical migration, as well as the evolution of the CO_2 plume during both the injection phase and subsequent monitoring periods. Constructed as a fully compositional dynamic reservoir model, the Hackberry model was built using the INTERSECT™ reservoir simulation framework. This model integrates all pertinent dynamic data specific to Hackberry and encapsulates the relevant physical phenomena associated with CO_2 injection in saline aquifers. Key among these are the mechanisms of residual trapping and CO_2 dissolution trapping, which are critical for understanding the long-term behavior and stability of CO_2 in the subsurface. This model has been built and calibrated using available seismic and well log and core data, ensuring its accuracy and reliability.

2.3.1 Relative Permeability and Capillary Pressure

Proper definition of relative permeability and capillary pressure curves is crucial in CO_2 injection process. During the injection period, the less wetting CO_2 displaces the more wetting brine in a drainage-like process. However, after injection, the buoyant CO_2 migrates laterally and upward, while water displaces CO_2 at the trailing edge of the plume in an imbibition process. Consequently, accounting for trapping and relative permeability hysteresis of CO_2 is essential to correctly characterize the migration and final distribution of the injected CO_2.

In the absence of valid SCAL experiments for Hackberry, a combination of analogue data was used for saturation end-points, Corey exponents, and CO_2-water functions (Table 2-3) based on CO_2-water experiments as discussed by Krevor et al (2011) and Doughty (2007).

Table 2-3 – Proposed Relative Permeability End-Points

	Low	Mid	High
Swirr & Krgmax	0.03 / 1	0.15 / 0.73	0.25 / 0.6
Sgr	0.25	0.335	0.42
Gas mobility (nLiq / nG)	6 / 2.2	4.6 / 2.2	3.2 / 2.2
Drainage only: Gravity instability impact (nG)	1.4	1.7	1.9

The CO_2-water relative permeability curves were based on the Brooks-Corey model fitted to analogue data. Capillary pressure curves were based on the van Genutchnen model fitted to analogue data, assuming entry pressure (Pe) equals 0.363 psi, and pore size distribution index (I) equal 0.67.

Two sets of relative permeabilities featuring drainage and imbibition process were assigned to all grid blocks in model for SST and for clayey-SST facies. Low, mid, and high relative permeabilities and capillary pressure functions are shown in Figure 2-26. Additionally, fractional flow curves for the low, mid, and high cases are also shown (CO_2-water viscosity ratio of 0.094 assumed) in Figure 2-27.

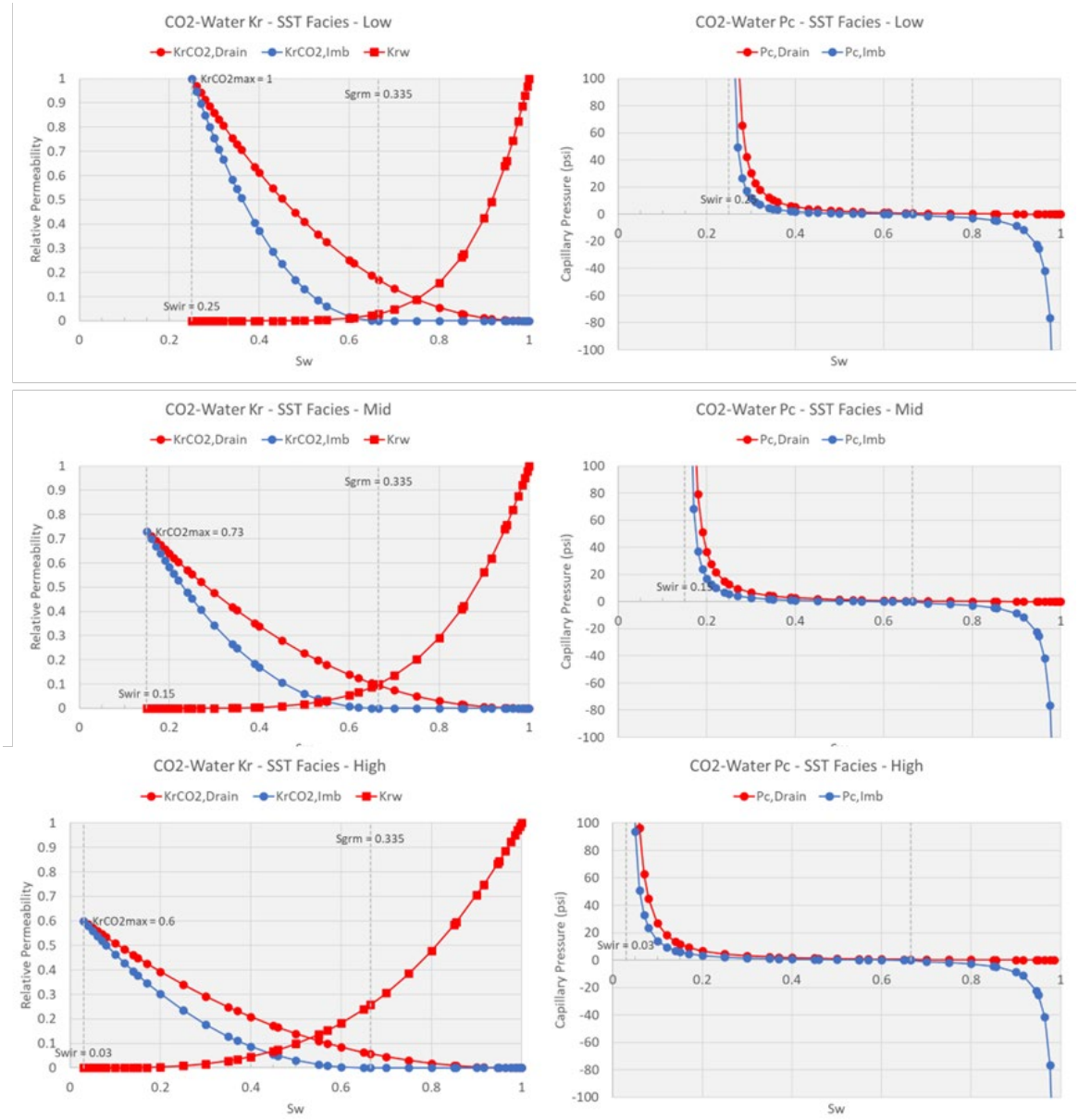


Figure 2-26 – Low, mid, and high relative permeabilities and capillary pressure for drainage and imbibition in SST facies used in CO_2 injection modeling for Hackberry.

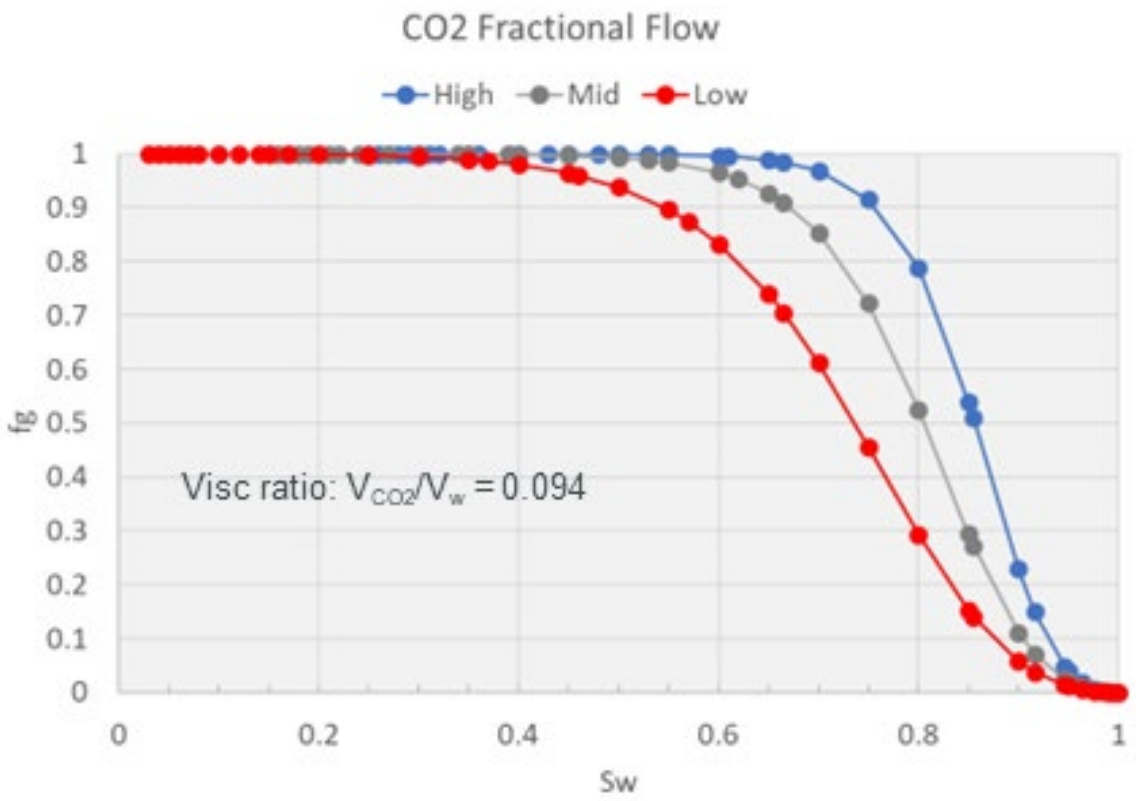
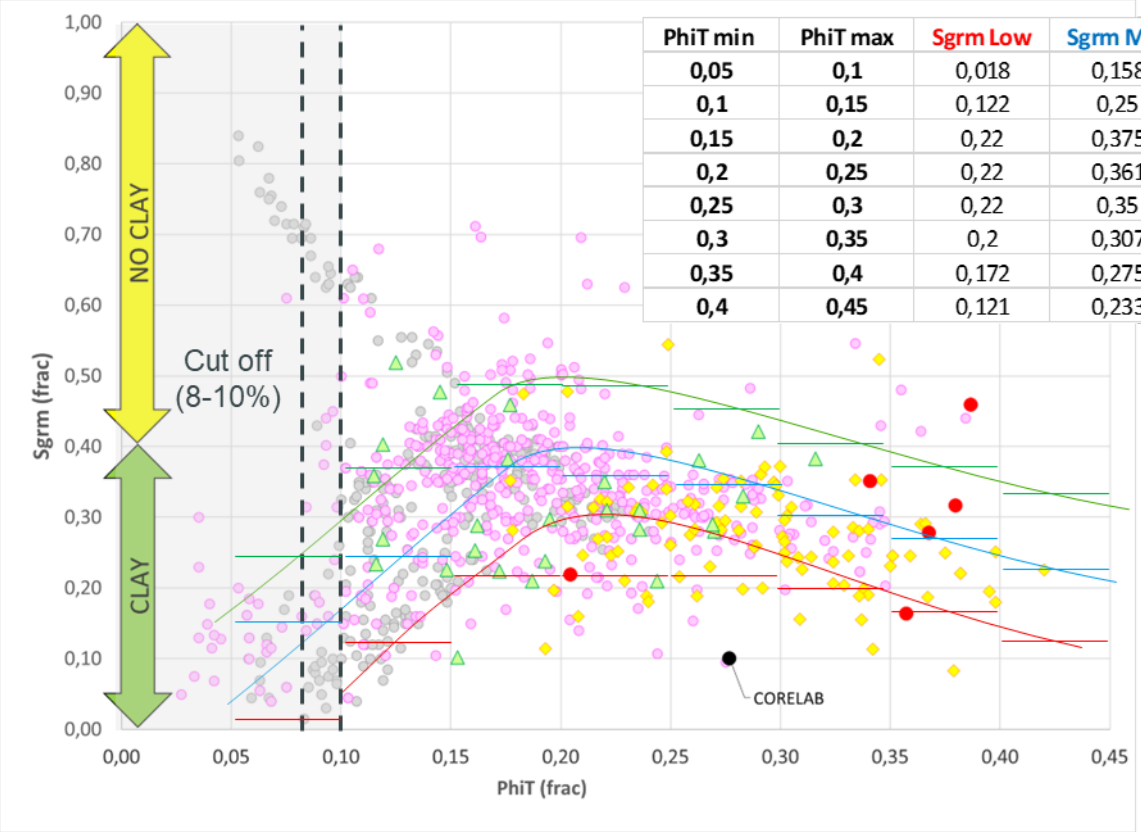


Figure 2-27 – Low, mid, and high CO_2-water fractional flow curves in SST facies used in CO_2 injection modeling for Hackberry.

2.3.2 Maximum Residual Gas Saturation

The maximum residual gas saturation (Sgrm) refers to the maximum amount of gas that remains trapped after as gas flows in the presence of water in the pore space. This trapping occurs due to capillary forces within the reservoir rock. The maximum residual gas saturation is the highest proportion of immobile or trapped gas relative to the total pore volume of the rock. Higher Sgrm values are desirable as a larger portion of the injected CO_2 will remain trapped in the rock, reducing the risk of the fluid escaping vertically or laterally away from the storage site.

For this project, the maximum residual gas saturation was defined based on measurements collected by TotalEnergies's research center in Pau, France (Centre Scientifique et Technique Jean Féger, CSTJF) for consolidated rocks (research by K. Suzanne and G. Hamon, 2002, and Northern Lights CO_2 laboratory sample tests), unconsolidated rocks, and analogue data from CO_2-water publicly available data (Burnside and Naylor, IJGGC, 2014). The Sgrm was correlated with total porosity (PhiT) as demonstrated in Figure 2-28. For systems with some clay content, as total porosity decreases, Sgrm increases up to a point where the relation reverses. Three stepwise Sgrm functions of PhiT representing low, mid, and high estimates of Sgrm are shown in Figure 2-28. Intrinsically, porosity vs. depth trend determines Sgrm variability with depth for Hackberry.

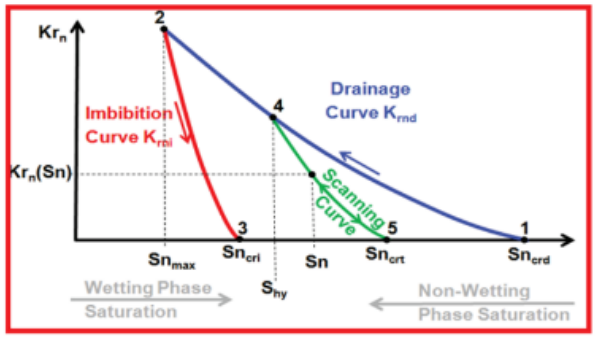


PhiT min	PhiT max	Sgrm Low	Sgrm Mid	Sgrm High
0,05	0,1	0,018	0,158	0,25
0,1	0,15	0,122	0,25	0,375
0,15	0,2	0,22	0,375	0,49
0,2	0,25	0,22	0,361	0,49
0,25	0,3	0,22	0,35	0,459
0,3	0,35	0,2	0,307	0,408
0,35	0,4	0,172	0,275	0,375
0,4	0,45	0,121	0,233	0,359

Figure 2-28 – Maximum residual gas saturation relationship with total porosity.

2.3.3 Hysteresis Model

The Killough hysteresis model, as shown in Figure 2-29, was used in CO_2 injection studies for the Hackberry project. This model accounts for the hysteresis effects in relative permeabilities in reservoir simulation in INTERSECT™ and refers to the observation that the relative permeability for a given fluid saturation differs depending on whether the saturation is increasing or decreasing. The Killough hysteresis model includes the concept of scanning curves, which are intermediate paths of relative permeability between the primary drainage and imbibition curves.



Feuille de calcul:

Trapped critical saturation: Sncrt → Land correlation

$$S_{ncrt} = S_{ncrd} + \frac{S_{hy} - S_{ncrd}}{1 + C(S_{hy} - S_{ncrd})} \quad \text{where} \quad C = \frac{1}{S_{ncri} - S_{ncrd}} - \frac{1}{S_{n\,max} - S_{ncrd}}$$

Usually: $S_{ncrd} = 0$ → $S_{ncrt} = \frac{S_{hy}}{1 + C \cdot S_{hy}}$ where $C = \frac{1}{S_{ncri}} - \frac{1}{S_{n\,max}}$

Scanning curve Krn(Sn)

$$K_{rn}(S_n) = \frac{K_{rni}(S_{norm}) K_{rnd}(S_{hy})}{K_{rnd}(S_{n\,max})} \quad \text{where} \quad S_{norm} = S_{ncri} + \frac{(S_n - S_{ncrt})(S_{n\,max} - S_{ncri})}{S_{hy} - S_{ncrt}}$$

Rem: for convergence issu that might appear when S_{hy} is small, a paramater "a" as been introduced (item 4 of EHYSTR) so that:

$$S_{ncrt} = S_{ncrd} + \frac{S_{hy} - S_{ncrd}}{A + C(S_{hy} - S_{ncrd})} \quad \text{where} \quad A = 1 + a \cdot (S_{n\,max} - S_{hy})$$

Rem: a is defaulted to 0.1

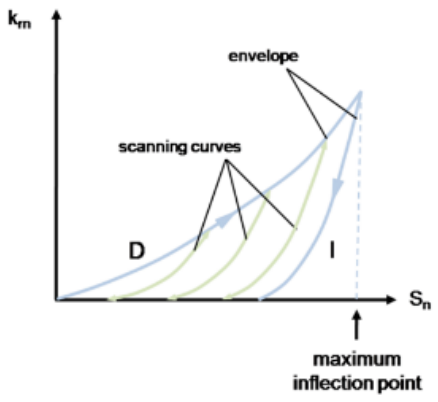


Figure 2.22. Non-wetting phase kr hysteresis: Killough reversibility

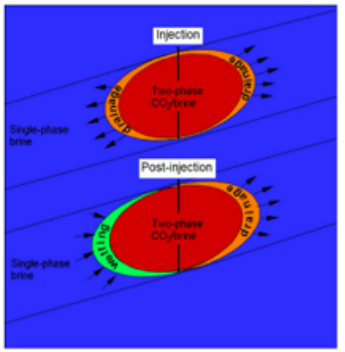


Fig. 1. Schematic of CO_2 injection period (top), in which drainage occurs at all plume boundaries, and post-injection period (bottom), in which drainage occurs at the leading edge of the plume on the right and wetting occurs at the trailing edge of the plume on the left as the plume migrates, e.g. by buoyancy forces.

Figure 2-29 – Killough Hysteresis Model and Scanning Curves

2.3.4 Fluid Modeling

The composition of the injection stream is defined with 98% CO_2 and 2% methane (CH_4). This composition is based on the Cameron LNG simplified composition stream, in which higher molecular weight components and some impurities have been removed from the stream.

In terms of the EOS, the fluid model uses the Peng-Robinson EOS, specifically calibrated for a binary system comprising CO_2 and methane (CH_4). The injected fluid has 2% lower density and 5% higher compressibility relative to pure CO_2. Compared to the Cameron LNG full composition stream, the difference in density and compressibility is negligible, as shown in Figure 2-30.

At Reservoir Conditions	Pure CO2	CLNG Full Comp	CLNG Simplified Comp
Density, kg/m3	812.2	793.8	794.3
Compressibility, 1/bara	0.00129	0.00135	0.00135
Viscosity, cP	0.0715	0.0698	0.0697
Critical temperature, °C	31.0	29.9	29.8
Critical pressure, bara	73.8	75.1	75.0
Molar amount, mole%			
CO2	100	98.2691	98.3900
WATER	0	0	0
N2	0	0.0010	0
O2	0	0	0
H2	0	0	0
METHANE	0	1.6102	1.6100
CO	0	0	0
H2S	0	0.0011	0
NO2	0	0	0
NO	0	0	0
SO2	0	0	0
ETHANE	0	0.0545	0
BENZENE	0	0	0
PROPANE	0	0.0344	0
nBUTANE	0	0.0125	0
ISOBUTANE	0	0.0051	0
HEPTANES	0	0.0044	0
OCTANES	0	0.0021	0
ISOPENTANES	0	0.0021	0
HEXANES	0	0.0011	0
nPENTANE	0	0.0011	0
NONANES	0	0.0008	0

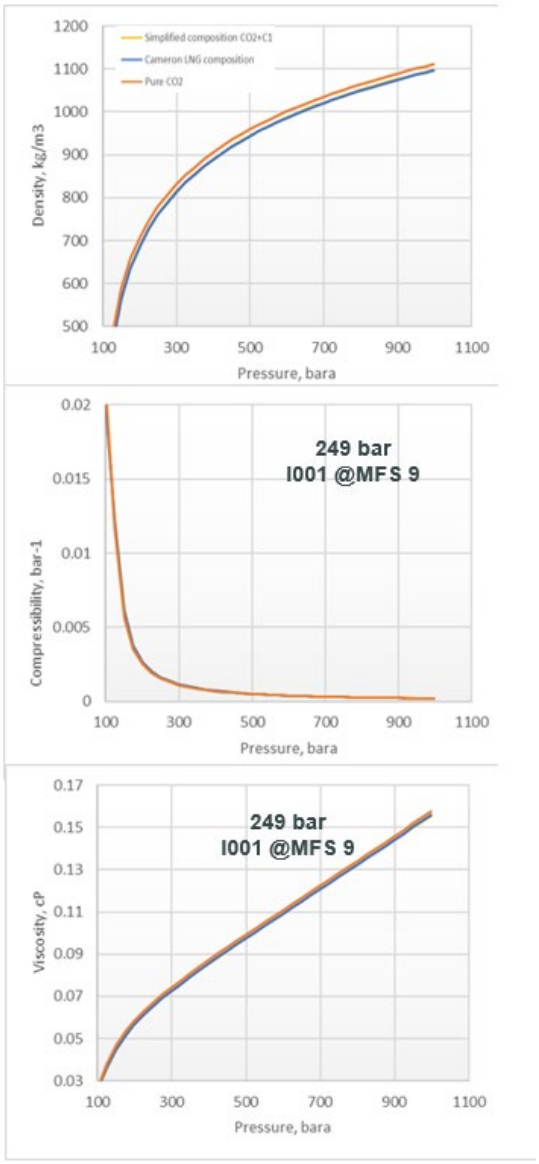
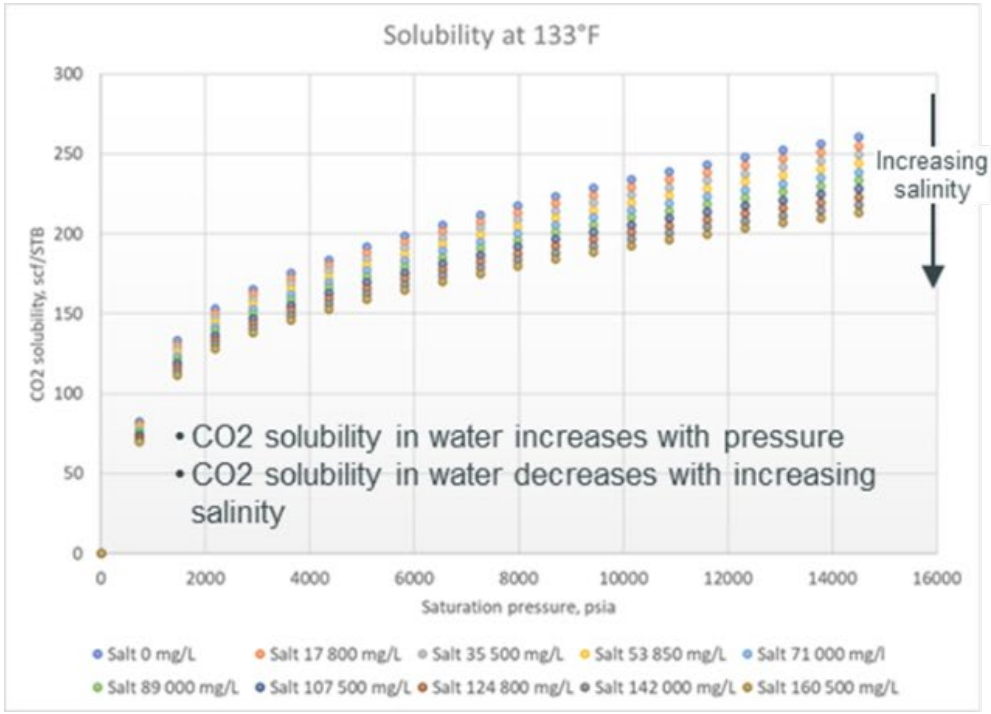


Figure 2-30 – Injection fluid composition streams and impact on density compressibility, and viscosity.

A crucial aspect in the development of the simulation model for HCS Well No. 001 was the creation of CO_2 solubility in brine tables. These tables were defined to reflect variations in pressure, salinity, and temperature of CO_2 solubility at injection condition in the reservoir, as shown in Figure 2-31. The tables were generated by subject matter experts at TotalEnergies's research center in Pau, France (CSTJF) and span a comprehensive range of injection conditions expected in Hackberry. The modeling of CO_2 solubility uses the Soreide and Whitson modification of the Peng-Robinson EOS. These tables are focused on CO_2, with methane and other hydrocarbon components not directly considered due to their perceived negligible solubility. The CO_2 solubility tables were exported for CO_2 injection modeling in INTERSECT and are the basis for CO_2 solubility trapping mechanism in the Hackberry model.



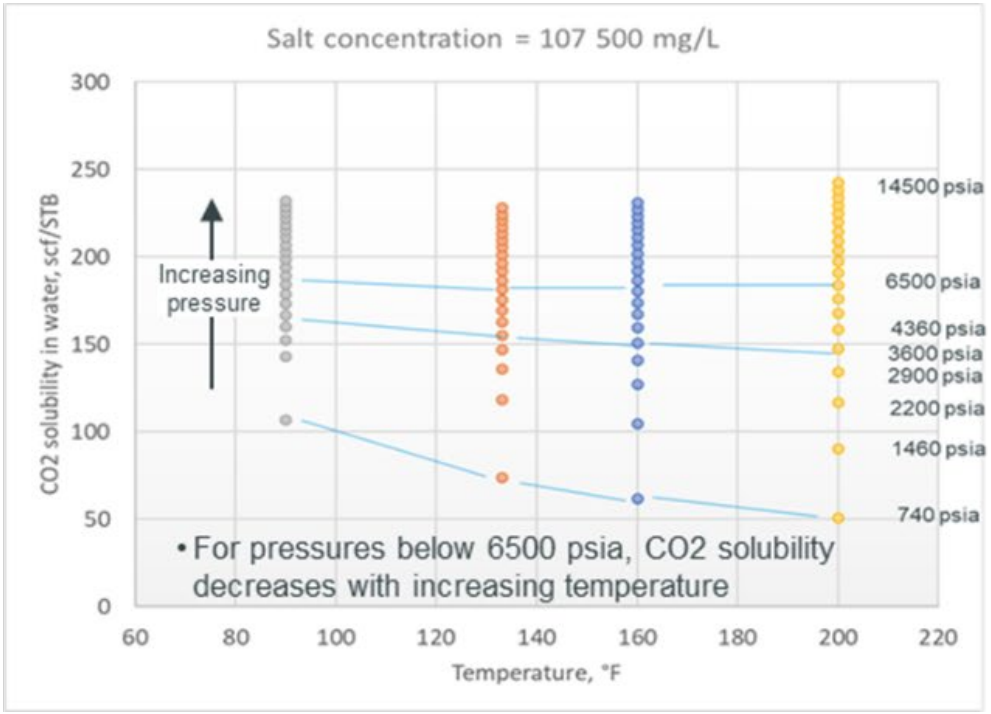


Figure 2-31 – CO_2 solubility in water as a function of pressure, temperature, and salinity.

The dynamic model is initialized using the Peng-Robinson EOS with CO_2 solubility tables. This initialization is critical for accurately simulating the behavior of the injected fluid under reservoir conditions for Hackberry.

2.3.5 Initial Pressure and Temperature Estimation

A regional pressure trend of 0.465 psi/ft was initially considered (0.480 psi/ft observed at LA Storage SWD No. 003 data (SN 975774)), as shown in Figure 2-32.

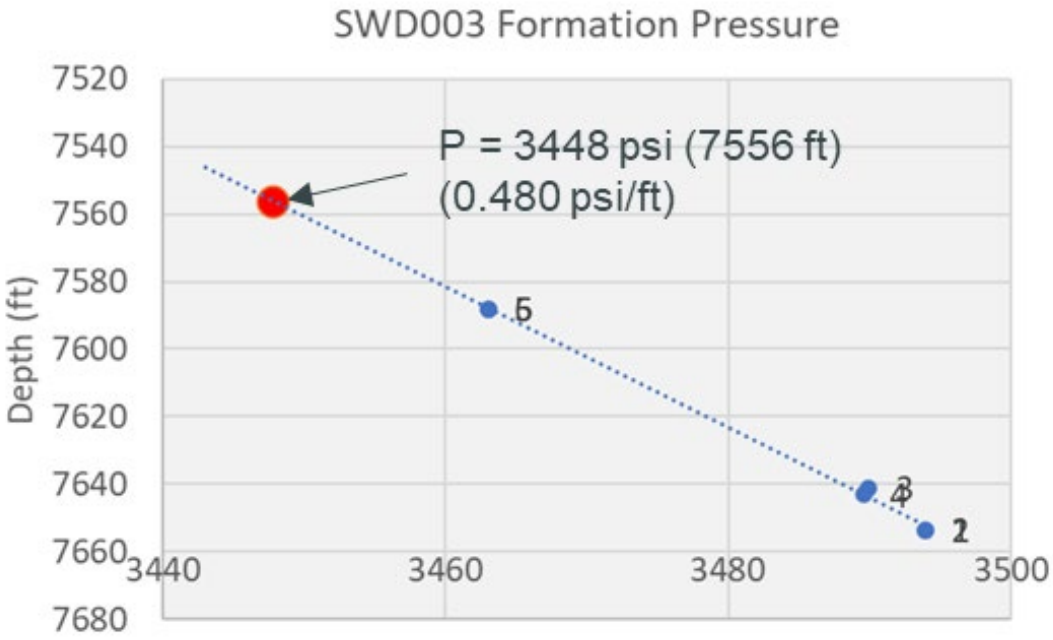


Figure 2-32 – LA Storage SWD No. 003 (SN 975774) Formation Pressure

Publicly available data from USGS (2011) was used to estimate pressure and temperature in the Louisiana region at Hackberry (Figure 2-33 and Figure 2-34). Based on these data, the estimated pressure is 3,514 psi at 7,556 ft (top of perforations), with no overpressure expected in the Miocene (0.70 psi/ft reached in Anahuac sands at 10,000 ft to 11,000 ft). Reservoir temperature gradient is expected to be 0.85°F/100 ft, leading to a temperature of 132°F at 7,556 ft.

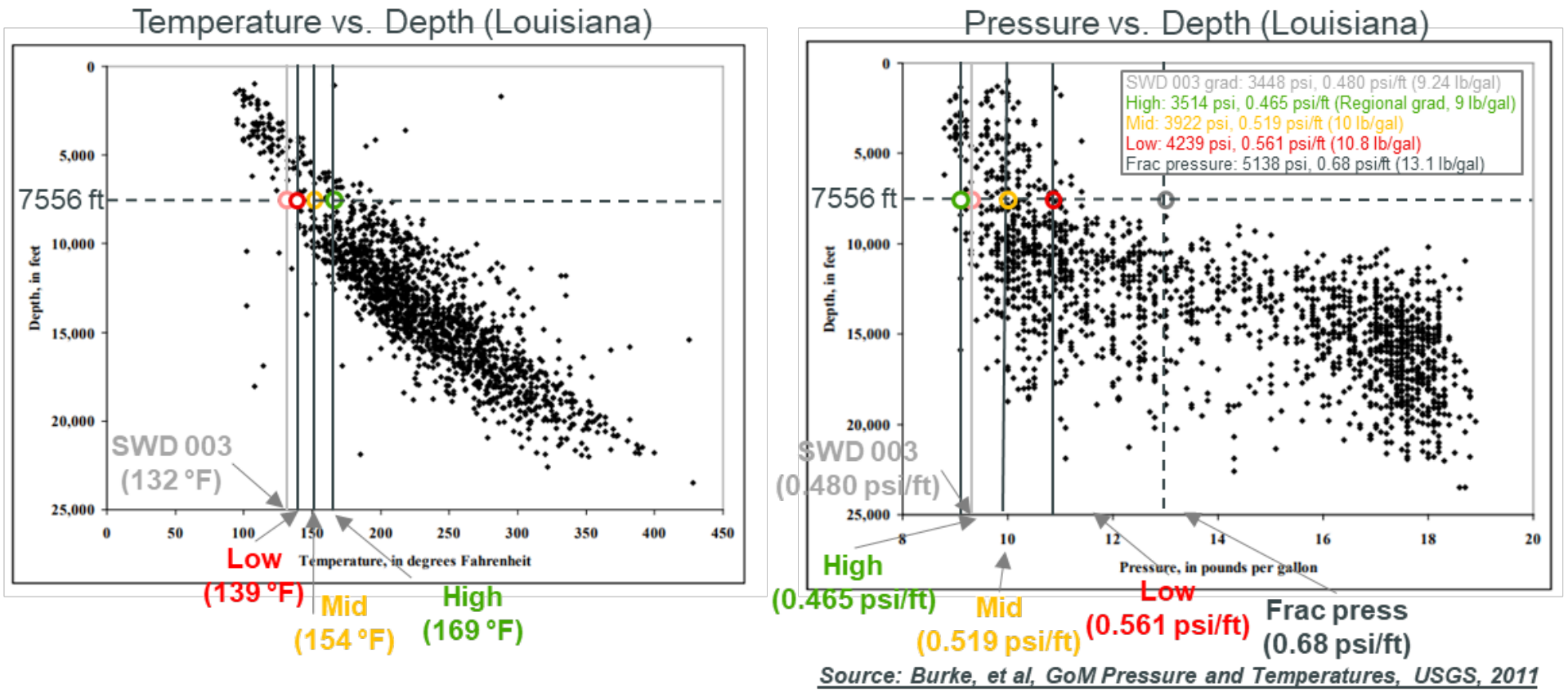
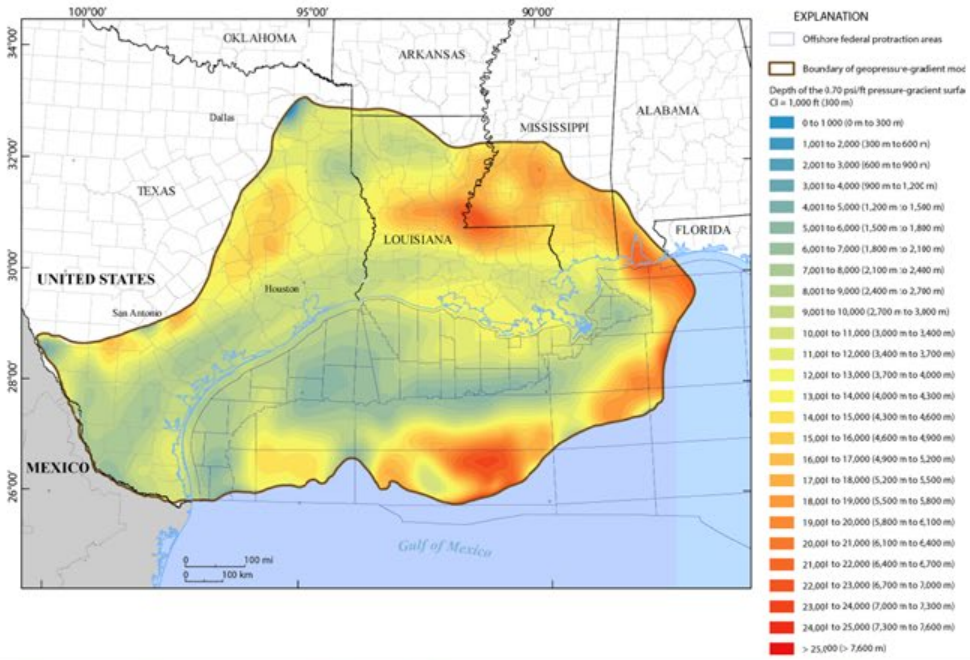
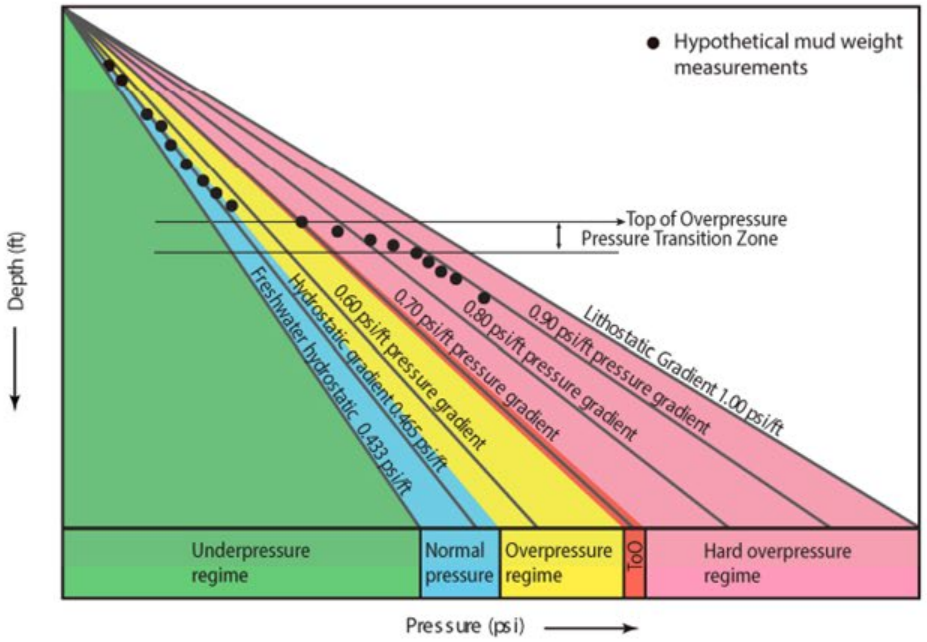


Figure 2-33 – Pressure and Temperate Estimates for Hackberry





Source: Burke, et al, Top of Overpressure map (0.7 psi/ft pressure gradient), 2012

Generalized pressure gradients and associated pressure regimes

Figure 2-34 – Top of Overpressure and Generalized Pressure Gradients

2.3.6 Faults

In the simulation model, a total of 14 faults are defined, all with northwest-southeast direction, as shown in Figures 2-35 and 2-36. These faults are modeled under the assumption that they act as partial barriers or baffles to flow. However, in terms of their own properties, these faults are characterized by a complete lack of permeability within the fault zone itself. Consequently, they do not facilitate any lateral or vertical flow, thus preventing any form of leakage through them.

These faults were defined with transmissibility multiplier (TM) of 0.1 in the base-case model (partially open), to 0 in the low case model (completely sealing), and to 1 in the high case model (open).

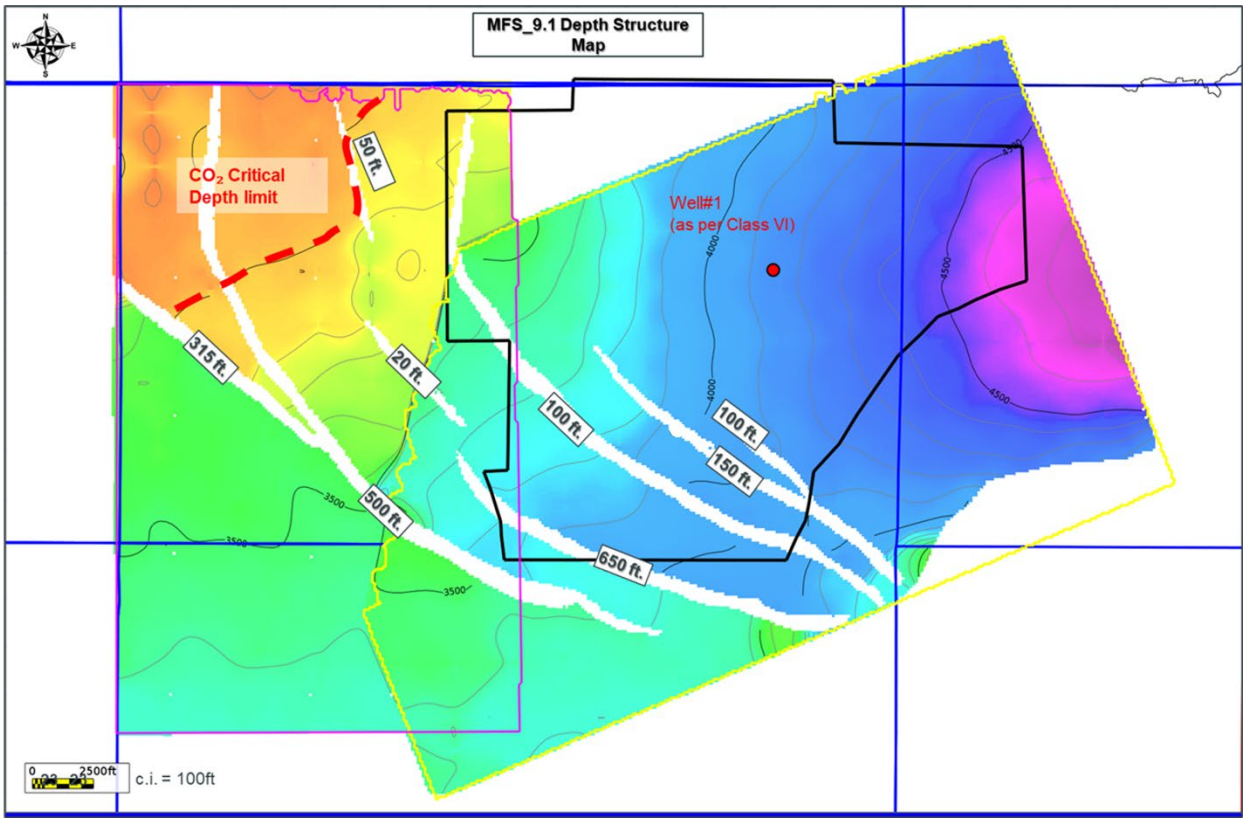
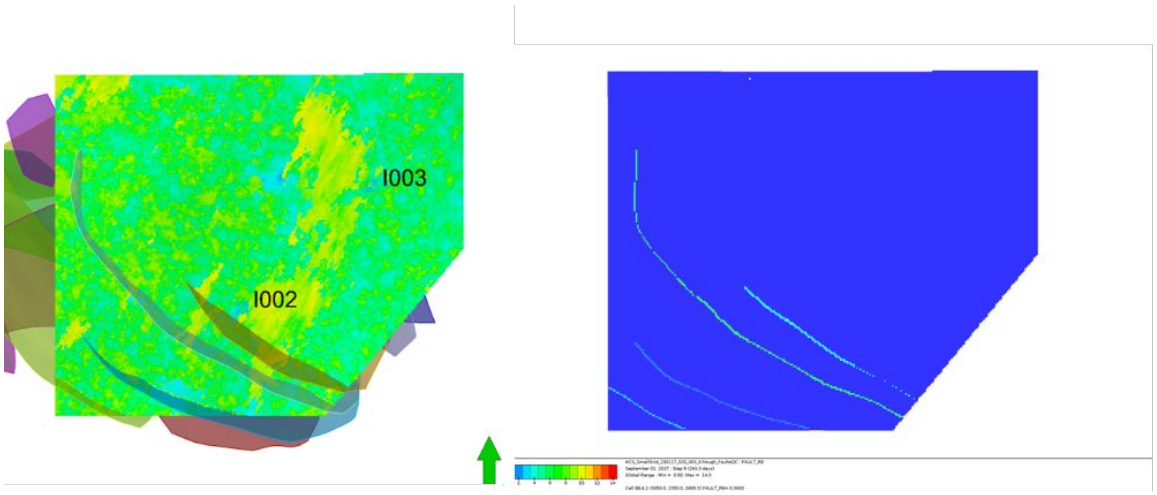


Figure 2-35 – Structure Map and Fault Throws



id	Fault in Petrel	Fault in IX	TM (Mid)
1	CJL_F01	Fault01	0.1
2	CJL_F02	Fault02	0.1
3	CJL_F03	Fault03	0.1
4	CJL_F04	Fault04	0.1
5	CJL_F05	Fault05	0.1
6	CJL_F06	Fault06	0.1
7	CJL_F08	Fault08	0.1
8	CJL_F09	Fault09	0.1
9	CJL_F10	Fault10	0.1
10	CJL_F14	Fault14	0.1
11	CJL_F16	Fault16	0.1
12	CJL_F17	Fault17	0.1
13	CJL_F18	Fault18	0.1
14	CJL_F21	Fault21	0.1

Figure 2-36 – Faults in the Static Model, at left, and Dynamic Model, right

2.3.7 Aquifer Modeling

A regional aquifer, extending the Hackberry storage aquifer area, is situated within robust and thick sand sections and is characterized by low to moderate activity. The Hackberry diapir, located to the east of the acreage act as no-flow boundary. In the southwest portion of the acreage there are low throw faults, which provide varying degrees of baffling, ranging from low to moderate (Figure 2-37).

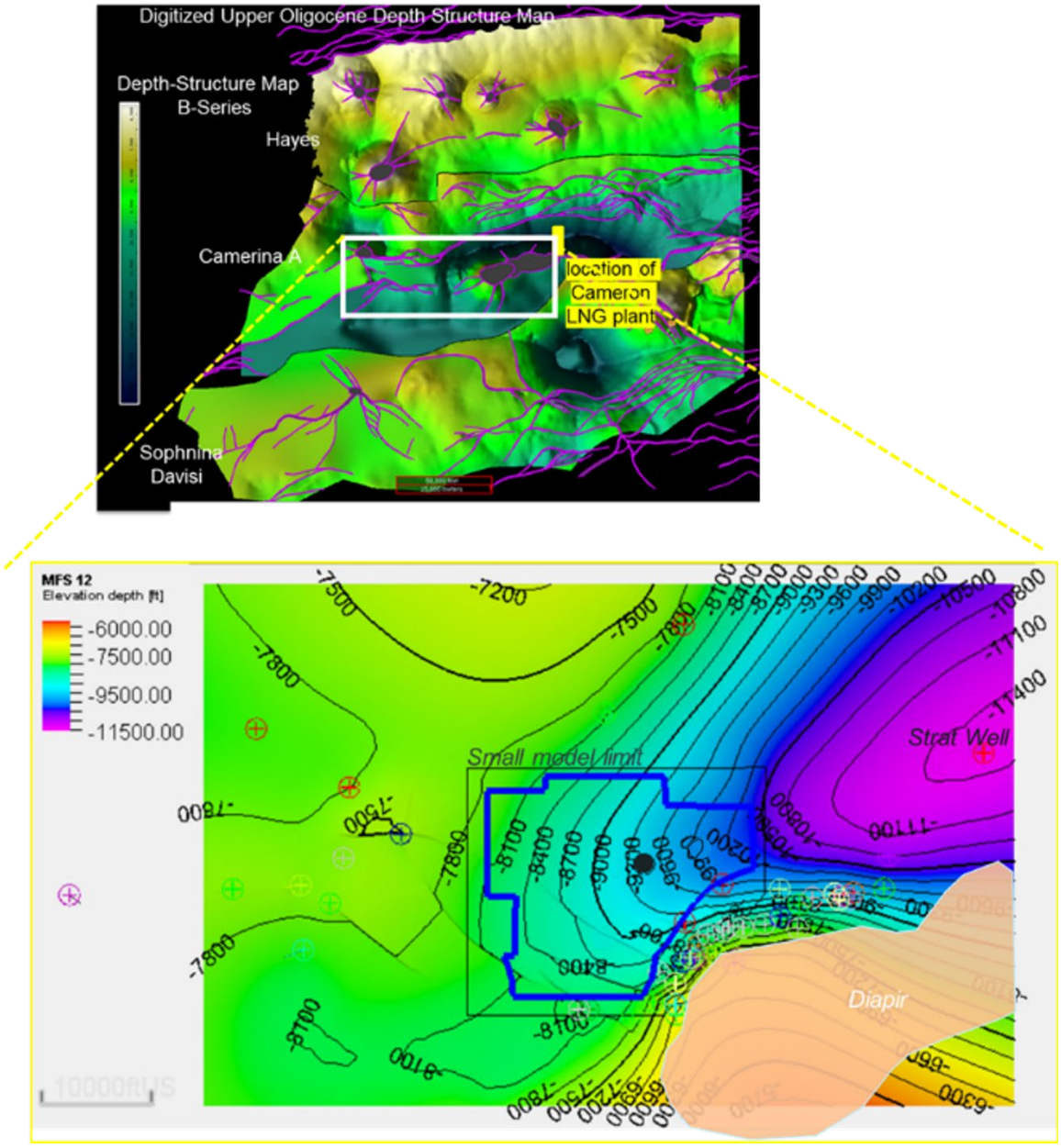
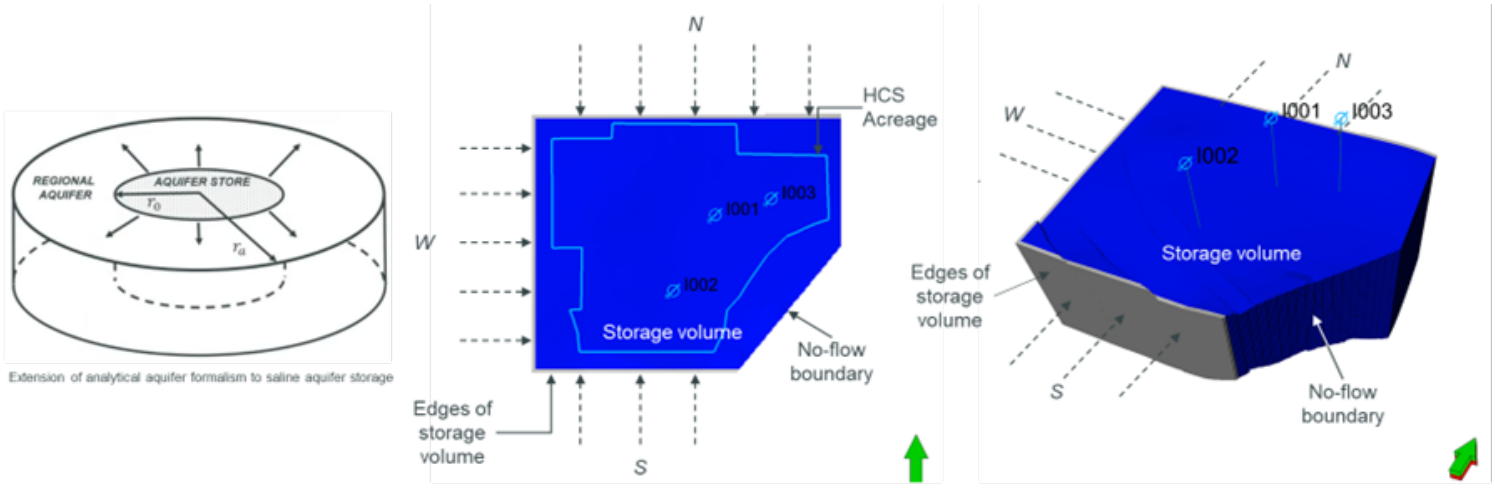


Figure 2-37 – Hackberry area extension.

In the simulation model, the Carter-Tracy analytical method is used to represent the influx/efflux of the regional aquifer for Hackberry. This model is defined with a ratio of external radius to internal radius (Re/Ri) set at 5. The Hackberry diapir located in the southeast is defined as a no-flow boundary (Figure 2-38). All parameters defined in Carter-Tracy analytical are shown in Table 2-4 and Figure 2-39.



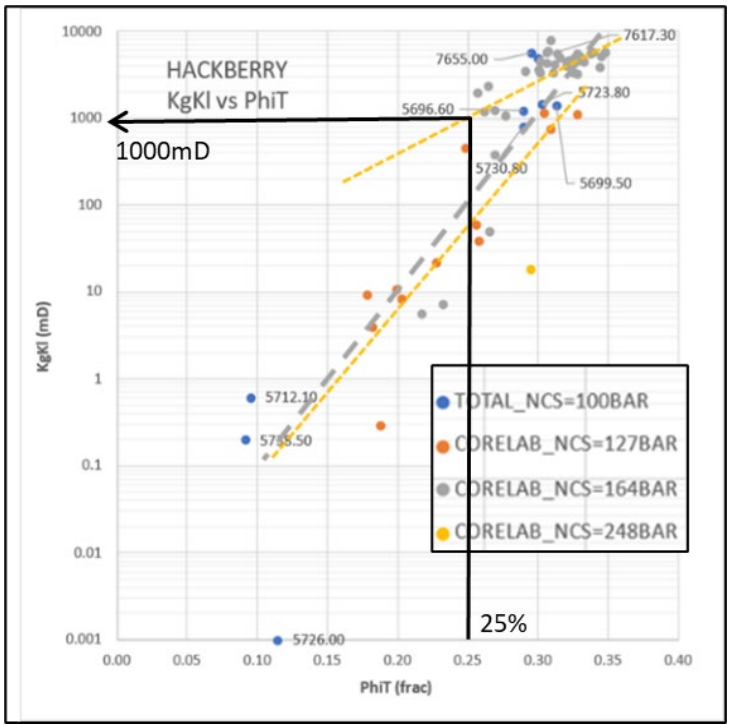


Figure 2-38 – Permeability vs. porosity relationship and model outlines showing flow boundaries.

Table 2-4 – Carter-Tracy Analytical Aquifer Model Representation and Parameters. The value of 1,000 mD is chosen by the reservoir engineer as a value representing an average value for the permeability prevailing in the Miocene aquifer surrounding Hackberry site (see Figure 2-38).

Carter-Tracy aquifer parameters	Value	Comments
Permeability (md)	1000	Based on core data
Porosity	0.25	Based on core data
Total compressibility (μpsi^{-1})	7	4.5e-6 (rock) + 2.5e-6 (water)
Re/Ri	5	Based on regional aquifer volume
Radius (ft)	19458	sqrt(2 * 27887 * 21325 / π))
Thickness (ft)	8000	Top to bottom (10600 ft - 2600 ft)
Angle	180	Encroachment angle
Salinity (g/l)	110	Based on SWD003 data

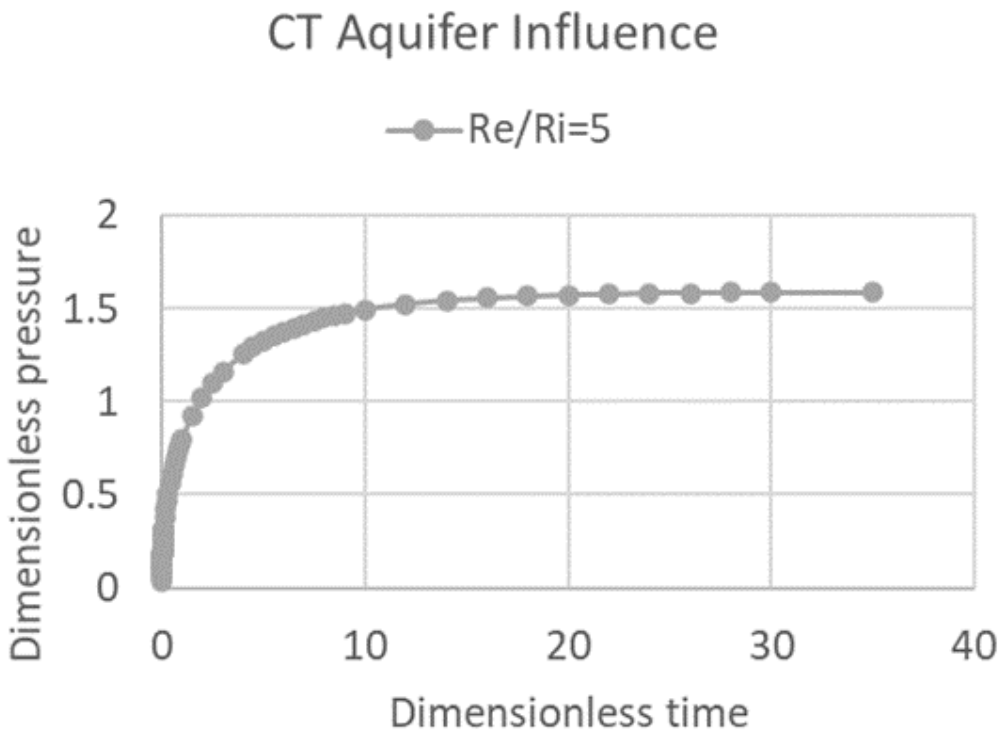


Figure 2-39 – Carter-Tracy Analytical Influence Model

2.3.8 CO_2 Injection Modeling and Simulation Platform

The modeling of CO_2 storage requires an accurate representation of specific subsurface elements and fluid characteristics which are essential to capture key physical phenomena associated with CO_2 storage, both during and after injection. One of the primary dynamics observed during injection is the upward migration of the CO_2 plume, predominantly controlled by convective currents from buoyancy effects. This buoyancy is a result of the density difference between CO_2

and the surrounding brine. Additionally, the solubility of CO_2 in buoyancy-induced flow is a crucial factor for CO_2 trapping, which plays a significant role in long-term stability and efficacy of CO_2 storage.

Another vital aspect to consider in the modeling process is the hysteretic behavior of CO_2 injection. This phenomenon occurs when CO_2, initially injected in supercritical state, becomes trapped in the pore spaces as it reaches its maximum residual CO_2 saturation following an imbibition process. This trapping mechanism is essential for long-term storage of CO_2, preventing it from migrating laterally or vertically. Understanding and accurately modeling this behavior is key to predicting the effectiveness of CO_2 storage saline aquifers.

Accurate prediction of CO_2 fronts and saturation levels away from the injection wells is also crucial and requires detailed representation of structural elements and high-resolution reservoir heterogeneities. The use of fine-scale grid blocks, both laterally and vertically, is imperative to capture the complexity of lateral and upward plume migration, as well as the dynamics of CO_2 solubility, which often manifests as CO_2 fingering. This level of detail helps avoid biases associated with grid upscaling, ensuring that the model closely mimics the actual behavior of CO_2 within the reservoir.

The model also incorporates rock type-dependent properties such as capillary pressure, relative permeabilities, and residual gas saturation (Sgr), as seen in Figure 2-40. These parameters are critical in determining how CO_2 interacts with the reservoir rock, influencing its movement and trapping within the formation. Accurate representation of these properties is essential for a realistic simulation of CO_2 storage. By integrating these complex geological and fluid dynamics, the model can provide reliable and comprehensive understanding of CO_2 storage in saline aquifers.

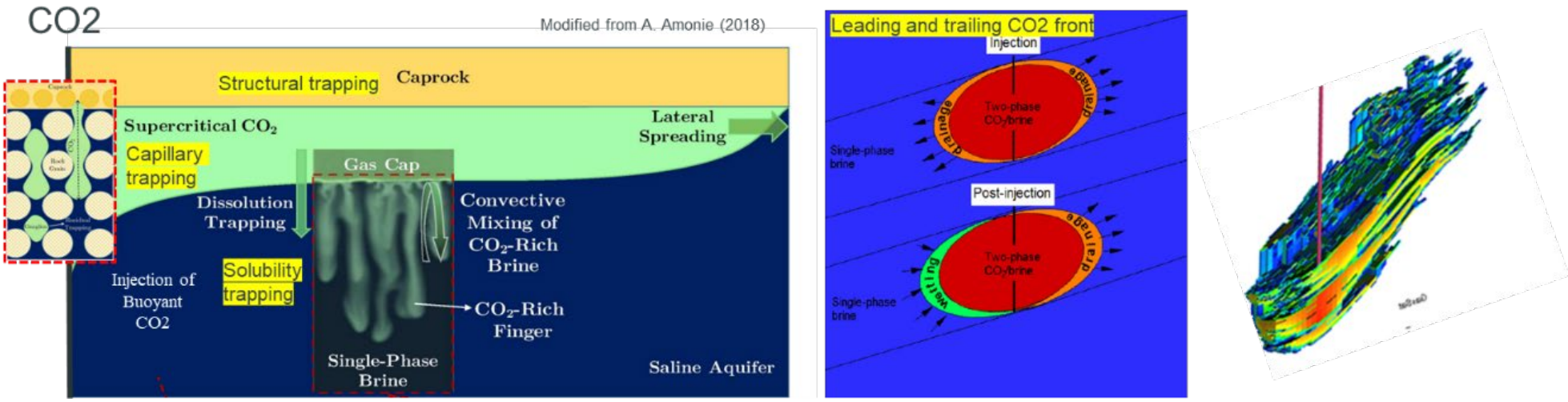


Figure 2-40 – CO_2 Injection Modeling

INTERSECT™ reservoir simulation software (version 2023.2), released in November 2022, was used to model CO_2 injection for Hackberry. This software features an advanced compositional modeling specifically designed for CO_2 injection, which includes salinity-dependent solubility. All dynamic simulations for Hackberry used parallel computing with 572 cores running on TotalEnergies' Pangea supercomputer cluster. Using INTERSECT with parallel computing allows the possibility to simulate the large models with several millions of cells with speed-up varying from 10x – 60x compared to other commercial simulators such as ECLIPSE™.

2.3.9 Simulation Grid

Two grids were designed and populated with all static and dynamic parameters for the purpose of modeling CO_2 injection, as shown in Figure 2-41: (1) large-extension grid, focused on pressure dissipation in an extended Hackberry area, with 111.8 million grid blocks (720 x 465 x 334), and (2) small-extension grid, focused on plume migration and sweep efficiency within the Hackberry acreage, with 20.8 million grid blocks (236 x 220 x 359). For most of the dynamic modeling results presented in this study, the small-extension grid was used, which covers the entire 13,600-acre (55 km^2) Hackberry property.

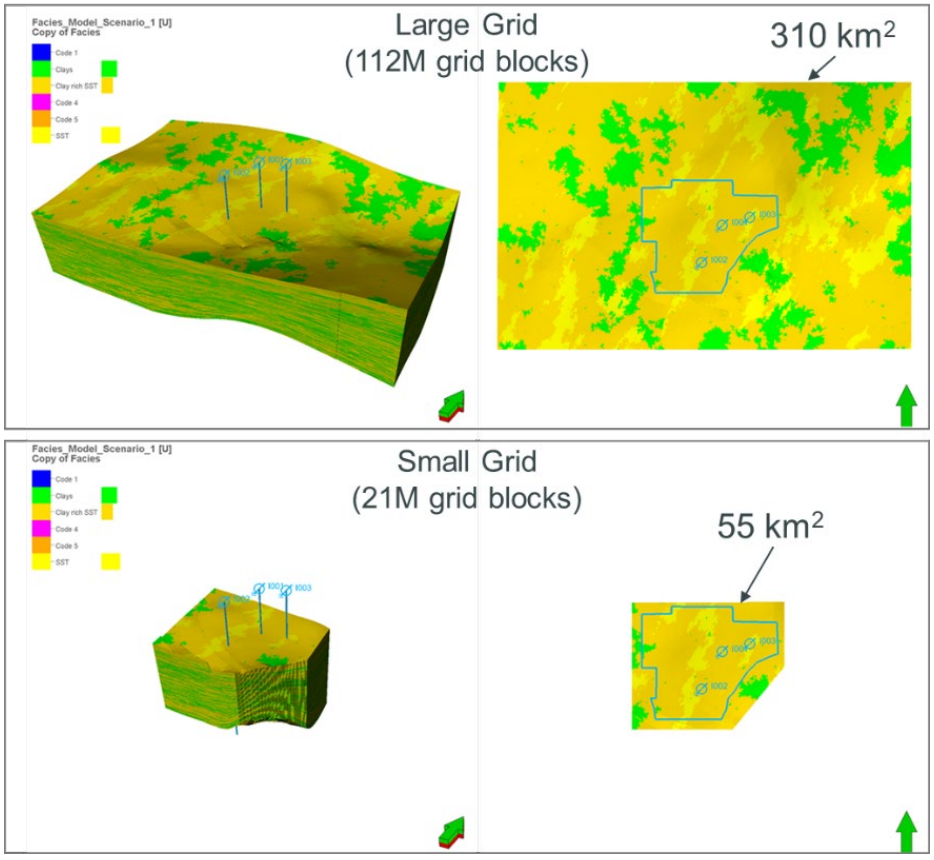


Figure 2-41 – Hackberry simulation grid. Top: large-extension grid. Bottom: small-extension grid.

2.3.10 Base-Case Parameters

The original base case for CO_2 injection at Hackberry was defined using the static and dynamic parameters described as follows. This model was set up and initialized in INTERSECT™ simulation framework.

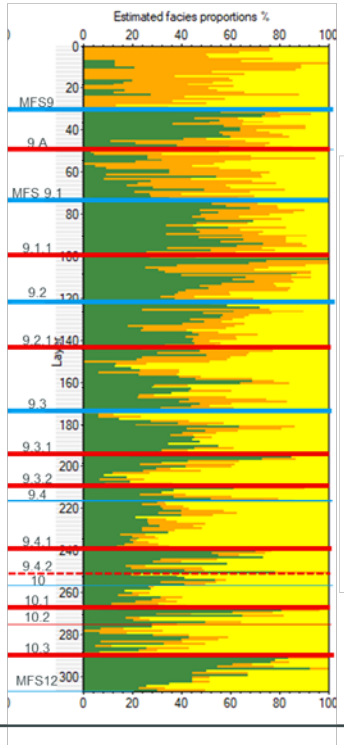
- Geological model
  - Based on geological Scenario 1 (Sequential Indicator Simulation (SIS) modeling)
  - Three facies: Sandstone or SST, clayey-Sandstone or silt and clay
- Faults
  - Transmissibility multiplier set to 0.1 (baffled connection)
- Regional aquifer
  - Carter-Tracy aquifer model, Re/Ri = 5, constant pressure limit
  - Aquifer model connected along sides of storage aquifer (except toward Hackberry dome in south-east, where there is a no-flow boundary)
- Pore volume compressibility
  - Cpv = 1.5 mpsi-1 at Pinit
- Relative permeabilities
  - SST: Swirr=0.15, Krgmax=0.73, nw=4.6, n CO_2=2.2
  - Clayey SST: Swirr=0.3, Krgmax=0.4, nw=4.6, ng=2.2
  - Sgrm: piece-wise function of PhiT
  - Killough hysteresis model
- Fluids
  - EOS PR, two components: CO_2 + CH4
  - CO_2 solubility tables varying with pressure, temperature, and salinity
- Initial reservoir conditions
  - Swini = 100%
  - Swirr = 15%
  - Pinit = 3,842 psi at 8,262 ft TVDSS
  - Salinity: 110 g/L (0.66 lb-mole/bbl)
  - Temperature = 133°F @ 8,262 ft TVDSS (91°F top – 158°F bottom)
- Injection
  - One well (HCS Well No. 001), start-up: Oct 1, 2027
  - Injection rate: from 1.0 MMT/yr (53.8 MMscf/d) to 2.0 MMT/yr (107.6 MMscf/d), for 20 years (Oct 1, 2047)
  - Uptime: 100%, no seasonality or TAR considered
  - Injection strategy: 20 completions bottom-up strategy, one flowing completion per year
- Post-injection monitoring
  - 100 years (Oct 1, 2147)

2.3.11 Injection Strategy

The completion strategy for CO_2 injection into HCS Well No. 001 was designed to meet the following objectives:

1. Maximize CO_2 storage capacity during the 20-year injection period; and
2. Minimize the lateral migration of the CO_2 plume from the injection well and minimize the critical pressure front over the entire 20-year period and beyond.

Twenty injection zones, defined as close as possible by stratigraphic sequences capped by lateral widespread shaly seals (the maximum flooding sequences or MFS), were built. The injection strategy then consists of bottom-up perforation campaigns, each of the 20 zones being open for injection for a one-year duration only (Figure 2-42). Further optimization of the injection strategy is likely to occur based on the stratigraphic results revealed by the drilling of the injector well. Effectively, further optimization may be obtained by injecting into the lower sand packages for a longer period in these sandstones for more than one year.



Top Perfos #	Zone	TVD SS (ft)	Thickness TVD ft	Injection Schedule	Injected CO2 volume (MT)	Cumulative Injected CO2 volume (MT)	Initial BHP (psi)	Max BHP (psi)	Max induced Pressure (psi)	Pc (Nicot) (psi)	Difference btwn max P and Pc (psi)
20	**Top 9.A**	4072	297	2047	2	40	1893	2769	53	73	20
19	**MFS 9.1**	4369	227	2046	2	38	2032	2971	54	80	26
18		4596	227	2045	2	36	2137	3125	41	85	44
17	MFS 9.1.1	4823	205	2044	2	34	2243	3280	54	90	36
16		5028	305	2043	2	32	2338	3419	312	94	-218
15	**MFS 9.2**	5333	247	2042	2	30	2480	3626	53	101	48
14	MFS 9.2.1	5580	249	2041	2	28	2595	3794	37	106	69
13		5829	340	2040	2	26	2710	3963	33	111	78
12	**MFS 9.3**	6169	222	2039	2	24	2869	4195	27	119	92
11		6391	222	2038	2	22	2972	4346	144	123	-21
10	MFS 9.3.1	6613	368	2037	2	20	3075	4497	50	128	78
9	MFS 9.3.2	6981	271	2036	2	18	3246	4747	89	136	47
8	**MFS 9.4**	7252	288	2035	2	16	3372	4931	61	142	81
7	MFS 9.4.1	7540	256	2034	2	14	3506	5127	63	148	85
6	MFS 9.4.2	7796	334	2033	2	12	3625	5301	53	154	101
5	**MFS 10**	8130	201	2032	2	10	3780	5529	34	161	127
4	**MFS 10.1**	8331	347	2031	2	8	3874	5665	38	165	127
3	**MFS 10.2**	8678	210	2030	2	6	4035	5901	71	173	102
2		8888	209	2029	2	4	4133	6044	63	177	114
1	**MFS 10.3**	9097	353	2028	2	2	4230	6186	82	182	100
Bottom	**MFS 12**	9450		*2027*							

Figure 2-42 – Injection strategy and definition of the 20 injection zones with maximum induced pressure with respect to critical pressure as per Nicot definition.

2.3.12 Base-Case Results

The expected facility capacity is a maximum of 2.0 MMT/yr whereas the most likely operating range during the first year of injection activity is estimated between 0.5 MMT/yr and 1.0 MMT/yr. Therefore, most of the sensitivities to geological and dynamic parameters presented in this report were performed on a 1.0 MMT/yr injection case. However, to define the maximum injection potential of the well, an injection rate of up to 2.0 MMT/yr is also tested.

Simulation results of CO_2 injection for Hackberry show that throughout the injection period in HCS No. 001, the CO_2 plume exhibits steady evolution, characterized by a consistent expansion across the injection interval following quick stabilization as injection stops after 20 years. Figure 2-43 shows the evolution of the plume at 5, 10, 20, and 120 years, represented as CO_2 volume (*HuPhiSg*), in the top-view maps.

The distribution of both trapped and mobile CO_2 is mostly uniform across the entire injection interval with few layers exhibiting relatively higher degree of lateral plume migration compared to others. Despite these variations, all CO_2 remained securely contained within the boundaries of the Hackberry acreage, ensuring no leakage across the storage boundaries.

In the lower zones of the reservoir, a higher concentration of dissolved CO_2 is observed, which is attributed to the increased pressure and temperature at these depths. This pressure-induced increased solubility is a critical factor in the overall storage efficiency and stability of the injected CO_2.

No vertical migration of the CO_2 plume during and after injection was observed above the successive MFS which act as geological barriers (Figure 2-44).

Based on this tested scenario, HCS Well No. 001 has the capability to safely inject 1.0 MMT/yr of CO_2 over a span of 20 years. This performance is achieved with minimal pressure drawdown, demonstrating the well's robustness and reservoir's suitability for long-term injection operations.

Note, in Figure 2-43 and 2-44, the term "*HuPhiSg*" corresponds to CO_2 thickness (while *Hu* stands for "useful height" or net thickness. *HuPhiSg* is equivalent to net thickness times porosity (Phi) times gas saturation (Sg). A wide range of CO_2 injection rates were tested in the dynamic model.

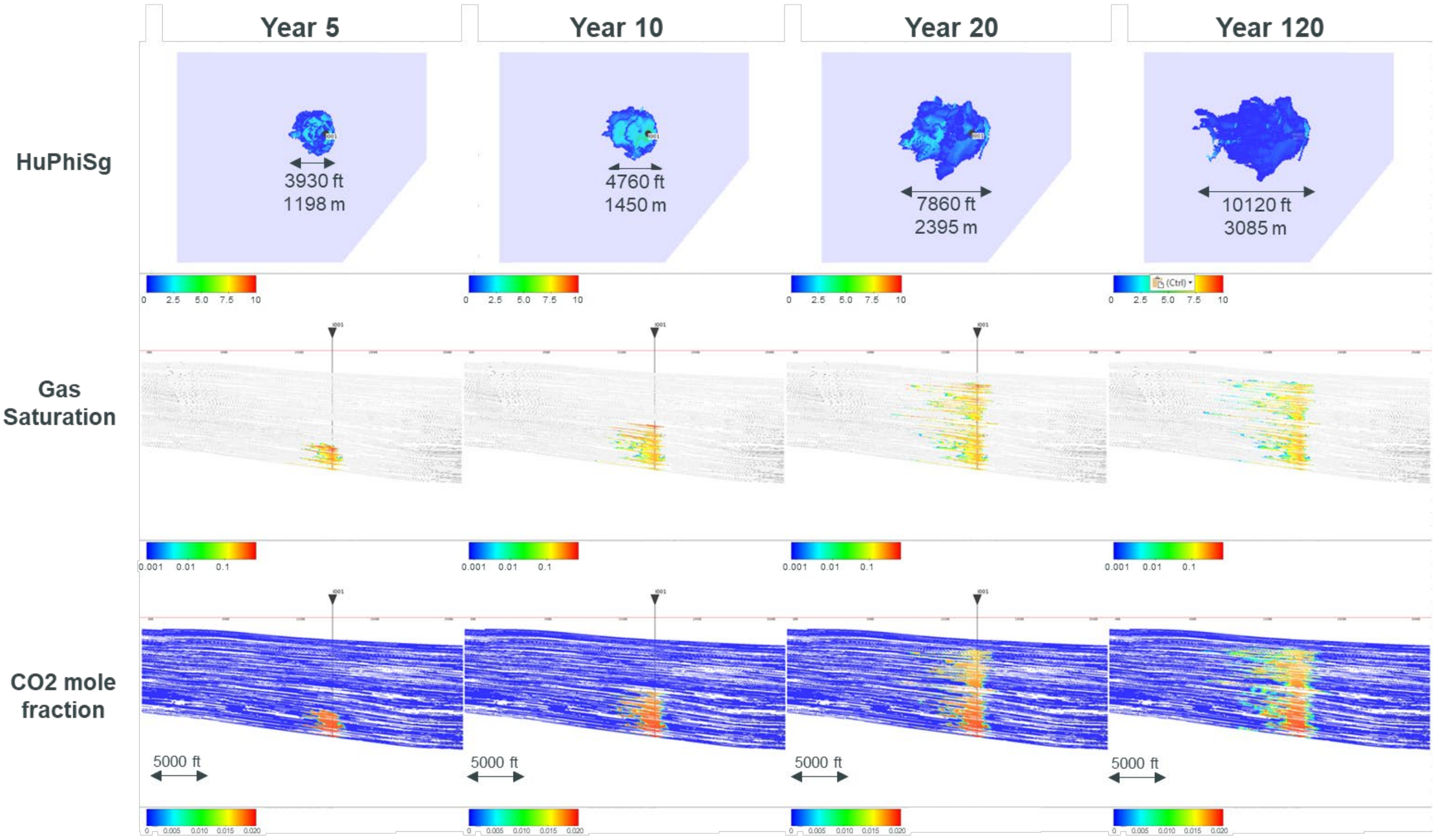
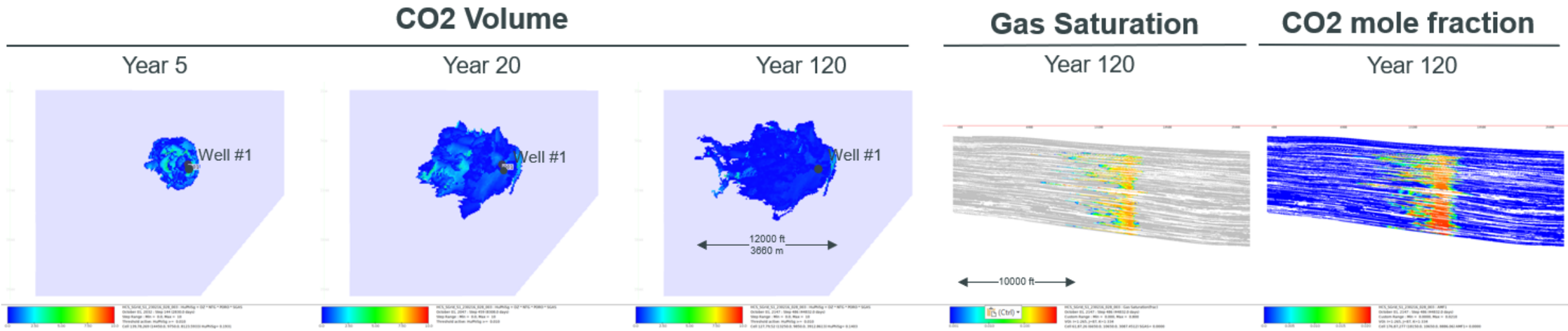


Figure 2-43 – Base Case Model Results, 1.0 MMT/yr (1)



Plume mostly concentrated around Well#1 smearing towards the West, as time increases, dominated by lateral/vertical heterogeneity, injection location and injection rate

- Trapped and mobile CO2 mostly distributed across the whole injection interval with few layers showing relatively more lateral plume migration than others, but all CO2 contained within the Hackberry acreage
- More CO2 dissolved in the lower zones due to higher pressure
- No vertical migration of the plume observed confirming MFS9 sealing capacity

Figure 2-44 – Base Case Model Results, Mobile and Trapped CO_2, 1.0 MMT/yr (2)

Bottomhole pressure in HCS Well No. 001 is characterized by distinct step changes, as seen in Figure 2-45. Each of these changes represents the opening of a completion to allow flow, which is maintained consistently throughout the duration of the injection phase. This systematic approach ensures a stable injection rate of 1.0 MMT/yr during the entire injection period.

Pore volume-weighted average reservoir pressure (water phase) exhibits a gradual increase as CO_2 is continuously injected. This increase in pressure is a direct consequence of the CO_2 injection within the reservoir. Once the injection phase ceases, pressure begins to dissipate leading to a return towards nearly initial conditions.

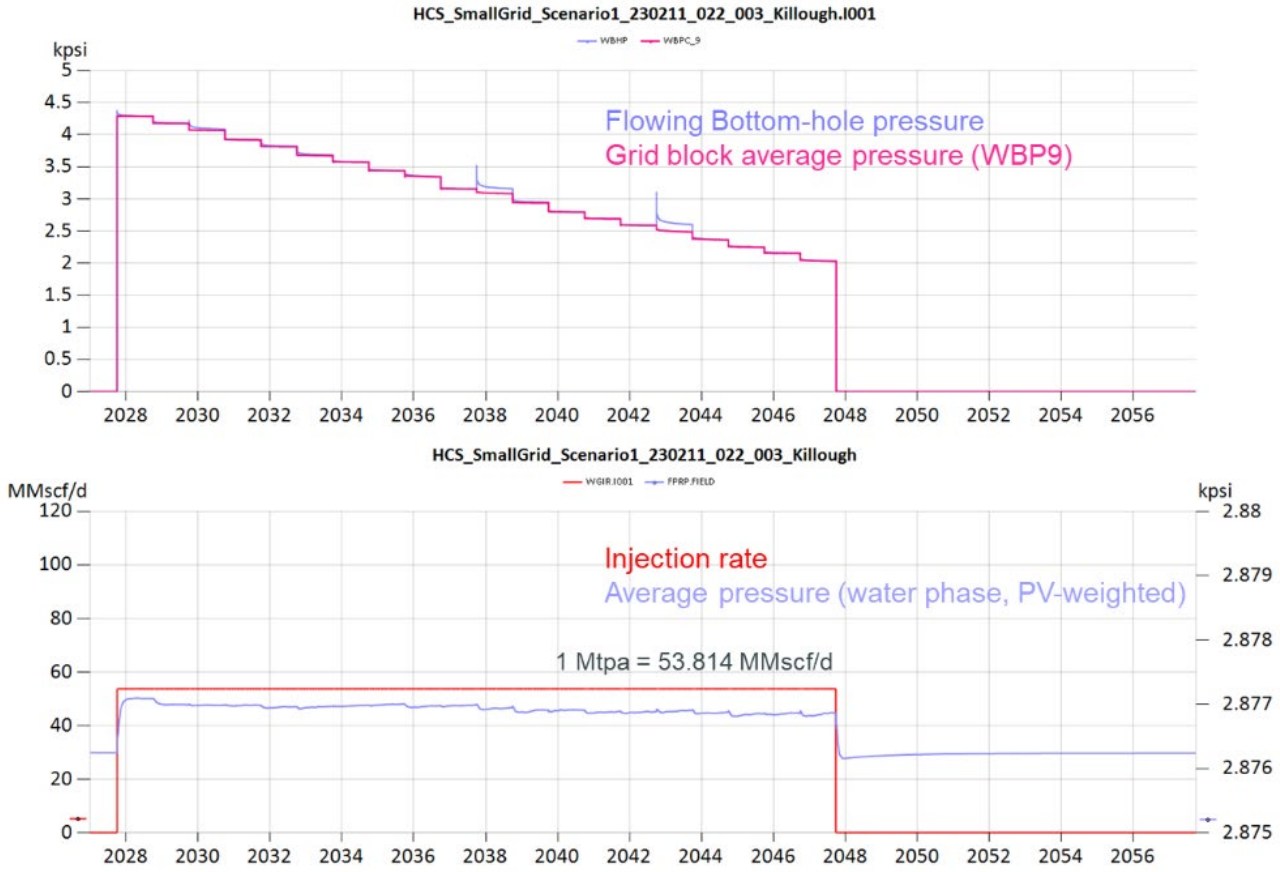


Figure 2-45 – Well-level injection results for the 1 MMT/Yr injection rate.

To accurately capture the pressure behavior and the transitions between completion operations (bottom-up completion strategy), log-spacing time-stepping was used in the simulation model, which allowed for detailed observation of the rapid changes in pressure and flow associated with injection. As the injection process progresses and the system stabilizes, these time steps were gradually lengthened. During injection, the maximum bottomhole pressure limit (by completed zone) is never reached indicating that HCS Well No. 001 can handle the injection volumes without exceeding maximum pressure constraints thus ensuring structural and operational limits (Figure 2-46). In terms of capacity, HCS Well No. 001 is capable of injecting 1.0 MMT/yr of CO_2 across all

completions over an extended period of 20 years. This consistent injection rate, achieved without reaching the maximum bottomhole pressure limit, underscores the efficacy of the well and the capacity of the aquifer to securely store CO_2.

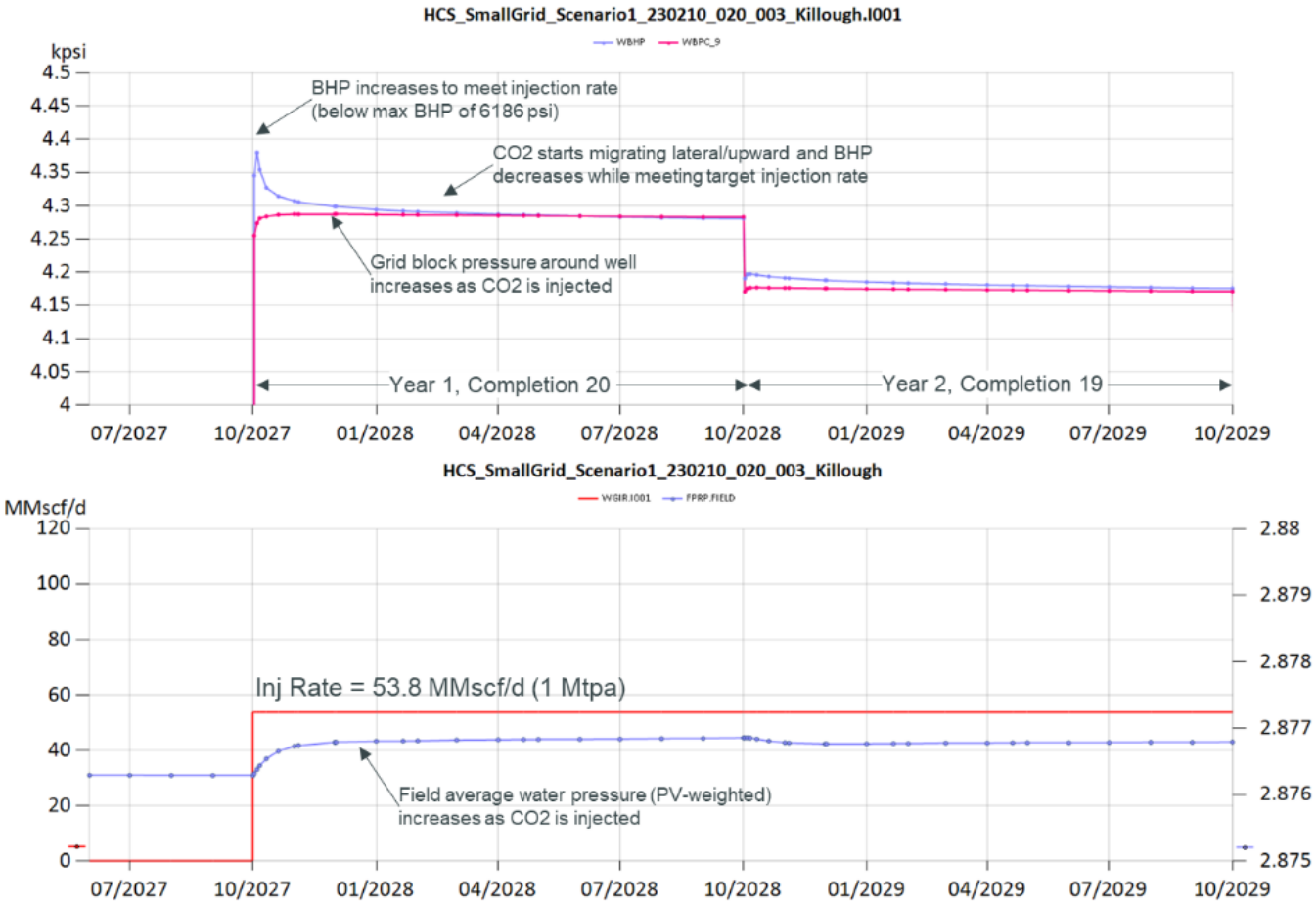


Figure 2-46 – Well-Level Injection Results (Extract)

Figure 2-47 shows the east-west cross section at HCS No. 001 at Year 5, 10, 20, and 120. During the 20 years of injection, CO_2 is injected according to 20-completions from bottom-up strategy. Three grid properties are shown: gas saturation, CO_2 concentration, and reservoir pressure (water). Gas migrates laterally and vertically according to the reservoir connective along HCS No. 001 while some gas is trapped due to CO_2 solubility during injection, and as injection moves from bottom to top completions, some gas is also trapped due to residual effects during the imbibition phase. These trapping mechanisms allow to safely inject CO_2 in HCS Well No. 001 for 20 years while maximizing reservoir exposure and avoiding vertical migration above MFS9.

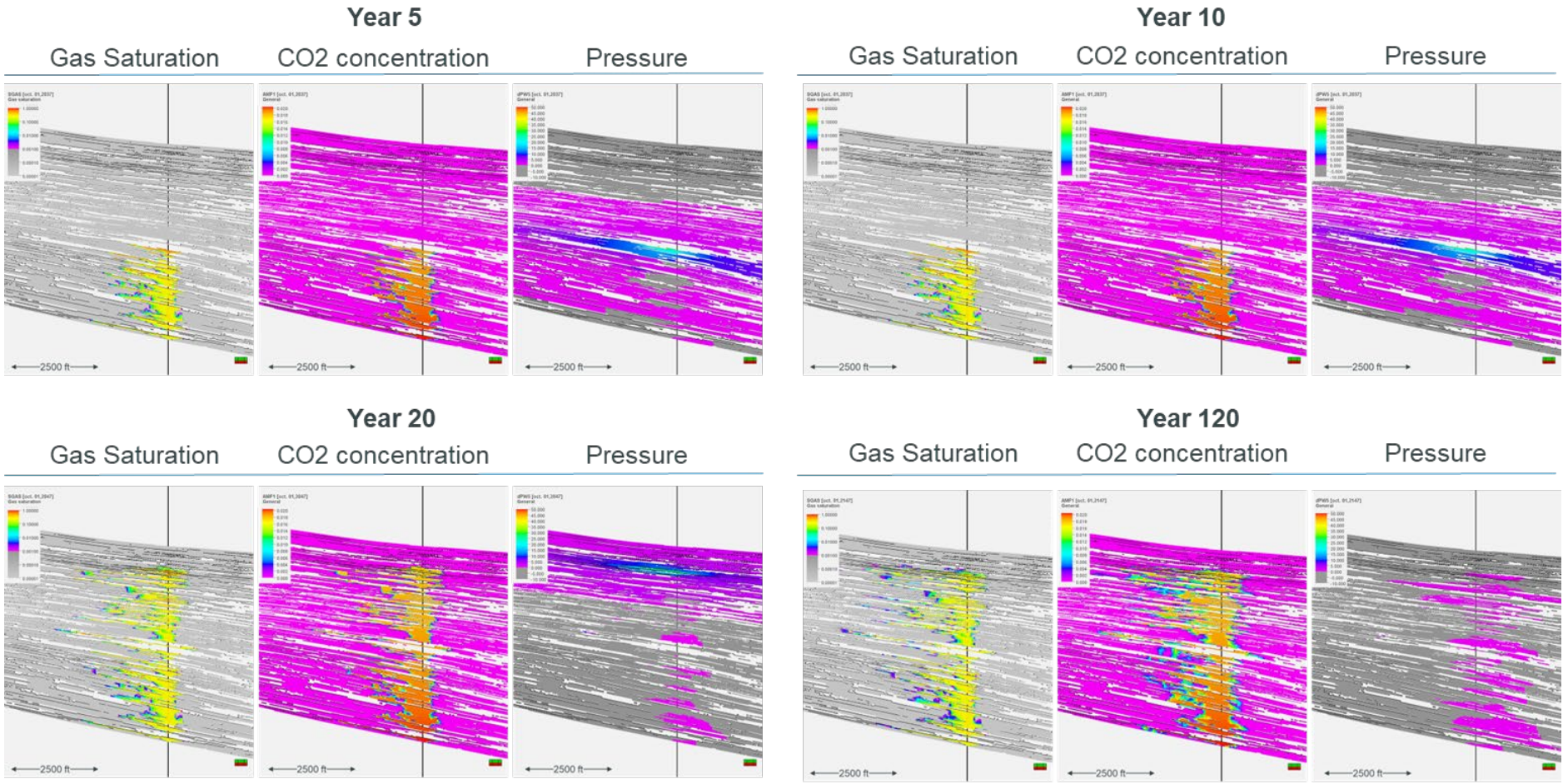


Figure 2-47 – Cross section views of the plume evolution during and after injection.

Figure 2-48 shows an aerial view of the CO_2 plume evolution at Year 5 and Year 20 (end of injection), and Year 120, for the 2.0 MMT/yr injection rate case, which is the maximum proposed rate for this project using the same injection strategy as the 1.0 MMT/yr case. As seen in the 1.0 MMT/yr case, the CO_2 plume, primarily centered around HCS Well No. 001, demonstrates a distinct movement pattern, gradually smearing westward over time. This directional spread is significantly influenced by the lateral and vertical heterogeneities of the subsurface formations, the specific location of the injection site, and the rate at which CO_2 is injected.

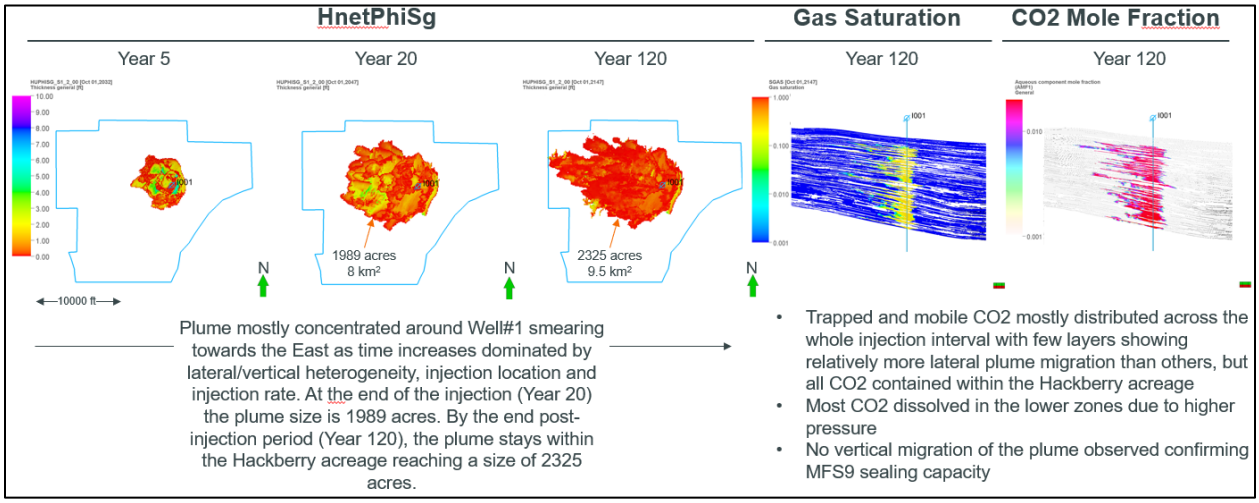


Figure 2-48 – Base Case Model Results, 2.0 MMT/yr

2.3.13 Critical Pressure Front

The concept of critical pressure (P_c) is integral to assessing the risk of fluid migration from the reservoir to unintended locations, such as the USDW. The critical pressure represents the minimum pressure required to drive fluids from the reservoir through any potential leakage pathways, such as improperly sealed wells or natural fractures. The calculation of critical pressure for Hackberry is based on methodology proposed by Nicot et al (2009), which considers the hydrostatic pressure, capillary pressure, and overlying column of water or fluids that might resist upward migration. The critical pressure represents the minimum pressure differential required to overcome the capillary and hydrostatic pressures resisting the upward migration of fluids, ensuring the containment of injected CO_2 within the Hackberry acreage.

The critical pressure was calculated based on the equation below:

$$P_c = \frac{1}{2g}(\rho_1 - \rho_u)(z_u - z_i)$$

where:

g: acceleration of gravity (9.81 m/s^2)
ρ_u: fluid density in the USDW (1,000 kg/m^3)
ρ_i: fluid density in the injection zone (1,100 kg/m^3)
z_u: depth to the base of the lowermost USDW (250 m)
z_i : depth of the top of the injection zone (m)

To delineate the extent of the critical pressure front, the simulation examines all grid blocks experiencing a pressure increase (Δp), relative to initial pressure, that exceeds the critical pressure difference (P_c). These blocks are then vertically stacked and analyzed across all time steps during injection, spanning the injection period of 20 years. The extent and shape of the critical pressure front (Figure 2-49) reflects the cumulative impact of injection operations over time, providing a basis for designing monitoring strategies and mitigating potential risks associated with CO_2 storage.

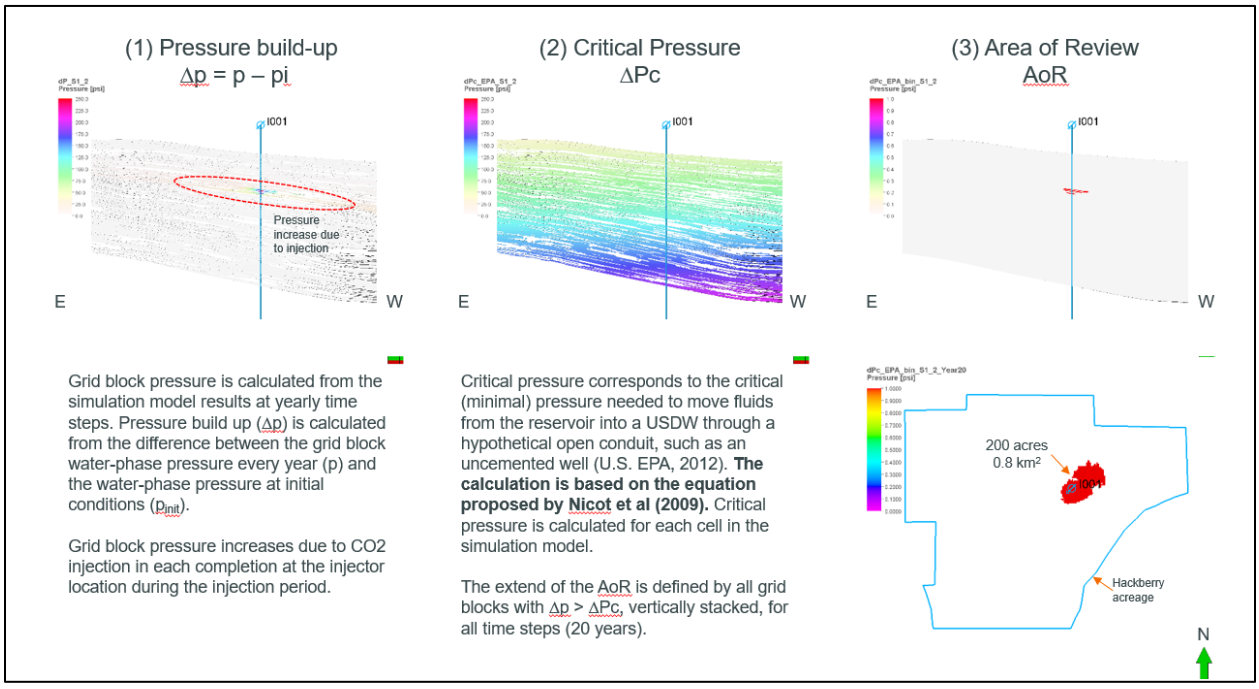


Figure 2-49 – Critical Pressure Front Extent, 2.0MMT/yr

Based on the simulation results for the injection scenario of 2.0 MMT/yr, the extent of the critical pressure front covers an area of 200 acres (approximately 0.8 km^2) by the conclusion of the injection phase at Year 20, as shown in Figure 2-50. The spatial extent of the critical pressure is significantly smaller than the actual size of the CO_2 plume, which spreads over a much larger area of 1,989 acres (or 8 km^2).

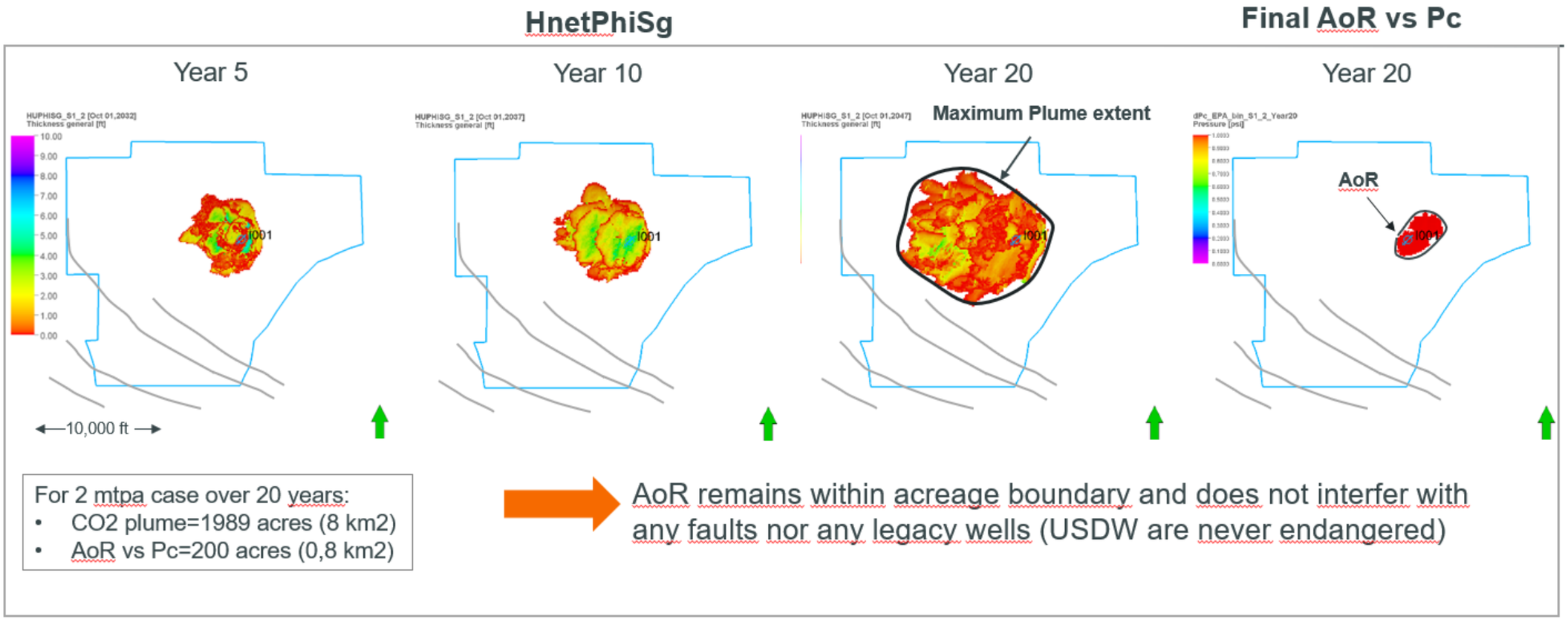


Figure 2-50 – Critical Pressure Front and CO_2 Plume, 2.0 MMT/yr

2.3.14 Trapping Mechanisms and Plume Evolution

As CO_2 injection progresses from bottom to top in the reservoir during yearly injection periods, two simultaneous processes occur: the dissolution of CO_2 in water and its trapping due to hysteresis effects. The efficiency of both these processes is linked to the bottom-up completion strategy. During CO_2 injection the amount of trapped and dissolved CO_2 increases reaching 27% and 71% of the total CO_2 trapping contribution at the end of the injection, respectively. These values indicate that a significant portion of the injected CO_2 is effectively immobilized within the reservoir post-injection. At the same time, the proportion of moveable CO_2 decreases during the injection phase, reaching 2%. This reduction represents how much CO_2 undergoes from mobile to a stable, trapped state (Figure 2-51). The relative contributions of dissolved and trapped CO_2 are not uniform but vary according to the storage aquifer parameters including residual gas saturation (Sgrm), aquifer permeability, salinity, and temperature. These parameters play a role in influencing these contributions, underscoring the complexity of CO_2 storage.

The behavior of the CO_2 plume is dynamic. The plume evolves and migrates vertically and laterally during the injection period (20 years, 2047). This activity is followed by a stabilization period during the post-injection phase (100 years). During this time, the evolution of the plume slows down considerably, indicating a gradual shift towards equilibrium within the reservoir. This transition from a state of active migration to relative stability is an important aspect for long-term CO_2 storage at Hackberry.

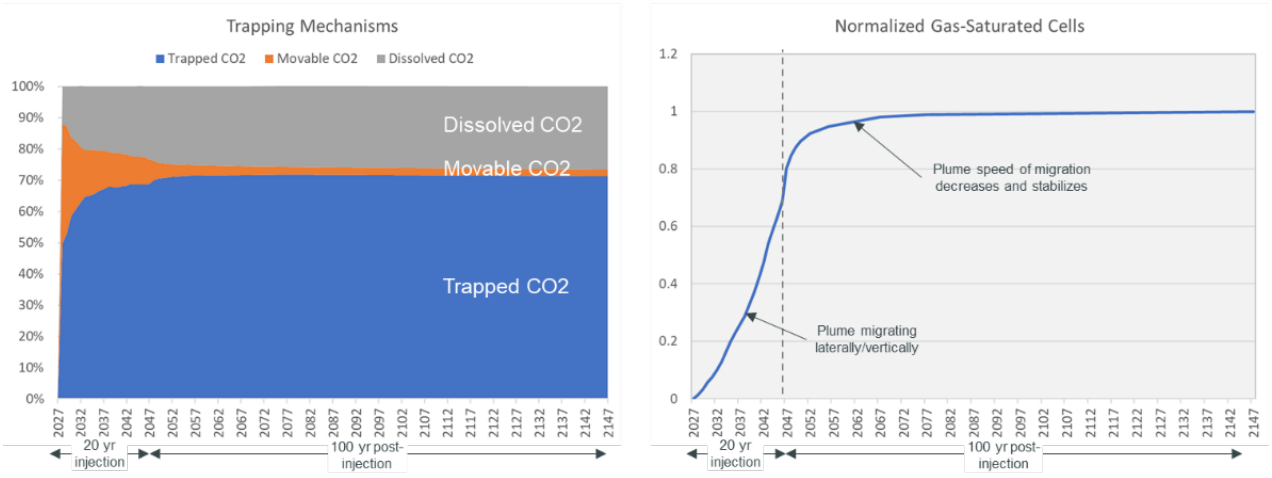


Figure 2-51 – CO_2 Trapping Mechanism and Plume Representation

Figure 2-52 provides a 3D visualization of the CO_2 plume at HCS Well No. 001, captured at the end of 20-year injection. This figure illustrates how the CO_2 plume has evolved both laterally and vertically within the aquifer pore volume. The migration of the plume is influenced by gravity effects, which drive the vertical and lateral spread; reservoir connectivity, determining the pathways available for migration; and the bottom-up injection strategy, which dictates how CO_2 is injected and how it would spread in the aquifer.

The CO_2 saturation corresponds to both the mobile and trapped gas saturation. The CO_2 dissolved in the aqueous phase results from the solubility of CO_2 in water, which varies according to pressure, temperature, and salinity conditions of the reservoir. The figure shows the complex interplay physics governing the behavior of CO_2 and offers a detailed view of the plume shape, extension, and distribution in the aquifer.

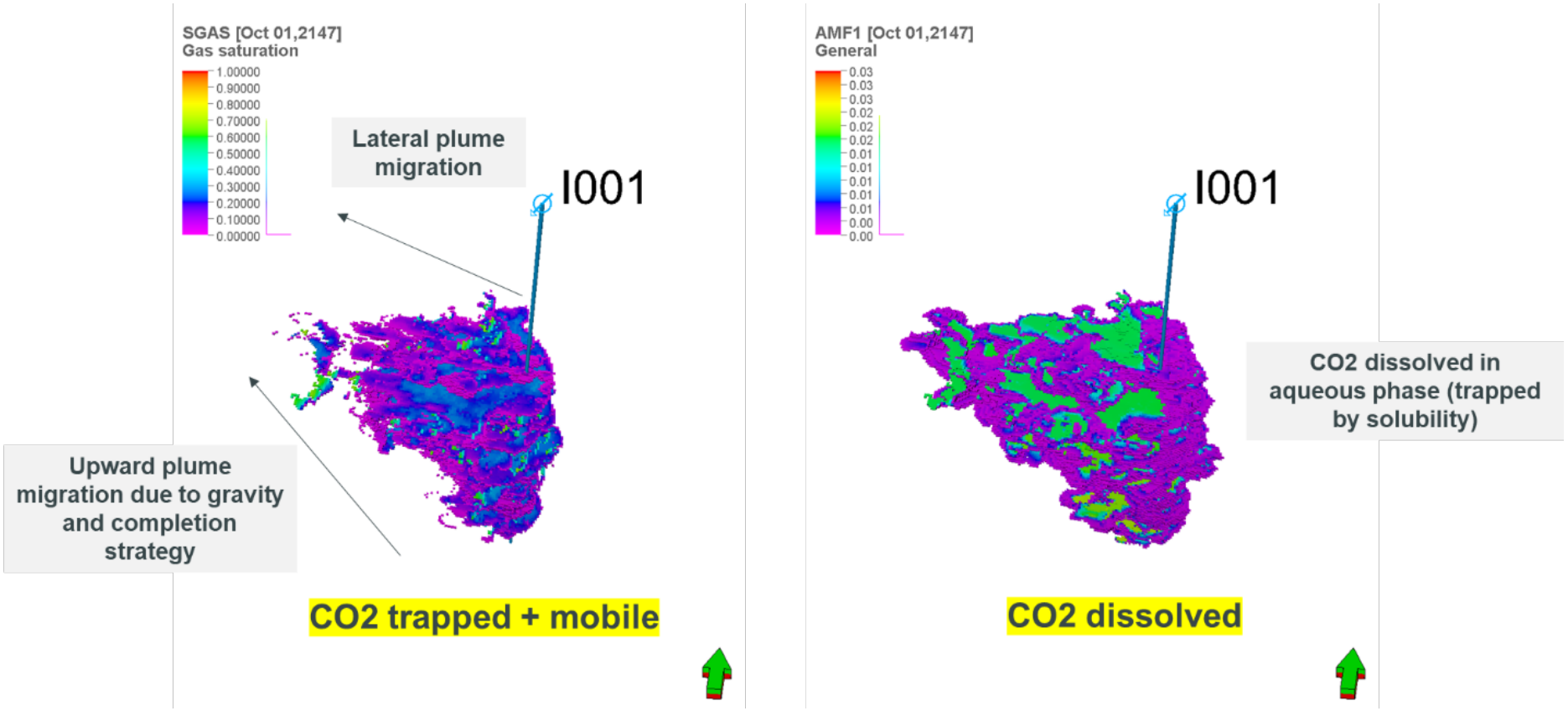


Figure 2-52 – 3D representation of the CO_2 plume at year 20. Left: Gas saturation. Right: CO_2 concentration.

The vertical cross section (Figure 2-53) shows CO_2 saturation and CO_2 concentration at varying distances from the injector — ranging from 50 to 500 ft — and across different stratigraphic levels of the reservoir model (specifically at layers z = 303, 198, and 56 of the model). This cross section is focused on Year 20 (end of injection), when all completion stages, from bottom layer to top, have been injected. As CO_2 is injected, its saturation within a specific layer of the reservoir increases rapidly, eventually reaching a peak. This peak represents the maximum CO_2 saturation within that layer. Following this peak, the saturation declines, stabilizing at a level represented by the maximum residual gas saturation (Sgrm). This decline in saturation is indicative of the dynamic movement of the gas within the reservoir: initially, the CO_2 spreads laterally, thereby increasing gas saturation in adjacent areas. Subsequently, influenced by gravitational forces, the gas begins to move upward, which results in a decrease in gas saturation at that injection layer.

At the same time, CO_2 dissolves in the water phase, near instantaneously. The gas achieves its maximum concentration under the prevailing pressure and temperature conditions of the aquifer. The solubility of the CO_2 in the aqueous phase is a crucial aspect of the overall storage mechanism, impacting both the distribution of the gas within the reservoir and its long-term storage. This cross section shows the complex interplay of CO_2 physics at Hackberry.

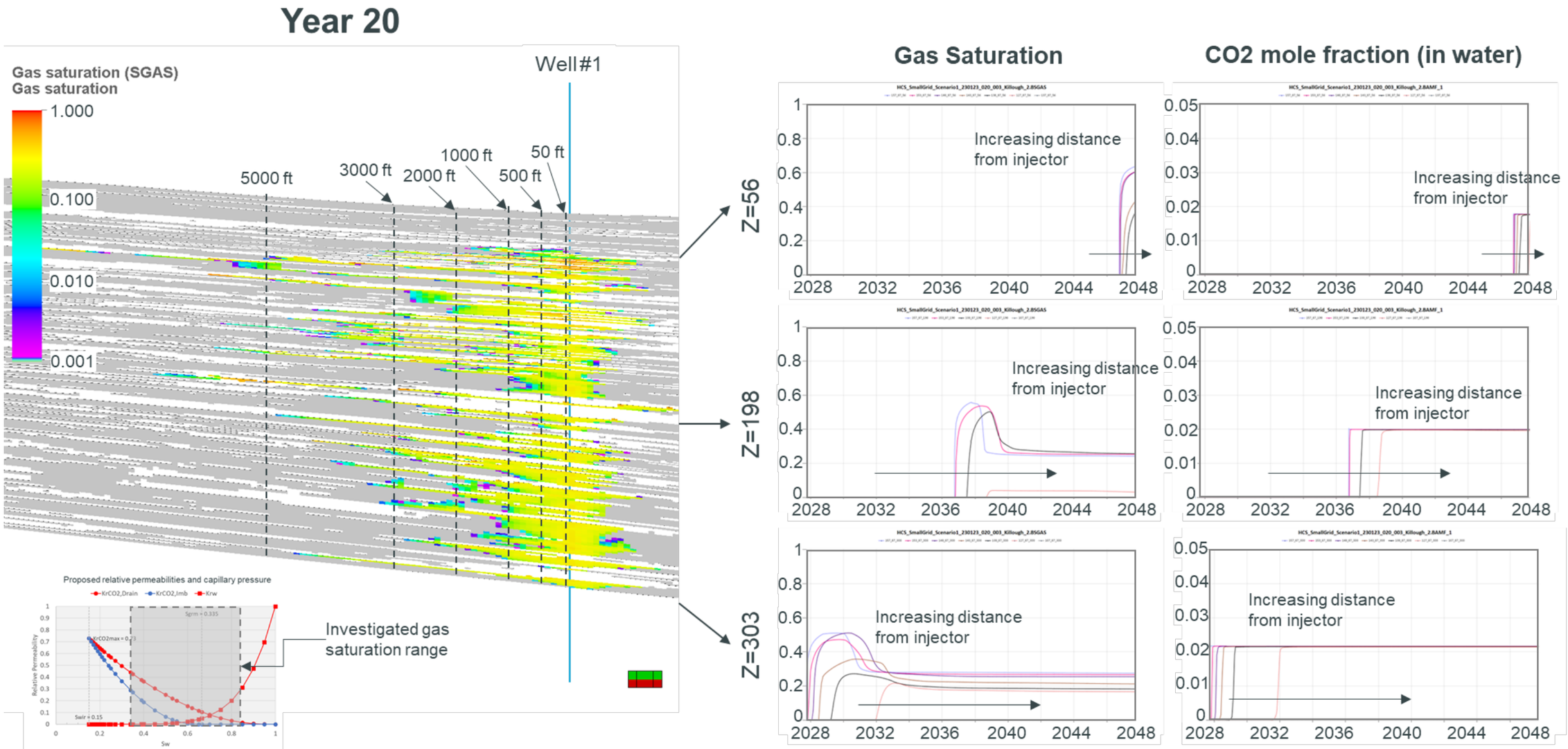


Figure 2-53 – CO_2 Saturation Tracking Through Space

2.3.15 Plume Dissipation

Simulation results for the 2.0 MMT/yr injection scenario provide an understanding of the behavior of the CO_2 plume movement in the injection zone during the post-injection phase. Figure 2-54 illustrates the temporal variation of gas saturation (CO_2) over a century, tracking changes from the end of the injection period at Year 20 through the end of the monitoring period at Year 120. These visualizations are crucial for understanding the long-term behavior of the injected CO_2 and the effectiveness of the aquifer as a storage medium.

After the 20-year injection phase, a notable and rapid decrease in CO_2 saturation occurs, leading towards plume stabilization. Approximately 30 years post-injection (around Year 2077), the plume achieves a near-stable state, indicating the diminishing movement of the CO_2 within the injection zone. The rate of saturation change provides a quantitative insight into this stabilizing trend: ten years post-injection (by 2057), the average saturation change is 6.82%, which then sharply decreases to 1.19% by Year 40 (2067), followed by minor changes to 1.16% by Year 50 (2077), and further to 0.81% by Year 60 (2087).

Beyond the 50-year mark post-injection, the saturation change continues to decline very gradually, maintaining an average saturation change of less than 1% from years 70 to 120. This long-lasting period of minimal CO_2 saturation change confirms the effectiveness of the CO_2 trapping mechanisms that contribute to the long-term stability and secure containment of the stored CO_2 in the Hackberry aquifer.

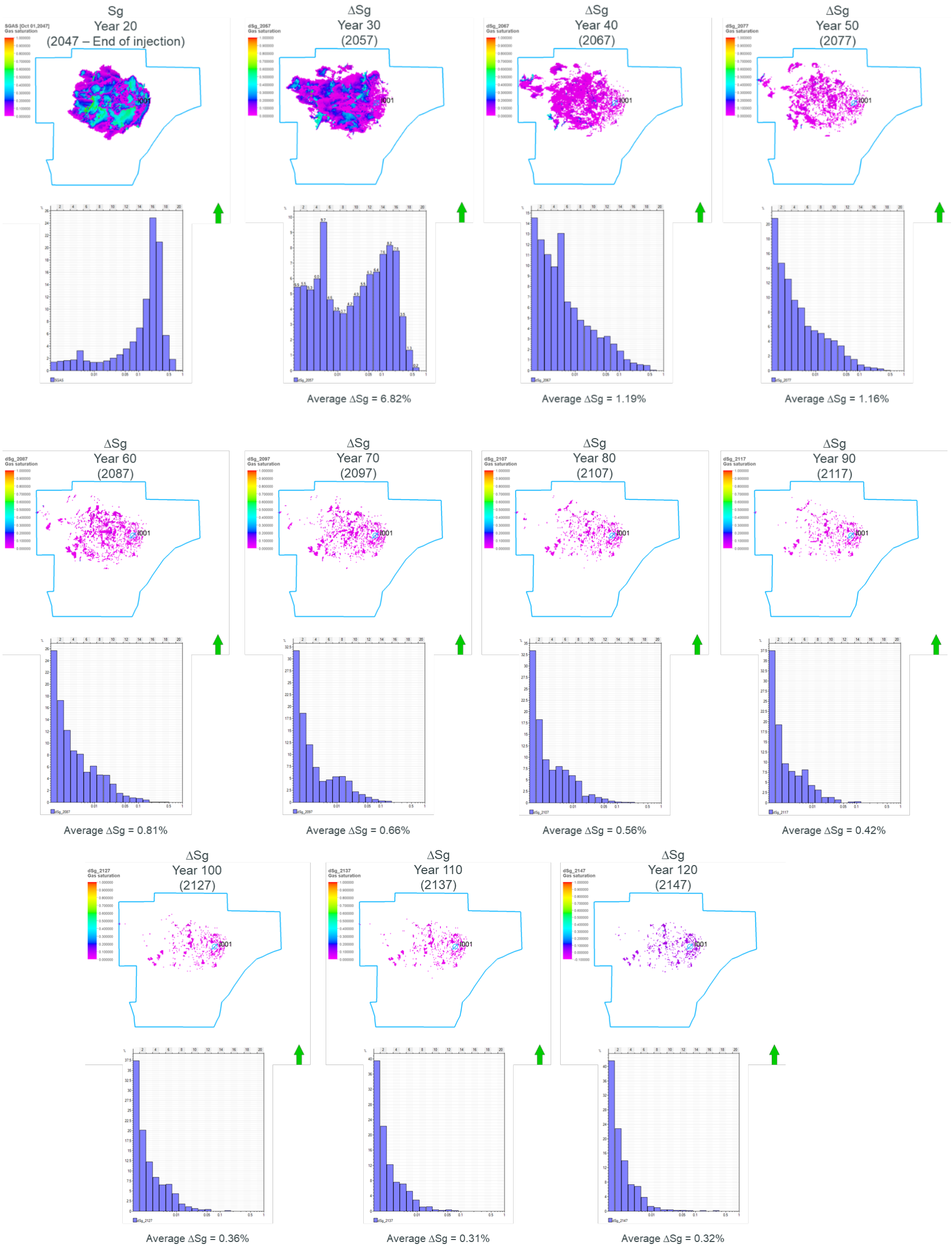


Figure 2-54 – Plume Dissipation, 2.0 MMT/yr

2.3.16 Regional Aquifer Rate and Influx

As CO_2 is injected into the injection zone by HCS Well No. 001, the regional aquifer connected to it, modeled by the Carter-Tracy analytical aquifer model, experiences water influx. The rate of water influx is determined by the total compressibility of the aquifer system, which dictates how the aquifer volume changes in response to pressure variations. Additionally, aquifer properties such as porosity and permeability, as well as geometrical factors of the aquifer, including its shape and size, contribute to the dynamics of water movement.

Upon the cessation of CO_2 injection at the end of Year 20, a stabilization of flow occurs within the regional aquifer, as shown in Figure 2-55. The influx of water into the regional aquifer ceases, indicating an equilibrium state in the storage aquifer. This stabilization reflects the balance achieved between the injected CO_2, the storage aquifer, and the surrounding regional aquifer.

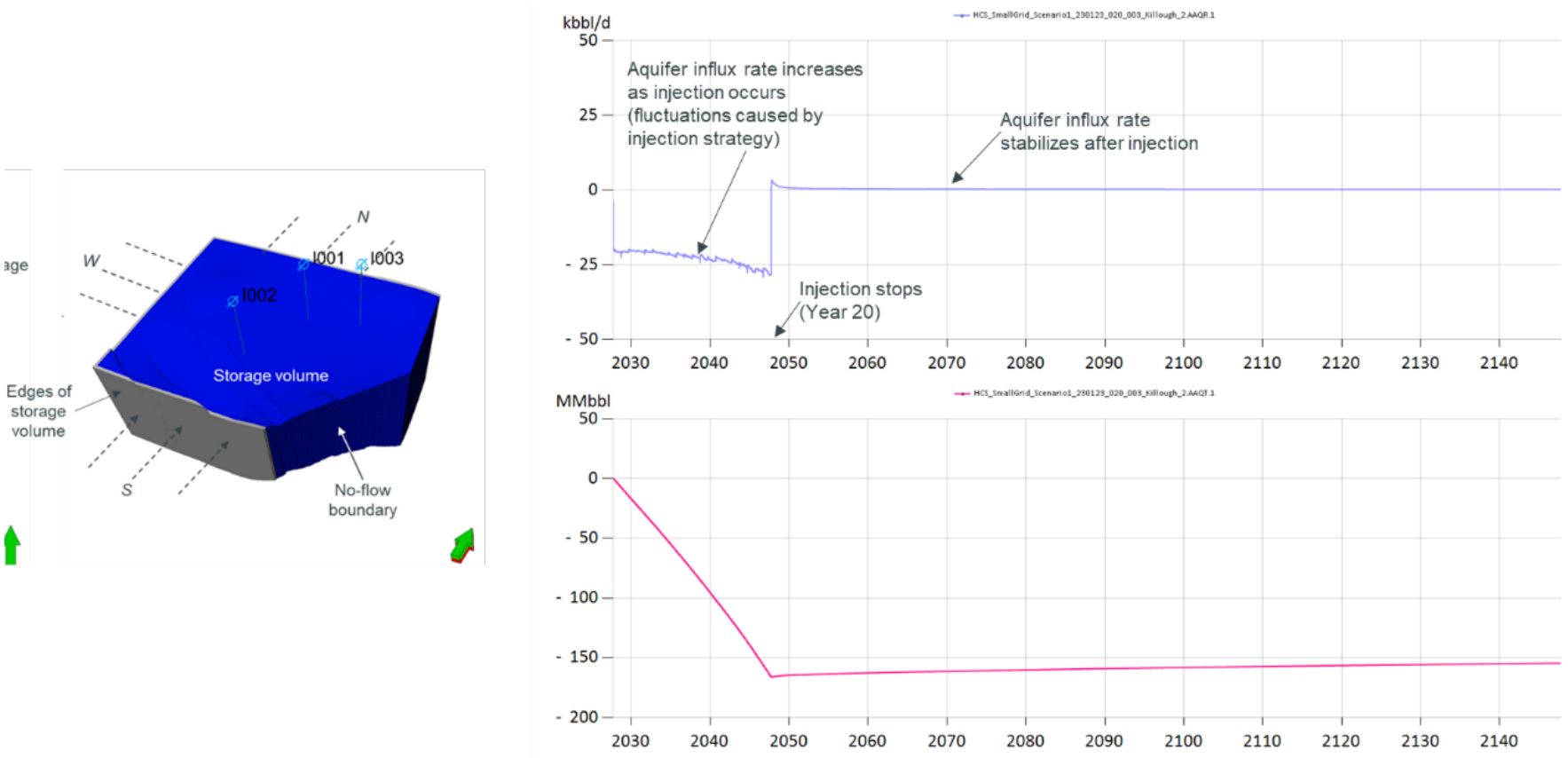


Figure 2-55 – Regional Aquifer Response to CO_2 Injection

2.3.17 Injection Rate Sensitivity

Simulation results (Figure 2-56) indicate that CO_2 plume is mostly concentrated around HCS Well No. 001 and gradually smears or extends towards the west as time progresses. This directional spread is influenced by the reservoir heterogeneities and connectivity and especially strata dip.

A critical finding is that as CO_2 rate injection rate increases, the plume placement efficiency in which the CO_2 is distributed within the reservoir decreases. Injection rates up to 2.0 MMT/yr would lead to a CO_2 plume that will be contained within the Hackberry acreage during the injection period (20 years) and after injection ceases (120 years).

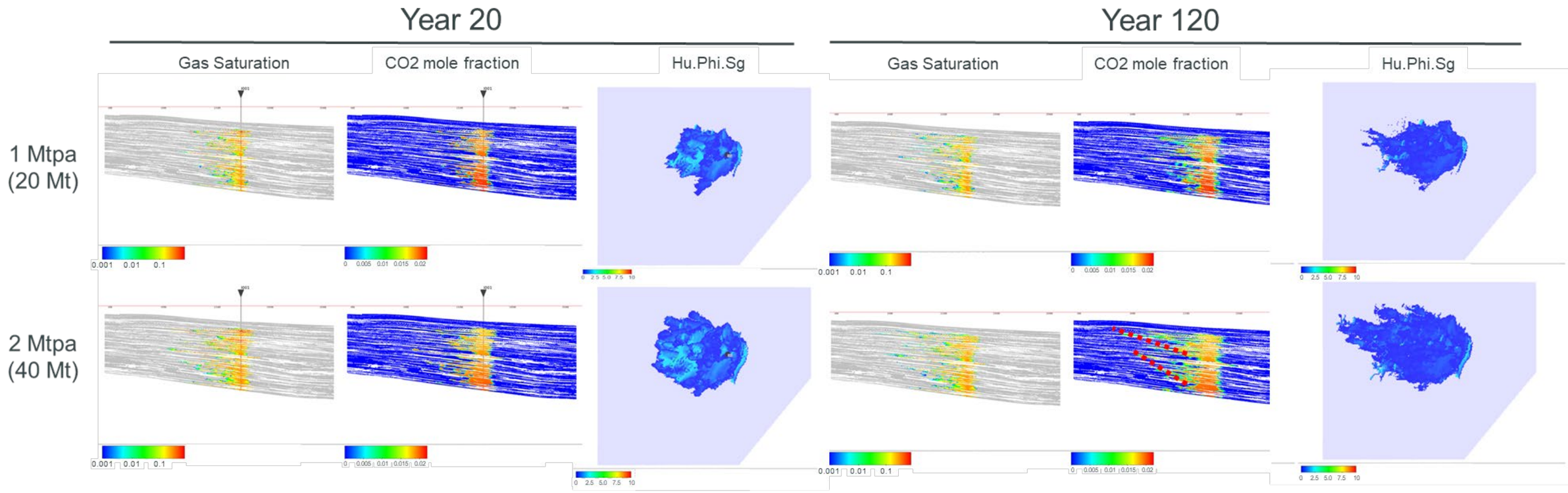


Figure 2-56 – Injection Rate Sensitivity

2.4 Geological Scenario Sensitivity

Geological scenarios 1, 2.1, 2.2, 3, and 4 were used to investigate the impact of geological uncertain parameters on the plume size and distribution of HCS Well No. 001 over 20 years of injection, such as:

- Sand and clay proportion and distribution (net-to-gross), and
- Lateral continuity of vertical barriers, the MFS (maximum flooding surfaces).

In the various geological scenarios considered, and for the 1.0 MMT/yr injection rate case, gas saturation and CO_2 concentration exhibit some local variability, as shown in Figure 2-57. Despite these local differences, there is consistency in the overall distribution and size of the CO_2 plume, as well as its evolution over time. These global similarities across different scenarios suggest a robust behavior of CO_2 injection at Hackberry, regardless of geological variations. While there are some small variations in the boundaries of the plume, these are not significant enough to alter the general pattern of CO_2 distribution. Additionally, simulation results show that in all geological scenarios assessed, there is no risk of the CO_2 escaping vertically out of the storage volume, indicating a high level of containment of the injected CO_2. Injection of 1.0 MMT/yr in HCS Well No. 001 proves to be a robust case, effectively managing the CO_2 plume. Over time, the plume is observed to be mostly concentrated around HCS Well No. 001, with a tendency to smear or spread towards the west as the injection continues (following the regional dip).

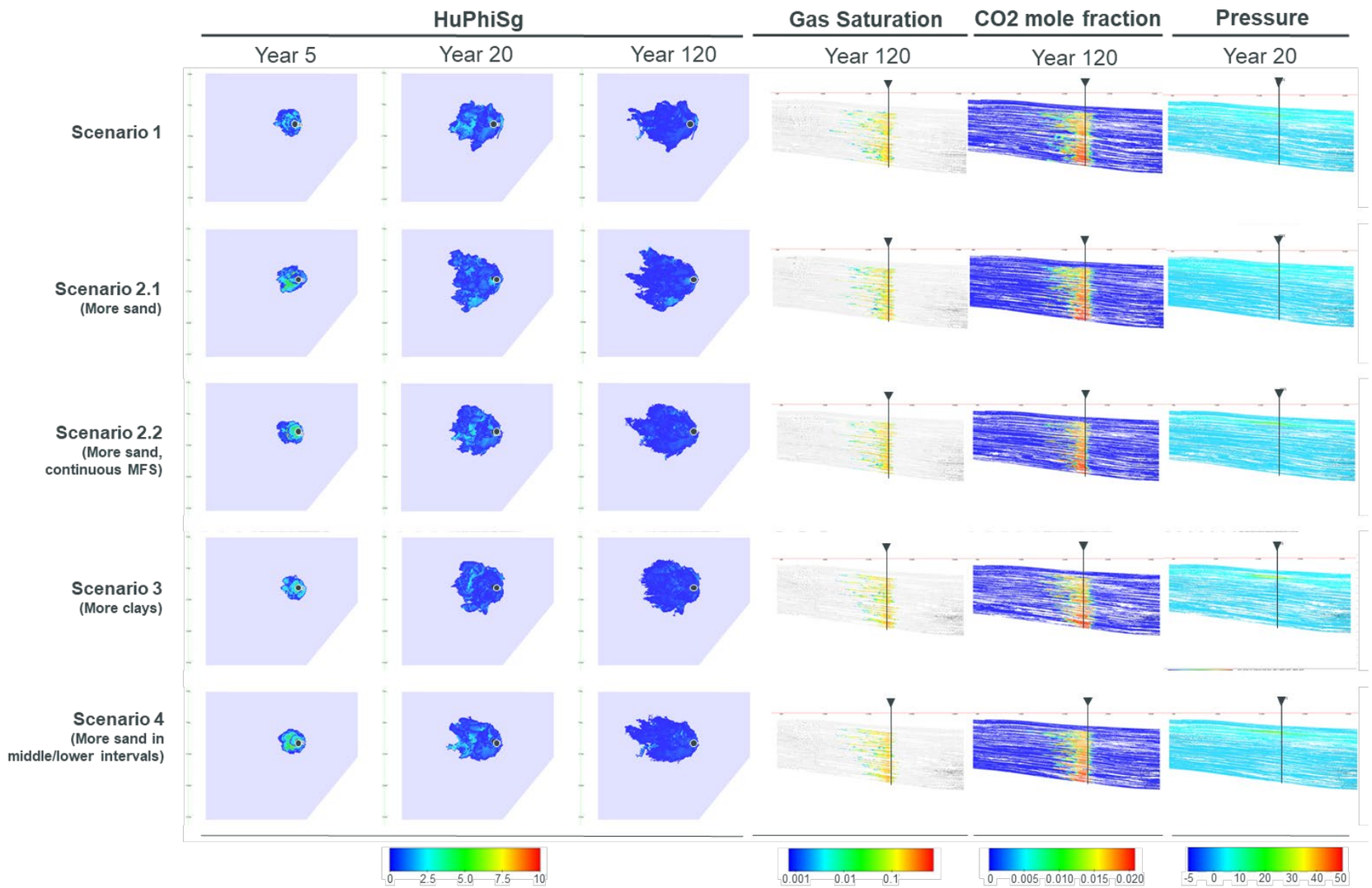


Figure 2-57 – Geological scenarios 1, 2.1, 2.2, 3, and 4 were used to investigate the impact of various geological parameters on the plume growth rate.

2.5 Dynamic Parameters Sensitivity Analysis

A mono-parameter sensitivity analysis was carried out to determine the most significant reservoir parameters to the CO_2 plume stability and trapping mechanism effectiveness. Table 2-5 shows 11 parameters and their low, mid, and high assumptions. This study was executed with HCS Well No. 001 injecting 1.0 MMT/yr for 20 years.

Table 2-5 – Parameters Used in the CO_2 Plume Sensitivity Analysis

id	Parameter	Symbol	Low	Mid	High	Comments
1	Permeability	PERM	0.5	1	2	Global permeability multiplier. Permeability uncertainty based on core data.
2	Kv/Kh	KVKH	0.01	0.1	0.4	Vertical anisotropy ratio. Based on GoM analogue data and grid block size.
3	Faults	FAULTS	0	0.1	1	Faults transmissibility multiplier. Same for all faults.
4	Aquifer size	AQR	2	5	10	Carter-Tracy Re/Ri. Regional aquifer to storage aquifer ratio
5	Aquifer permeability	AQPERM	0.5	1	2	Carter-Tracy aquifer permeability
6	Pore volume compressibility	CR	7.8 μpsi^{-1}	4.5 μpsi^{-1}	2.9 μpsi^{-1}	Pore volume compressibility. Based on elastic properties (SWD-003 well logs).
7	Relperms	RELPERMS	Low Swir=0.25, Krgm=1, nw=4.6, nCO2=2.2	Mid Swir=0.15, Krgm=0.73, nw=4.6, nCO2=2.2	High Swir=0.03, Krgm=0.6, nw=4.6, nCO2=2.2	Gas-Water relative permeabilities and capillary pressure by facies (SST, clay-SST) for drainage and imbibition. End-points based on analogue data from CSTJF.
8	Max residual gas saturation	SGRM	Low	Mid	High	Sgrm (imbibition) by grid block as piece-wise function of PhiT. Based on internal/external analogue data.
9	Salinity	SALT	200 kppm	110 kppm	90 kppm	Brine salinity. Based on SWD-003 data
10	Initial pressure	PINIT	3842 psi	3966 psi	4288 psi	Initial pressure at -8262 ftTVDSS. Based on SWD-003 data and regional pressure gradient (USGS, 2011)
11	Initial temperature	TINIT	133 °F	139 °F	154 °F	Temperature at -8262 ftTVDSS. SWD-003 data and regional temperature variation (USGS, 2011). Temperature gradient: 0.85 F/100 ft.

The most significant parameters for CO_2 injection at Hackberry, accounting for 90% of the total variability, include the maximum residual gas saturation, permeability, initial temperature, relative permeability, and the ratio of vertical to horizontal permeability (Kv/Kh). These factors play a pivotal role in determining the behavior and stability of the CO_2 plume within the reservoir.

Parameters such as salinity and initial pressure are found to be relatively less impactful (Figure 2-58). Their influence on the plume dynamics, while present, is considerably less pronounced. Additionally, regional aquifer parameters, fault transmissibility multipliers (TM), and pore volume compressibility have almost negligible impact on the overall variability. This observation suggests that these factors can be considered secondary in the modeling of the CO_2 plume.

Interestingly, high values of maximum residual gas saturation and the Kv/Kh ratio, along with low relative permeability, are associated with greater plume stability. This effect is caused by the increased trapped gas saturation, which enhances CO_2 plume containment, and higher vertical mobility due to the Kv/Kh ratio, contributing to more efficient vertical dispersion of the CO_2. Conversely, lower values of salinity and initial pressure tend to result in reduced plume stability.

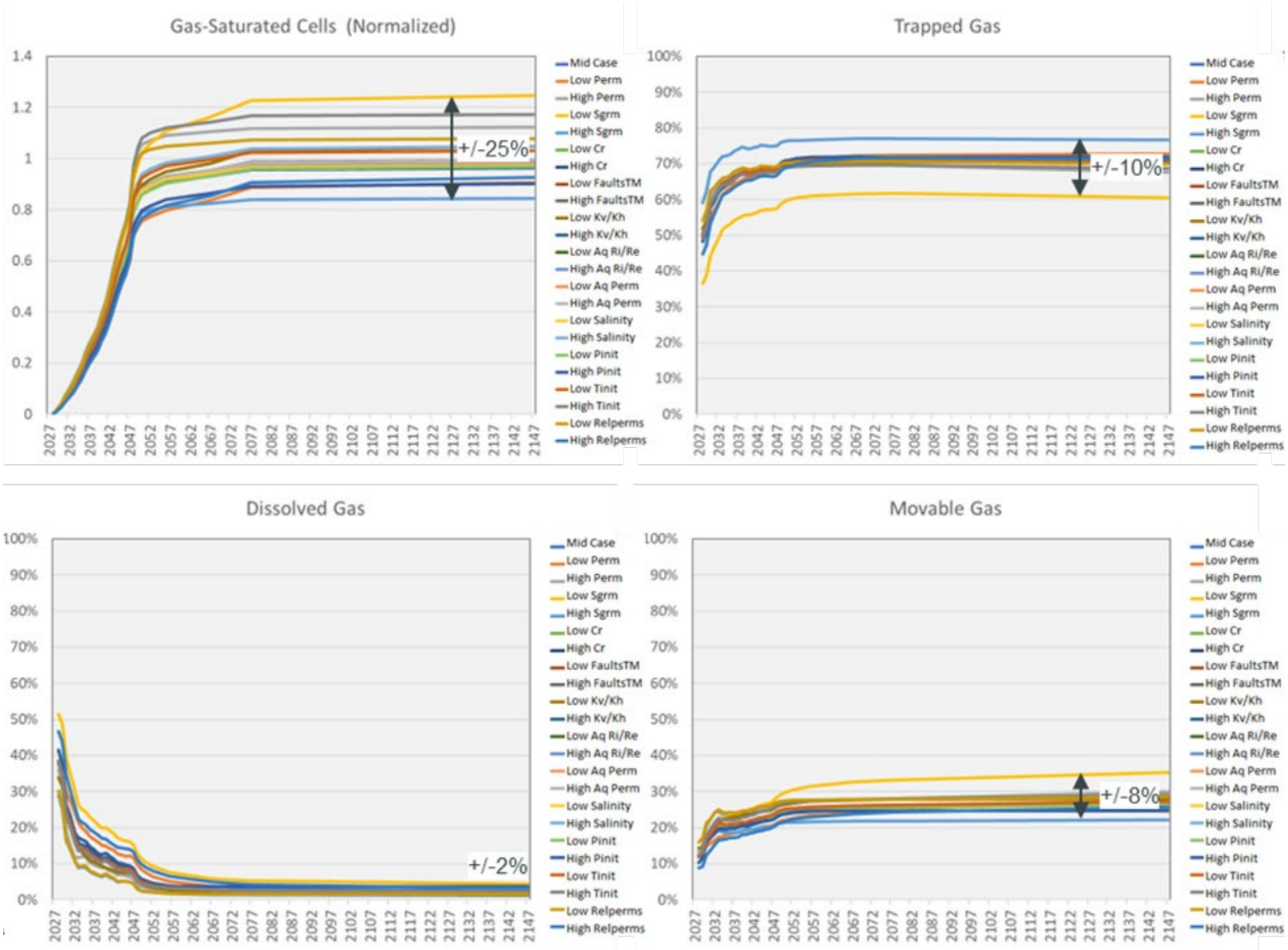


Figure 2-58 – Mono-parameters sensitivity results: CO_2 plume stability and trapping mechanisms.

Tornado and Pareto plots were generated for each CO_2 trapping mechanism (Figure 2-59). These plots are normalized in terms of plume stability and are defined at Year 120. For trapped CO_2, the plots reveal a strong dependency on two key factors: maximum residual gas saturation (Sgrm) and permeability. A higher value of Sgrm and a lower value of permeability are particularly conducive to trapping of CO_2. This combination promotes the retention of CO_2 within the Hackberry aquifer, enhancing its containment and long-term stability. Relative permeabilities and initial temperature are also influential. However, the ratio of vertical to horizontal permeability (Kv/Kh), salinity, and initial pressure, while still impactful, exhibit a comparatively lower impact on CO_2 plume stability.

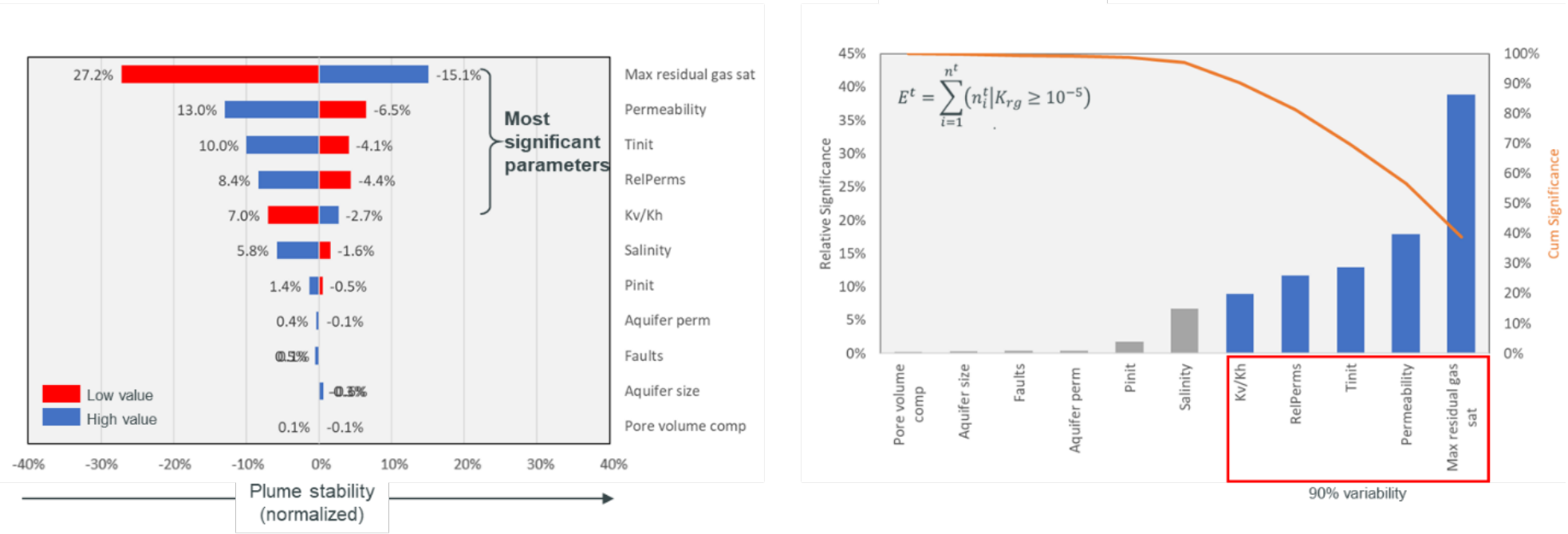


Figure 2-59 – Tornado and Pareto Plot on Plume Stability

Tornado plots were also created to understand the sensitivity of the uncertain parameters to individual CO_2 trapping mechanisms at Year 120, shown in Figure 2-60.

For trapped CO_2, the Pareto plot indicates a strong influence of maximum residual gas saturation (Sgrm) and permeability. High levels of Sgrm significantly increase CO_2 trapping. In contrast, low permeability is beneficial for CO_2 trapping as it restricts the mobility of the gas, thereby facilitating its retention within the pore volume.

CO_2 dissolution in water is impacted by maximum residual gas saturation (Sgrm), permeability, relative permeabilities, and initial reservoir temperature. The initial temperature determines the solubility of CO_2 in water, with higher temperatures generally leading to lower solubility. However, the ratio of vertical to horizontal permeability (Kv/Kh) and salinity, while still relevant, have a less significant impact on CO_2 dissolution.

Consequently, movable CO_2 is influenced by maximum residual gas saturation (Sgrm), relative permeabilities, and Kv/Kh. These parameters determine how CO_2 would flow in the aquifer pore volume, impacting its distribution, plume size, and overall effectiveness of the CO_2 injection in Hackberry.

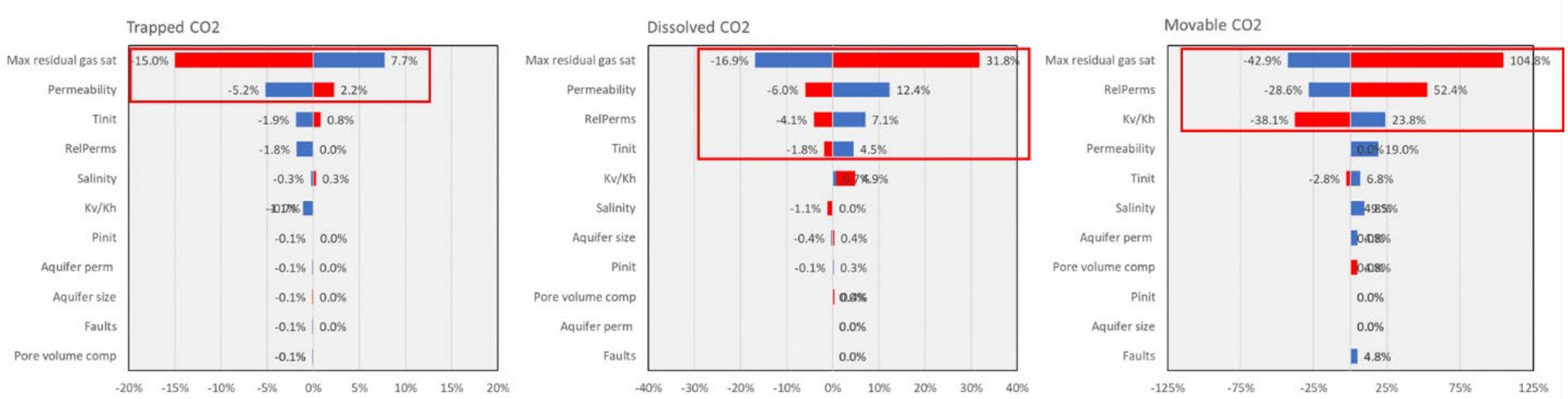


Figure 2-60 – Tornado Plots on CO_2 Trapping Mechanisms

2.6 Additional Modeling Summary

The additional geocellular and dynamic modeling, along with the sensitivity analyses performed, support the expected extents of the CO_2 plume and critical pressure front for HCS Well No. 001 and provide confidence in the assumptions made in the modeling efforts. Upon the drilling and testing of HCS Well No. 001, the models will be updated to reflect the site-specific data obtained. Subsequent data from the proposed monitoring and testing programs will be used to further update the AOR delineation over time.

2.7 References

Bump, A. P. and Sovarka, S. D., Fetch-trap Pairs: Exploring definition of carbon storage prospects to increase capacity and flexibility in areas with competing uses, International Journal of Greenhouse Gas Control, Volume 122, 2023.

Underground Injection Control – Class VI Permit Application for Hackberry Carbon Sequestration Well No. 001

Cameron Parish, Louisiana

SECTION 3 – AREA OF REVIEW

Prepared for *Hackberry Carbon Sequestration, LLC*
Cameron, LA

By

Lonquist Sequestration, LLC
Austin, TX

August 2021
Revised January 2025

SECTION 3 – AREA OF REVIEW AND CORRECTIVE ACTION PLAN

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3.1 Facility Information

Facility name:	**Hackberry Carbon Sequestration, LLC**
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Location:	1500 Post Oak Blvd, Suite 1000 Houston, TX 77056

3.2 Area of Review Discussion

Statewide Order 29-N-6, ***§615.B*** [EPA ***40 CFR §146.84***] requires that an area of review (AOR) be conducted for a Class VI carbon sequestration well application. This AOR is defined as the region surrounding the geologic sequestration project where USDWs may be endangered by the injection activity. The area of review is delineated using computational modeling that accounts for the physical and chemical properties of all phases of the injected carbon dioxide stream and is based on available site characterization, monitoring, and operational data. The dynamic simulation results are presented in Section 2 which delineates the AOR construction based on plume saturation extent and associated critical pressure (Figures 2-48 and 2-49).

The AOR is conducted with three primary purposes:

1. Identification of any subsurface geological features which may influence the ability to store sequestered gases for an indefinite length of time.
2. Identification of any artificial penetrations or manmade structures which may influence the ability to store sequestered gases for an indefinite length of time.
3. Identification of pore space rights impacted by the extent of the injection plume over the modeled time period.

In accordance with Statewide Order and Federal EPA requirements, Hackberry Carbon Sequestration (HCS) will reevaluate the AOR at each of the following intervals:

- A minimum frequency of five years
- Detection of a significant change in the plume
- As otherwise warranted by routine monitoring or operational conditions

Wells identified that require corrective action within the reevaluated AOR will be addressed with an amended AOR and corrective action plan that will be submitted to the EPA UIC Program Director for approval. All amendments and corrective plans will be approved, incorporated into the permit, and will be subject to permit modification requirements per ***§144.39.***

Alternatively, wells that do not require AOR amendments or corrective action will demonstrate to the EPA UIC Program Director that no changes are needed through monitoring data support and modeling results. All modeling inputs and data used to support AOR reevaluations will be retained for 10 years.

An unfortunate impact to carbon sequestration projects, resulting from qualifying carbon injection wells as storage wells instead of disposal wells, is that pore space rights now become of paramount importance in the evaluation of a project's potential. To minimize this risk, a specific injection strategy (Section 2 – Plume Model) and a robust reservoir monitoring plan (Section 5 – Testing and Monitoring) will be undertaken to control the extent of the resulting subsurface injectate plume.

The Hackberry Carbon Sequestration (HCS) Well No. 001 employs such a strategy to ensure that the plume extents remain within controlled pore space. For this well, approximately 1,700 net feet (ft) of useable sand formations have been targeted for injection pay. These sand formations, of Miocene age rock, will be accessed in discrete completions, staged out over the proposed active life of the well, which is 20 years. Each of these sand packages are separated by shale layers which will allow for the sequestered carbon to be contained within each of the discrete injection horizons.

The goal of this completion strategy is to create multiple plumes, stacked on top of each other and separated by laterally constant shale beds to minimize the lateral extent of the resultant plumes, thereby keeping them within controlled pore space. Figure 3-1 is a cross section in the most elongated plume direction, towards the northwest, illustrating the vertical stacking of these successive plumes from the base to the top of the Miocene section. Each individual plume is confined by identified shale layers under which the plumes will propagate.

Figure 3-1 – Northwest-southeast 3D seismic cross section overlaid by the simulated plume expressed as CO_2 saturation (scale from 0 to 0.5). The encapsulated map displays the cross section location and the top MFS 9 structure overlaid by the plume extent after 20 years of injection (cumulated CO_2 thickness map). The red lines represent the maximum extent of the plume 100 years after the stop of injection (+120 years), the blue lines represent the extent of the plume at the end of injection (+ 20 years).

Each plume has varying extents as a function of the permeability of each layer (considering similar dynamic parameters such as solubility, maximum residual gas saturation or SGrm). The plume preferentially grows updip; therefore, the plume is asymmetric towards the north and northwest.

However, the AOR, as discussed in Section 2.3.13, is not only defined by the areal extent of the plume but also by the critical pressure which is the pressure above which the fluids, either brine or CO_2, will rise through any conduits that may exist within the plume path, such legacy wells or faults The Nicot et al (2009) formula is used in accordance with EPA guidance as discussed in Section 2.3.13. Therefore, the AOR definition must properly address all these components plus the saturation front at any time, the associated injection pressure, the critical pressure, its pathways, the faults and legacy wells.

In accordance with the requirements of ***§615.B.1 [§146.84]***, a review was conducted to determine if there were any artificial penetrations or other features which may endanger the lowermost underground sources of drinking water (USDW) as a result of injection activity or operations. This review includes mapping the AOR to identify any manmade structures found within that area of review. Any artificial penetrations or other artifacts were then evaluated for depth of completion, construction details, and/or plugging and abandonment practices utilized

to determine if said penetrations could possibly affect the containment integrity of the storage formation(s).

Figure 3-2 is a synthesis of the AOR for the proposed injector well. At the HCS site, the AOR includes the critical pressure extent, which is much smaller than the CO_2 plume because of the high permeabilities. This map is an output of the plume modeling presented in Section 2.3.12 and displays:

- The maximum plume extent at the end of injection in Year 20 (injection of 40 MMT)
- The plume extent, 100 years after the end of injection (Year 120)
- The seismically picked faults at the MFS 9 surface
- The outline of the critical pressure extent calculated at each cell of the model
- All legacy wells

-

The USDW is never endangered as the critical pressure front remains at a distance greater than 6,000 ft from the nearest fault to the west and 4,800 ft from the nearest legacy well to the south, GL-D-RA-A-28.

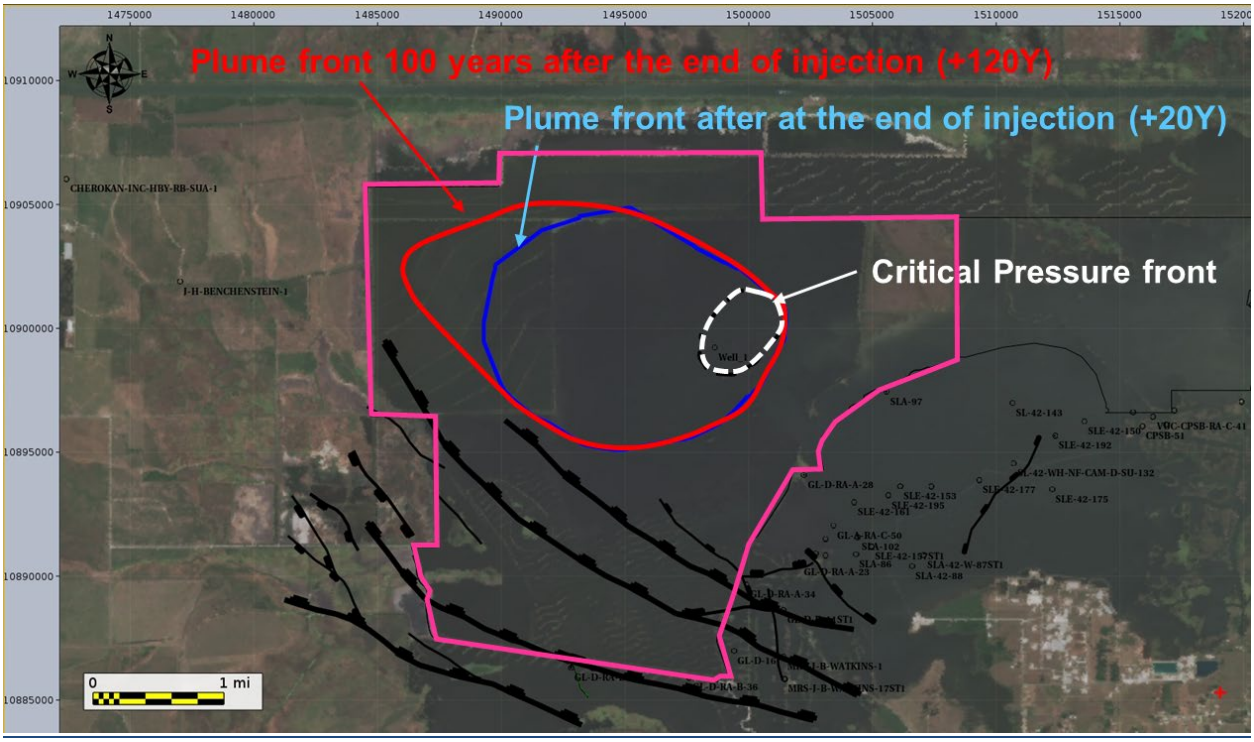

Figure 3-2 – Combined map illustrating the AOR at Hackberry with the maximum plume extent at Years 20 and 120, the outline of the critical pressure, the fault pattern on top of Amphistegina B map, and all legacy wells.

Figures 3-3 to 3-7 display the evolution of the AOR every 5 years from the planned start of injection in Year 2027. These figures display a map with the maximum plume extent represented by a cumulative net CO_2 thickness map (NetxPhixCO2 saturation). The background displays the maximum plume outlines extent after 20 (blue) and 120 years (red). The map shows all legacy wells, and the fault pattern projected on MFS 9. In the middle of each figure, a 3D representation of the plume is shown (CO_2 saturation). It shows the successive plume extents separated by shale layers. In the right, a histogram of the generated pressure (year pressure minus initial reservoir pressure) and the value of the critical pressure (Pc) calculated at the top of the shallowest perforation depth as a conservative value. These statistics show that the excess pressure rarely exceeds a few psi in average with a maximum delta pressure, for very few cells surrounding the well bore, in the range of 30 to 50 psi at the most. These maximum values are systematically much lower than the Pc which indicates that, in case of vertical path along the plume path, the brine will never be able to flow upwards.

As an overall result, the USDW is shown to never be endangered during the life of the project.

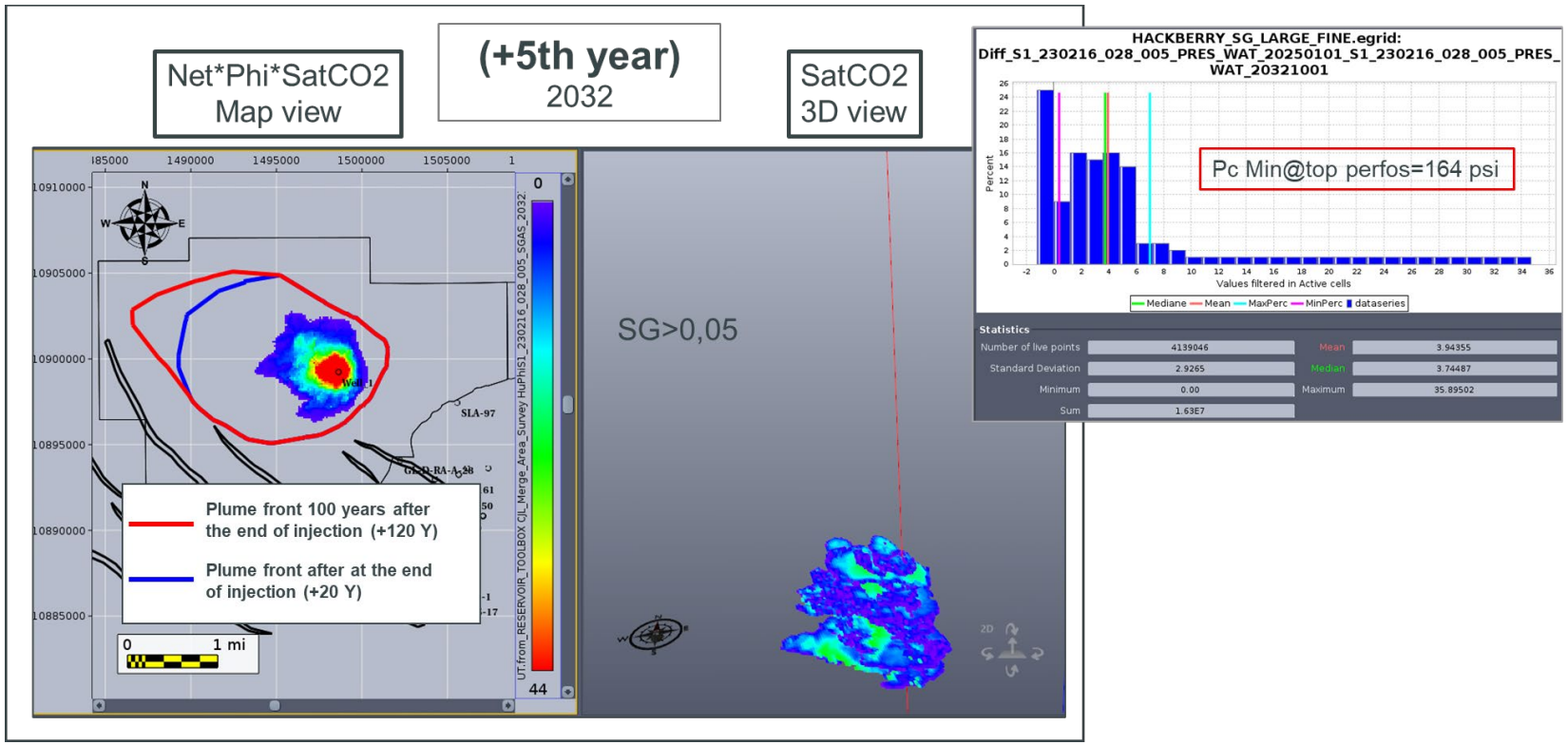

Figure 3-3 – Area of Review, 5 Years After Start of Injection

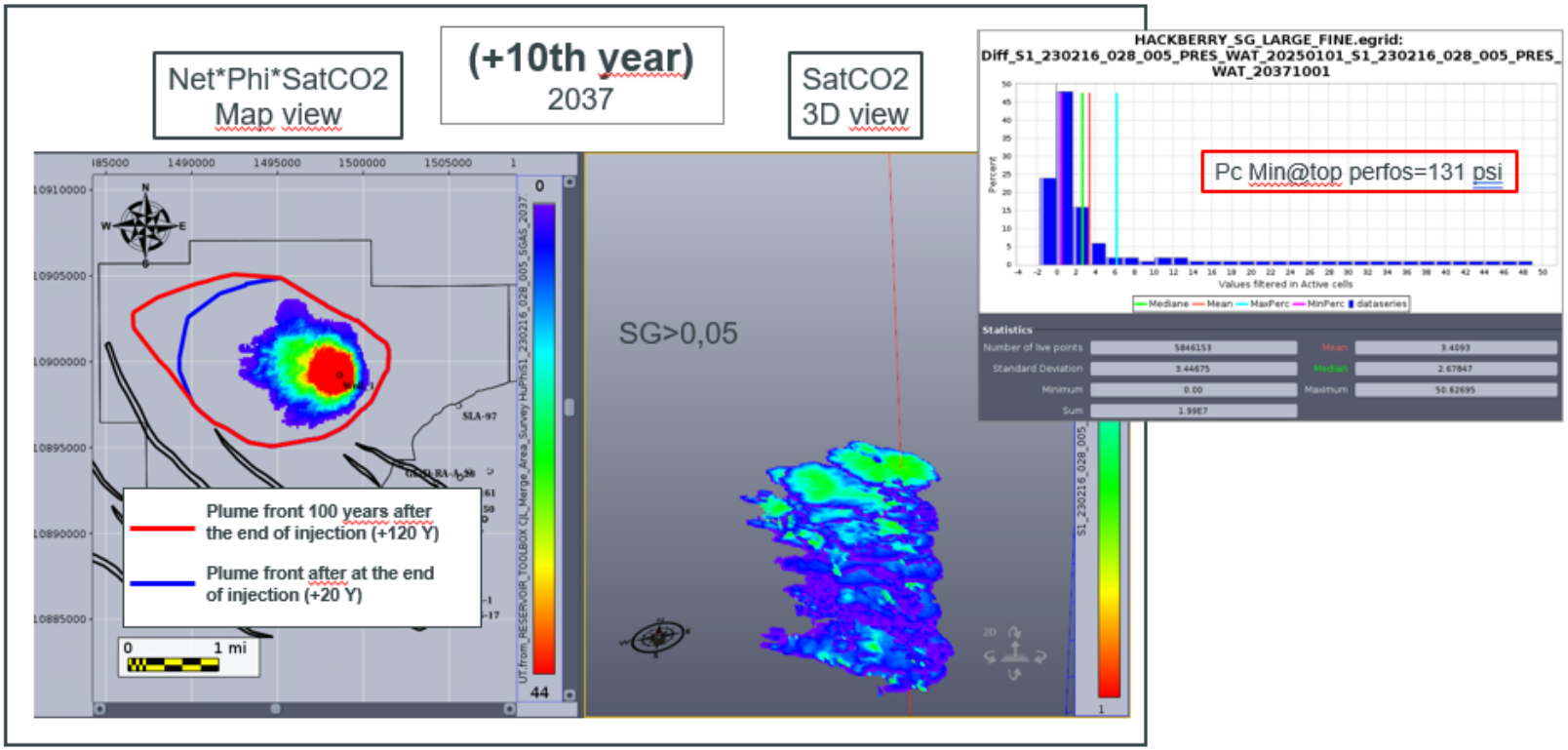

Figure 3-4 – Area of Review, 10 Years After Start of Injection

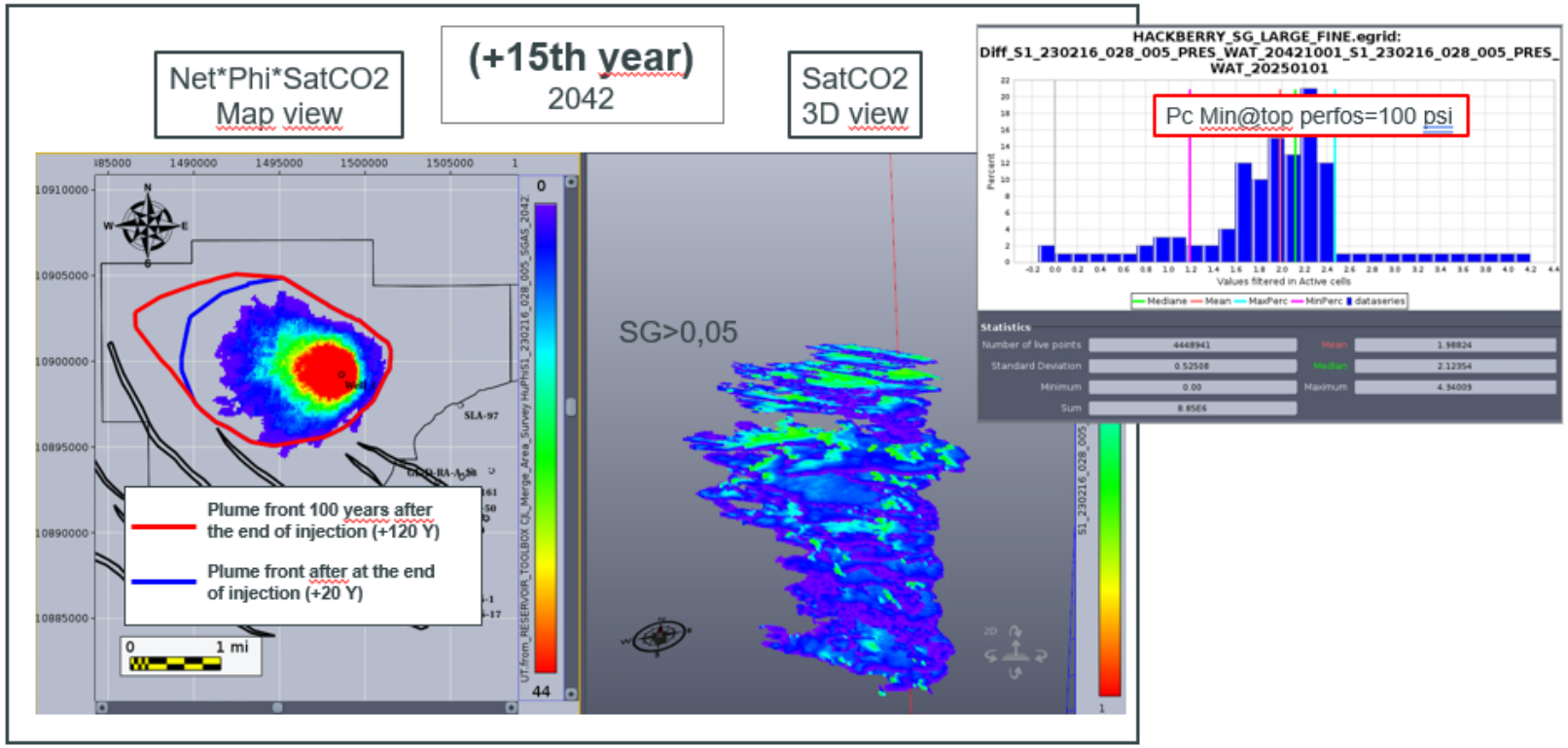

Figure 3-5 – Area of Review, 15 Years After Start of Injection

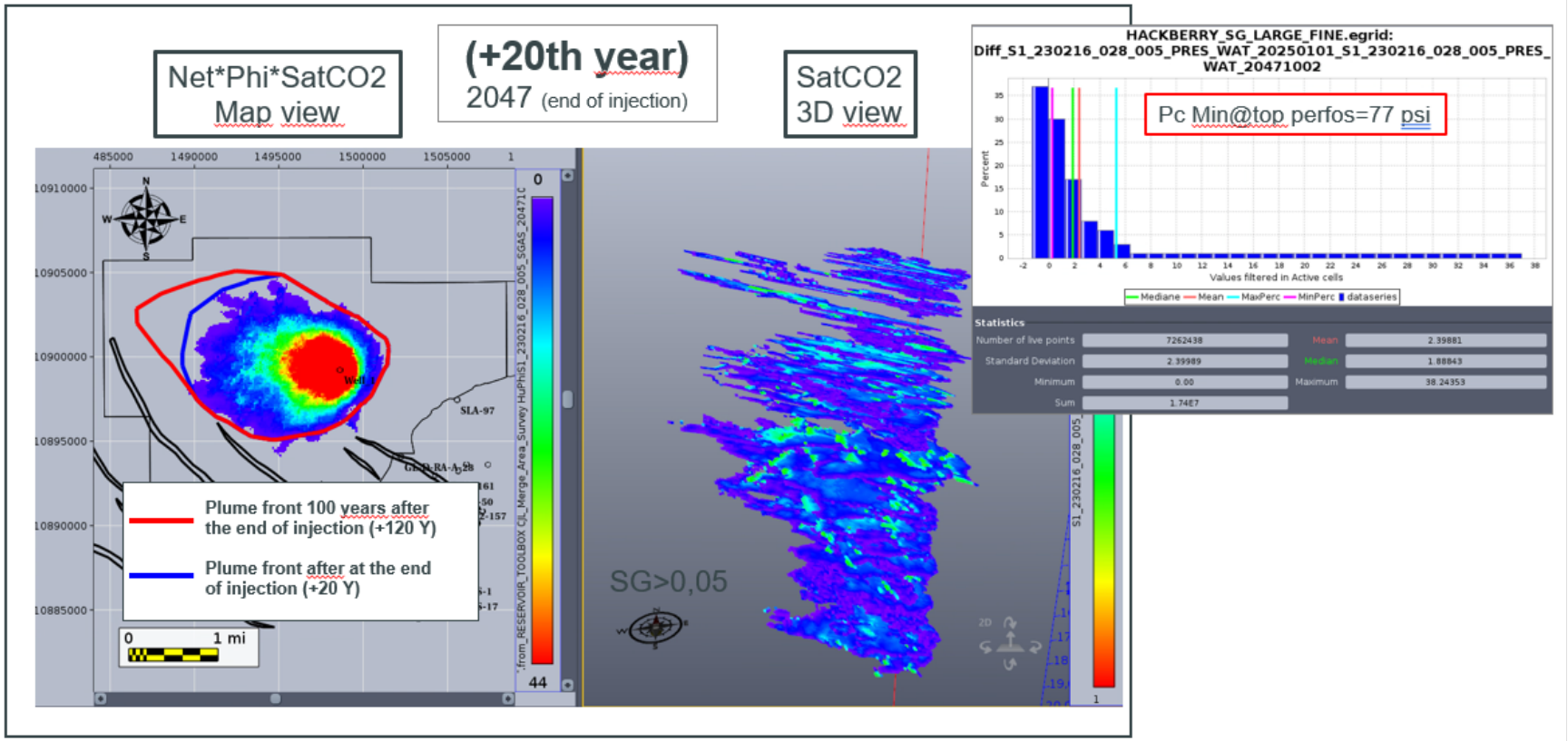

Figure 3-6 – Area of Review, 20 Years After Start of Injection

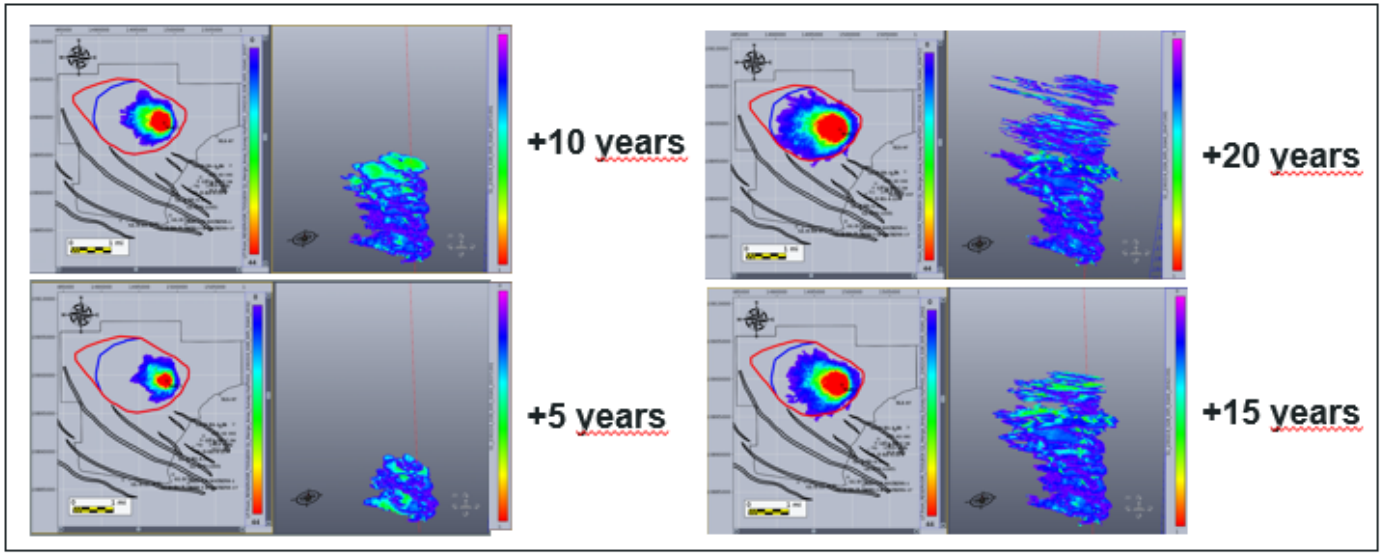

Figure 3-7 – Synthesis of the AOR Evolution from Year 5 to 20

3.2.1 Area of Review Implications and Results

As stated in the Introduction Section of this application, the proposed location of the HCS Well No. 001 is ideally suited for carbon sequestration. The results of the AOR evaluation yielded no artificial penetrations within the AOR boundaries. No faults or other geologic features were found within the AOR which may affect the integrity of the disposal intervals from keeping the sequestered fluid permanently contained. No other man-made structures were found within the AOR.

No freshwater wells were found within the AOR. The closest freshwater wells to HCS Well No. 001 are over a mile away with the closest being measured at 11,093 ft away. This well, 023-5625Z, has been plugged and abandoned. The well is approximately 6,961 ft from the outer plume extent of the injectate.

The closest drinking water well, 023-5444Z, is 20,186 ft away from HCS Well No. 001. From the edge of the modeled plume, this well is approximately 16,207 ft away and is also plugged and abandoned.

Water samples were pulled from the closest wells which were active, accessible, and authorization was granted. Baseline test results have been included at the end of this Appendix.

3.2.1.1 Magnetometer Survey

Collier Geophysics (Collier) was contracted by HCS for a geophysical surveying project at Black Lake near Hackberry, LA. The project aimed to conduct geophysical surveying over an area spanning approximately 1,500 acres. The primary objective of the survey was to gather subsurface information about potential abandoned or orphaned oil and gas wells within the specified area. See Appendix T for the geophysical investigation Report.

To achieve the project objectives, Collier employed Unmanned Aerial Vehicle (UAV) Magnetic (Mag) data collection techniques. The survey encompassed the designated 1,500-acre Area of Investigation (AOI) and was conducted over a five-day period. Multiple Flight Operation Staging Locations (FOSL) were utilized, with operations facilitated from both boat and barge platforms to access the site effectively.

Throughout the survey period, Collier successfully collected comprehensive geophysical data over the entire AOI. The UAV Mag data acquisition methodology proved efficient in capturing subsurface information pertinent to identifying potential abandoned or orphaned oil and gas wells within the surveyed area. The utilization of multiple FOSLs ensured operational flexibility and enabled systematic coverage of the designated area.

Legacy oil and gas wells will typically exhibit a distinctive circular magnetization high intensity anomaly similar to a bullseye shape. Oil and gas anomalies usually have magnetic amplitudes of tens of nano teslas (nT) which are not present in this dataset. In addition, this bullseye shape usually has a width of approximately 50 meters or three or more survey lines, which again is not

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present. A review of the magnetic data does not indicate the presence of magnetic anomalies representing the presence of legacy oil and gas wells.

3.3 Corrective Action Plan and Schedule

Table 3-1 – Corrective Action Plan

Well Name/ Location	Planned Corrective Action Method	Planned Date of Corrective Action	Notes/Comments
NONE	NONE	NONE	NONE

3.4 Area of Review Reevaluation Plan and Schedule

3.4.1 Proposed Reevaluation Cycle

HCS will reevaluate the AOR at a minimum of every five years, per SWO 29-N-6 ***§615.B.2.b.i*** [EPA *40 CFR* ***§146.84(b)(2)(i)***]. As fully described in Section 5.6.6, the indirect monitoring techniques rely on vertical seismic profile (VSP) walk-away surveys and micro-gravimetry. The first baseline surveys (M0) will be performed before the start of the injection. Regarding the VSP acquisitions, a first survey will be acquired two years after the start-up to ensure the conformance of the model (direction and speed of growth of the plume). Then, the next monitoring survey will be acquired three years afterwards to conform with the five years commitment. All subsequent acquisitions will be performed every five years thereafter. Regarding the micro-gravimetry survey, the first survey (after the baseline) will be performed only after 5 years of injection.

One variable that may affect the measured plume migration behavior is that initial injection rates may not reach the capacity being modeled which is 2 MMT/yr. As such, the anticipated measured plume migration is simulated to be less than the extents modeled. Should this be the case, the life of each discrete completion can be extended without impacting the area of review.

Table 3-2 lists some of the possible triggers for an AOR reevaluation.

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Table 3-2 – Triggers for AOR Reevaluations

Reevaluation Trigger	Measure to be Taken	Schedule for Reevaluation
SWO 29-N-6 §615.B.2.b.i 40 CFR 146.84(b)(2)(i)	Reevaluate the AOR as required by statute via indirect monitoring acquisitions (Section 5).	At least once every five years
Survey identifies a greater extent than modeled	Re-run the reservoir plume model with new data. Reevaluate the AOR.	Within one (1) month of detection
Survey identifies the plume direction is different than modeled	Re-run the reservoir plume model with new data. Reevaluate the AOR.	Within one (1) month of detection
Operational Change: Injection rate increases to a rate greater than that modeled	Re-run the reservoir plume model with new data. If plume increases in extents, reevaluate the AOR.	Within one month of detection
Operational Change: Injectate composition changes significantly	Re-run the reservoir plume model with new data. If plume increases in extents, reevaluate the AOR.	Within one month of detection
New site characterization data	Re-run the reservoir plume model with new data. If plume increases in extents, reevaluate the AOR.	Within one month of detection
New operations brought online within or near the plume extents	Re-run the reservoir plume model with new data. If plume increases in shape or extents, reevaluate the AOR.	Within one month of detection
Seismic event detected by passive seismic monitoring or other emergency	Perform direct assessment and if necessary, perform a plume migration survey via indirect monitoring techniques (Section 5). If plume increases in shape or extents, reevaluate the AOR.	Within one month of detection

All AOR maps and resultant tables have been included in Appendix E in a higher-resolution format for ease of detailed review. The complete area of review section includes the following maps and associated tables:

- Appendix E-1 Area of Review: All Oil and Gas Wells Map
- Appendix E-2 Area of Review: Well Penetration List

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- Appendix E-3 Area of Review: Freshwater Wells Map
- Appendix E-4 Area of Review: Freshwater Wells List
- Appendix E-5 Area of Review: Drinking Water Wells List
- Appendix E-6 Area of Review: Freshwater Wells with Imagery Map
- Appendix E-7 Area of Review: Freshwater Wells with Imagery and Distances Map
- Appendix E-8 Area of Review: Sampled Freshwater Wells with Imagery Map

Underground Injection Control – Class VI Permit Application for Hackberry Carbon Sequestration Well No. 001

Cameron Parish, Louisiana

SECTION 4 - ENGINEERING DESIGN AND OPERATING STRATEGY

Prepared for *Hackberry Carbon Sequestration, LLC*
Cameron, LA

By

Lonquist Sequestration, LLC
Austin, TX

August 2021
Revised January 2025

SECTION 4 – ENGINEERING DESIGN AND OPERATING STRATEGY

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4.1 Introduction

The design, construction, and operation of injection wells falls under the jurisdiction of the US EPA Underground Injection Control (UIC) program. Injection wells governed by the UIC program have operated since its inception in 1977. With the advent of Class VI regulations in 2010, and in no small part to the Bipartisan Budget Act of 2018 and subsequent IRS tax code 45Q in 2019, the industry has seen a recent flurry of activity in captured carbon injection wells.

All regions of the United States are being evaluated for the suitability for carbon sequestration from a geologic perspective. In all instances, due to the classification of Class VI wells as storage wells, reservoir management will be imperative for the purposes of plume migration control. Some depositional environments offer more options for reservoir management strategies than others. The Gulf Coast Basin, the basin which the proposed Hackberry Carbon Sequestration (HCS) Well No. 001 is located, is one such location.

The Gulf Coast Basin consists of many Miocene- and Pliocene-aged sand horizons interbedded with shales which offer great injection intervals. In addition, due to their stacked nature as identified in *Section 1 – Site Characterization*, these sands offer the ability to inject into variable discrete intervals thus allowing for the controlled development of the injectate plume. It is this strategy that Hackberry Carbon Sequestration, LLC (HCS) will employ for the operation of the Hackberry Carbon Sequestration (HCS) Well No. 001.

4.2 Engineering Design

The design of the HCS Well No. 001 was developed with several considerations in mind, including volume and rate of injection, chemical composition and physical properties of the injectate fluid, corrosion concerns and metallurgical evaluations, and operational details necessary to maintain reservoir management for the well.

Carbon sequestration wells are designed along similar parameters and considerations as acid gas injection well, including special metallurgies. While CO_2 is not inherently hazardous, when mixed with water under the right conditions, carbonic acid can form with a pH as low as 3. As with all classes of injection wells, the protection of underground sources of drinking water (USDW) is of paramount importance. Of secondary importance, the protection of other subsurface natural resources, if present, must also be protected. This is accomplished through the casing design for the injection well which is engineered to prevent injected fluids from escaping the confinement intervals into which they have been disposed.

HCS Well No. 001 is to be located within the waterline near Black Lake. As such, the drilling and completion of the well will be conducted utilizing a shallow barge rig. One advantage this offers is that the total surface disturbance for this project will be greatly reduced as compared to a location onshore. The only substantial surface disturbance for this project will be at the location of the surface facility for the well. This surface facility will occupy an estimated 10 acres and will be comprised of a control room, compression and pumping equipment, and employee facilities.

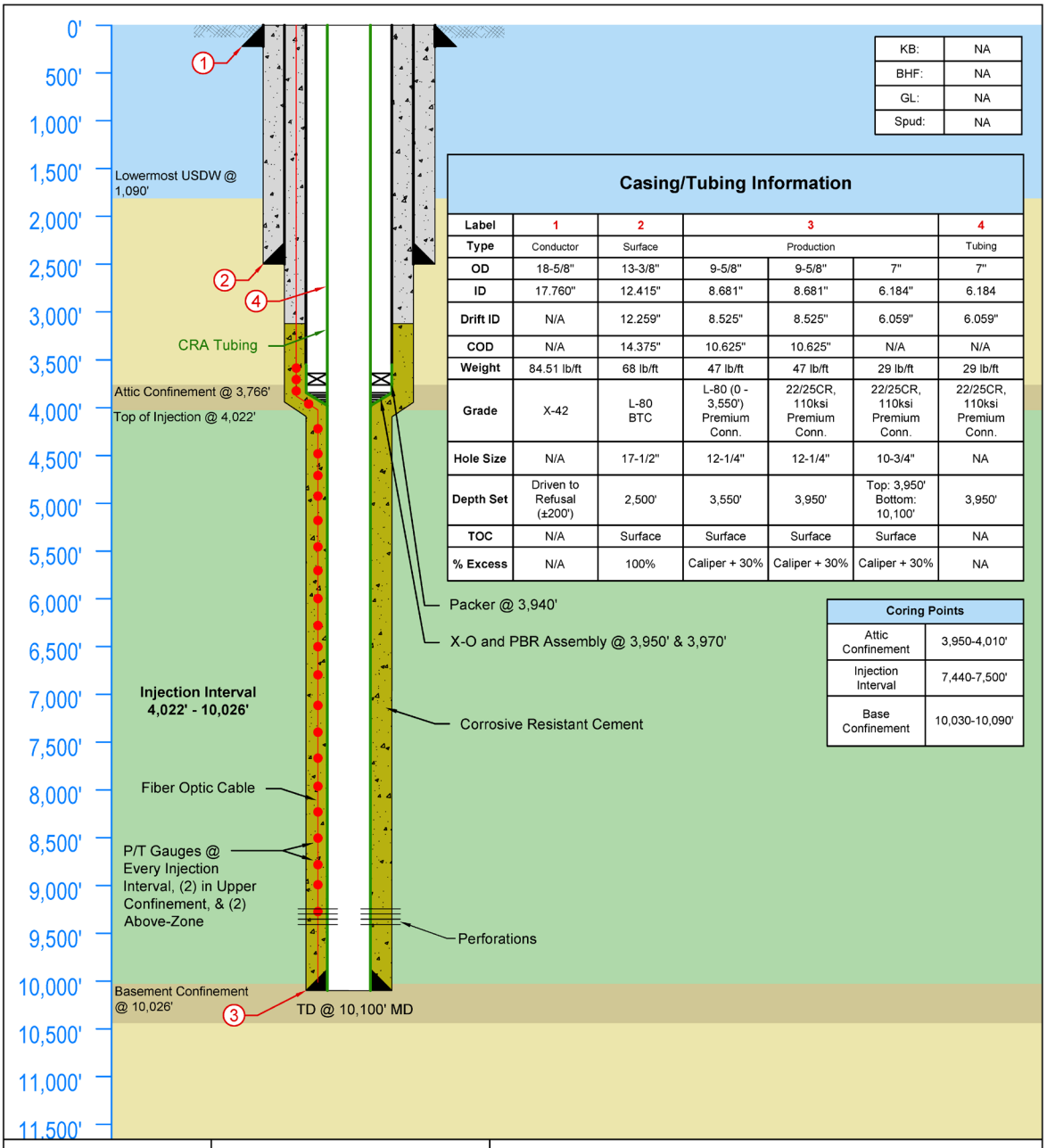
4.2.1 General Outline of Well Design and Completion Schematic

HCS Well No. 001 was designed with the following specifications:

- Surface Casing
  - To be set below the base of the lowermost USDW, which is at approximately 1,090 ft
    - The final USDW depth will be determined via openhole logging during the drilling of the well. If necessary, final surface casing setting depth will be adjusted.
  - 13-3/8 in. OD casing
  - 17-1/2 in. hole size
  - Cemented back to surface
- Production Casing
  - 9-5/8 in. x 7 in. casing set to total depth (TD) of well, estimated to be 10,100 ft
    - The production casing will consist of 9-5/8 in. L-80 from surface to a galvanic crossover, transitioning to 9-5/8 in. x 7 in. 22/25 Chrome (CR) casing to total depth.
      - Galvanic crossover between 9-5/8 in. L-80 and 9-5/8 in. 22/25CR casing set at approximately 3,550 ft
    - 9-5/8 in. casing across the upper confining zone (UCZ) will be 22/25CR material
      - 22/25 Chrome polished bore receptacle with seal assembly, at approximately 3,950 ft
      - 22/25 Chrome taper (or swedge) from 9-5/8 in. casing to 7 in. casing below the PBR
    - 7 in. casing will be 22/25CR material, set to an estimated depth of 10,100 ft
  - 12-1/4 in. x 10-3/4 in. hole size
  - Cemented back to surface
    - Cement to be comprised of the following make-up:
      - Lead: 11.0 pound per gallon (ppg) PermaSet system or similar acid-resistant cement (caliper volume plus 30% excess in openhole)
        - Placed from surface to 3,266 ft
      - Tail: 13.0 ppg PermaSet system or similar acid-resistant cement (caliper volume plus 30% excess in openhole)
        - Placed from 3,266 ft to total depth
- Injection Tubing
  - 7 in. tubing set on packer, with tail pipe and seal assembly stung into the PBR
  - Packer will be set +/-50 ft above the 9-5/8 in. x 7 in. taper in the UCZ
  - Per metallurgical analysis, composition to be of 22/25CR duplex stainless steel or greater
  - Annular fluid to consist of corrosion inhibitor fluid

- Packer
  - 9-5/8 in. x 7.0 in. permanent production packer
  - Minimum ID: 6.184 in.
  - Maximum ID: 7.5 in.
  - Elastomer options - Nitrile, HNBR, or Aflas. The elastomer used will be appropriate for CO_2 service.
  - Temperature limitation 100 to 350°F
  - Inconel-lined (flow-wetted) anchor, mandrel and cylinder for corrosion resistance
- Wellhead
  - 13-3/8 in. SOW x 13-5/8 in. 5M – casinghead
  - 13-5/8 in. x 9-5/8 in. - casing hanger
  - 13-5/8 in. 5M x 11 in. 5M casing Spool
    - Production Tree 7 1/16 in. 5M, gate valve, manual
    - 7 1/16 in. 5M, gate valve, pneumatic
    - 7 1/16 in. X 5 1/8 in. 5M flow cross with 5-1/8 in. 5M wing valves
    - 7 1/16 in. 5M, gate valve, manual, for crown with cap
  - Stainless and inconel-lined wetted sections for corrosion resistance
  - See schematic for details

A complete drilling and completion prognosis has been included in Appendix F.



KB:	NA
BHF:	NA
GL:	NA
Spud:	NA

Casing/Tubing Information

Label	1	2	3			4
Type	Conductor	Surface	Production			Tubing
OD	18-5/8"	13-3/8"	9-5/8"	9-5/8"	7"	7"
ID	17.760"	12.415"	8.681"	8.681"	6.184"	6.184
Drift ID	N/A	12.259"	8.525"	8.525"	6.059"	6.059"
COD	N/A	14.375"	10.625"	10.625"	N/A	N/A
Weight	84.51 lb/ft	68 lb/ft	47 lb/ft	47 lb/ft	29 lb/ft	29 lb/ft
Grade	X-42	L-80 BTC	L-80 (0 - 3,550') Premium Conn.	22/25CR, 110ksi Premium Conn.	22/25CR, 110ksi Premium Conn.	22/25CR, 110ksi Premium Conn.
Hole Size	N/A	17-1/2"	12-1/4"	12-1/4"	10-3/4"	NA
Depth Set	Driven to Refusal (±200')	2,500'	3,550'	3,950'	Top: 3,950' Bottom: 10,100'	3,950'
TOC	N/A	Surface	Surface	Surface	Surface	NA
% Excess	N/A	100%	Caliper + 30%	Caliper + 30%	Caliper + 30%	NA

Coring Points	
Attic Confinement	3,950-4,010'
Injection Interval	7,440-7,500'
Base Confinement	10,030-10,090'

LONQUIST SEQUESTRATION LLC	Hackberry Carbon Sequestration, LLC	Hackberry Carbon Sequestration Well No. 001	
	Country: USA	**State/Province:** Louisiana	**County/Parish:** Cameron
	API No: TBD	**Field:**	**Well Type/Status:** Class VI CCS
Louisiana License EF-7423	**Permit No:** TBD	**Project No:** 2393.4	**Date:** 01/27/2025
12912 Hill Country Blvd. Ste F-200 Austin, Texas 78738 Tel: 512.732.9812 Fax: 512.732.9816	**Drawn:** Joseph Lovewell	**Reviewed:** Joseph Lovewell	**Approved:** Ben H Bergman
	Rev No: 2	**Notes:**	

Figure 4-1 – Hackberry Carbon Sequestration Well No. 001 Schematic

4.2.2 Detailed Discussion of Injection Well Design

The typical procedure followed in the design of injection wells is to determine the minimum requirements for the injection tubing and then work back up through the production casing string, any intermediate casing strings (if necessary), and finishing with surface casing requirements. This was the procedure employed for the design of the Hackberry Carbon Sequestration Well No. 001.

To properly size the injection tubing, desired injection parameters were necessary. HCS plans to inject a maximum volume of captured carbon gas of 2 million metric tons/yr (MMT/yr) into this proposed well. This translates to a rate of 103.55 million standard cubic feet per day (MMscf/day) at standard conditions.

Table 4-1 – CO_2 Standard Conditions

Temperature °F	Pressure psia	Density lbm/ft^3	Enthalpy Btu/lbm	Entropy Btu/lbm-°R
60	14.7	0.11666	214.18	0.64759

From these defined criteria, calculations were made to optimize the size of the tubing considering calculated pipe friction losses, exit velocities, compression requirements, and economic evaluations. Injection results were calculated taking the approximate depth of the deepest discrete completion intervals since this would represent a worse-case scenario. The following inputs were populated into Lonquist Sequestration's proprietary calculation spreadsheet:

Table 4-2 – CO_2 Injection Parameters

User Inputs		
Injection Volume at Std. Atm. 60°F	103.550	*MMscf/day*
Plant Outlet Temperature	120	*°F*
Plant Outlet Pressure	1,200	*psi*
Formation Mid-perf Depth	9,195	*feet*
Formation Pressure Gradient	0.540	*psi/ft*
Local Geothermal Gradient	0.85	*°F/100 ft*
Local Ambient Surface Temperature	75	*°F*
Tubing Set Depth	8289	*feet*
Tubing Nominal Diameter	7	*inches*
Tubing ID (incl. liner/coating thickness)	6.004	*inches*
Tubing Roughness	0.00591	*inches*
Average Fluid Viscosity in Pipe	0.038	*cP*
From chart in Friction Calcs Tab		

The following results were determined from these inputs:

Table 4-3 – Calculated Injection Parameters

Calculated Parameters		
Formation Mid-perf Temperature	153.2	*°F*
Formation Mid-perf Pressure	4,965	*psi*
Plant Outlet Density	14.973	*lbm/cuft*
Compressor Outlet Density	39.541	*lbm/cuft*
Formation Mid-perf Density	52.272	*lbm/cuft*
Average Wellbore Density	45.907	*lbm/cuft*
Pipe Friction Pressure Loss	386	*psi*
Fluid Column Head Pressure	2,931	*psi*
Compressor Outlet Temperature	146.7	*°F*
Compressor Outlet Pressure	2,420	*psi*

Fluid Conditions	Temperature	Pressure
Plant Outlet	120 °F	1,200 psi
Compressor Outlet	147 °F	2,420 psi
Formation Mid-perf	153 °F	4,965 psi

These results identified that 7-in. tubing will be the appropriate size necessary to move the desired volumes of CO_2 gas into this well. Calculated pipe friction loss and exit velocities were manageable at 537 psi and 17.878 ft/sec, respectively. This design parameter was further verified by confirming that the results above maintained the injected CO_2 gas in a supercritical phase.

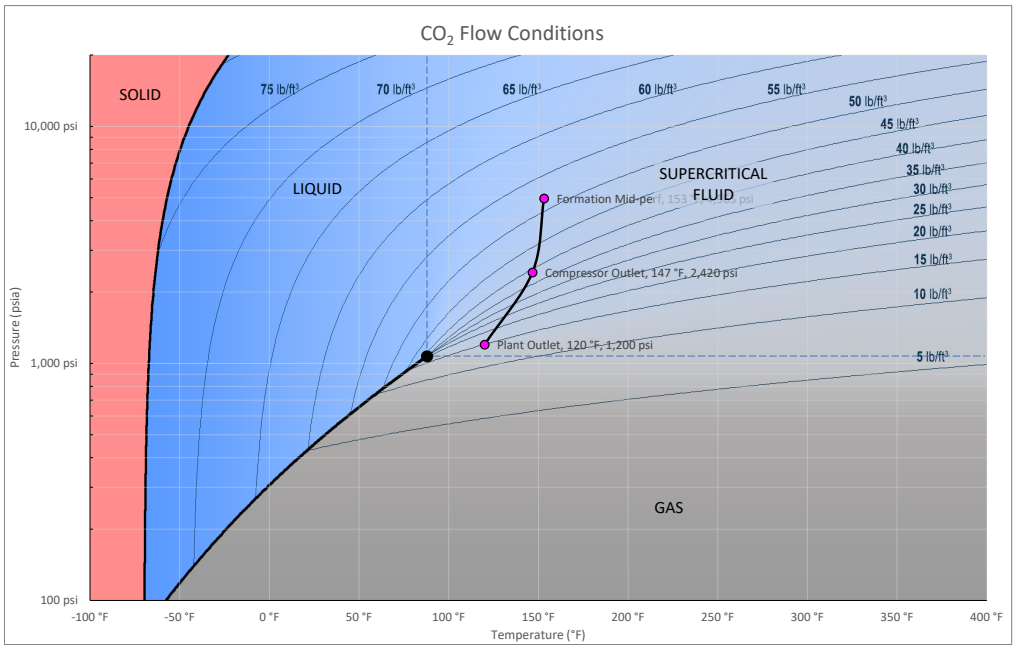


Figure 4-2 – CO_2 Flow Conditions

Based on appropriate bit size selection, pipe clearance considerations, and recommended annular spacing for assurance of good cementing jobs, it was determined that the following casing sizes will be required to accommodate the 7 in. injection tubing:

- 20 in. drive pipe
- 13-3/8 in. surface casing
- 9-5/8 in. X 7 in. production casing

4.2.2.1 Drive Pipe

Due to the very loose, unconsolidated nature of the immediate sediments found beneath Black Lake's waterline, a drive pipe will be necessary to ensure that hole integrity can be maintained during the initial drilling of the well. The 20 in. pipe will be driven by hydraulic ram, until refusal or ~200 blows per foot of advancement.

The drive pipe size was selected to facilitate the desired bit size requirement for the drilling of the surface casing. With an inner diameter (ID) of 18.73 in., a 17-1/2 in. bit can be utilized for the development of the next section of the well.

Once the drive pipe is established, the inner portions of the pipe can be flushed out and evacuated and drilling can commence.

4.2.2.2 Surface Casing

13-3/8 in. casing has been selected as the size for the surface casing section of the well. This section will be drilled with a 17-1/2 in. bit which will give sufficient annular space for a good cement job back to surface. This casing will protect groundwater resources by being set deeper

than the lowermost USDW (as determined by openhole logging). After cementing, a cement bond log will be run to evaluate and verify good bonding throughout the surface hole. Once the production casing has been run and cemented to the surface, there will be four barriers between the USDW formation and the wellbore.

Summaries of surface engineering and cementing calculations can be seen in Table 4-4 and Table 4-5:

Table 4-4 – Surface Casing Engineering Calculations

Description	Casing Wt. (lb/ft)	Depth (ft)	Tensile (psi)	Collapse (psi)	Burst (psi)	Capacity (bbl/ft)	ID (in.)	Drift ID (in.)
13-3/8 in., 68 lb/ft, L-80, BTC (0 – 2,500 ft TD)	68	2,500	952,000	2,260	5,020	0.1497	12.415	12.259
Design Criteria			170,000	1,625	1,625			
Safety Factor			5.60	1.39	3.09			

Section	ID (in.)	MD (ft)	TVD (ft)
Drive Pipe	17.76	200	200
Openhole	17.5	2,500	2,500

Section	OD (in.)	ID (in.)	Weight (lb/ft)	MD (ft)	TVD (ft)
Surface	13.375	12.415	68	2,500	2,500

Table 4-5 – Surface Casing Cement Calculations

System	Top (ft)	Bottom (ft)	Cement Volume (ft^3)
Lead	0	1,500	1,955
Tail	1,500	2,500	1,427

Section	Footage (ft)	Capacity ($ft^{3)}$	Excess (%)	Cement Volume (ft^3)
Drive Pipe/Casing Annulus	200	0.7446	0%	149
OH/Casing Annulus - Lead Cement	1,300	0.6946	100%	1,806
OH/Casing Annulus Tail Cement	1,000	0.6946	100%	1,389
Shoe Track	45	0.8407	0%	38

To ensure that the cementing job successfully achieves returns to surface, a 100% excess for cement quantities was used. The surface casing will have Buttress connections.

4.2.2.3 Production Casing

Due to the unconsolidated nature of the Miocene sands being targeted for injection in this well,

the production casing, or long string, will be run all the way to the total depth of the well. The production casing will be cemented all the way back to surface.

There are several key design criteria for the long string:

1. A 9-7/8 in. x 7 in. tapered casing design to accommodate multiple recompletions over the life of the well,
2. The use of 22Cr/25Cr material from above the UCZ through the injection interval to TD
3. The use of fiberoptic/electric cable along the exterior of the casing
4. Integration of tools such as a galvanic crossover, stage tool, polished bore receptacle (PBR), float equipment and centralizers
5. The use of acid-resistant cement systems from 500 ft above the UCZ, through the injection zone, to TD

The purpose of the acid-resistant cement is to resist degradation of the cement due to being exposed to an acidic environment thereby extending the integrity and life of the well. As stated, this cement will be placed such that the top of the acid-resistant cement is above the top of the gross injection zone. The entire cement column will be brought back to the surface.

The use of specialty metals within the gross injection interval is done to accommodate the movement and resetting of the packer throughout the life of the well. The well has been designed in specific subsections within the gross injection interval. These subsections will be used to facilitate the application of the operating strategies for the well.

The completion strategy for the well will be designed to start injecting at the lowest sand interval selected. The CO_2 injectate will be injected for the predetermined amount of time derived from the reservoir injection plume modeling. When that interval has reached that predetermined time, a corrosion resistant bridge plug will be set above the injection interval and 50 ft of acid-resistant cement will be placed on top of the bridge plug. This work will be done with a wireline unit without having to pull the packer and tubing. The next zone above the zone that has been safely plugged will be perforated and now used for the injection of the CO_2 injectate. This will be an efficient and economic method for performing the work as a workover rig will not need to be used to perform the work. This process will continue to be repeated throughout the life of the well until the uppermost sand interval has completed the designated duration for that zone.

Finally, a fiber optic cable sensor package will be installed with the completion of the production casing and will be cemented into place. The fiber optic cable will be used to perform vertical seismic profile (VSP) surveys of the plume and record formation temperatures and pressures in sections that have been injected into. This ability is considered part of the overall long term monitoring system of the well. As the life of the well progresses, the system in place will still be able to monitor all the data from both the zones that have been plugged with bridge plugs, as the well as each new injection zone that will be completed.

The engineering and design parameters for the production casing are summarized in Tables 4-6

to 4-7:

Table 4-6 – Production Casing Engineering Calculations

Description	Casing Wt. (lb/ft)	Depth (ft)	Tensile (psi)	Collapse (psi)	Burst (psi)	Capacity (bbl/ft)	ID (in.)	Drift ID (in.)
9-5/8 in., 47 lb/ft, L80 (0 – 3,550 ft TD)	47	3,550	1,086,000	4,760	6,870	0.0732	8.681	8.525
Design Criteria			364,000	2,308	2,308			
Safety Factor			2.98	2.06	2.98			
9-5/8 in., 47 lb/ft, 22CR/25CR, 110ksi (3,550 ft – 3,950 ft)	47	400	1,493,000	5,310	9,440	0.0732	8.681	8.525
Design Criteria			197,150	2,568	2,568			
Safety Factor			7.57	2.07	3.68			
7 in., 29 lb/ft 22CR/25CR, 110ksi (3,950 ft – 10,100 ft)	29	6,150	929,000	8,510	11,220	0.0371	6.184	6.059
Design Criteria			178,350	6,565	6,565			
Safety Factor			5.21	1.30	1.71			

Section	ID (in.)	MD (ft)	TVD (ft)
Surface Casing	12.415	2,500	2,500
Open Hole	12.25	3,950	3,950
Open Hole	10.75	10,100	10,100

Section	OD (in.)	ID (in.)	Weight (lb/ft)	MD (ft)	TVD (ft)
9 5/8 in.	9.625	8.681	47	3,950	3,950
7 in.	7.000	6.184	29	10,100	10,100

Table 4-7 – Production Casing Cement Calculations

System	Top (ft)	Bottom (ft)	Cement Volume (ft^3)
Lead	0	3,266	1,150
Tail	3,266	10,100	3,200

Section	Footage (ft)	Capacity (ft^3/ft)	Excess (%)	Cement Volume (ft^3)
Surface Casing/9-5/8" Casing Annulus Lead Cement	2,500	0.3354	0%	838
12-1/4" Open Hole x 9 5/8" Casing Annulus Lead Cement	766	0.3132	30%	312
12-1/4" Open Hole x 9 5/8" Casing Annulus Tail Cement	684	0.3132	30%	278
10-3/4" Open Hole X 7" Casing Annulus Tail Cement	6,150	0.3630	30%	2,903
Shoe Track	90	0.2086	0%	19

The production casing will be installed using premium connections.

4.2.2.4 Centralizers

Centralizer selection and installation for the referenced well will have two, separate functions. The bow-spring centralizer design for the 13-3/8 in. surface casing will be planned to protect any shallow aquifer zones per state regulations. The specific placement is to ensure a continuous, unform, column of cement is present throughout the 2,500 ft of 13-3/8 in. x 17-1/2 in. annular void. The recommended locations will be:

- Above the shoe joint
- Above the float collar
- Subsequent five joints of casing
- Every fourth joint (160 ft) to surface

Total Centralizers – 20 joints

Centralizer placement for the 9-5/8 x 7 in. long string casing will be designed regarding the installation of the fiber optic cable (FOC) and TEC. Clamped centralizers and eccentric centralizers will both be utilized to ensure the FOC and TEC are not damaged. The recommended procedure will be:

1. Utilize two eccentric centralizers (slide-on) across a two-joint shoe track. Install cable clamp above top eccentric centralizer for cable security
2. Install clamp iron centralizers every 160 ft or four joints to surface, cable detection clamps every three to four joints
3. Fiber module protectors every five to six joints

4.2.2.5 Injection Tubing

As previously discussed in this section, the injection tubing size was selected based on injection volumes, rates, and composition. Once a size was selected, a detailed metallurgical analysis was conducted for determination of appropriate materials to be used for the handling of CO_2. This evaluation was done with the assumption that carbonic acid would form as a result of condensed water from the injection stream as well as contact of the CO_2 with the connate fluids within the injection formation. A complete summary of the metallurgical analysis is included in Appendix G of this application.

As discussed above, the results of the metallurgical analysis determined that due to the corrosive nature of the CO_2 in contact with water within the system, a minimum recommendation of 22CR or 25CR (duplex stainless steel) would be necessary to ensure adequate protection against the corrosive environment of the well.

Table 4-8 – Injection Tubing Specifications

Description	Casing Wt. (lb/ft)	Depth (ft)	Tensile (psi)	Collapse (psi)	Burst (psi)	Capacity (bbl/ft)	ID (in.)	Drift ID (in.)
7 in., 29 lb/ft, 22CR/25CR, 110ksi (0 – 3,950 ft)	29	3,950	929,000	8,510	11,220	0.0371	6.184	6.059
Design Criteria			114,550	6,054	6,465			
Safety Factor			8.11	1.41	1.74			
		Evacuated tubing, brine on backside with 4,000 psi applied						
		Evacuated annulus, full column of 12 ppg mud with 4,000 psi applied						

The tubing will be installed using premium connections.

4.2.2.6 Packer Discussion

The longstring will be made up of the same 7 in. casing as used in the "Mono-Bore" tapered 9-5/8 in. x 7 in. casing system. There will be a polished bore receptacle (PBR) run just below the 9-5/8 in. x 7 in. casing crossover when the production casing is run. When the longstring is run, there will be a seal assembly on the bottom of the longstring that will sting into the PBR. The project currently plans to run the seal assembly without the sealing elements. This will provide smooth "Mono-bore" access for recompletion operations and will avoid any potential concern of a trapped/un-observable annular space. A liner top packer will be located directly above the seal assembly as a barrier for that annulus. Once the packer is set, it will be pressure-tested to verify there is no communication between the 7 in. x 9-7/8 in. annulus and the 7 in. casing set

through the zone below that will be injected into. The project is evaluating the possibility of running the PBR seal assembly with the sealing elements if deemed necessary.

The tapered casing string and the mono-bore tubing design requires the use of polished bore receptacle at the bottom of the 9-5/8 in. casing. The tubing is then run with a seal assembly that will sting into the receptacle. This design will ensure a mono- bore completion within the well. Once set in the PBR, the 9-5/8 in. x 7 in. packer will be set and tested completing the system.

Figure 4-3 is a representative example of the packer to be used.

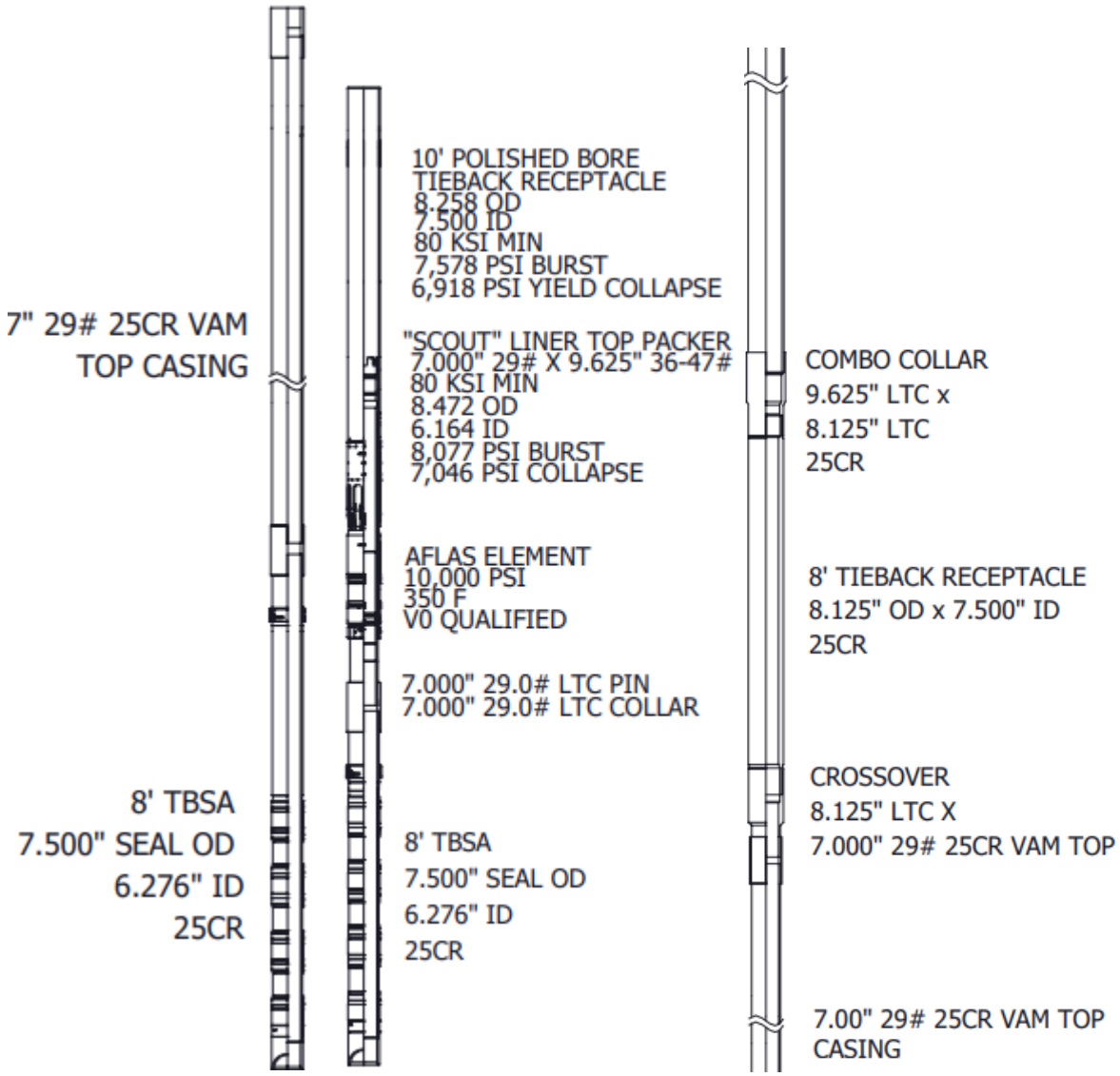


Figure 4-3 – 7 in. Seal Assembly, 9 5/8 in. Permanent Packer Illustration

Prior to setting the packer, the tubing/longstring casing annulus will be filled with a non-corrosive fluid as approved by the Director. Pressure will be maintained on the annulus at a pressure that exceeds the operating injection pressure of the well.

4.2.2.7 Safety Valve

Given HCS Well No. 001's location onshore and based on LAC 43 XVII.3621.A.7.a.i, a downhole shut-off system is not required. The HCS project is not subject to the risk factors considered in the EPA Class VI implementation guide of "high temperature, high pressure, presence of hydrogen sulfide, proximity to populated areas, or high likelihood of damage to the wellhead" that would increase the necessity of a downhole shut-off device. The project is evaluating whether to include a surface controlled subsurface safety valve in the 7 in. tubing that would fail safe and could be operated either hydraulically or pneumatically.

Pressure Gauge

Pressure gauges will be installed on the fiber optic system to continuously monitor for the reservoir pressures during and post-injection within each of the completion stages. Equipment examples are shown for multiple options being evaluated.

Array Pressure Temperature Sensor

The Halliburton Array sensors (Figure 4-4) are welded into the TEC cable when deployed behind casing and have a proven track record of measuring reservoir pressure and temperature through the cement sheath. One to 25 sensors can be installed on a single TEC line and read independently of each other (e.g., if one sensor is lost the remaining sensors continue reading). (Garcia, E. et al, 2019).

Figure 4-4– Halliburton Array Pressure Temperature Sensor

SureSENS QPT (Quartz Pressure Temperature) Elite Gauge

The SureSENS QPT Elite measures static and dynamic pressures and temperatures and is reliable and accurate. The QPT Elite is highly robust, ensuring mechanical integrity by deep-penetration and high-vacuum, electron-beam fusion welds, without the need for filler material. Only two fittings (the pressure port and the TEC) are required to interface the gauge with the carrier. The fittings can be externally tested in the direction they will experience pressure, eliminating the need for an internal pressure test tool.

Figure 4-5– SureSENS QPT Elite Gauge Illustration

QPT Elite Pressure Interface – Pressure Testable Manifold

The gauge pressure interface connection to the carrier is via a pressure testable manifold interface, which is attached to the mandrel, and triple metal seals rings are pressure tested to ensure integrity prior to deployment. The three metal seals provide redundant metal to metal sealing which are tested in the same direction as the applied pressure in final installation. This provides a true, unique bi-directional dual testable metal-to-metal design.

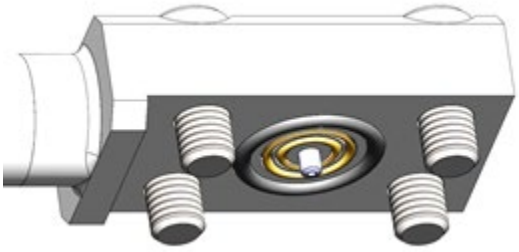


Figure 4-6 – External Sensor Illustration

Table 4-9 – QPT Elite Pressure Interface – Pressure Test Manifold Specifications

Length	25.5 in. to 26.5 in. (64.77 cm to 67.31 cm)					
Height/Width	0.750 in. (19.05 mm) / 1.318 in. to 2.50 in. (33.50 mm to 63.50 mm)					
Seals	Metallic seals and EB welds					
Transducer	Shear mode quartz					
Transducer options	10,000 psi (689.5 bar)	15,000 psi (1103.2 bar)	20,000 psi (1379.0 bar)	25,000 psi (1723.6 bar)	30,000 psi (2068.4 bar)	35,000 psi (2413.7 bar)
Material	Inconel 718	MP35N				
Pressure range	15 psi to 11,000 psi (1 bar to 758.4 bar)	15 psi to 18,000 psi (1 bar to 1241.1 bar)	15 psi to 23,000 psi (1 bar to 1620.3 bar)	15 psi to 28,000 psi (1 bar to 1930.5 bar)	15 psi to 33,000 psi (1 bar to 2275.3 bar)	15 psi to 37,500 psi (1 bar to 2585.5 bar)
Temperature rating (operating)	-99.4°F to 302°F (-73°C to 150°C)	-99.4 to 437°F (-73°C to 225°C)				
Storage temperature	-40°F to 302°F (-40°C to 150°C)					
Temperature shock	5.4°F (3°C) per minute					
Vibration	>10 G, 10 Hz-2 kHz					
Shock	500 G					
Pressure measurement range (calibrated)	200 psi to 10,000 psi (13.8 bar to 689.5 bar)	200 psi to 16,000 psi (13.8bar to 1103.2 bar)	200 psi to 20,000 psi (13.8 bar to 1379.0 bar)	200 psi to 25,000 psi (13.8 bar to 1723.6 bar)	200 psi to 30,000 psi (13.8 bar to 2068.4 bar)	200 psi to 35,000 psi (13.8 bar to 2413.7 bar)
Pressure accuracy	+-0.015% 1.5 psi at full scale	+-0.02% 3.2 psi at full scale	+-0.02% 4.0 psi at full scale	+-0.02% 5.0 psi at full scale	+-0.025% 7.5 psi at full scale	+ -0.03% 10.5 psi at full scale
Pressure resolution	0.0001 psi					
Pressure stability	0.02% full scale, 2.0 psi/year	+-0.02% full scale, 3.2 psi/year	+-0.02% full scale, 4.0 psi/year	+-0.02% full scale, 5.0 psi/year	+-0.02% full scale, 7.5 psi/year	+ -0.03% full scale, 10.5 psi/year
Temperature measurement range (calibrated)	77°F to 302°F (25°C to 150°C)	77°F to 437°F (25°C to 225°C)				
Temperature accuracy	0.27°F (0.15°C)					
Temperature resolution	0.0001°F					
Temperature stability	0.018°F (<0.01°C) per year					
Maximum sample rate/second	>16					
Number of gauges support/TEC	32					
Cable distance transmission	50,000 ft (15,240 m)					

4.2.2.8 Wellhead Discussion

The wellhead proposal, similar to the production packer, should be designed to combat working pressures and corrosion complications. The wellhead equipment will be manufactured to have a combination of stainless-steel components across the hanger and casing spool whereas Inconel lining will be located across trims, stems, gates, valves, etc. Final pressure rating will be confirmed prior to the beginning of the manufacturing process. The wellhead will be configured as in Figure 4-7. The manufacturer of the wellhead may differ from the one shown in Figure 4-7.

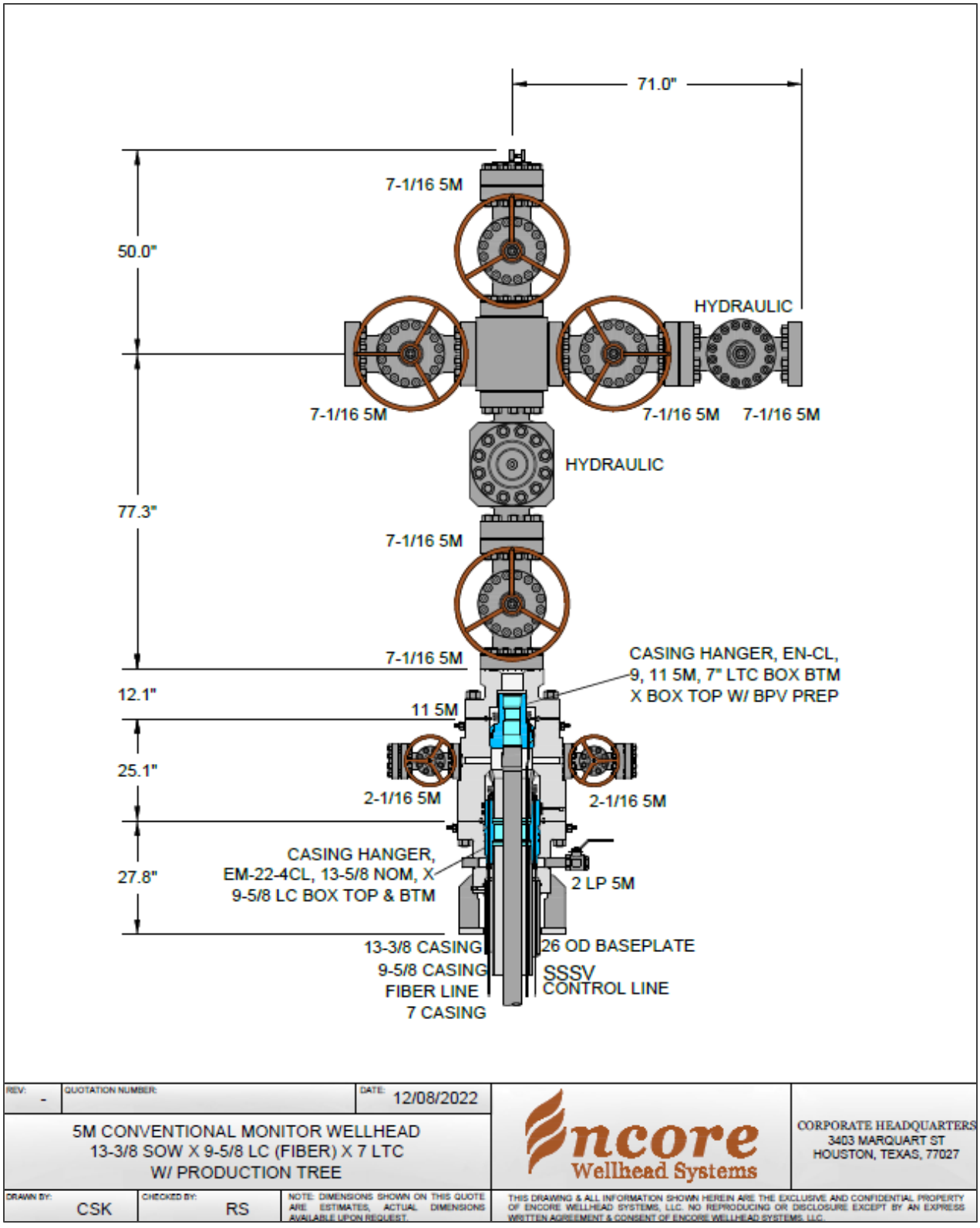


Figure 4-7 – Hackberry Carbon Sequestration Well No. 001 Preliminary Wellhead Schematic

4.2.3 Completion/Stimulation Plans

HCS Well No. 001 may be stimulated during completion operations, to clean up the well after drilling and/or to improve injection performance. Final stimulation designs will be determined based on the conditions met during drilling. HCS will submit proposed stimulation procedures to the UIC Director at least 30 days prior to beginning such operations. Such procedures may include the following activities:

- Stimulation of the formation matrix with hydrochloric acid and/or hydrofluoric acid
- Washout of the wellbore with nitrogen through coiled tubing
- Permeability enhancement through pressure pumping

4.3 Testing and Logging During Drilling and Completion Operations

4.3.1 Coring Plan

As discussed in the drilling procedure in Appendix F-1, core samples will be taken during the drilling of well in the upper confining section, the injection zone and the lower confining section. Due to the size of the gross injection zone, coring the entirety of the confining intervals and the injection interval is highly improbable. To fully evaluate the properties of the injection zone, formation properties will be determined by a combination of comprehensive openhole logging and discrete core sampling of multiple locations throughout the zone. The data derived from the core analysis will be directly applied to the openhole logging response at the core depth and then correlated to the parameters observed across the entire openhole log.

Due to the highly unconsolidated nature of the formations in this area, special efforts will be made to ensure that the cores obtained are as high a quality as possible using the most current technologies available. These efforts include managing the mud systems, watching pump pressures, and running short (30 ft) core barrels instead of the normal 60 ft.

4.3.2 Logging Plan

A full suite of electric logs will be run in each openhole section and cement bond longs will be run on each string of casing, as required by state regulations. A complete list of logs that will be run is included with the drilling and completion prognosis in Appendix F. Of note, this suite includes a dipole sonic log and digital imaging, both resistivity and ultrasonic, as well as magnetic resonance and formation lithology. In conjunction with the directional survey, the log results also provide the size and orientation of such fractures.

4.3.3 Formation Fluid Testing

Prior to setting the production casing string, samples of the formation fluid will be obtained by running an openhole fluid recovery tool (RDT). Recovery sections will be determined based on

openhole evaluations. HCS will record the fluid temperature, pH, conductivity, reservoir pressure, and static fluid level of the injection zone. Two samples will be taken per section as described in the Drilling and Completion Prognosis, Appendix F.

4.3.4 Step-Rate Test

After the initial injection interval is perforated, a step-rate test will be performed as discussed in Section 5 – Testing and Monitoring Plan.

4.4 Injection Well Operating Strategy

- Injection Zone (Gross): 4,022 ft to 10,026 ft
- Maximum/Average Injection Volume: 103.550 MMscf per day
- Maximum/Expected Surface Pressure Injection: 2,700 psi / 2,425 psi
- Maximum Annular Pressure: 2,800 psi

Hackberry Carbon Sequestration Well No. 001 is designed to inject 2 MMT/yr of CO_2. This equates to an injection rate of 103.550 MMscf per day at standard atmospheric conditions. The gas will be compressed at the surface to nearly 3,000 psi prior to injection. This pressure will be sufficient to move the gas into the injection formation and ensure that the injectate streams stays in a supercritical phase or state of being. Because of the depths of injection zone, the CO_2 will remain in liquified form until it is either absorbed into the connate fluid of the formation or is chemically bound to the existing geochemistry.

The bottomhole pressure is calculated to increase only by 677 psi, which will occur during the initial stages of injection with the pressure dropping over time. The formation pressure at the extent of the plume migration is only expected to rise by 250 psi. This relatively low-pressure build-up within the reservoir is a result of the injection intervals having such high porosities and permeabilities. These reservoir properties allow for the formation pressure to balance out and relieve itself much more readily than more restrictive geologies. Surface injection pressures will not be allowed to exceed 90% of the fracture pressure of the injection reservoir.

The operating plan was devised with optimization of reservoir pore space and plume expansion management in mind. The loose Miocene sands, while ideal for carbon sequestration due to their significant thicknesses and high porosities and permeabilities, also pose complications to operational considerations. Miocene sands require substantial reservoir management practices in order to facilitate a controlled injection operation. Unlike typical disposal wells, the plume growth will be controlled by a complex series of injection operations over multiple intervals over time.

Due to the differences in physical properties between CO_2 and the connate brine in the formation, plume modeling indicates that the injectate will rush to the shallowest portions of the opened sand packages first with the small amounts of supercritical fluid “floating” upward to the uppermost portion of the interval being injected into. This is due to the CO_2 being less dense

than brine. Typical densities for the injectate, ranges from 39 lb/ft^3 in the shallowest intervals to 52.8 lb/ft^3 into the deepest sands. This is compared to 67 lb/ft^3 for the brine in the same formations.

The result is a significant "mushroom cap" effect with the top of the mushroom expanding outward in a nearly uncontrolled fashion (Figure 4-8).

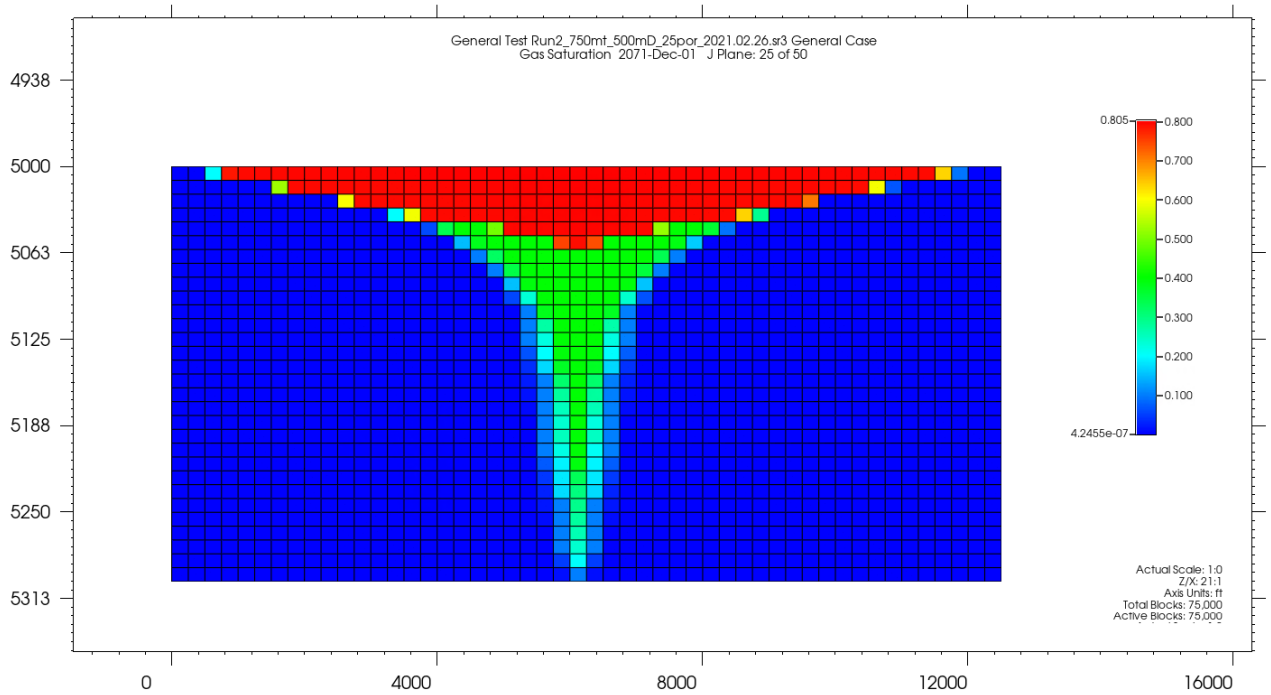


Figure 4-8 – Typical Plume Profile in Loose Formations

Figure 4-8 shows that only approximately 5%-10% of the total pore space is actually occupied by the injected fluids. This amount is an extremely inefficient utilization of available formation pore space. In addition, since pore space rights are a required consideration with carbon sequestration wells and are determined by the lateral extent of the farthest-reaching portion of the plume, this result is not desirable.

As such, reservoir management is extremely important for disposal wells into thick, loose sand formations. The operating strategy for HCS Well No. 001 is as follows:

- The gross injection interval will be broken into several 'discrete injection intervals'
- These injection intervals are then divided into discrete completion intervals
- The discrete intervals are perforated
- The injectate fluids are injected into the discrete completions for a relatively short period of time – not less than one year – not greater than five years (estimated)
- Plume migration surveys are conducted each year to contrast actual plume development with the simulated plume model
- Once the surveyed plume has reached the model results or cause a sufficient enough change to cease injection, the interval is isolated and a recompletion to the next interval

is performed.

- The completed subsection is then plugged with a duplex stainless steel (or equivalent) bridge plug. The bridge plug and casing is then tested.
- The abandoned subsection remains open below the bridge plug to allow for continual monitoring of bottomhole pressures and temperatures in the abandoned formations
- This process repeats until the entirety of the gross injection interval has been completed

Figure 4-9 depicts this process in a general form.

Figure 4-9 – Operational Completion Strategy

An example of the completion schedule is shown in Table 4-10. The subsections were determined from the modeling of various discrete sand packages. These packages may consist of only a single sand interval or may be comprised of multiple sands injected into as a group. Each of these discrete sands were injected into and modeled for the various durations identified in the following table. The final application of recompletion stages will be based on several factors including actual injection rates, plume model behavior, reservoir pressure buildups, etc.

Table 4-10 – Hackberry Carbon Sequestration Well No. 001 Completion Interval Injection Schedule Example.

Stage	Perf Year	Top (ft)	Thickness (ft)	Net Pay (ft)	Geologic Layer
1		10,026	--		Anahuac
1	1/2/3	8,907	199	199	Miocene 4 Sand
1		8,887	20		Shale
1	4/5	8,864	23	183	Miocene 4 Sand
1		8,781	84		Shale
1	4/5	8,759	22		Miocene 4 Sand
1		8,709	50		Shale
1	4/5	8,571	138		Miocene 4 Sand
1		8,550	21		Shale
1	6	8,485	65	127	Miocene 4 Sand
1		8,470	16		Shale
1	6	8,453	16		Miocene 4 Sand
1		8,411	42		Shale
1	6	8,365	46		Miocene 4 Sand
2		8,269	96		Shale
2	7/8	8,166	103	103	Miocene 4 Sand
2		8,127	39		Shale
2	9	8,089	38	78	Miocene 4 Sand
2		8,006	83		Shale
2	9	7,966	40		Miocene 4 Sand
2		7,914	52		Shale
2	10	7,899	15	107	Miocene 4 Sand
2		7,832	67		Shale
2	10	7,774	58		Miocene 4 Sand
2		7,755	19		Shale

Stage	Perf Year	Top (ft)	Thickness (ft)	Net Pay (ft)	Geologic Layer
2	10	7,721	34		Miocene 4 Sand
3		7,688	33		Shale
3	11	7,620	68	68	Miocene 4 Sand
3		7,598	22		Shale
3	12	7,572	25		Miocene 4 Sand
3		7,554	18		Shale
3	12	7,506	48		Miocene 4 Sand
3		7,465	41	173	Shale
3	12	7,433	32		Miocene 4 Sand
3		7,387	78		Shale
3	12	7,320	67		Miocene 4 Sand
3		7,251	69		Shale
3		7,211	40		Miocene 4 Sand
3		7,180	31		Shale
3	13/14/15	7,104	76		Miocene 4 Sand
3		6,870	185	202	Shale
3	13/14/15	6,744	126		Miocene 3 Sand
4		6,673	71		Shale
4	16	6,640	32		Miocene 3 Sand
4		6,580	60		Shale
4	16	6,560	20		Miocene 3 Sand
4		6,281	163	144	Shale
4	16	6,253	28		Miocene 2 Sand
4		6,131	204		Shale
4	16	6,068	63		Miocene 2 Sand
4		5,888	180		Shale
4	17/18	5,867	21	151	Miocene 2 Sand
4		5,733	134		Shale

Stage	Perf Year	Top (ft)	Thickness (ft)	Net Pay (ft)	Geologic Layer
4	17/18	5,603	130		Miocene 2 Sand
4		5,528	75		Shale
4	19	5,507	21		Miocene 2 Sand
4		5,384	87	72	Shale
4	19	5,364	20		Miocene 1 Sand
4		5,335	28		Shale
4	19	5,304	31		Miocene 1 Sand
4		5,195	109		Shale
4	20	5,178	17		Miocene 1 Sand
4		5,000	178		Shale
4	20	4,977	23	93	Miocene 1 Sand
4		4,902	75		Shale
4	20	4,849	53		Miocene 1 Sand

The sand packages shown in Table 4-10 were selected from the type log referenced throughout the evaluation and design of HCS Well No. 001. These depths may differ from other perf/stage figures as these will be finalized once the well is drilled based on actual data. The actual discrete intervals completed, and final stages, will be dependent upon the actual openhole log results from the well once it is drilled.

4.5 Injection Well Operational Strategy Summary

To further expand upon the bullet list above, some additional details are offered in summary. The gross injection interval will be subdivided into stages. These stages are established based on the designed injection rate and timed to coincide with a five-year permit renewal schedule. Each stage is then completed in discrete injection intervals. These discrete intervals will be exploited for a period of time such that the plume buildup and migration does not exceed modeled limits.

VSP surveys and gravity surveys will be performed to measure actual plume growth within the active injection interval. Once the measured plume reaches modeled extents, the next shallowest sand package will be opened with perforations. The new sand will then be injected into following the same practices as previously described. Due to the density difference between the injected fluids and connate fluids of the formation, the injected carbon stream will favor the shallowest perforations with minimal further influence on the deeper sands. Once all the discrete packages within a stage have reached modeled plume extents, the stage will be plugged and

abandoned. The next stage will be completed, developed, and operated in the same fashion until all stages have been exploited. Once all stages have been completed, the well will be plugged and abandoned.

This completion and operating strategy is employed to achieve maximum utilization of available pore space while maintaining control of plume growth and migration. Without this strategy, it is estimated that less than 10% of the entire gross injection interval would be utilized and the maximum extent of the injection plume would be approximately three times larger than the maximum extent modeled for this well. As previously discussed, the location for this project is ideally situated for carbon sequestration purposes. Combining the best engineering practices in the design of the well with a state-of-the-art monitoring system and a robust reservoir management strategy, this well will serve the State of Louisiana for years to come.

Appendix F: Well Construction Schematics and Procedures

- Appendix F-1 Drilling and Completion Prognosis
- Appendix F-2 Initial Injection Wellbore Schematic
- Appendix F-3 Cement Program

APPENDIX A – GEOPHYSICAL MONITORING TECHNIQUES

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A.1 Introduction

This section provides more detailed information about the proposed direct and indirect methods proposed for monitoring and determining the extents of the CO_2 plumes for the Hackberry Project.

A.2 Hackberry Petro-Elastic Model and 1D Seismic Signal Feasibility Study

Prior to finalizing a specific geophysical technology for the CO_2 plume monitoring, a detailed feasibility study was done to understand and quantify the changes in acoustic impedance and seismic signal induced by the penetration of supercritical CO_2 in the reservoir pores. This modeling work is critical to anticipate the strength of the time-lapse 4D signal which one can expect at different times of the project, different target depths and under different reservoir configurations.

The workflow applied during the study:

- Import, pre-condition, and QC provided data.
- Update Petro-Elastic Model (PEM) and QC:
  - Rewrite of the PEM in modern Java code in an internal interpretation workbench.
  - Define PVT relationships based on the evolution of fluids density and bulk modulus with pressure (hydrocarbons, brine, and injected gases).
  - Define the expected pressure and temperature gradients in the subsurface
  - Update rock frame relationships based on analogue cases (4D accelerability).
  - Test the effective effect of fluid substitution and rock frame changes separately.
- Build experimental design for each reservoir target:
  - Develop base case and alternative, if any
  - For the major 4D effect obtained, design and refine with internal software testing for massive modeling (Cassis1D).
  - Represent Cassis1D result on cross-plot to address detectability limits.
- Apply 4D-PEM for base and monitor(s)
- Compute seismic traces, differences, and ratios.
- Compute time-shifts.
- Synthetize result in a table for each reservoir target:
  - For each scenario
  - For rock frame activation/deactivation if the case
  - With color coding of detectability
  - With thickness evaluation for detectability, when possible.

Figure A-1 is a graphical representation of this workflow for 4D signal feasibility.

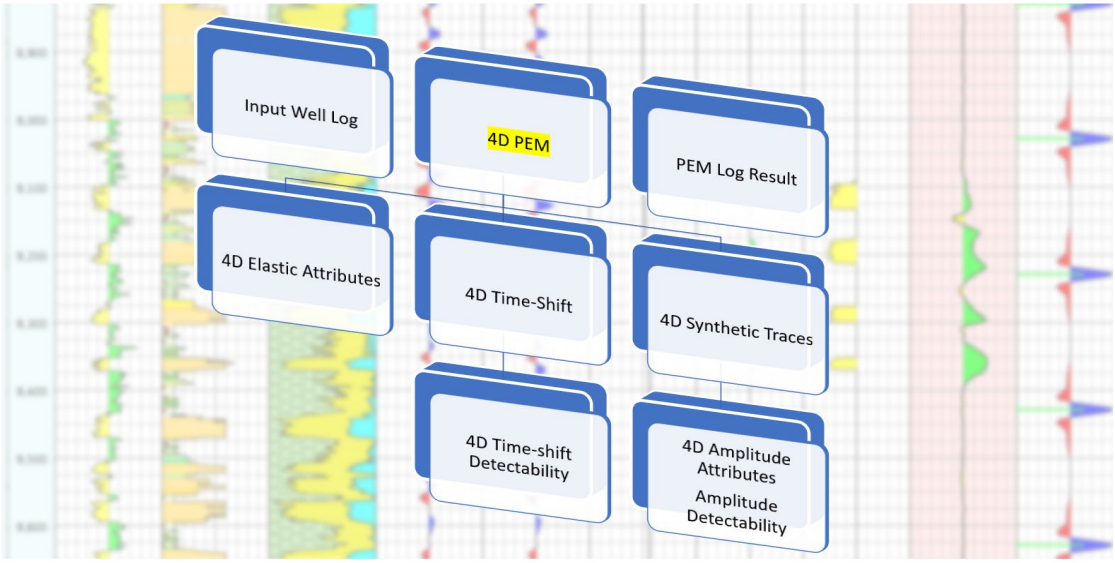


Figure A-1 – 1D modeling workflow with the 4D-PEM being the central element of the process.

A.2.1 Definition of a 4D Petro-Elastic Model (4D PEM)

A petro-elastic model (PEM) is a set of equations which aim to convert geological (porosity, matrix composition) and dynamic parameters (changes in pressure, temperature, and saturations) into elastic and density properties (density (ρ), P- and S-Velocities, (Vp, Vs)). See Rappin et al. (2023) for more details on the importance of a PEM for 4D seismic monitoring.

PEM parameters used as inputs to reconstruct petro-elastic logs are:

- True vertical depth log
- Effective porosity log
- Clay volume log
- Effective water saturation log
- CO_2 gas saturation (if any)
- Pressure
- Fluid properties (density, incompressibility)
- Temperature
- Connate water salinity
- Accelerability effect

The 4D-PEM relies on initial pressure and temperature conditions which were defined based on local gradients information. The PEM units are in Bar and degree Celsius (°C). The applied pressure gradient was: P(Bar) = 0.105186 Bar/meter (depth TVDSS) or P(psi) = 0.465 psi/meter (depth in feet).

The applied temperature was: T(°C) = 0.013488 °C/meter (depth TVDSS) or T(°F) = 0.0074 °F/foot (depth in feet), as shown in Figure A-2.

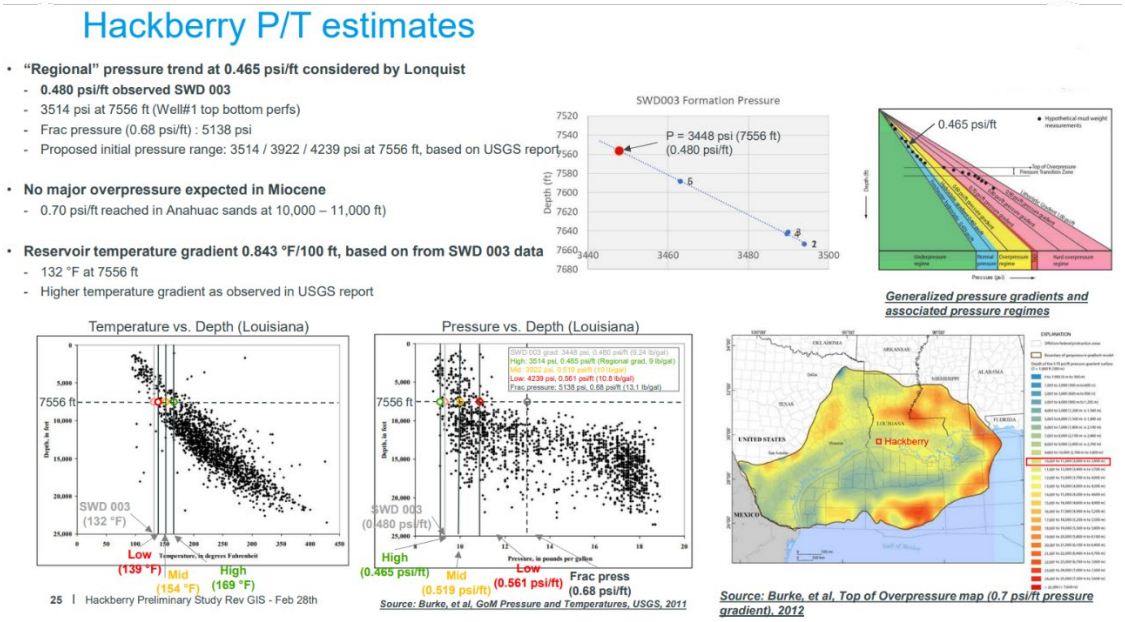


Figure A-2 – Applied Temperature and Pressure Gradients for Hackberry Modeling

To reproduce the change of elastic properties, it is assumed that:

- The fluid substitution effect can be addressed using Gassman's equations.
  - For gas saturation less than 10%, and assuming dissemination of the gas in fluid, the fluid bulk modulus is computed using Wood's equation:

Wood: $$K_{fluid} = \left[\sum_{i=1}^{n} \frac{Sat_i}{K_i}\right]^{-1}$$

where:

Sat_i are saturation for different fluids (water, oil, hydrocarbon gas, acid gas …)

K_i are corresponding bulk moduli.

  - For strong gas saturation changes, patchy saturation of a gas surrounded by a fluid, Brie's equation is used.

Brie: $$K_{fluid} = \left(K_{ini} - K_{gas}\right) Sat_{ini}^{e} + Sat_{gas}$$

Where:

Sat_{ini} = the saturation of initial fluid (can be a mixture of different fluid)
Sat_{gas} = the injected gas saturation,

K_{ini} and K_{gas} are the corresponding bulk moduli.

- Pressure effect on fluid is modeled using fluid property (density, bulk modulus) changes versus pressure and temperature. Reference temperatures were given from the thermal gradient measured on the field or well log.

- Fluid pressure change is responsible for an effective stress change (rock frame) with negligible porosity change (this is an assumption that must be verified). The resulting impact on velocities is called the accelerability effect.

The static part of the PEM is enriched with fluid property computation based on water descriptions based on PVT analysis for hydrocarbon and acid gases description (Span and Wagner 1996 (Figure A-3)).

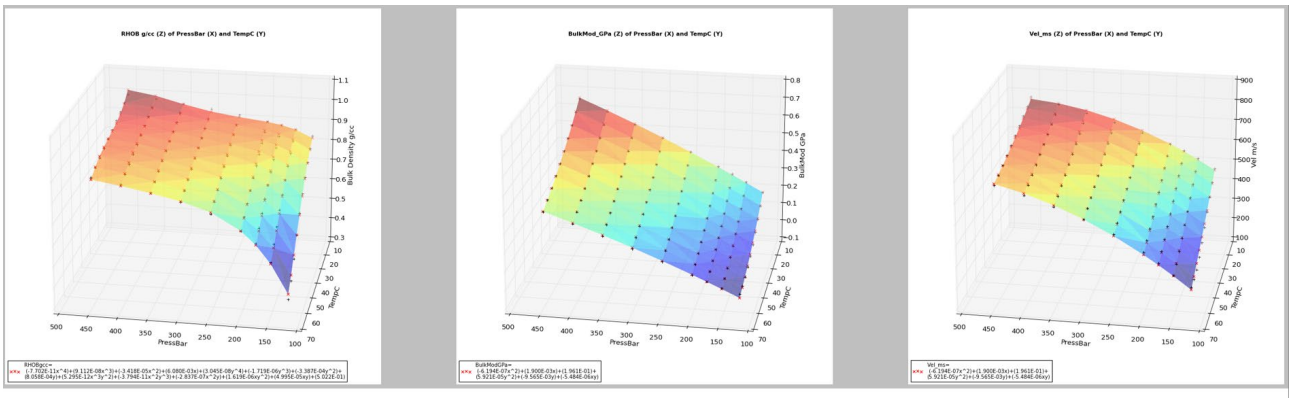


Figure A-3 – CO_2 PVT properties used in the 4D PEM; left: RHOB, middle: Bulk Modulus, right: Velocity function of reservoir pressure and temperature. Salinity fixed at 110g/l – reference from well SWD-003 LA-Storage

The rock frame relationship is derived from two analogue measurements.

A.2.1.1 Workflow Application

The 4D-PEM is used in two steps:

- Application at the well based on experimental design to estimate, Rhob, Vp, Vs logs, 4D acoustic and elastic attributes, 4D time-shift, 4D amplitudes, 4D seismic synthetic traces and time-shift and amplitude detectabilities (Figure A-3).
- In the case where detectability is reached, application of massive modeling to evaluate the detection limit (Figure A-4).

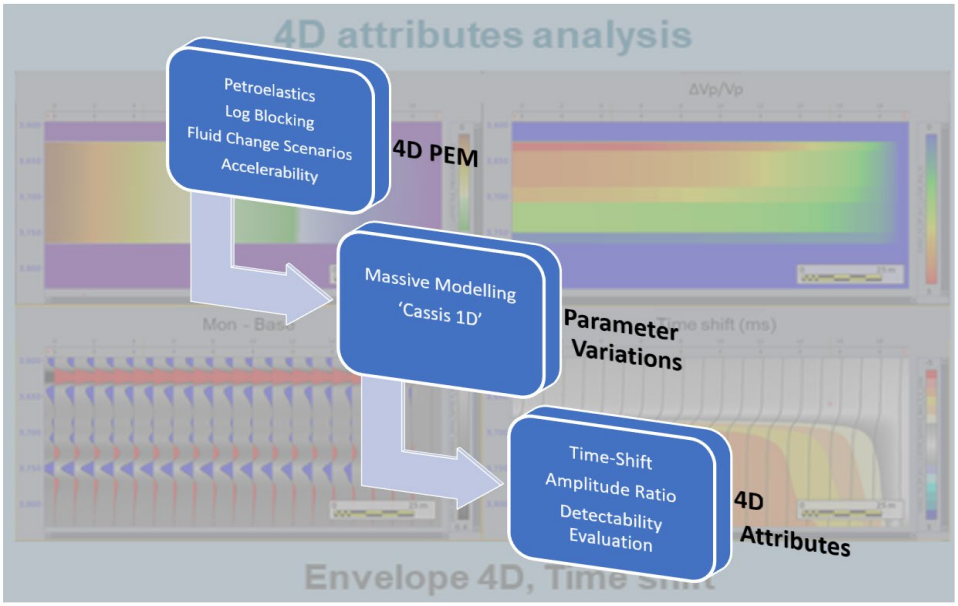


Figure A-4 – Massive modeling workflow (based on in-house workbench CASSIS 1D) using the 4D PEM model.

A.2.2.1 Workflow Application and Results

It was assumed that the Miocene reservoirs properties of the HCS Project will be similar to the ones observed at the well LA Storage SWD No. 003. Therefore, the 4D-PEM was applied on validated logs for the LA Storage SWD No. 003:

- Quantitative petrophysical logs corresponding to material content (clay, sand, calcite, dolomite).
- Sonic logs for validation of PEM modeled logs (initial state = base).
- Unit log, corresponding to a vertical description of all different units.
- PVT density, bulk modulus, and velocity relationships for CO_2 variations with pressure and temperature – from empirical data.
- The wavelet selected for the perturbative PEM study was based on frequency analysis of the 3D CGG PSDM seismic cube and with discussion with the VSP specialist to select a wavelet as realistic for a walkaway monitor as a stretched 17Hz ricker waveform. Walkaway profile images should normally have higher resolution at target around the well.
- Salinity, which can be an impactful factor, was fixed here for the 1D Cassis modelling at 110 g/L based on measurements from the LA Storage SWD No. 003 well.
- After computation of all the required logs, the data set is converted in two-way time (TWT) domain for convolution with the seismic wavelet.

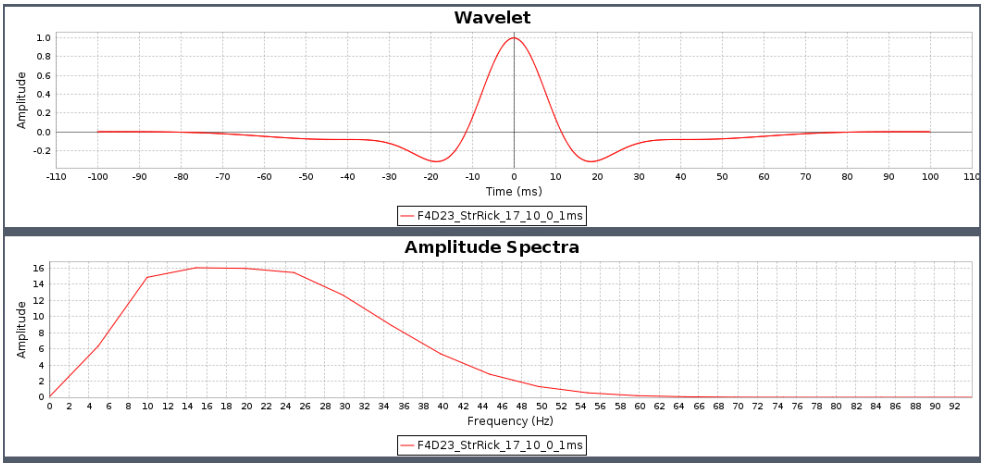


Figure A-5 – Wavelet Used for the 1D PEM Modeling (stretched 17hz Ricker wavelet)

CASE 1: Shallow reservoir interval – MFS 9.A, 1D sensitivity analysis

The protocol of modeling for shallow reservoir interval (MFS 9.A) is driven by the CO_2 to be stored and based on reservoir simulation for saturation modeling and several cases of simulation, gas and pressure ranges (Figure A-6 and Figure A-7). Blocking of this reservoir group for the Cassis

1D modeling can be seen in the left track, with thin black and orange logs for respectively the Vclay and the Effective Porosity. Note that the very thin shale layers are also included.

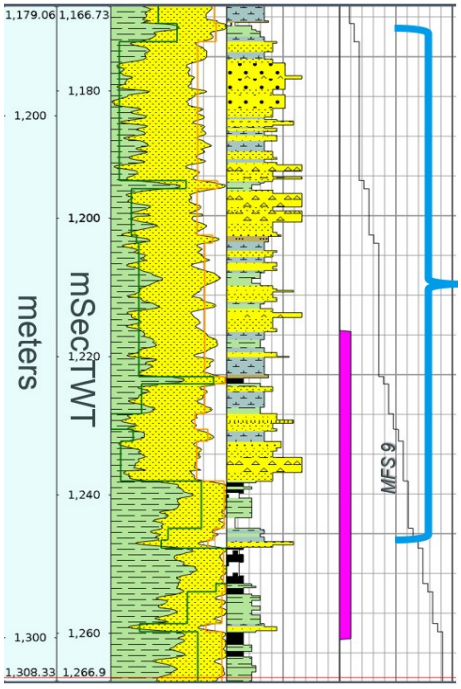


Figure A-6 – Gas injection simulation at the Shallow MFS 9.A interval for the Cassis 1D modeling, log blocking overlain.

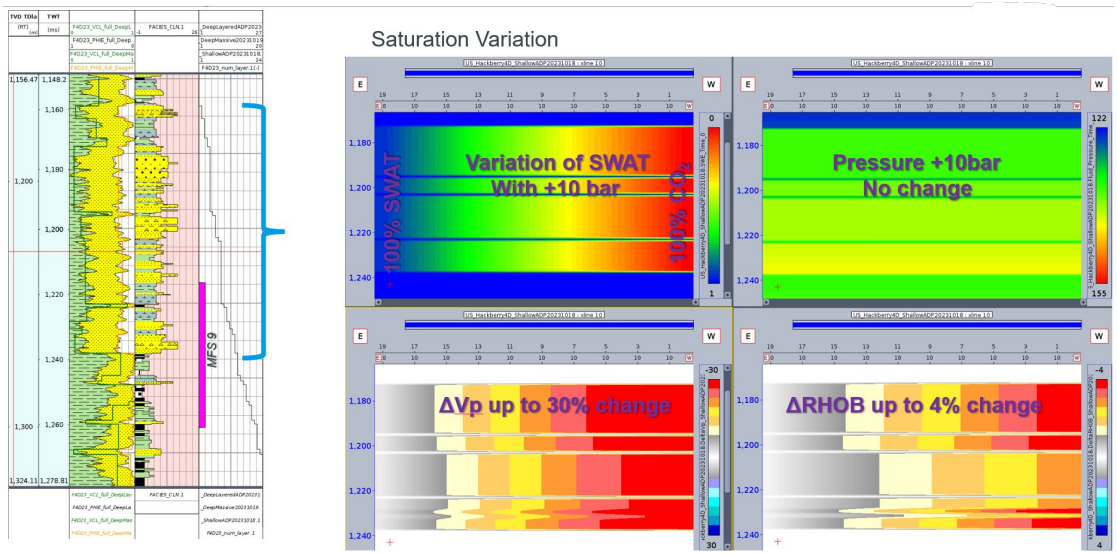


Figure A-7 – Dynamic Cassis 1D modeling results for the shallow interval without a time-shift @ 10 bar (145psi).

The modeling of the reservoir close to MFS-9.A displays a strong decrease in p-wave velocity (ΔVp) up to 30% with a small ΔRHOB density decrease of up to 4% with water saturation changes (see figure above). The maximum 4% change in density (ΔRHOB) may still be detectable and will

be tested in the later, optional part of the 4D gravity feasibility (Stenvold et al. 2008, Vatshelle et al. 2017).

Figure A-8 displays the effect of varying water/CO_2 saturation as a set of seismic traces with strong amplitude change as CO_2 is introduced to the system.

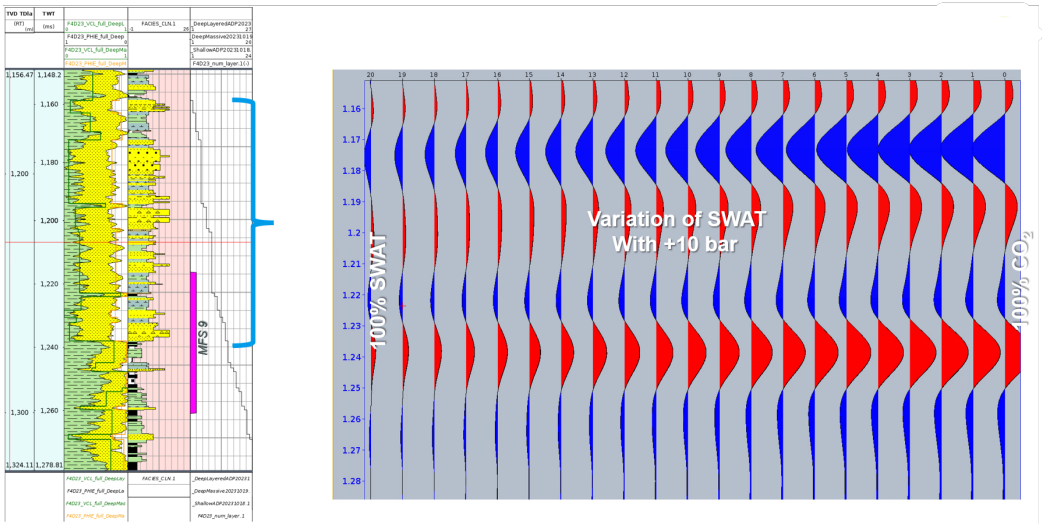


Figure A-8 – Dynamic Cassis 1D modeling results for the shallow interval – no time-shift included.

Figure A-9 demonstrates the strong slow-down or time-shift as CO_2 concentration is increased all along the reservoir thickness. Thus, assuming the CO_2 stabilizes, and saturations variations are homogeneous from top to base reservoir, there are two very strong effects for the seismic response as the CO_2 is injected at this level – both in amplitude and time-shift. Figures A-9 and A-10 examine the detection limits of these effects.

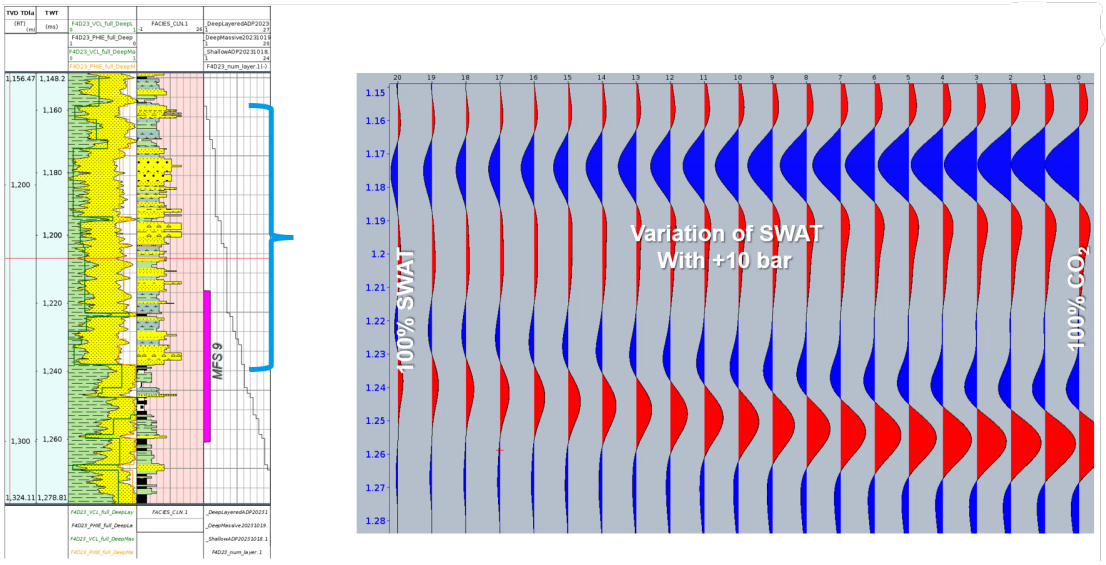


Figure A-9 – Dynamic Cassis 1D modeling results for the shallow interval – with time-shift.

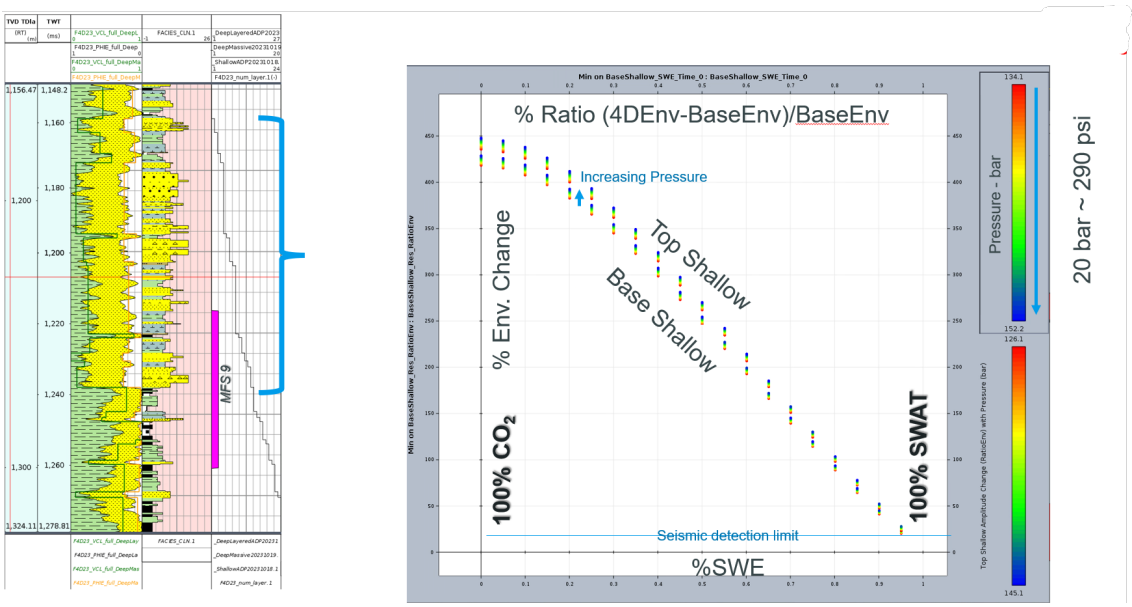


Figure A-10 – Shallow interval top and base amplitude ratios for detection limits.

Based on empirical uncertainty levels often seen in onshore VSP seismic monitoring programs for a 4D seismic signal, amplitude ratio display in the above figure demonstrates that the 4D effect should be detectable starting from CO_2 saturation of 5% with maximum change at 450% when CO_2 saturation reaches 100% (Figure A-11). In practice, the CO_2 will normally never exceed a saturation of 50-60%, which will mainly occur in the vicinity of the well injection perforations. Also displayed are the pressure variations in color over 20 bar (approximately 290 psi) which are seen as a negligible effect on the 4D seismic signal.

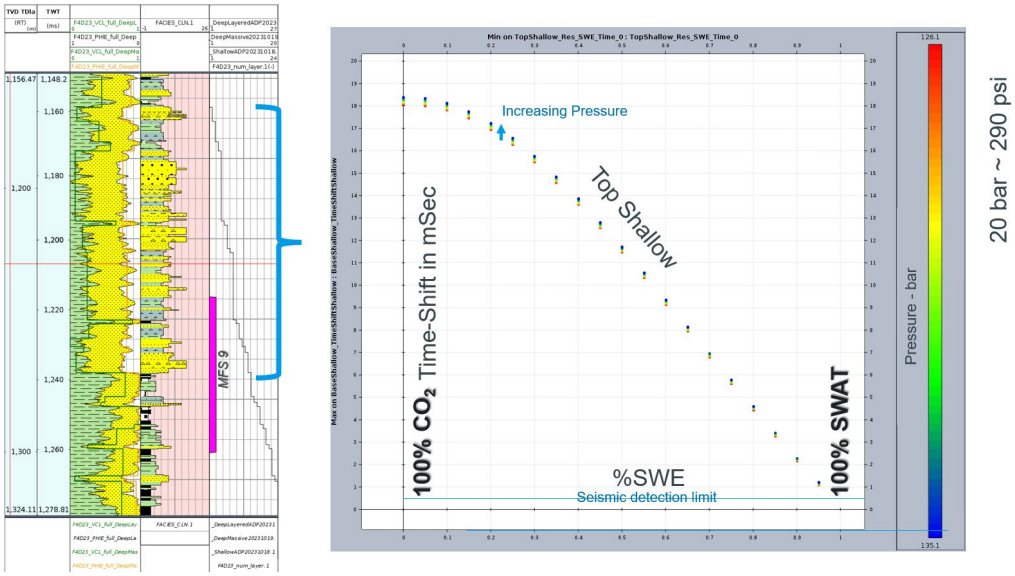


Figure A-11 – Shallow interval evolution of top reservoir group time-shift detection limits with CO_2 injection/saturation.

Based on empirical uncertainty levels for a 4D seismic signal, the above figure shows detectable time-shift of the signal starting from 5% CO_2 saturation. This, in combination with the very strong amplitude change should render the 4D seismic signal very sensitive to CO_2 presence at about 5% saturation level for the shallow reservoir group.

CASE 2: Deep-Massive reservoir interval – MFS 10, 1D sensitivity analysis

The protocol for modeling the deep massive reservoir interval (MFS 10) is driven by CO_2 to be stored and based on reservoir simulation for saturation modeling and several cases of simulation, gas, and pressure ranges (Figure A-12). The deep massive section was modeled in addition to the previous shallow interval to test detectability and 4D seismic response in the higher temperature and pressure regime and for a thicker, more massive reservoir interval (typical of the one expected from MFS10 to MFS12). Blocking of this reservoir group for the Cassis 1D modelling can be seen overlain on the black and orange blocky logs on the left track.

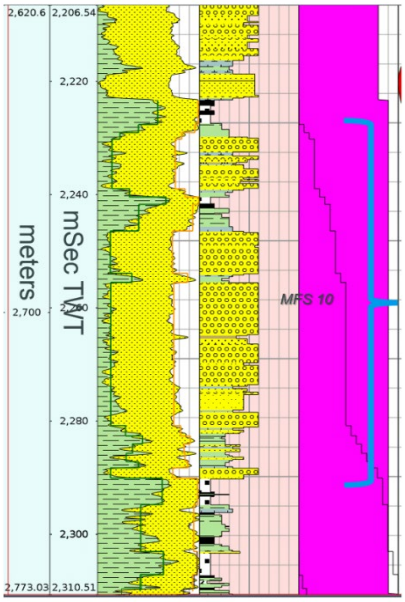


Figure A-12 – Gas injection simulation at the Deep Massive MFS 10 interval for the Cassis 1D modeling.

Figure A-13 displays a decrease in p-wave velocity (ΔVp) at the deep massive complex of up to 15% and smaller ΔRHOB density decrease of up to 3% with water/CO_2 saturation changes. The maximum 3% change in density (ΔRHOB) may be detectable and will be tested in the later, optional part of the 4D gravity gradiometry monitoring feasibility. The differences in velocity and density variations between the shallow and deep reservoirs is due to absolute increase of velocity and density due to compaction and different fluid PVT due to changes in temperature and pressure.

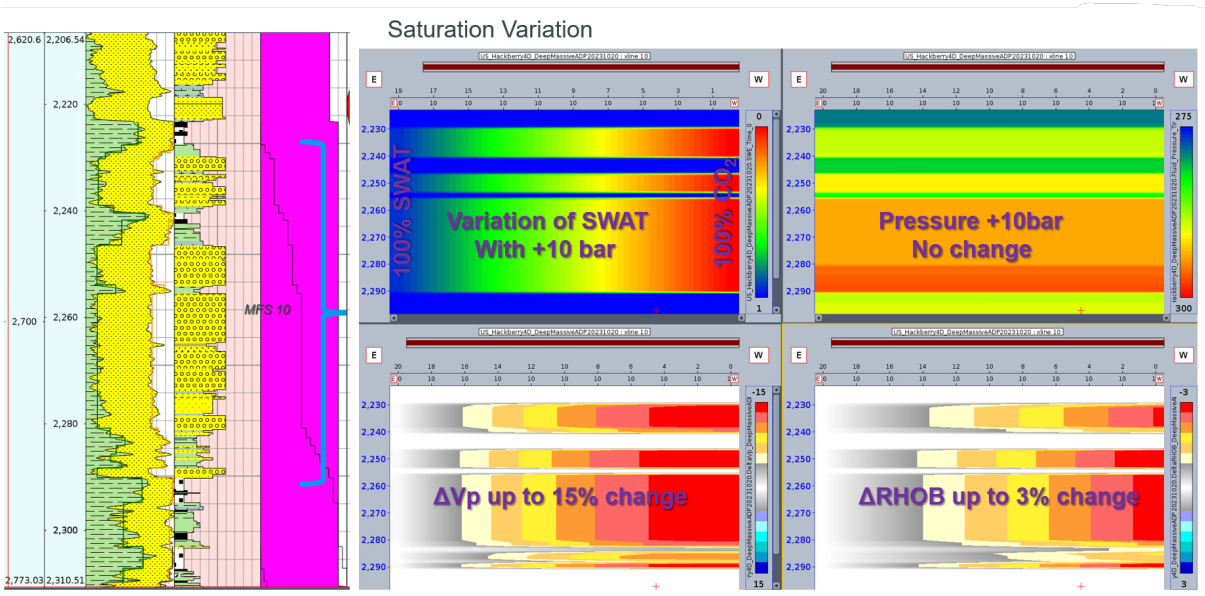


Figure A-13 – Dynamic Cassis 1D modeling results for the deep massive interval – without time-shift @ 10 bar (145psi).

Figure A-14 displays the effect of varying water/CO_2 saturation as a set of seismic traces with strong amplitude change as CO_2 is introduced to the system.

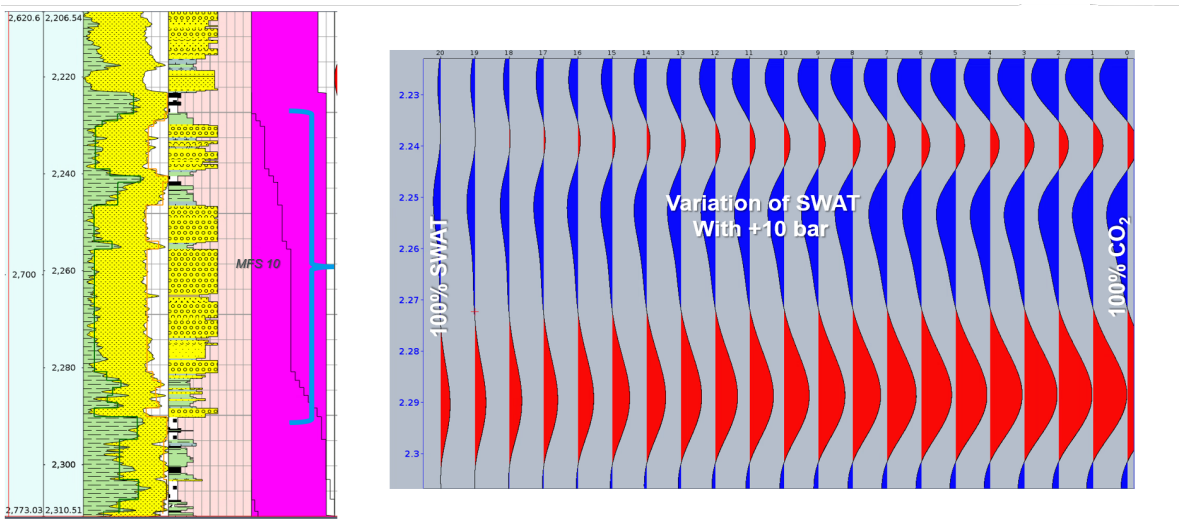


Figure A-14 – Dynamic Cassis 1D modeling results for the deep massive interval – no time-shift included.

Figure A-15 demonstrates a significant slow-down or time-shift as CO_2 concentration is increased. Thus, there are two strong combined effects for the seismic response as the gas is injected at this level – both in amplitude and time-shift. Figures A-15 and A-16 show the detection limits of these effects.

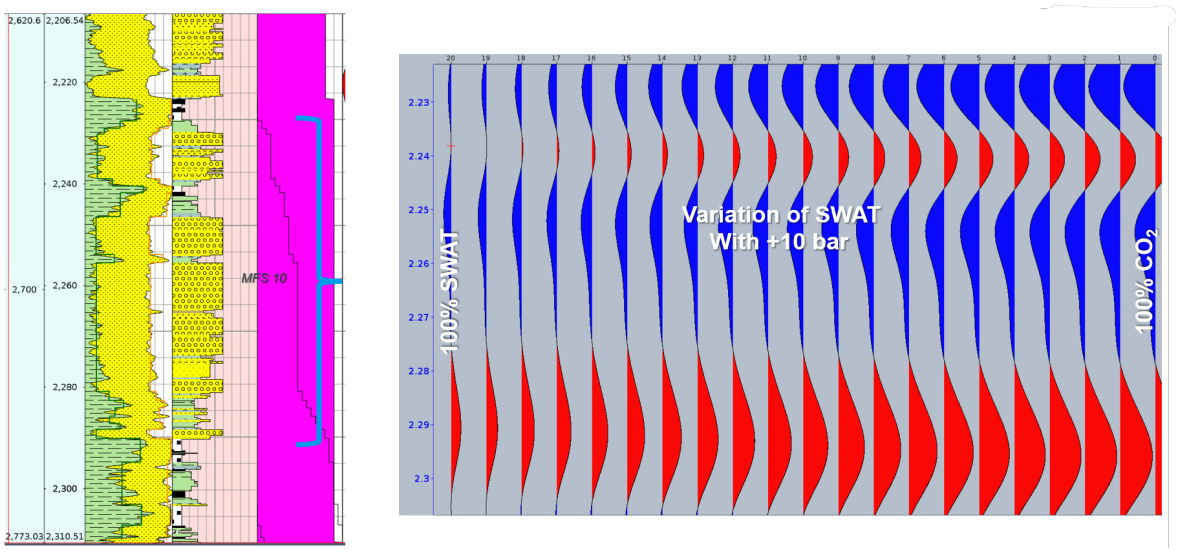


Figure A-15 – Dynamic Cassis 1D model-ling results for the deep massive interval – with time-shift included.

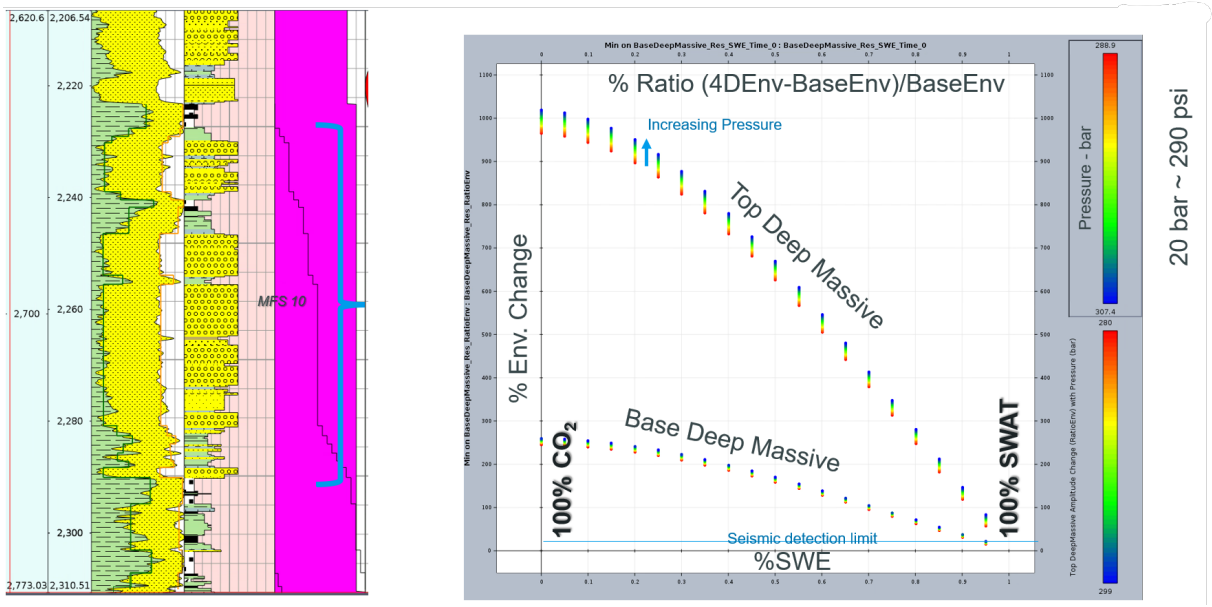


Figure A-16 – Deep Massive interval top and base amplitude ratios for detection limits.

Based on empirical uncertainty levels often seen in onshore VSP seismic monitoring programs for a 4D seismic signal, in Figure A-16, amplitude ratio display demonstrates that saturation of about 5% to 10% should be detectable with maximum change at 250%. Also displayed here are the pressure variations in color over 20 bar (approximately 290 psi) which are seen as a negligible effect on the seismic signal.

Based on empirical uncertainty levels for a 4D seismic signal, Figure A-17 shows a very low detectable limit for time-shift of the signal with about 5% CO_2 gas presence. This, in combination with the very strong amplitude change should render the 4D seismic signal sensitive to CO_2

presence at about the 5% saturation level for the deep massive reservoir group. The pressure variation here in the time-shift is stronger than previous responses but still seen as secondary and much smaller than the amplitude change and time-shift.

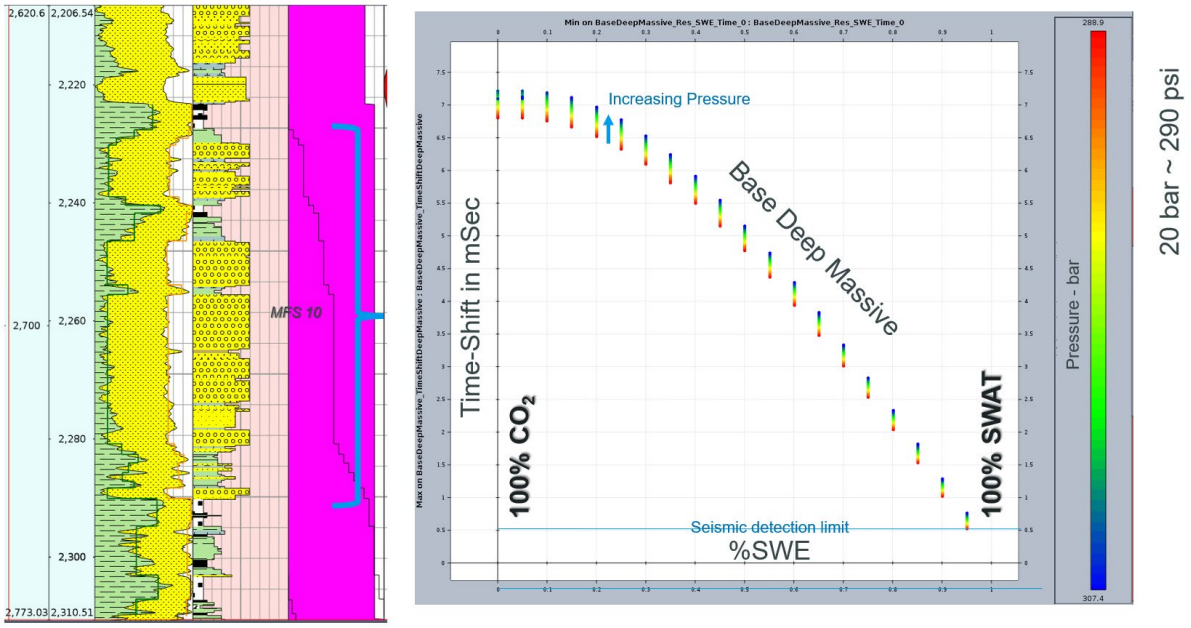


Figure A-17 – Deep Massive interval evolution of base reservoir time-shift detection limits with CO_2 injection/saturation.

CASE 3: Deep-layered reservoir interval – MFS 10.3, 1D sensitivity analysis

The protocol of modeling for the deep layered reservoir interval (MFS 10.3) is driven by gas to be stored and based on reservoir simulation for saturation modeling and several cases of simulation, gas, and pressure ranges (Figure A-18). The deep-layered section was modeled in addition to the previous shallow and deep massive interval to test detectability and 4D seismic response in the higher temperature and pressure regime and for multiple, stacked thinner reservoir combination. Blocking of this reservoir group for the Cassis 1D modeling can be seen in the logs.

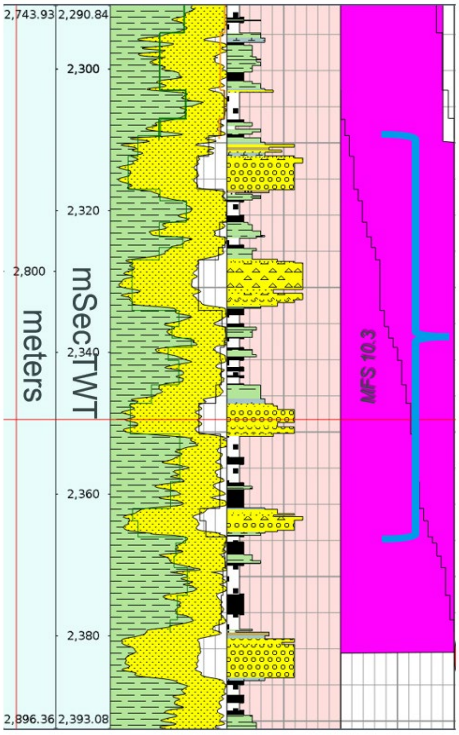


Figure A-18 – Gas injection simulation at the Deep Layered MFS 10.3 intervals for the Cassis 1D modeling.

Figure A-19 displays decrease in p-wave velocity (ΔVp) at a lower level than the deep-layered complex globally of 14% and smaller ΔRHOB density variation with water/CO_2 saturation changes. The 3% change in density (ΔRHOB) may be detectable and will be tested in the later, optional part of the feasibility.

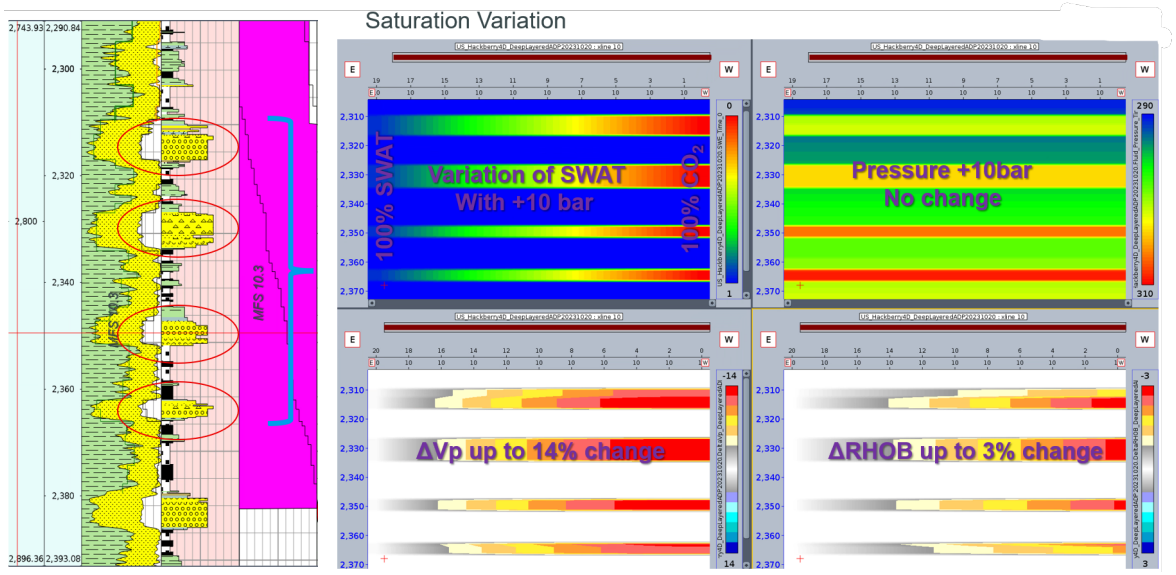


Figure A-19 – Dynamic Cassis 1D modelling results for the deep-layered intervals – no time-shift at 10 bar (145 psi). Individual layered reservoirs circled left.

Figure A-20 displays the effect of varying water/CO_2 saturation as a set of seismic traces with a significant amplitude change as CO_2 is introduced to the layered reservoir system.

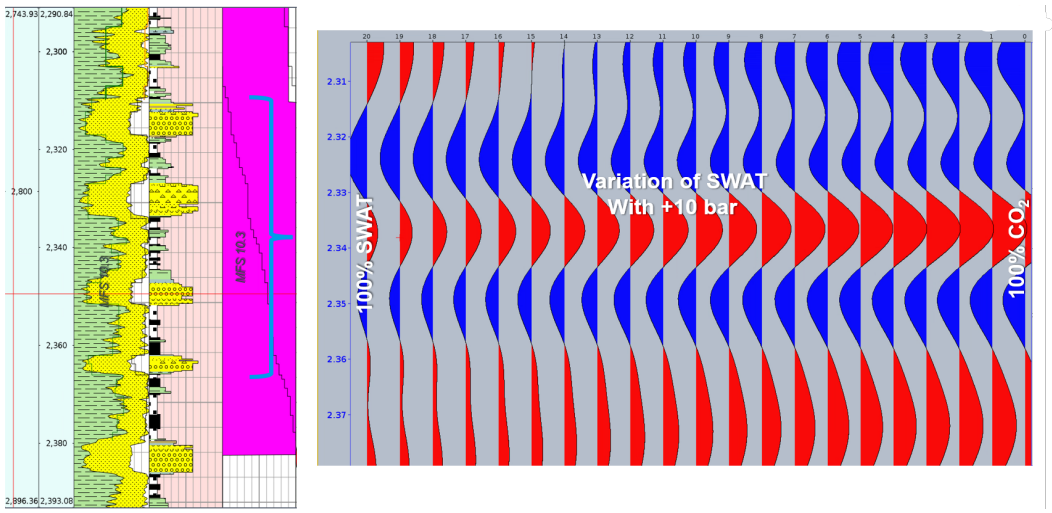


Figure A-20 – Dynamic Cassis 1D modeling results for the Deep Layered intervals – without time-shift.

Figure A-21 demonstrates some slow-down or time-shift as CO_2 concentration is increased. Thus, there are two effects for the seismic response as the gas is injected at this level – both in amplitude and time-shift. Figure A-22 examines the detection limits of these effects.

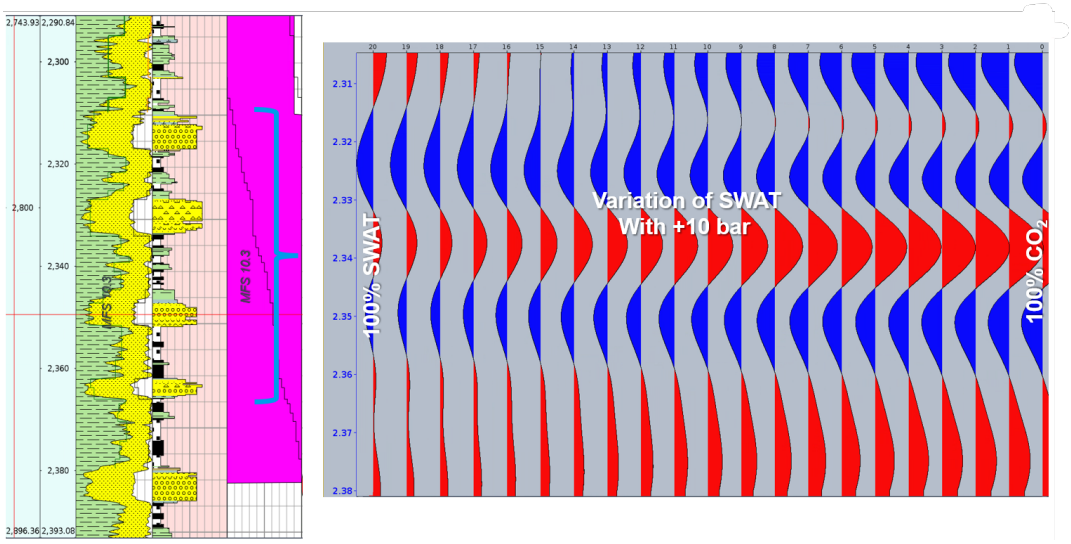


Figure A-21 – Dynamic Cassis 1D modeling results for the deep-layered interval – with time-shift applied.

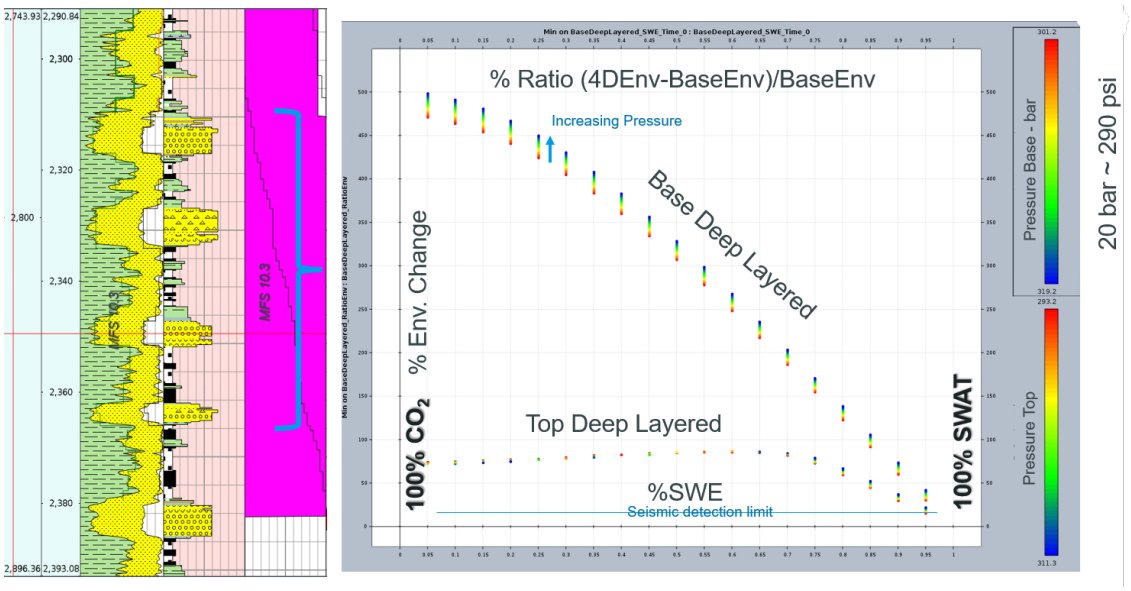


Figure A-22 – Deep layered interval top and base amplitude ratios for detection limits.

Based on empirical uncertainty levels often seen in onshore VSP seismic monitoring programs for a 4D seismic signal, Figure A-22 presents the amplitude ratio display, this demonstrates that saturation of about 5% should be detectable with maximum change at 75 to 500%. Also displayed here are the pressure variations in color over 20 bar (approximately 290psi) which are seen again as a negligible effect on the seismic signal.

Based on empirical uncertainty levels for a 4D seismic signal, Figure A-23 shows a very low detectable limit for time-shift of the signal with about 10% CO_2 gas presence. This, in combination with the very strong amplitude change, should render the 4D seismic signal sensitive to CO_2 presence at about the 10% saturation level for the deep-layered reservoir group. The pressure variation here in the time-shift is relatively stronger but still seen as secondary and much smaller than the amplitude changes and time-shift induced by saturation changes.

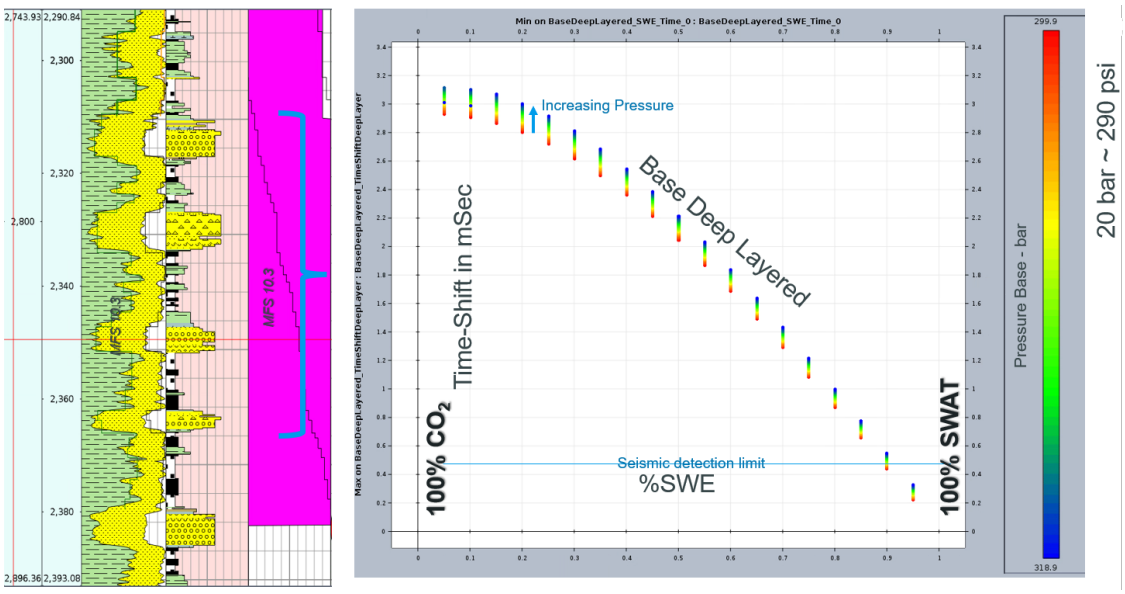


Figure A-23 – Deep-layered interval evolution of base reservoir time-shift detection limits with CO_2 injection/saturation.

CASE 4: Deep, Single Layered reservoir interval – MFS 10.3, 1D sensitivity

To examine further the limits of detection and sensitivity for the 4D seismic and density signal, a single thin layer in the deep layered group of MFS 10.3 was examined (Figure A-24). The 4D time-shift detection limits for CO_2 saturation rise to 50% due to the increased difficulty in detection for a thinner layer (in this example: about 10m or 30ft thickness.

As seen in Figure A-24, the thinner deep layer requires greater CO_2 saturation for 4D time-shift detection at about 50% and again with a pressure impact that is secondary to the saturation induced changes. Nevertheless, for such thin reservoir, the seismic amplitude changes induced by an increase of CO_2 saturation will be quickly visible due to the strong change in impedance.

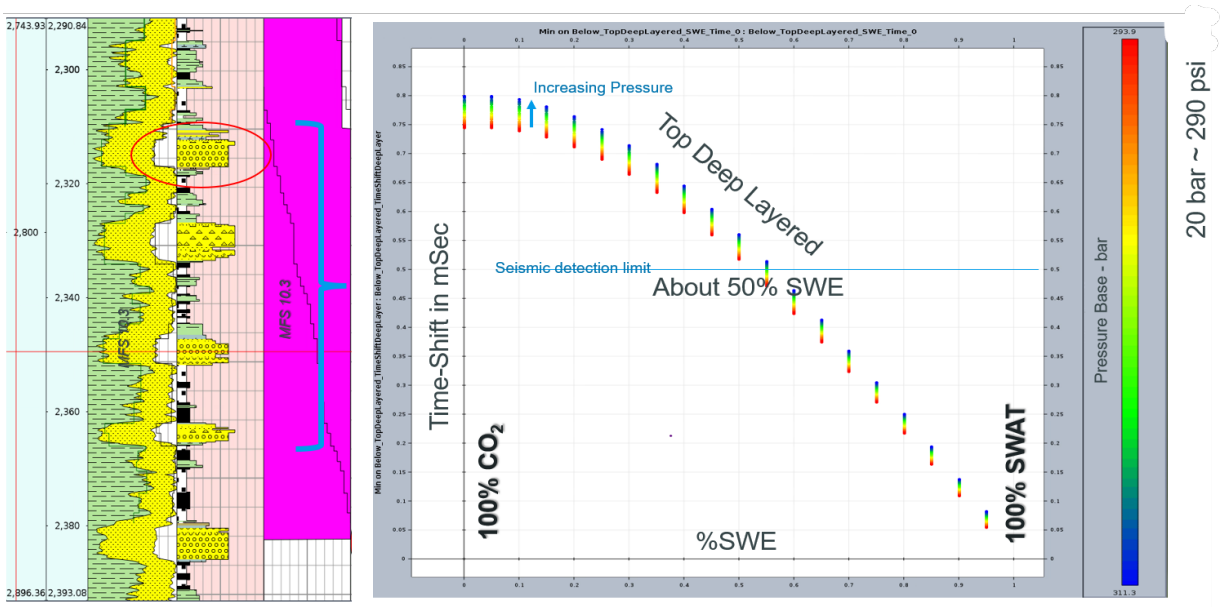


Figure A-24 – Deep, single-layer time shift detection limit

CASE 5: Minimum detection thickness – MFS10 reservoir, 1D sensitivity analysis

Sensitivity testing for minimum detectable thickness was performed by building a "ramp" or wedge model in the MFS10 deep-massive group. The sand wedge was increasing in thickness from 0 to 90 ft with 1.5 ft intervals, and the CO_2 saturation was fixed at 85%, which corresponds to an extreme case. The model was run until a response was observed.

These tests, shown in Figure A-25, demonstrated that a thickness of approximately 3 to 4 ft would correspond to the minimum detection thickness. This would create a 4D time-shift of about 3 to 4 milliseconds. This corresponds to an extreme situation of CO_2 saturation (85%), which will normally not occur in the reservoir.

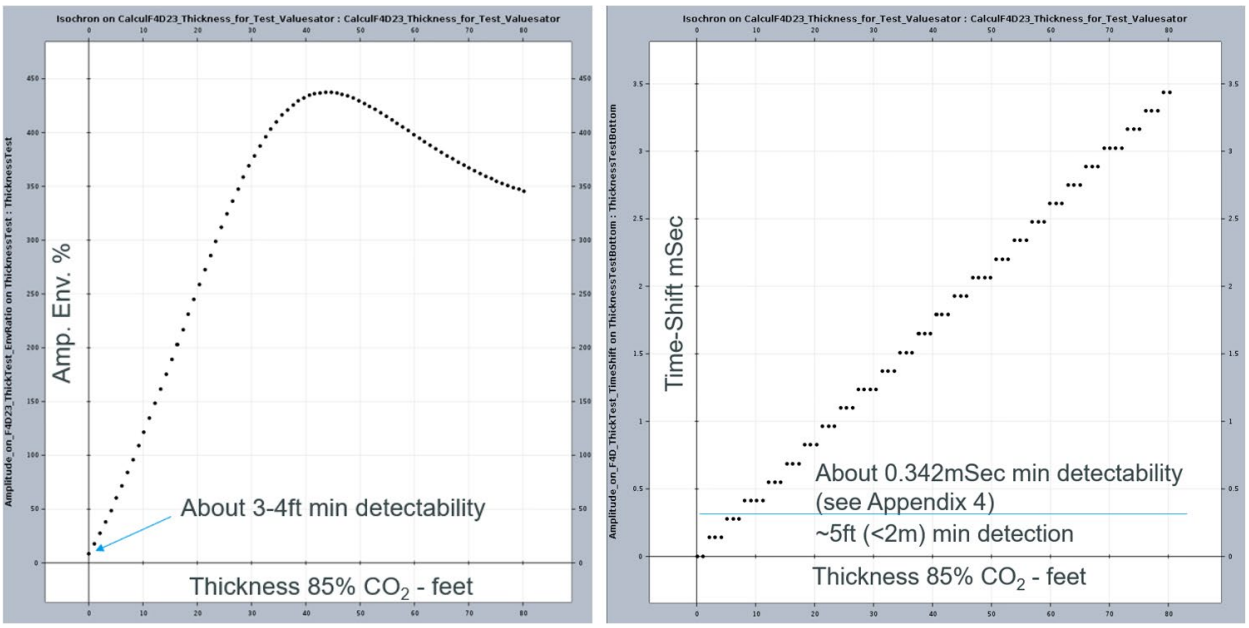


Figure A-25 – Minimum detection plots for thickness in feet at 85% CO_2 saturation. Vertical scales in amplitude envelope (%) and time-shift (mSec).

A further challenge for detecting very thin, low saturation CO_2 was addressed by modeling a single deep, 20-ft reservoir with increasing gas column in single foot thickness while simultaneously increasing gas saturation in 5% increments. These tests show that minimum detection can be as small as 2 ft and 5% CO_2. However, there will likely be another limiting factor in the minimum sampling interval of the seismic data itself of 1 millisecond which would equate to approximately 5 ft sampling thickness. The signal detectability will also depend on the level of 4D signal over the 4D background noise (Figure A-26).

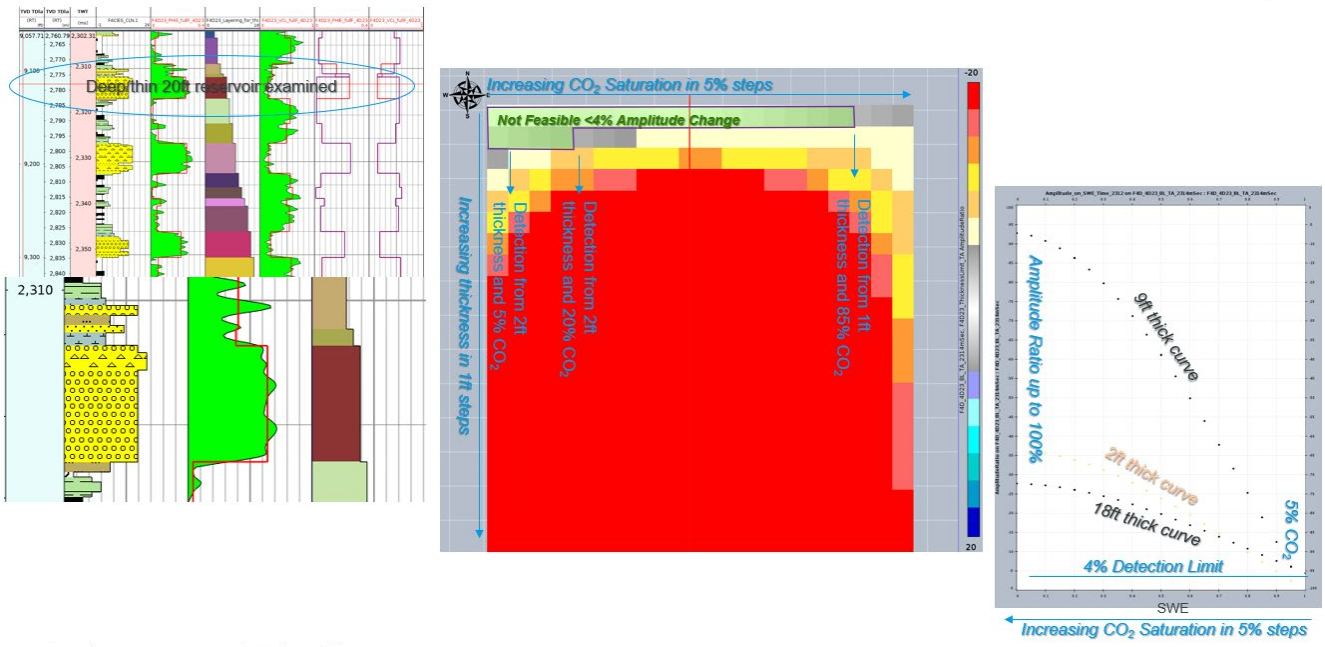


Figure A-26 – Minimum detection thickness and saturation for a thin, 20 ft deep reservoir.

A.2.2 4D Signal Feasibility Conclusions

The 4D signal feasibility study was performed on four types of target reservoirs: (1) deep aggregation of four thin reservoirs to test the detection limits and interference of nearby reservoirs at the greatest depth, (2) a single thin reservoir of this group to test the thickness detection limits at greatest depth, (3) a thicker section above those units to test for detection interference, and (4) the shallowest grouping of reservoirs to examine the lower pressure and temperature regime.

Since no 4D seismic acquisition experiment is available in the area, realistic repeatability noise values ranging from 5 to 20% were considered. The detectability of the 4D signal for each of the three targets was based on:

- Time-shift evaluation versus Woodward's detection limit.
- Amplitude change ratio at top and base of reservoir.
- Pressure affects detectability.
- Density contrasts were also considered in view of a possible 4D gravity gradiometry monitoring.

The 4D PEM has been used to characterize the 4D signal detectability (time shift/amplitude change) on the four target reservoir groups. Within the PEM modeling, consideration was also given to changes in salinity, pressure and temperature as these factors change greatly from the deeper to shallower part of the injection scheme and they have an impact on fluid compressibility.

The main conclusions of this analysis are:

High 4D seismic signal and **possible** density contrast expected on:

- **Shallow Reservoir** (MFS 9.A approximately 4,265 ft):
  - **Fluid Change** (gas replacing water): Injection of CO_2 generates a **strong** 4D seismic signal. Significant changes in amplitude and time-shift are seen in the PEM modeling starting from 5% CO_2 saturation.
  - **Pressure Change**: Despite the uncertainty on the rock matrix compressibility, the pressure impact should be of **lower, negligible impact**.
  - **Density Change**: Possible detectability of a 4D gravity signal at this level with approximately 4% $\Delta\rho/\rho$ change expected.
- **Deep Massive Reservoir** (MFS 10 approximately 8,200 ft):
  - **Fluid Change** (gas replacing water): Injection of CO_2 generates **strong** 4D seismic signal. Significant changes in amplitude and time-shift are seen in the PEM modeling starting from 5 and 10% CO_2 saturations, respectively.
  - **Pressure Change**: Despite the uncertainty on the rock matrix compressibility, the pressure impact should be of **lower, negligible impact**.
  - **Density Change**: Possible detectability of a 4D gravity signal at this level with approximately 2-3% $\Delta\rho/\rho$ change expected.
- **Deep Layered Reservoir** (MFS 10.3 approximately 9,200 ft):
  - **Fluid Change** (gas replacing water): Injection of CO_2 generates strong 4D seismic signal. Significant changes in amplitude and time-shift are seen in the PEM modelling starting from 5 and 10% CO_2 saturations, respectively.
  - **Pressure Change**: Despite the uncertainty on the rock matrix compressibility, the pressure impact should be of **lower, negligible impact**.
  - **Density Change**: Possible detectability of a 4D gravity signal at this level with approx. 1.5% $\Delta\rho/\rho$ change expected.

High 4D seismic signal, **no** density contrast expected on:

- **Deep Layered Single Reservoir** (MFS 10.3 approximately 9,100 ft):
  - **Fluid Change** (gas replacing Water): Injection of CO_2 generates strong 4D seismic signal. Significant changes in amplitude and time-shift are seen in the PEM modeling starting from 5 and 50% CO_2 saturations, respectively.
  - **Pressure Change**: Despite the uncertainty on the rock matrix compressibility, the pressure impact should be of **lower, negligible impact**.
  - **Density Change**: No detectability of a 4D gravity signal at this level with almost no $\Delta\rho/\rho$ change expected.
  - **The minimum detection limit** was assessed at this deepest level at approximately 1m (3-4 ft).

The above results on detectability can be summarized in Table A-1:

Table A-1 – Petro-Elastic Model Sensitivities

Target	Amplitude	Time-shift	Density (4D Gravity)
Shallow	S_CO_2 > 5%	S_CO_2 > 5%	Possible - 4% Δρ/ρ
Deep-massive	S_CO_2 : 5-10%	S_CO_2 > 5%	Possible
Deep-layered (unit)	S_CO_2 > 5%	S_CO_2 > ~10%	Possible? - 1.5% Δρ/ρ
Deep-layered (single unit)	S_CO_2 > ~5%	S_CO_2 > ~50%	No

A.3 1D and 2D Models

To determine the magnitude of changes in the CO_2 plume, 1D and 2D models are generated to measure the effect on different scenarios. In this section we will explain the methodology behind each one of these models.

Seismic surveys create a seismic wave that travels through the earth and are subsequently reflected back to geophones that listen for these waves. Seismic waves can be created by a "shot," which is a term that refers to explosives or other mechanical sources. Geophones are sensors that listen for the sound waves that are reflected back to surface or to the well bore as seen in Figure A-27. Specifically, they allow engineers to determine the time it takes for seismic waves to bounce off each transition zone between formations. The differences in time between each reflection allow for the calculation of a velocity in each formation. The variation in sonic velocities allows for geologists to understand the lithology of the subsurface.

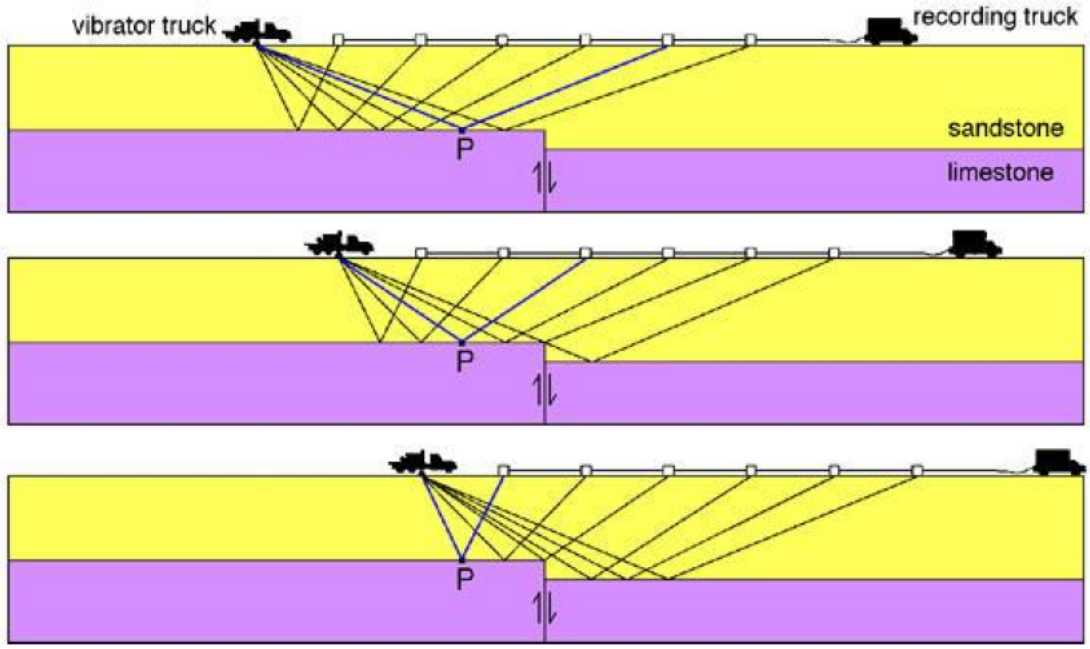


Figure A-27 – Illustration of seismic surveys (this example is on land – the truck would be replaced by shallow-bottom boat)

A.3.1 1D Model

One-dimensional (1D) seismic surveys operate on the same principles as previously discussed. Figure A-28 shows an example of a checkshot survey which is a common method of obtaining 1D seismic data. However, the geophones are placed vertically, along the wellbore. As the shots are fired from surface, the geophones can record the seismic waves at various depths. They provide the most accurate measures of sonic velocities of the geologic layers effected by the construction of the wellbore. These are generally used to create more accurate 2D, 3D and 4D surveys. The 1D survey approach assumes that each formation is horizontally homogeneous so they can only provide average sonic velocities. The data from 1D surveys can also be used to correct sonic logs and generate synthetic seismograms. Synthetic seismograms are used to predict the seismic responses of the subsurface. Acoustic logs are a special variation of 1D seismic surveys. They use wireline sonic tools to generate acoustic data along the wellbore. These are used for different purposes than seismic surveys, but they can lead to a 1D understanding of the variation in velocities.

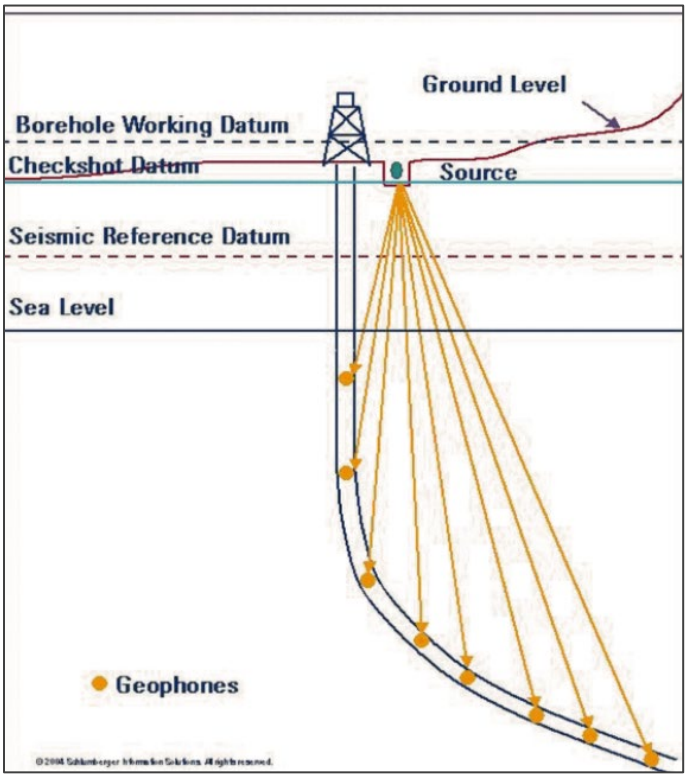


Figure A-28 – Illustration of a Checkshot Survey

For each case a 1D offset model is generated and differences in reflection amplitudes are estimated as shown in Figure A-28. A clear response is seen in this example 1D output.

A.3.2 2D Model

Following the results of the interpretation of a 1D model, a subsequent geological model is built to reflect the two saturation cases, connate formation fluids as one case and CO_2 replaced fluid as the second case.

The 2D seismic surveys work off the same principles as previously discussed, but they provide a picture of a thin slice of the Earth's crust. The geophones are instead placed in a line along the surface and record the seismic waves as they reflect off each formation. 2D surveys require multiple lines to be set in order to achieve the best results. They ideally set each line to be orthogonal to the strike of a geologic structure and parallel to the dip of said structure. They provide information of various formations, faults, and other subsurface characteristics. The intersection of multiple 2D surveys allows for the geologist to interpret contour lines and generate geologic maps. These surveys are cheaper and have less environmental impact than 3D surveys. 2D surveys are commonly used for initial exploration of unexplored areas to give geologists an understanding of what formations lie beneath the surface.

Figure A-44 shows the 2D geologic model built to reflect the two saturation cases and VSP geometry is used as indicated. This shows how VSP technology monitors the CO_2 front. In situ log results, or openhole sonic or density logs, are inserted in the left and formation log on the right. A weighted distance linear interpolation is used to generate the 2D P-wave model.

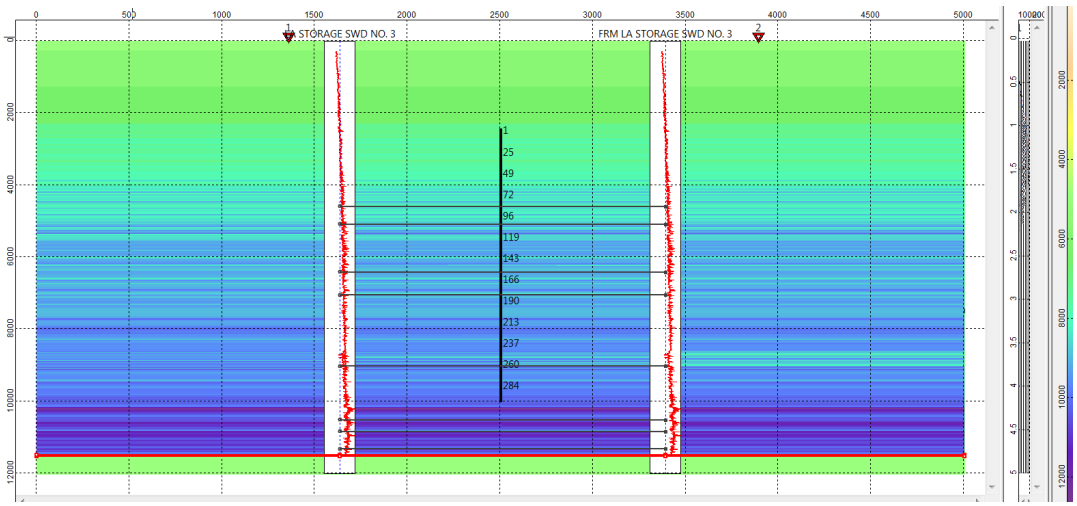


Figure A-29 – Geological Model Used for 2D Modeling for a VSP Survey

An expected response using 100% water and a modeled response using CO_2 indicates a change of amplitude and is interpreted that it is feasible to use VSP to monitor fluid changes with the rock for this project as seen in Figure A-30.

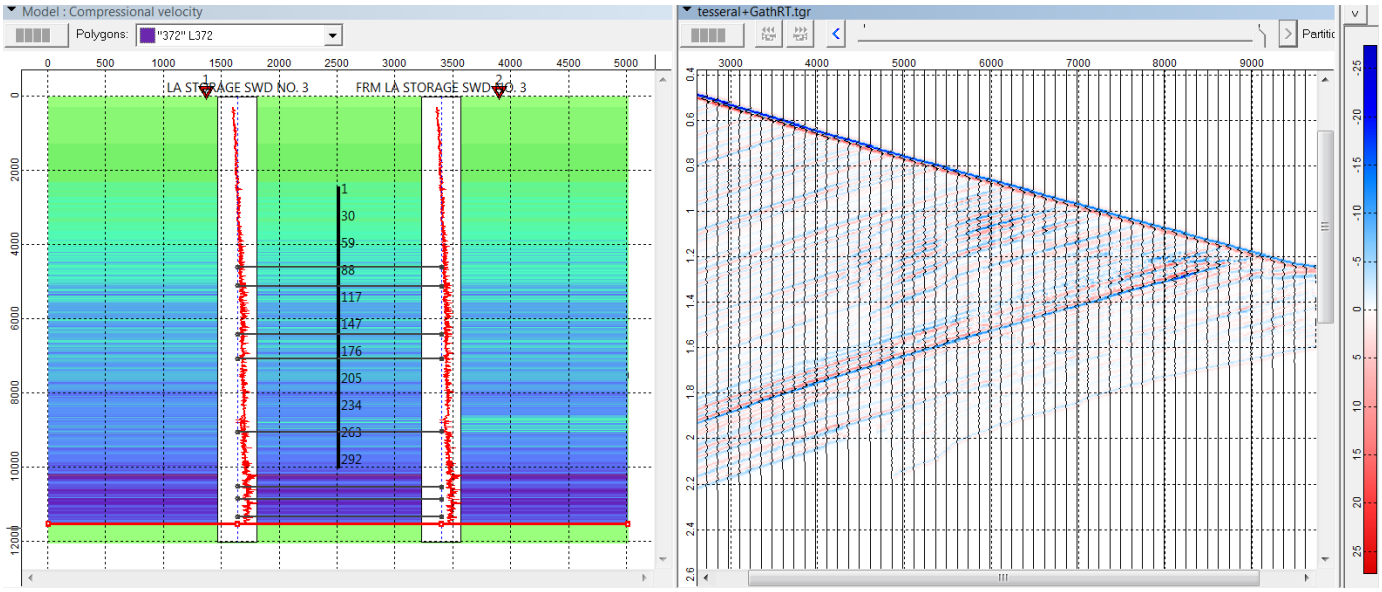


Figure A-30 – One-shot Geometry for VSP Geometry (Top: on the Water Zone, Bottom: on the CO_2 Zone)

A.3.3 Processing Workflow and 4D Seismic Volume Determinations

The final interpretation from consecutive surveys will be made by observing gas volume build-ups over time. When 1D, 2D, and 3D seismic surveys are combined with a time component (i.e., surveys conducted at various time periods from one another (Year 1, Year 5, Year 10, etc.), a 4D model is produced). The 4D interpretation of a seismic survey will identify changing volumes of gas build-up which are represented by log shifts on 1D and 2D responses or heat blooms on 3D models.

A.3.1.3 Inversion Workflow

Baseline surveys will be inverted using post-stack seismic volumes, well log data and a structural model to generate the basic low component model. Subsequent monitor surveys will use the same low component and residual corrections for consistency and the detection of changes over time. These changes over time will be assumed to be due to the injection activities.

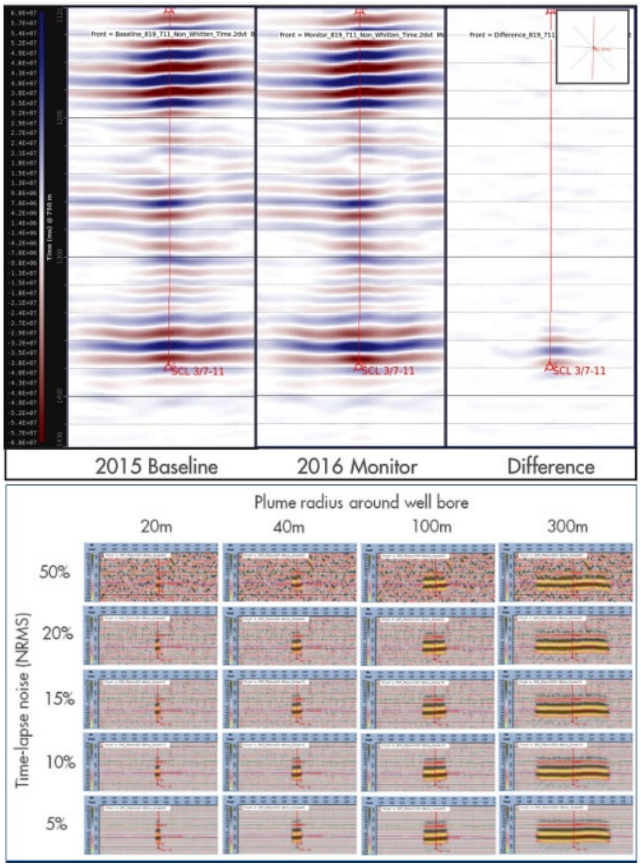


Figure A-31 – Baseline and subsequent VSP used to determine difference in amplitude attributed to CO_2 injection as measured from the injector well Itself. Estimation of plume growth over time in plot on the right.

A.3.2.3 Baseline Survey

A quality baseline survey is essential for a quality monitoring program. This survey represents the only opportunity to capture an image of the reservoir before any perturbation of the reservoir occurs due to injection or offset activity (man-made or natural). Without the baseline survey, no interpretation of formation changes can be made. Any errors made in the construction of the baseline image will impair sensitivity and interfere with the sensitivity to which formation changes can be made. Further, the size of the baseline survey determines the extent to which plume can be measured. Given uncertainty in the reservoir models, it is important to acquire a baseline survey with sufficient extent to provide utilization in the event the initial reservoir models are not accurately predicting the plume migration.

An example of a 4D time-lapse model is shown in Figure A-32 visualized in 3D space with analysis software. Each horizon can be displayed along with a color code for differences in amplitude over time.

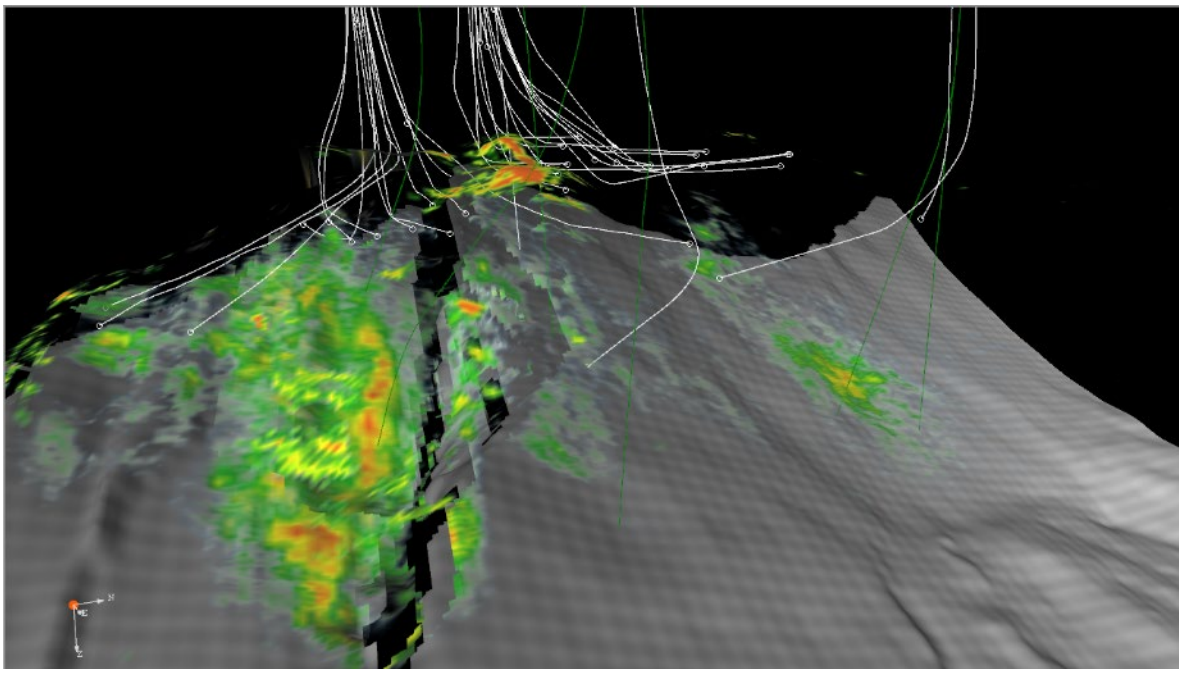


Figure A-32 – Example of a 4D Output

From the described 4D signal modeling results and overview workflow, different geophysical technologies have been assessed to confirm their usefulness in monitoring both primary and secondary CO_2 saturation front for the HCS project.

A.4 Geophysical Monitoring Technologies

A.4.1 Technology 1: 4D Walkaway Vertical Seismic Profile VSP 4D

As previously described, 4D walkaway VSP is a well-adapted geophysical monitoring technology to perform a cost-efficient tracking of the CO_2 vertical and lateral plume migration. A detailed feasibility study was conducted to determine optimal acquisition design, identify key acquisition challenges and technology limitations for the Hackberry storage site.

The walkaway VSP consists of acquiring a subsurface seismic image by positioning several receivers in the borehole (i.e., the DAS) and by moving along a straight profile several seismic sources (Figure A-33). Each shot is recorded and processed to obtain a final high resolution subsurface image.

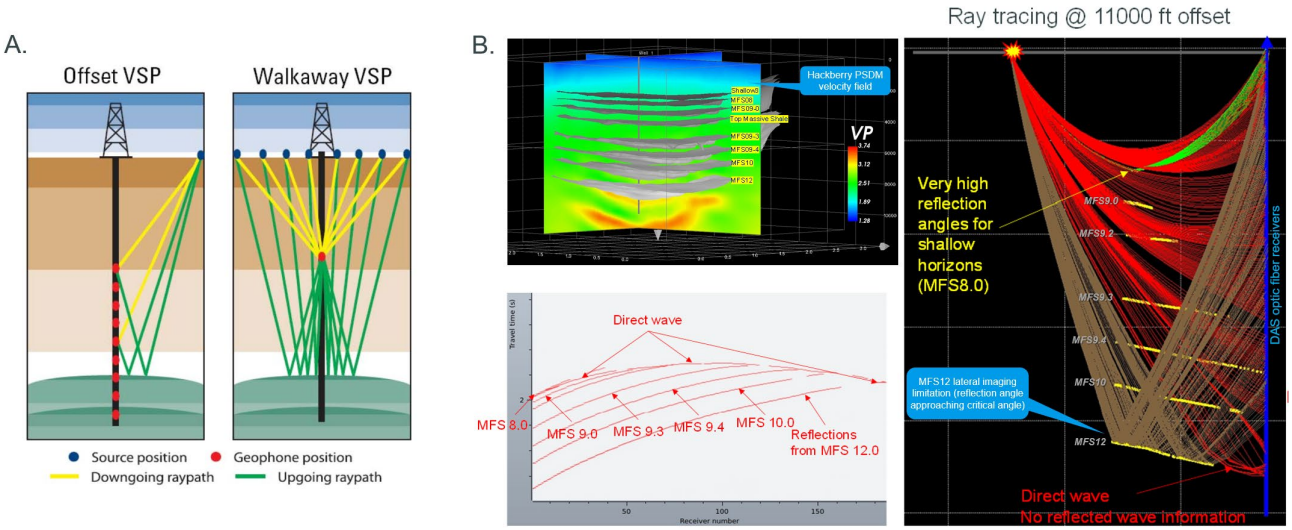


Figure A-33 – A. schematic illustration of walkaway acquisition principle, in practice several DAS receivers will record wavefield along the entire well trajectory. B. Images extracted from the Hackberry study, (right) representation of ray-tracing from source offset 11000ft to receiver along well trajectory.

A.4.1.1 Ray-Tracing and Illumination Analysis

Ray-tracing was performed to estimate the maximum acceptable source offset before reaching the critical reflection angle, considering the local geological structural dip. The offset is defined as the distance between the sequestration well location (equipped with DAS receiver) and the seismic source. A maximum source offset going approximately from 8,500 to 11,000 ft was established east and west, respectively, of the injection well. The modeling was done for eight different azimuths. The structural context within the HCS acreage is relatively simple which gives high confidence in the different modeling results.

This source offset limitation has a direct impact on the imaging capabilities of a given walkaway profile. The walkaway profile will be able to image geological reflectors up to a specific limit (also called illumination limit). This limit varies as a function of the depth of the imaged geological reflector. The deeper the reflector the larger the limit (conical shape illumination).

Hackberry storage site key characteristic is the large depth difference between the deep and shallow targets (i.e. from MFS12 up to MFS9.0). A detailed illumination analysis was therefore done for seven targets (MFS12, 10, 9.4, 9.3, 9.2, 9.1, MFS9.0) and across eight azimuths of the walkaway program. Based on a source acquisition effort covering the eight azimuths and up to the maximum allowed offset, Figure A-34 illustrates the illumination obtained for three targets (MFS9.0 shallowest, MFS9.4 and MFS12.0 deepest). Whereas shallow targets get narrow illuminations, deep targets get large illuminations.

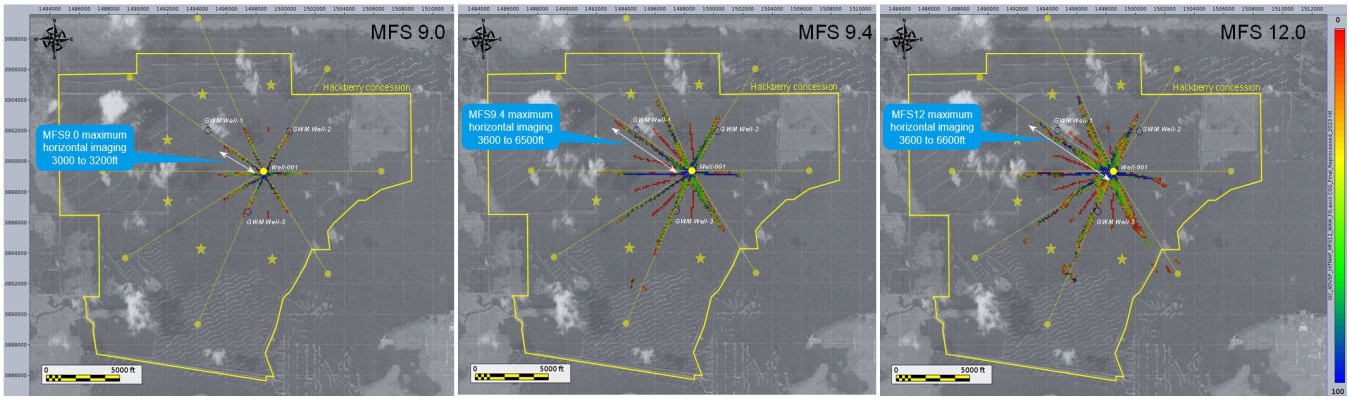


Figure A-34 – Illuminations based on ray-tracing obtained for shallow to deep targets, across eight azimuth profiles.

For each target and each azimuth, it is then possible to estimate the maximum horizontal imaging limits that one can get with the walkaway profile technology. A summary is provided below for each target. As shown in Figure A-4, the imaging limit is not only a function of the target depth but also azimuth direction. A larger illumination limit is systematically obtained toward the structural up-dip directions simply due to the ray-tracing characteristics.

- Shallowest targets close to **MFS9.0** (upper confining zone): maximum horizontal imaging from **3,000 to 3,200 ft.**
- Intermediate targets close to **MFS9.1**: maximum horizontal imaging from **3,600 to 4,000 ft**.
- Intermediate targets close to **MFS9.2**: maximum horizontal imaging from **3,600 to 4,700 ft**.
- Intermediate targets close to **MFS9.3**: maximum horizontal imaging from **3,600 to 5,300 ft**.
- Intermediate targets close to **MFS9.4**: maximum horizontal imaging from **3,600 to 6,500 ft.**
- Intermediate targets close to **MFS10**: maximum horizontal imaging from **3,600 to 6,500 ft**.
- Deepest targets close to **MFS12** (above Anahuac shales): maximum horizontal imaging from **3,600 to 6,600 ft**

A.4.2.1 Walkaway Profile Illumination vs. CO_2 Plume Extension

The analysis was done at 5-year intervals after the start of injection and after the end of injection. The purpose was to confirm, for each analyzed depth interval, whether the plume was likely to migrate beyond the walkaway imaging zone or not. Figure A-35 illustrates the walkaway profile imaging limits along the east-west direction and the CO_2 lateral plume extension. Similar results were obtained along the other azimuthal directions.

For the deep targets below MFS9.4, the plume never migrates laterally beyond the walkaway profile image limits. However, for the shallow targets from MFS9.4 up to MFS9.0 between 15 and 20 years after injection, the plume can extend beyond walkaway profile imaging limits. Larger lateral CO_2 migrations are related to higher permeability layers in the reservoir model.

Figure A-35 – VSP illumination (in dark blue) on the seismic section view for IL405 (back-ground) passing through the CO_2 sequestration Well-001 in a west-east direction. The CO_2 plume, characterized by supercritical gas saturation (blue-red color scale, clipped at 50%) for the base case reservoir modeling scenario is shown at six time-intervals between 5 years and 30 years after first CO_2 injection.

The same situation can be observed in map view by comparing the plume size versus the walkaway illumination limits for a specific target and at a specific injection interval. Figure A-36 illustrates the CO_2 plume lateral extension after 20 years of injection. For the MFS12 level there is still a large margin before the plume migrates beyond the multi-azimuth limits, for MFS9.3 and 9.2 the western and northern extension of the plume clearly goes beyond the imaging limits.

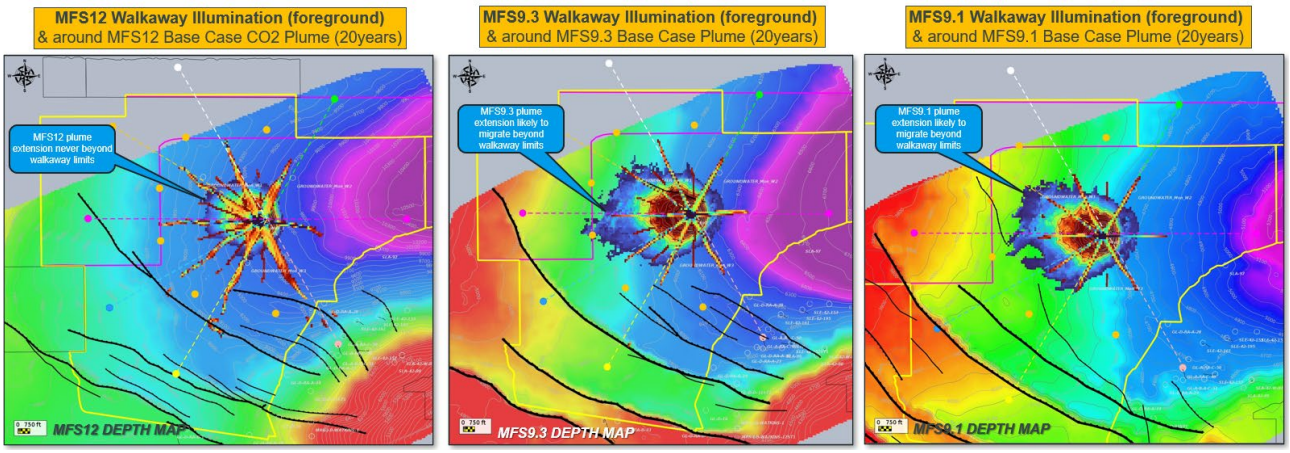


Figure A-36 – Basemap view at MFS12, 9.3 and 9.1 level , comparison between the plume lateral extension and the limits of walkaway profile imaging.

A.4.3.1 Resolutions and Uncertainties of Conventional Walkaway Measurements

The first VSP walkaway profile limitation is the lateral imaging, which is inherent to the target reflection critical angle and depth. The second limitation is that it will only provide a 2D image profile and not a 3D volume. To compensate for this second limitation while remaining cost-efficient, a rich multi-azimuthal acquisition program is recommended with up to eight walkaway half-profiles per survey.

To help building the most reliable image of the plume shape based on 2D lines designs, the following improvements were planned:

- A 4D walkaway acquisition program based on eight half-profiles with blind angle between profiles reduced to 30° in the north and west directions where the plume is simulated to preferentially grow.
- In addition, six 4D fixed-offset VSP will also be installed on the VSP set-up area to help reconstruct the plume shape between the walkaway half-profiles.
- Finally, the plume shape building will benefit of the spatial imaging from 4D gravity gradiometry baseline and monitors (Technology 2).

The third relative walkaway limitation relates to both vertical and lateral seismic resolutions. The vertical spacing between receivers is optimal with DAS and the sources station horizontal spacing is recommended at 150 ft. This design will not cause any aliasing effect in the pseudo-flat environment of the Hackberry storage site. Acquisition parameters will maximize the VSP image resolution:

- Vertically, 15-30 ft, respectively for the shallow and deep targets
- Laterally, 50-70 ft, respectively for the shallow and deep targets

The image resolution will progressively decrease away from the borehole as it reaches the imaging limits. Thanks to the accurate velocity profile recorded along the well trajectory, the vertical and lateral positioning of the walkaway profiles will be very good for all azimuths with very low uncertainties.

The purpose of 4D walkaway profile is to identify seismic changes between the baseline and the monitors profiles that are mainly induced by changes in CO_2 saturation. The DAS receiver, cemented behind casing, will yield an excellent seismic repeatability during the life of the project. In Black Lake, the deployment of dynamite shot-holes as seismic source below lake bottom (approximately 60 ft deep) will also provide an excellent positioning and signature repeatability under strict acquisition conditions.

Assuming maximized repeatability conditions and optimal 4D processing, the dominant seismic signal differences observed between baseline and monitor surveys will result from a change in fluid saturation in the pore volume. The very small variations in reservoir pressure triggered in the CO_2 injection will remain undetectable with 4D walkaway profile.

Modeling of the 4D signal synthetic has shown that seismic amplitudes are very sensitive to a change in CO_2 saturation in the pore space; therefore, a clear 4D signal will be detectable a soon as the CO_2 incremental saturation will exceed 5% in the reservoir pore space. Moreover, the reservoir does not necessarily need to be invaded by CO_2 across the whole reservoir thickness to be detected by 4D walkaway profile. A reservoir with a thickness as low as 5 ft and filled with 5% of CO_2 in the fluid pore space will normally trigger a visible 4D signal because the acoustic impedance differences between the baseline and 4D monitor profiles will generate large reflectivities and amplitude differences. This detectability limit is subject to the 4D background noise indicated in percentage of normalized root mean square (RMS) and every effort will be done during acquisition and processing to minimize such background noise.

Finally, the 4D walkaway baseline and monitor profiles will be acoustically 4D inverted. The modeling has shown that acoustic changes are sufficient to define CO_2 front qualitatively. The 4D inversion results will be calibrated to the impedance profile of the sequestration well, the 4D acoustic impedance differences will be used as qualitative and quantitative input to the dynamic reservoir model history matching process.

The uncertainty relative to the exact location of the CO_2 front along a 2D walkaway profile is well treated in the Quest project (Harvey et al. 2022) and presented in Figure A-37.

The Quest project is in a similar structural context and depth as Hackberry. The injection started in 2015. A second monitor walkaway profile was acquired after two years of injection, after approximately 0.9 million ton of CO_2 had been injected in the same reservoir. The 4D signal triggered by the CO_2 saturation increase is clearly visible at about 7,200 ft TVD (~2,200 m). The paper highlights the uncertainty on the exact limit of the plume as a transition zone is evidenced on both sides of the strongest signal and centered zone. The central zone is characterized by a

reliable, very strong and massive 4D signal. On both sides of this clear centered zone, there is a transition zone of approximately 400 ft wide that could, however, be further reduced with a 4D acoustic inversion (Wang et al. 2023). Then, all around, the ultimate fringe lacks of any 4D signal and CO_2 saturation is most likely very low to null.

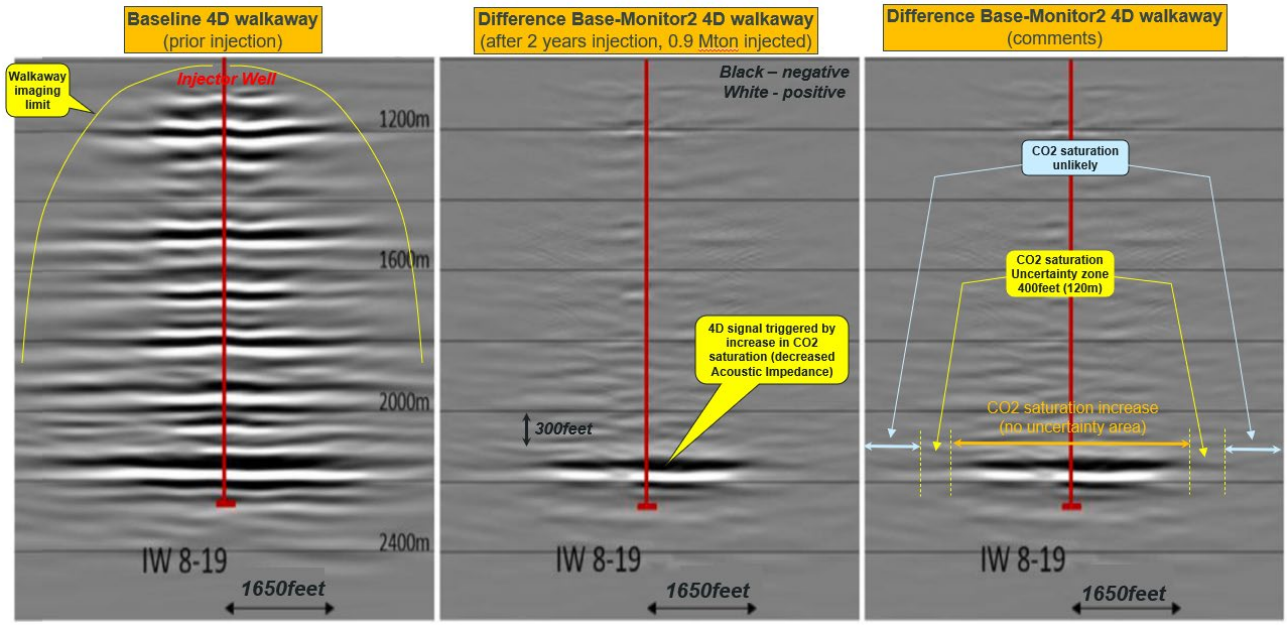


Figure A-37 – Results from QUEST Alberta Carbon injection project case history . Left: baseline walkaway profile acquired across well 8-19. Center: 4D seismic difference base-monitor2 after two years of injection with 0.9-MMT of CO_2 injected. Right: same as center with illustration of uncertainty taper zone at the CO_2 primary plume front edge (black color refers to negative amplitudes).

The last and perhaps most important uncertainty is the CO_2 saturation value in the pore space away from the well. This parameter remains challenging to determine with accuracy since CO_2 saturation is not the only parameter that changes during injection. Pressure, salinity and temperatures will also vary, all these have an impact on rock compressibility and therefore impedance. Research and development workflows based on calibrated petro-elastic models, deep-learning inversion and history matching will allow a rough estimation of the CO_2 saturation around and away from the well.

A.4.4.1 Walkaway VSP Operability

Investigation toward specialized seismic VSP contractors indicated that the HCS site is an ultra-shallow environment that is not convenient for walkaway acquisition using standard VSP marine airgun as seismic source; therefore, the target depths would require a large airgun capacity which cannot operate with stability in shallow water. Using an airgun in this environment will result in:

- Poor signal quality and stability (problematic for deep targets such as MFS12)
- Strong reverberation and intense multiples caused by the shallow water layer
- Unstable source signature from shot to shot

- Unreliable and difficult positioning, which will degrade the 4D source repeatability specifications.
- Risk of endangering wildlife due to powerful airgun seismic wave in the water media.

The best recommended source to maximize signal quality and repeatability at the specified targets depths is small quantities of dynamite buried in shot hole at a depth ranging from 60 to 120 feet. The dynamite shot hole parameters must be tested ahead of walkaway baseline acquisition. The 4D walkaway program in ultra-shallow water using dynamite shothole is a complex and costly field operation which is the reason why the eight walkaway half-profiles are preferred instead of a 3D walk-around VSP. The most favourable acquisition period would be from mid-January to mid-May. For the eight walkaway profiles, the acquisition duration would be approximately 1.5 to 2 months.

In summary, the efficiency of using the VSP method to quantify CO_2 plume development over time has been demonstrated in several cases worldwide. In this specific case for HCS, the results using offset petro-physical data have produced a modeled differential in density and compressional velocity that is likely to produce detectable changes in the reservoir where CO_2 has replaced connate fluid. There is a high certainty that deploying this method in a time-lapse format will produce a 4D image of the extent of the plume and its development in the future. In addition, the utilization of the VSP in the injection well using a permanently installed fiber optic sensor will produce an image centered on the spot of injection with a higher resolution than a traditional wireline deployed geophone array and eliminates the need to create additional penetrations in the cap-rock for monitoring purposes. The use of the fiber optic installed in this well will also ease pressure and temperature monitoring in all sections of the well, which will be used in the indirect calculations of the pressure plume.

Finally, and most importantly, this VSP system, along with the indirect plume calculations, will allow for a monitoring of plume migration without the need to create additional artificial penetrations which could inadvertently form a conduit out of the confinement intervals.

A.4.2 Technology 2: 4D Micro-gravity

The 4D micro-gravity brings the capability to monitoring gravity field azimuthal variations due to fluid density decrease when changing fluids from brine to supercritical CO_2 within the rock pore volume (Gettings et al. 2008). This type of data could be collected and used to history match, validate and extend the VSP monitoring. Gravity field perturbation induced by CO_2 injection is expected to be detectable above 3µGal using state-of-art micro-gravimeter, modeling based on surface micro-gravity performed over Hackberry demonstrates that the field perturbation will go above this threshold during the injection phase.

This allows for full azimuthal coverage, low resolution providing indication on CO_2 plume anisotropy. Due to its limited environmental footprint and extended three-dimensional coverage

capabilities micro-gravity could be an appropriate technology for determining ultimate CO_2 plume lateral and vertical extension beyond VSP imaging should it be needed.
Figure A-38 illustrates the impact of the CO_2 plume on the perturbation of the micro-gravity field. The surface gravimetry modeling example was taken at Year 2042 (approximately 15 years after injection start). A clear gravity anomaly of almost 10 micro-Gal would be generated in this injection scenario. The plume appears very homogeneous, and the gravity field perturbation is almost isotropic. These results combined with the multi-azimuthal walkaway surveys will increase our confidence on the storage conformance and containment.

It should be noted that the modeling performed was only based on surface gravity field measurement. Increased performance should be obtained when including gravimeter inside the sequestration wellbore during the baseline and monitors acquisitions.

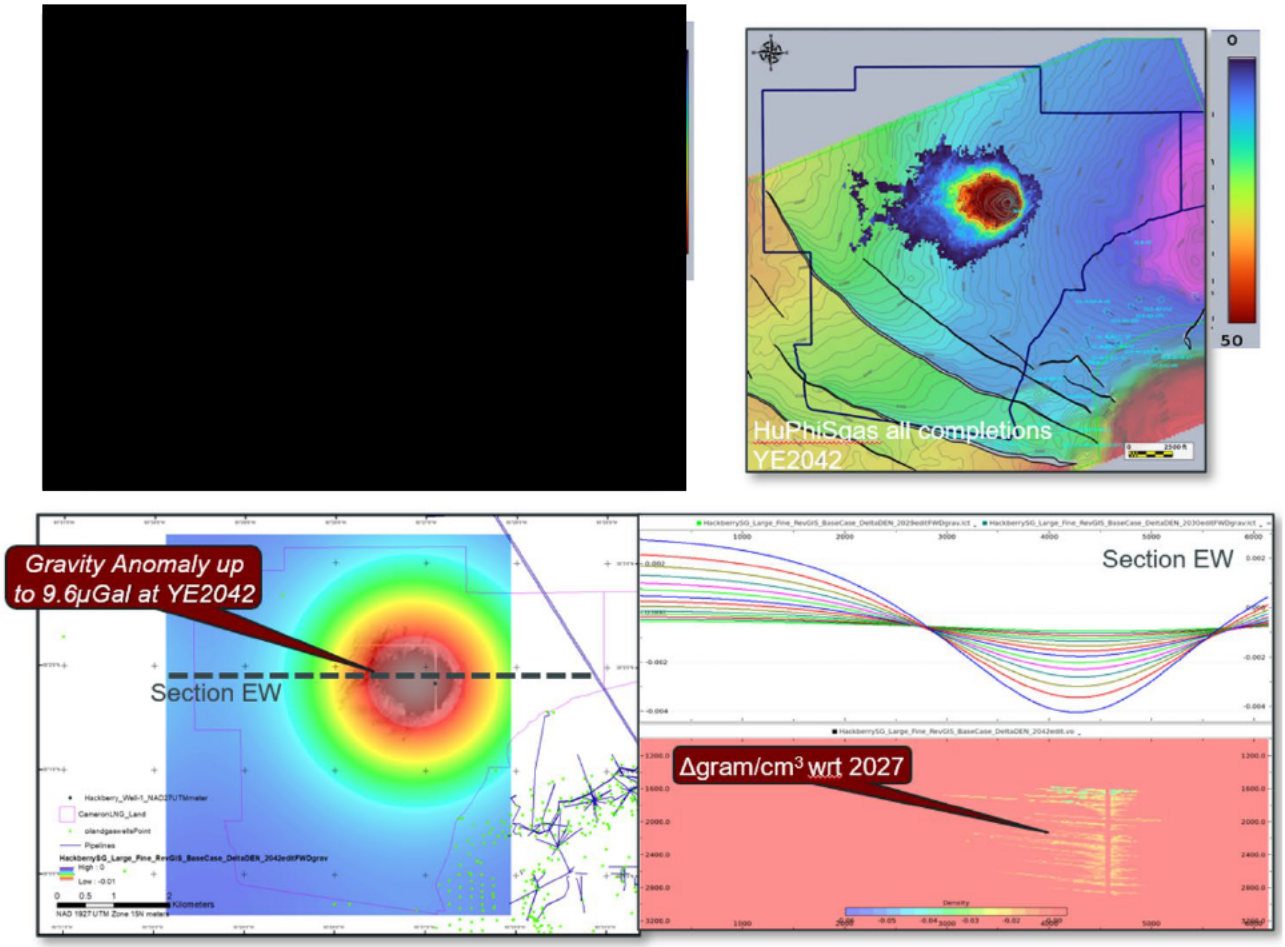


Figure A-38 – Gravity Modeling Example. Upper left: CO_2 plume in 3D view after several completions (3D seismic in background), upper right: map view of the corresponding plume presented as a vertically cumulated gas thickness for all completions, lower left: micro-gravity field perturbation in map view, lower right: EW profile evolution of the micro-gravity every year until 2042

Additional modeling involving combined surface 4D gravity with borehole gravimeters monitoring (BHGM) could be investigated to further increase the monitoring efficiency to detect

containment failure or anomalous vertical CO_2 migration in the vicinity of the well bore. As presented by Lee Wan et al. (2020) and Zhdanov et al. (2020), the surface gravity monitoring can be complemented using temporary gravitometer inside the sequestration well to provide additional information on the changes in the gravity field and potentially detect lateral CO_2 leakage in the well vicinity. Using BHGM measurements can significantly improve the inversion and migration result and provide a better representation of the sub-surface density distribution and enhance deep targets imaging.

Finally, the 4D gravimetry gradiometry monitoring will also be able to detect field perturbations induced by important CO_2 vertical leakages above the confining unit(s) if the quantity of CO_2 is sufficient as shown by Borges et al. (2024) (Figure A-39) and Lee Wan et al. (2020). In this configuration, if the CO_2 leaks vertically along a favorable path (e.g., sub-seismic fault or connected sandy/silty pathways) and accumulates in a kind-of chimney shape, it may not be detected by the walkaway profiles due to its position and narrow lateral extension in between two walkaway profiles then the gravity field will be able to detect it leading to a complementary monitoring action and a possible remediation.

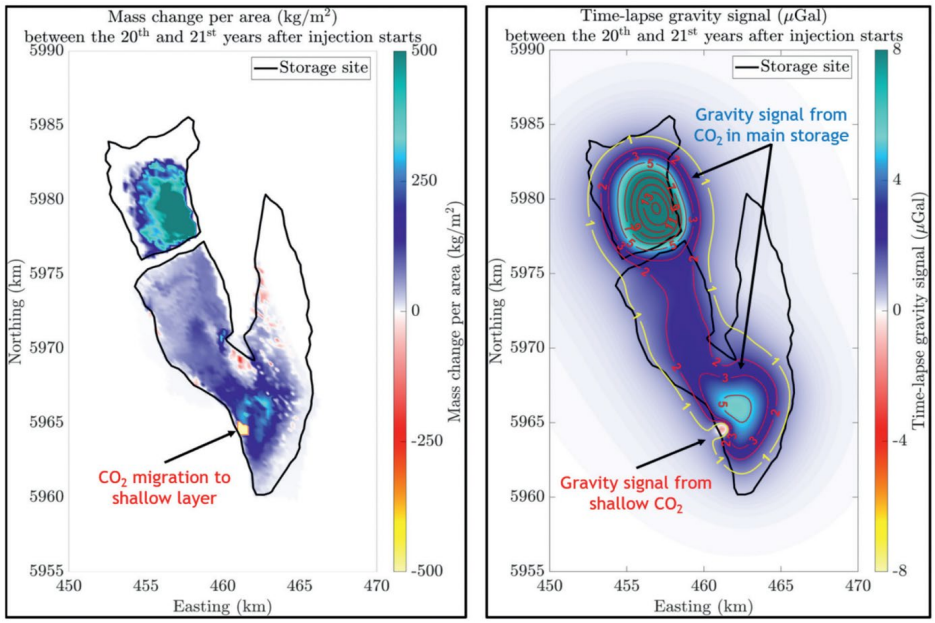


Figure A-39 – Field Perturbations Induced by CO_2 Leakages. Left: Extract from Borges et al. (2024) (First Break EAGE), map views of mass change per area in kg/m^2, note the big mass decrease at the location of the CO_2 leakage. Right: modeled time-lapse gravity change between injection Years 20 and 21, highlighting the strong local anomaly right at the location of the CO_2 leakage zone. This anomaly represents 100k ton of CO_2 up to a layer depth of 1,700 ft.

A.4.1.2 Operational Deployments of 4D Micro-gravity Monitoring

A surface gravity survey in the Black Lake context should be relatively straightforward. It requires light logistics and can monitor in 3D the entire concession and more if needed. It has extremely low impacts on the environment. Scouting and monitoring can be performed cost-efficiently in simultaneous operations during the VSP walkaway acquisition. Gravity stations should be to

record the field on a 500 x 500 m grid, an estimated time of 20 to 30 minutes field recording per station. Across a square of 50 km^2 this would represent about 200 stations for a one-month duration. The station density can be increased in an area of high priority if required to refine the field perturbation monitoring.

Borehole gravity gradiometers (BHGMs) are insensitive to wellbore conditions (e.g., rugosity or casing); however, they cannot be deployed permanently like optic fibers. They could be deployed temporarily in the wellbore simultaneously during the surface gravity surveys, this would constrain the survey on periods of workover (e.g., change of completion etc.) to allow access to the borehole.

The BHGM can also be used to monitor near the wellbore in case there are any suspicions of nearby CO_2 leakage.

To conclude on the use of 4D micro-gravity technology during the HCS project, it should be added that due to the bottom to top completion injection strategy, this technology will be less efficient at the beginning of injection since it will occur in the deepest formations. The modeling shows that the first detectable 4D effects will be observed after seven years of injection. This period of first detectability depends on the injection rate and completion depths; therefore, a new model including the use of BHGM is recommended once the final reservoir model and completion/injection strategy are finalized.

Figure A-40 – Typical Scintrex CG-5 gravity meter and Trimble geodetic grade GPS as it would be deployed temporarily in the Hackberry area.

A.4.3 Technology 3: Contingent 2D/4D Bridging Surface Active Seismic Imaging

The walkaway VSP acquisition program is intended to monitor and control the CO_2 plume azimuthal and vertical propagation, support reservoir model updates, and ensure optimal choices in the CO_2 multiple completion strategy. In the event that, on some layers, the CO_2 plume extends beyond the visibility cone inherent to all VSP acquisitions, additional 2D seismic data could complement the design with traditional geophone/hydrophone receivers. It is recommended to keep consistent azimuths between the walkaway profile and 2D/4D surveys. The purpose of the 2D/4D survey will be to bridge the imaging gap of the walkaway.

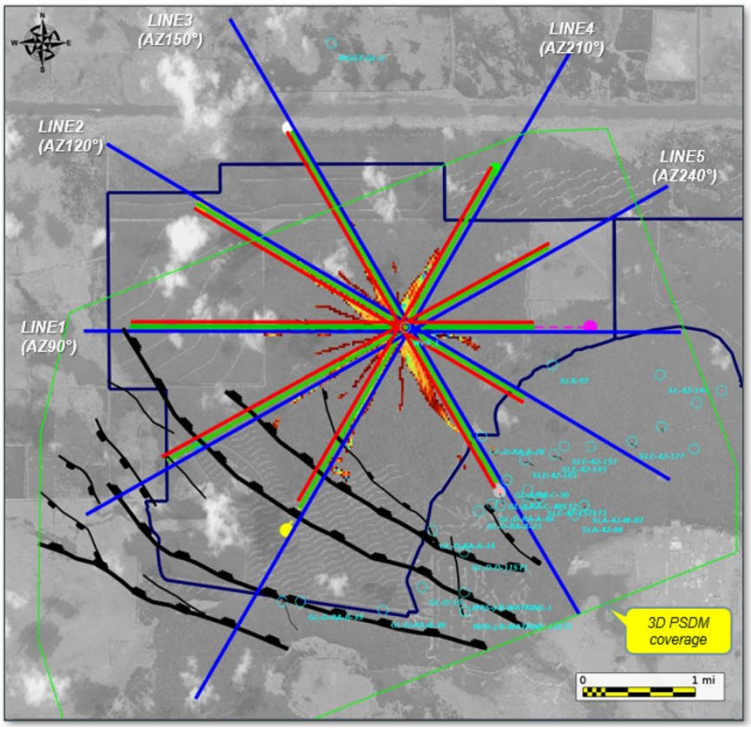
Figure A-41 – Illustration of 2D surface seismic acquisition design performed to recommend an optimal source and receiver configuration.

The bridging design shows that, to acquire a 2D line providing a fully migrated seismic image covering the complete CO_2 plume extension (set at 100 years after injection stops), a very limited number of extra seismic sources will be required in addition to the sources needed for the walkaway monitor surveys. Both walkaway and 2D/4D surveys source efforts are therefore very complementary, when acquiring the 2D/4D lines it will still be possible to also record the walkaway profile to maintain a high-resolution monitoring around the borehole.

The 2D/4D acquisition program will require the mobilization of approximately 2,200 surface receiver stations (hydrophones or submersible nodes) at the lake bottom. In the end, a minimal additional acquisition effort will be required to deploy surface receivers along the walkaway line azimuths. As illustrated in Figure A-42, after a first monitoring period based on walkaway imaging (Phase 1), the value of including surface receivers and adding extra seismic sources in the walkaway acquisition should be quite high to image beyond the walkaway limits (Phase 3).

[redacted]

Figure A-42 – 2D/4D Example. Left: definition of the three phases approach to adjust the active seismic monitoring program to contingent lateral migration of CO_2. Right: schematic illustration of the 2D/4D bridging survey.



Source stations
Receiver stations
Full-Fold length

Recommended TTE 2D design program, (optimized for Deep & Shallow Targets)

Acquisition program	Five 2D lines
Source stations interval	150 feet
Source Type	Dynamite (1lbx5 or 5.5lbx1)
Explosive Type	Environment friendly
Shot Hole depth	12 to 60 feet (to be tested)
Charge size (lbs)	5 to 11 (to be tested)
Total Source stations	639
Source deployment	Mounted Rig on Airboat
Full Fold total length	18.2 miles
2D Fold	40
Receivers total length	30 miles
Receiver stations interval	75 feet
Receiver Type	Hydrophones & Geophones
Array	Point receiver, tbd.
Total Receiver stations	2114
Receiver deployment	Airboat & Marsh buggy

Figure A-43 – Potential Survey Layout. Left: acquisition layout for five lines oriented with strictly the same azimuth of walkaway profiles. Right: preliminary 2D/4D acquisition parameters adapted to the walkaway specification.

The triggering of such 2D/4D bridging survey will have to be anticipated after calibration of the reservoir model to the walkaway profile 4D anomaly and by calculation of the plume front growth. It remains in a contingent program because adaptation of the injection strategy should be first realized (injection pressure, injection zone shift, etc.). An advantage of the design is its relative flexibility, 2D lines can be added, shortened/extended or simply removed if required; this will be a function of the plume anisotropy and other observations made in the early direct and indirect monitoring period.

Similar conclusions for walkaway VSP technology can be made regarding the field acquisition operational constraints. Repeatable dynamite sources are recommended.

A.4.4 Technology 4: Deployment of Passive Seismic Network

A.4.1.4 Feasibility Study

As part of the Hackberry multi-specialty geophysical monitoring design, HCS investigated the benefits of passive seismic monitoring (PSM) and recommended a fit-for-purpose network design. This work was performed in relation with the contractor, Nanometrics, under supervision of a PSM specialist.

The objective of a passive seismic feasibility study is to identify possible cost-efficient solutions for the monitoring of the seismic subsurface activity (i.e., the natural seismic activity of the area and more importantly the induced seismicity related in this case, to the operations of CO_2 injection in deep, intermediate and shallower reservoirs). The feasibility should also demonstrate the ultimate short- and long-term benefits of PSM in the context of Hackberry considering unlikely but potential risks related to CO_2 injection in the Miocene reservoirs (i.e., very low injection pressure, multiple completions, etc.).

A.4.2.4 Methodology

From a scientific point of view, there is no difference between induced and natural seismic events and the way they can be monitored: in both cases we refer to the principles of earthquake seismology which focuses on the detection, localization, and characterization of seismic events, whatever their nature.

A micro-seismic event is defined as a faint earth tremor caused by natural phenomena but in the early 2000s the study of events with magnitude less than 2 (i.e., micro-seismic events) came to be associated with passive seismic monitoring for hydraulic fracture stimulation, and more recently with the monitoring of CO_2 underground plumes in CCS projects (Figure A-44).

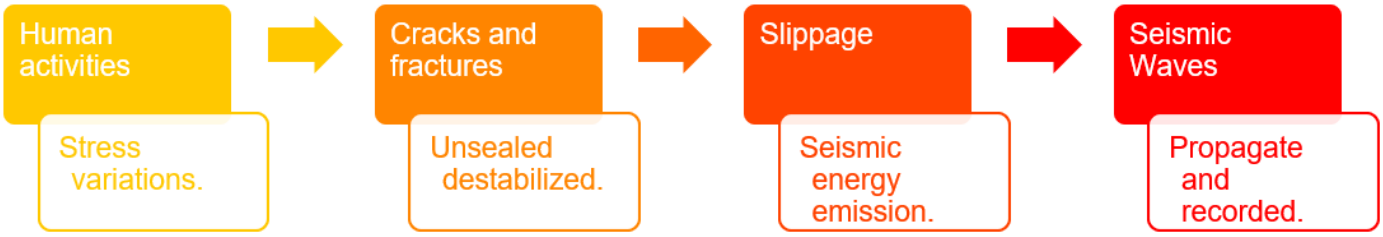
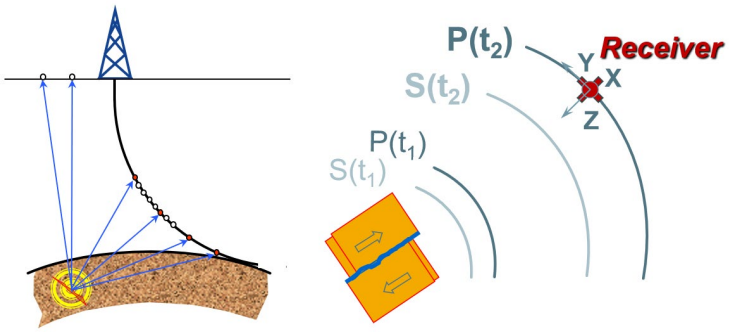


Figure A-44 – Event Chain from the Origin of PSEs to Their Recording

A schematic representation of a passive seismic event (PSE) is shown in Figure A-45. The left panel illustrates a PSE as arrows departing from yellow concentric circles, reaching seismic sensors installed either at the surface (passive network stations) or within a well (Shallow borehole arrays or DAS optic fiber).

The central panel gives an idea of what the nucleation of a PSE consists in, and how the seismic signal is emitted and propagated within the surrounding medium until it reaches one or more receivers. The right panel shows the relationship between the geometry of the fracture that generated the seismic event and the magnitude of the seismic event (i.e., the energy emitted by its source). Magnitude can be defined in many ways, depending on which portion or characteristic of the seismic waves is used for its computation, therefore this table should be simply considered as a general overview of this parameter.



Magnitude range	Class	Length Scale	Displacement Scale
8 – 10	Great	100-1000km	4-40m
6 – 8	Large	10-100km	0.4-4m
4 – 6	Moderate	1-10km	4-40cm
2 – 4	Small	0.1-1km	4-40mm
0 – 2	Micro**	10-100m	0.4-4mm
-2 – 0	Nano	1-10m	40-400µm
-4 – -2	Pico	0.1-1m	4-40µm
-6 – -4	Femto	1-10cm	0.4-4µm
-8 – -6	Atto	1-10mm	0.04-0.4µm

Figure A-45 – Schematic representation of a micro-seismic event and its recording (receivers can be in boreholes or on ground).

The information that can be extracted from passive seismic network data is mostly related to the source of the PSE (e.g., their magnitude, positions, and associated focal mechanisms). Maps are created from this information, then interpreted, correlated with subsurface features (e.g., faults) and operational events (e.g., new completion, injection rate change) to understand what is happening beneath the ground surface, particularly near our installations and operations.

The HCS project is located in coastal western Louisiana. Constraints for surface access due to lakes, swamps and infrastructure were considered in the study. Based on sparse historical station coverage, the study area has shown low natural seismicity (only magnitudes exceeding 2.5 are reported in the public domain, as shown in Figure A-46). With the nearest public stations east of Houston, north of Lake Charles and near New Orleans, the expected magnitude of completeness for the Hackberry area is in the order of Magnitude 3+. Therefore, caution has to be exercised when using this data to assess the risk of future lower magnitude seismicity in the study area.

The technical objectives of this feasibility study were to determine optimal design parameters for permanent micro-seismic monitoring (MSM) and passive seismic monitoring (PSM) networks for the project. Considerations were given to the network ability to map potentially active faults and fractures within the storage complex and its vicinity (pre-existing and nascent) and the monitoring of related risks to well and confining unit integrity throughout project life. The system also needs to be capable of supporting the implementation of an early warning system for (induced or natural) seismic risk mitigation.

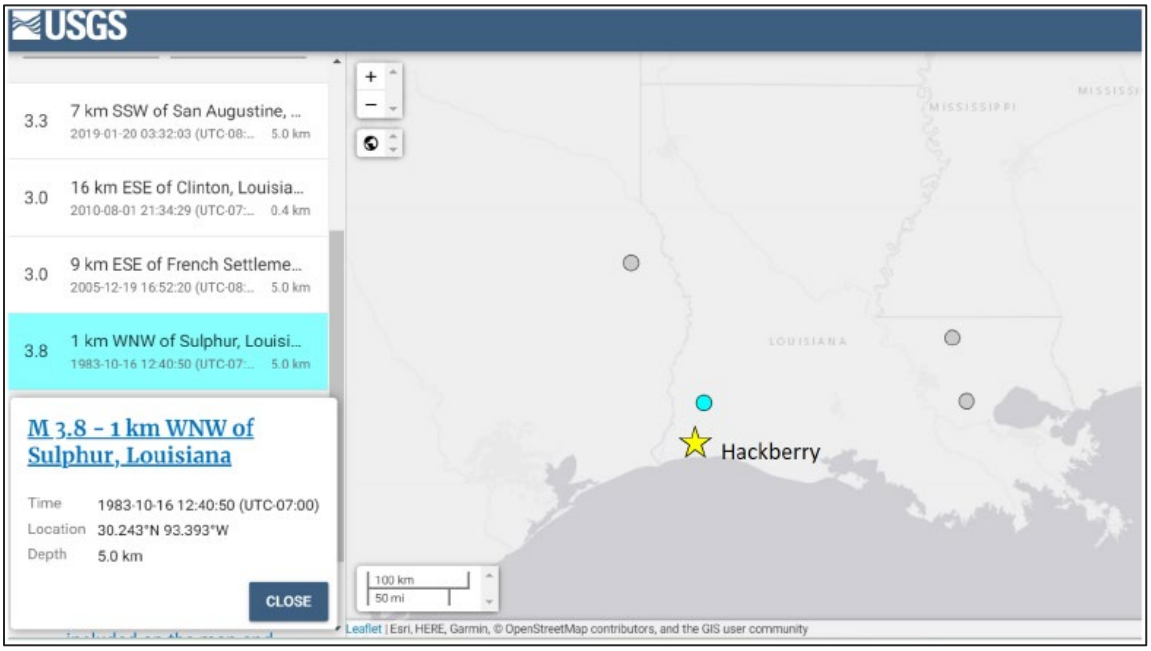


Figure A-46 – Historical seismic events catalogue based on publicly available network data for the past 40 years (USGS).

A.4.3.4 Design Study Results

The network design, performed by the contractor, Nanometrics, considered land and potential access restrictions, background noise, infrastructure, security, etc., from the land restriction analysis.

Generally, the performance of a seismic array can be evaluated considering the following two parameters:

- Magnitude of Completeness (Mc) (i.e., the smallest event in terms of Richter scale magnitude that can be detected by at least four stations of a given network layout, considering velocity model, instrument noise floors, environmental background noise and attenuation parameters).
- Seismic event location uncertainty (i.e., the horizontal and vertical location accuracy associated to the monitoring network).

The number and distribution of surface seismic stations will impact mostly the Mc, plus the horizontal and vertical location accuracy. The inclusion of downhole geophones will greatly improve the vertical location accuracy and also the Mc in the reservoir area.

Among the different modeling parameters considered in our network design:

- The station distribution: this parameter is mainly impacted by land restriction, and it will be defined to maximize Mc and location accuracy in the AOR. The recommended design tried to avoid positioning recording stations in the middle of Black Lake to minimize environmental impacts and complex maintenance.
- The background noise: this data was acquired from six regional public stations and was applied only to surface stations, stations potentially deployed in boreholes are considered as less sensitive to the surface noise as they are buried. Proper noise recording during a field scouting trip is strongly recommended, given distance of the five considered stations from the AOR.
- The attenuation level: this parameter affects the detection level of the monitoring network, and its value may be subject to variations. For this reason, different values were considered during modeling. This value will be updated once the zero-offset VSP is available.
- The velocity model: this parameter affects both the Mc and location accuracy. This will also be updated once the velocity profile at well will be available.

A more complete description of the techniques used to evaluate these parameters, as well as all the results obtained from the different experiments can be found in the report written by Nanometrics. Here for the sake of simplicity and brevity, HCS will report only the results for the scenario considered as the best in terms of operational objectives, cost and benefits ratio.

5.1.1.1 Description of the Recommended Seismic Acquisition Layout

The layout of the scenario currently recommended for the HCS project is made up of five surface stations, equipped with broadband seismometers (orange triangles above satellite map presented in Figure A-64) distributed over the AOR.

Depending on the final position and number of the groundwater monitoring wells, an additional station in borehole can be considered to further reduce the Mc and enhance MSE positioning accuracy. The network model can easily be updated to obtain revised Mc and uncertainty maps.

The magnitude of completeness (Mc) was evaluated at three target depths: 4,920 ft (near MFS9.1 and 9.2), 9,842 feet (near MFS12) and 13,123 ft. The summary of the results obtained for the recommended scenario can be found in Tables A-2 and A-3, while the various modeling results are presented in Figure A-65. This array scenario fulfils the Mc target of +/-0.5 ML within the AOR from the free surface.

This network will also be supported and enhanced by the optical fiber continuously recording DAS and DSS data to detect geomechanical deformations and induced seismicity.

Table A-2 – Mc model results in local magnitude (ML) obtained for three target depths.

Location	Target Depth (ft)		
	4,920	9,842	13,123
Minimum within AOR	-0.18	0.1	0.29
Maximum within AOR	0.68	0.78	0.88
Minimum within plume	-0.16	0.12	0.31
Maximum within plume	0.48	0.62	0.71

Table A-3 – Location Accuracy Model (ft) results obtained for three target depths.

Location	Target Depth (ft)		
	4,920	9,842	13,123
Minimum within AOR	295	230	230
Maximum within AOR	394	590	590
Minimum within plume	475	640	672
Maximum within plume	890	1,430	1,050

This base case surface station positioning scenario was designed to optimize both Mc and positioning accuracy. Once the well results will be available (velocity field, attenuation factor, geological profile) and the final USDW monitoring wells positions approved, an optimization of the final stations locations will be performed prior deploying the network in the field. Final station locations will be determined from field investigations to establish the stations within the HCS property.

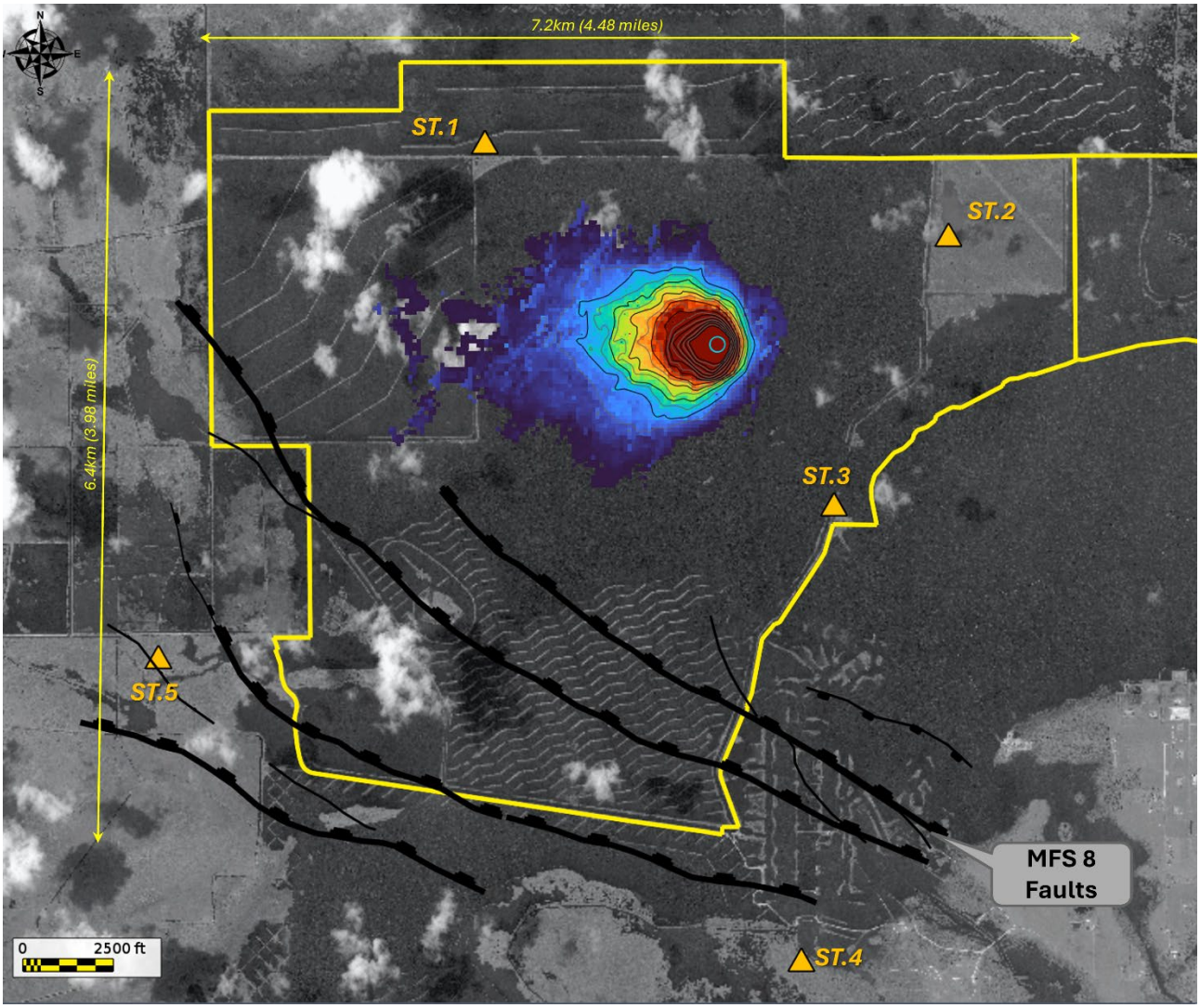


Figure A-47 –Surface design proposal for the Passive Seismic Monitoring. The orange triangles represent notional surface stations to be placed on emerged land.

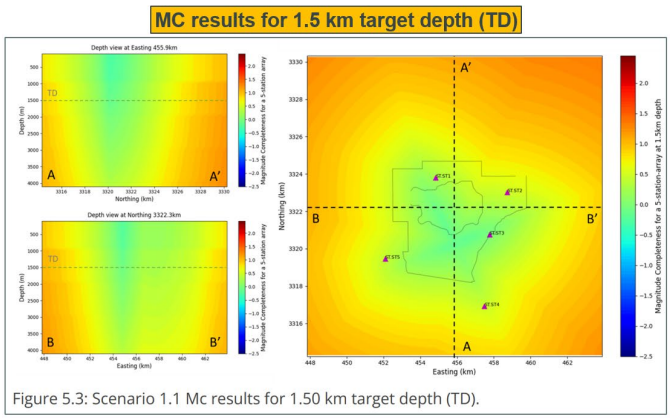


Figure 5.3: Scenario 1.1 Mc results for 1.50 km target depth (TD).

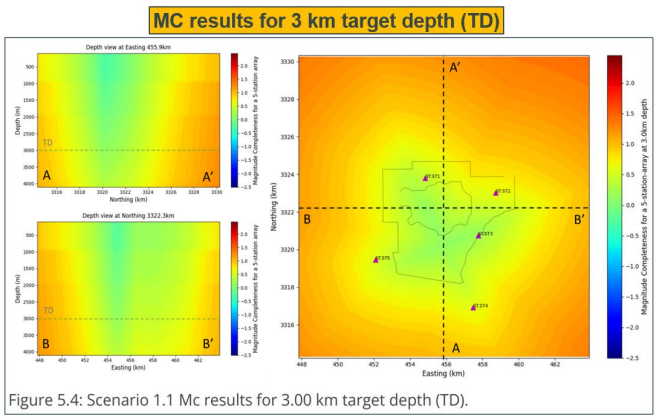


Figure 5.4: Scenario 1.1 Mc results for 3.00 km target depth (TD).

Figure A-48 – Modeling estimated magnitude of completeness results for 1.5 km (left) and 3.00 km (right) target depth.

Optional additional stations could be added later during the project should this be required to enhance the monitoring accuracy. In addition, the continuous recording of the cemented DAS fiber combined with buried geophone arrays in the USDW monitoring wells, should increase the performance of the network.

The maps presented in Figure A-49 depict both horizontal and vertical positioning uncertainty of a potential micro-seismic event triggered in the subsurface at three different depths. Such maps can be produced for any depth. The horizontal uncertainty is much lower than the vertical one; both uncertainties can further be reduced by adding surface stations and borehole stations in strategic locations.

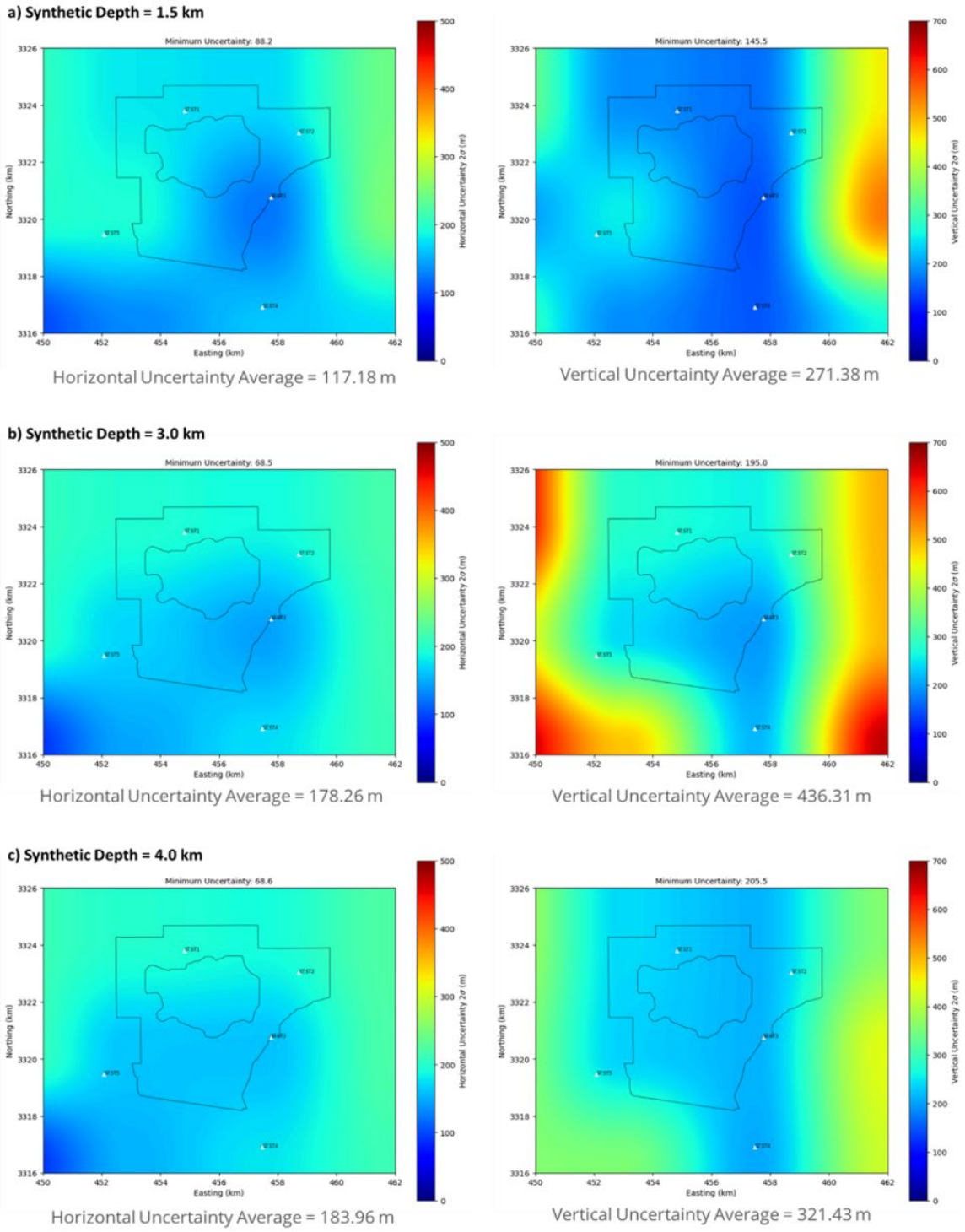


Figure A-49 – Location accuracy model results at three target depths based on a five surface stations scenario. Note, the vertical uncertainty is larger than the horizontal one.

A.4.4.4 Recommendations and Motivations to Deploy a Passive Seismic Network

The recommended stations network is designed to be as simple as possible while delivering reasonably accurate and sensitive net to record subtle micro-seismic events with a Mc specification around +/-0.5 ML. It will be easily accessible for maintenance and demobilization. It also can be enhanced during project lifetime, if required. The technical specifications and data recording methods are described in the feasibility report.

To allow sufficient recording time for baseline recording, HCS will install and activate the network at least one year prior to start the injection. Also another passive recording period is recommended during the Post-Injection Site Care (PISC) period, this will depend on the level of induced and natural seismicity detected during the project.

The Hackberry injection pressure regime will remain very low during the lifetime of the project and it is expected that the pressure will re-equilibrate as soon as the injection is stopped in a given formation. However, several tons of gas will partly replace water in the pore space within various unconsolidated reservoirs. Therefore, the likelihood of geomechanical event creation is still an unknown in this new industrial context.

In the context of a long-term underground CO_2 storage located on land and close to local human activities it seems paramount to deploy a technology that will:

- Enable the detection of potential induced seismicity whether it is triggered by HCS or third-party activity.
- Monitor risks related to injector well and confining unit integrity throughout project life
- Support the implementation of an early warning system for seismic risk mitigation.

A.4.5 Additional Technology Considered for Hackberry Geophysical Monitoring

As part of the investigation performed to identify geophysical technologies that would support an efficient CO_2 plume monitoring, electro-magnetic methods were considered as a complementary tool which could be deployed at the HCS project. This technology is still in a pilot phase.

The purpose of electro-magnetic techniques would be to map resistivity changes in the 3D subsurface induced by fluid movements (i.e., replacement of saline water by supercritical CO_2). There is a large contrast between CO_2 gas and brine and resistivity is proportional to gas saturation (Gasperikova, 2022).

Electromagnetic fields are recorded using surface and/or borehole array of receivers and surface and/or borehole transmitters.

Using modeling and synthetic experiments based on detailed reservoir models, several geophysical publications have demonstrated that very subtle fluid variations (CO_2 replacing water or water sweeping hydrocarbons) can be monitored using marine controlled-source electro-magnetic (CSEM) and borehole-source electro-magnetic (BSEM) (Stark 2010, Black and Zhdanov

2020, Yilo et al. 2023). This modeling shows that in general the measured electric fields are in the order of 1 µV/m to 100 nV/m, which can be quite small and difficult to discern in the presence of background noise.

Inversion methods allow the conversion of the measured baseline and monitors electromagnetic fields into baseline and monitor resistivity models in 2D and 3D. In general, the synthetics confirm tha electro-magnetic methods are feasible if the reservoir is not too deep and CO_2 saturation relatively high (e.g., Duperow formation at 3,900 ft in the Kevin dome sequestration site, Montana, Big Sky Carbon Sequestration Partnership, Zhdanov et al. (2013)).

Additionally, true field experiments publications confirmed that electromagnetic methods are feasible for monitoring in the evolution of CO_2 storage plume. To date, the best case-history remains the Sleipner 2D CSEM monitoring that confirmed the relation between 4D seismic signal and reservoir resistivity decrease induced by the CO_2 plume expansion (Park et al. (2013), Park et al. (2016), Figure A-50), in such a case that CSEM was able to follow the CO_2 plume extension but with depth ranging from 1,700 to 2,900 ft only. This technology could be used to monitor variation of CO_2 concentration above the upper confining unit (i.e., above 3,000 ft).

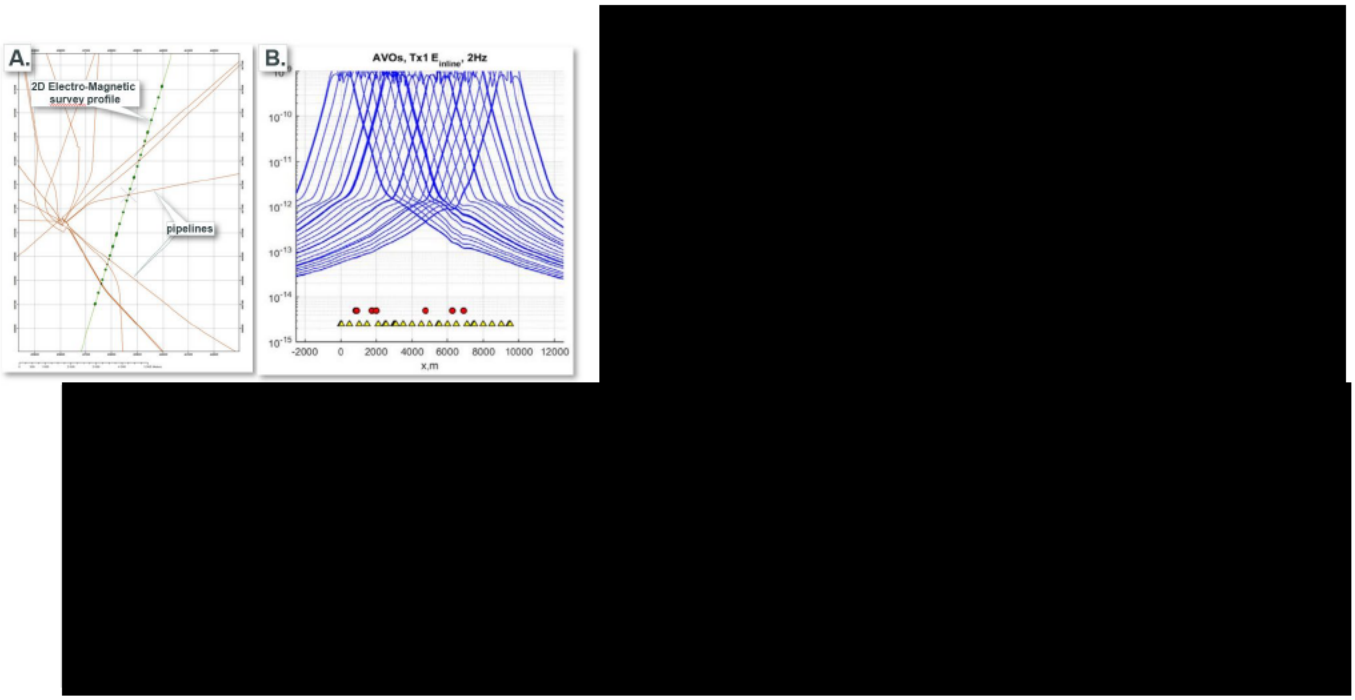


Figure A-50 – A. CSEM survey layout with seabed pipelines (brown lines) crossing the CSEM survey line (green dots and line). B. Sleipner CSEM inline Electric field recorded at 2 hz frequency in 2008, shown together with crossing seabed pipelines (red circles) and seabed receivers (yellow triangles), input to the resistivity inversion. C. Seismic sections in time domain, prior-injection 1994 (left) and during injection 2007 (right) before the CSEM survey in 2008. D and E inversion results along the CSEM profile (2008), respectively the inverted vertical resistivity signal (ρ_v) and the anisotropic ratio (i.e., vertical over horizontal resistivity ρ_v/ρ_h) clearly highlighting the consistency between the seismic amplitude increase and the resistivity increase induced by the presence of CO_2 in the reservoir.

Other CCS storage projects, such as Dakota SAFE project, have applied CSEM field experiments (Barajas-Olalde et al. (2021 and 2023)). With these feasibility study results, it is demonstrated that the CSEM method can monitor injected CO_2 in the study area and that changes in the resistivity data due to CO_2 injection can be resolved. Using CSEM to track CO_2 injection in the shallow Broom Creek formation (5,600 ft) is feasible. However, electromagnetic method might face greater challenges in the CO_2 monitoring of the deeper Deadwood formation (9,800 ft).

Based on these publications on pilot cases, there is hope that, complementing other techniques, electro-magnetic methods may support the detection of CO_2 leakages in middle to near sub-surface. So far, no publications could be found presenting 4D CSEM results in three-dimensional context for CCS with deep targets. Within the injection zone at HCS (i.e., below MFS 9.2, depth greater than 5,200 ft), the usefulness and relevance of electromagnetic methods require further investigation considering both CSEM and BSEM acquisition geometries.

Other challenges should be considered such as: near surface heterogeneities caused by artificial structures (pipelines, USDW wells, sequestration well, electric lines, other metallic structures etc.), surface field operability of receivers and transmitters in the ultra-shallow water environment, possible changes in water salinity across time which would impact the global resistivity response and the shallow water lake conditions and variations.

Concerning CSEM and BSEM technologies, no acquisition program is proposed. The recommended future evaluation includes:

- Continuation of scientific publications (synthetics modeling and field case-history results)
- Request for information from acquisition contractors and academics on progress to assess opportunities on HCS.
- Performance of a feasibility study once the key reservoir properties (resistivity, salinity, depth, thickness and porosity logs) are available and the reservoir model has been updated to confirm appropriateness of EM methods for shallow, intermediate and deep targets. If successful, a CSEM and BSEM program can be considered as part of the geophysical monitoring.

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Underground Injection Control – Class VI Permit Application for Hackberry Carbon Sequestration Well No. 001

Cameron Parish, Louisiana

SECTION 5 – TESTING AND MONITORING PLAN

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SECTION 5 – TESTING AND MONITORING PLAN

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5.1 Introduction

The operating plans for the proposed Hackberry Carbon Sequestration (HCS) Well No. 001 will include a robust testing and monitoring program, which is designed to satisfy the requirements of SWO 29-N-6 ***§3625.A*** [40 CFR ***§146.90***]. This section discusses the key details of this program.

5.2 Reporting Requirements

As per the requirement of 29-N-6 ***§3629A*** [***40 CFR §146.91***], HCS will provide quarterly reports to the UIC Director containing the following:

- Any changes to the physical, chemical and other relevant characteristics of the CO_2 stream from what has been described in the proposed operating data
- Monthly average, maximum and minimum values of injection pressure, flow rate and volume, and annular pressure
- Description of any event that exceeds operating parameters for annulus pressure or injection pressure as specified in the permit
- Description of any event which triggers a shut-off device and the response taken

- Monthly volume and/or mass of the CO_2 stream injected over the reporting period and the volume injected cumulatively over the life of the project, including the amount gained or lost
- Monthly annulus fluid volume added
- Results of any monitoring as described in this Section

In addition, reports will be submitted within 30 days after the following events:

- Any well workover and logging results
- Any test of the injection well conducted if required by the Director

Reports will be submitted to the Director, within 24 hours of the following:

- Any evidence that the injected CO_2 stream or associated pressure front may cause an endangerment to a USDW
- Any noncompliance with a permit condition, or malfunction of the injection system, which may cause fluid migration into or between USDWs
- Any triggering of a shut-off system, either down-hole or at the surface
- Any failure to maintain mechanical integrity

Notification must be made to the UIC, in writing, 30 days of advance of:

- Any planned workover
- Any planned stimulation activities
- Any other planned test of the injection well

All reports, submittals and notifications will be submitted to both the EPA and the Louisiana Department of Energy and Natural Resources (LDENR). All records will be retained by HCS throughout the life of the project and for 10 years following site closure. Data on the nature and composition of all injected fluids collected will be retained as well for 10 years after site closure. Raw operating data from the continuous recording devices in digital format will be retained for at least 10 years after collection. The records will be delivered to the Director after the retention period if required by the director. Monitoring data as described in Section 5 will be retained for 10 years after it is collected. Well plugging reports, post-injection site care data and the site closure report itself will be retained for 10 years following site closure.

5.3 Objectives of the Monitoring Plan

This monitoring plan aims to verify the conformance of the model with operations as well as prevent and mitigate any risks associated with the CO_2 injection and storage activity. This monitoring plan is designed to meet the requirements of Louisiana Administrative Code (LAC) **43:XVII.3625.A** [Title 40, U.S. Code of Federal Regulations (40 CFR**) §146.90**] and therefore will protect against movement of formation or injection fluids into the USDW and to ensure the CO_2 plume remains on the HCS acreage.

Brine or CO_2 migration out of the injection interval may occur at the well location itself or further away from the injection well, above and around the expanding CO_2 plume. In the first case, the monitoring of the containment of the storage site relies on direct measurements at the well (pressure in and above injection zone, temperature, CO_2 saturation). In the second case, the monitoring relies on both direct and indirect measurements (pressure measurements at the well, seismic monitoring around and away from the well, USDW sampling). The monitoring information acquired directly and indirectly is used to update the simulation model to assess the conformance of operations to the predictions, to evaluate the need for additional measurements and to support the decision for corrective actions as required.

The testing and monitoring plan will be continuously reviewed and updated no less than every five years. An amended testing and monitoring plan will also be submitted within one year of an area of review (AOR) reevaluation, should any significant change to the development scheme occur, such as the drilling of an additional well for monitoring or injection purpose, or as required by the Director.

The HCS site properties considered for the design of the monitoring plan include:

- One injection well is planned that has a maximum rate of 2 million metric tons per year (MMT/yr).
- The injection strategy uses several injection stages, perforated sequentially over time, from the lowest to the shallowest formations (bottom-up perforation strategy).
- Each injection stage has a distinct plume. This strategy helps to concentrate the plumes around the wellbore.
- The injection zone is an aquifer with the following characteristics:
    - Significant thickness, close to one mile vertically,
    - High permeability (1,000 to 4,000 mD). This high permeability limits the pressure increases and thus the maximum pressure increase expected at the wellbore is approximately 30 psi. This pressure differential is below the critical pressure, in all injection stages during all time periods. On average, this increase in pressure is approximately 5 psi. The result is that no brine should be hydraulically able to flow from the storage formations to USDW levels through artificial conduits or faults.
    - Each perforation zone is sealed by a regionally correlatable shale interval interpreted as a maximum flooding surface (MFS) (Section 1.2.2). Each stage is injected into a stratigraphic sequence sealed by a continuous shale caprock;

therefore, the containment of the plumes does not rely on a single ultimate, upper confining unit.
    - The upper confining zone is the regional 300 ft thick MFS Amphistegina B, whose sealing efficiency is described in Section 1.3.2. Additionally, there are other confining intervals above the Amphistegina B which will further prevent movement of fluids into the USDW.
- There are no legacy wells on the acreage and no legacy wells or faults within the AOR

The monitoring and testing plan of HCS project relies on three main strategies:

- Direct measurement at the injection well. These continuous measurements include permanently measuring pressure and temperatures along the wellbore. Behind casing saturation logging (such as pulsed neutron logging) will be done after completion and any subsequent workovers, and at least every 5 years. Pressure falloff tests will be performed every 5 years.
- Indirect measurements to track the plume front expansion using two geophysical techniques as described in Section 5.6.6.3.
- Integration of data into the simulation models. The dynamic geological representation of the CO_2 stored will be regularly updated with monitoring information to assess conformance operations versus predictions.

5.3.1 Direct Measurements at the Injection Well

Direct measurements at the injection well consist of two techniques, the direct assessment of the integrity of the well (cementation, corrosion, etc.), and the detection of vertical fluid migration around the wellbore.

Pressure and temperature gauges will be deployed along the wellbore. With the proposed instrumentation behind the production casing, HCS will be able to determine if the pressure is increasing in or above the currently operational zone with the pressure and temperature array system. The array system can support 25 independent pressure and temperature sensors that will be spaced across the injection stages, in the confining zone, and above the confining zone to allow the injection well to record the presence or absence of elevated pressure across all intervals. These sensors can be usefully deployed up into the 13-3/8 in. casing shoe, at a planned depth of 2,500 ft, which is 1,000 ft above the upper confining zone. These gauges will enable the identification and assessment of any vertical natural leakage above each perforation stage and will measure any CO_2 leakage above the upper confining zone. As stated in Section 1.3.2, if a leak of CO_2 occurs above this seal, there are other identified continuous, low-permeability layers (e.g., MFS 8) that are also recognized as regional barriers to flow.

Logging of the CO_2 saturation is planned after each workover and at least every 5 years. These logs will consist of running a sigma log using a Pulsed Neutron Log (PNL). Pressure fall-off tests will be performed before each successive perforation stage and will provide dynamic parameters, such as permeability that will be used to update subsequent models.

All these dynamic data (pressure, temperatures, CO_2 saturation distribution along the wellbore, and permeability) will continuously help to update the dynamic model, the accuracy of which will improve over time and will provide an improving image of the spatial CO_2 plume.

5.3.2 Indirect Measurements

The indirect measurement data will provide the spatial representation of the plume to ensure that the AOR will always be well defined. The first of these techniques is the time lapse vertical seismic profile (VSP) walkaway profiles. This technology is sensitive to a 5% CO_2 saturation increase in the aquifer. The VSP acquisition strategy is preferred to a repeated 3D survey in this very shallow lake environment. The second indirect monitoring technique is micro-gravimetry surveys, which, although they have a lower vertical resolution, can enable an accurate evaluation of the plume shape. This later technique can be triggered easily at relatively low cost. The resolution of the VSP techniques is in the range of hundreds of feet, which is sufficient to monitor across the HCS AOR with the nearest potential conduit over 8,000 ft from the site.

5.3.3 Dynamic Model

From the data acquired from the monitoring equipment, the model will be updated and verified for conformance to predictions.

Based on these integrated monitoring techniques, the plume and pressure fields will be well defined. Having an additional point of direct measurements, other than the injector well itself, by means of an in-zone monitoring (IZM) or above-zone monitoring (AZM) well, equipped with the same pressure and temperature gauges connected with DAS as the injector well itself, will bring little additional value to the understanding of the plume and pressure front. Because the increase in pressure decreases rapidly from the well, an IZM or AZM well may not be able to measure any subtle variation of pressure, likely only a few psi difference. However, in the injector well, the injection pressure remains high enough to be properly measured. If a leak occurs at a distance from the injector well, or any IZM or AZM well, it is unlikely to be detected in such offset wells.

An IZM or AZM well may provide local CO_2 saturation variations, from sampling or from PNL. However, although the simulation model can reproduce this data point, there are many unknown parameters or possibilities to get to the match and, therefore, the solution will not be unique and will depend upon reservoir heterogeneity, varying petrophysical parameters, anisotropy, commingle injection, etc. A model calibrated with the data acquired from the walkaway VSP acquisition program will result in a higher resolution estimate of the plume location.

Once the plume has crossed the monitoring well, no additional information could be acquired that can be used to identify the final lateral extent of the plume, precisely because it is only one spot. Additionally, the behind-casing logs will provide adequate information to derive CO_2 saturation all along the well including above the confining zone. Moreover, adding a monitoring well drilled in the AOR introduces a new potential vertical leak path.

5.4 Testing and Monitoring Strategy Summary

The following table summarizes the testing and monitoring programs, including their frequencies, for this project.

Table 5-1 – Testing and Monitoring Plan Measurements

Monitoring Type	Monitoring Program	Location	Frequency
Direct Measurement Internal and External Mechanical Integrity	• Annular pressure test • Temperature logs • Pressure fall-off test • Pulsed neutron logs • Casing Inspection Log	Downhole	• Annually • Annually • 5 years • 5 years • 5 years
CO_2 Injection Stream Composition	• CO_2 sampling station	Near Wellhead on Platform	Quarterly
Corrosion Monitoring	• Corrosion coupon system	Near Wellhead on Platform	Quarterly
Ambient Gas Monitoring	• Surface detection sensors	Wellhead	Continuously
Continuous Recording of Injection Pressure, Rate, and Volume	• Surface pressure and temperature gauges • Coriolis mass flowmeter	Wellhead/Flowline	Continuously
Well Annulus Pressure Between Tubing and Casing	• Annular pressure gauge	Wellhead	Continuously
Groundwater Monitoring	• • TDS, pH, CO_2 levels, Density, Specific Conductivity, Temp, Density etc.	USDW Monitoring Wells	Baseline surveys at Year 0 then Quarterly
Direct Reservoir Monitoring	• Fiber optic and pressure gauges behind casing	Injection well	Continuous
Indirect Reservoir Monitoring	• VSP seismic surveys	Injection Well and surrounding	Baseline survey at Year 0 followed by monitors at Year 2 and 5 after injection begins, then every 5 years until plume stabilizes
Indirect Reservoir Monitoring	• Microgravity	Regional over AOR	Baseline survey at Year 0 and monitors every 5 years or as needed

Monitoring Type	Monitoring Program	Location	Frequency
Indirect Reservoir Monitoring	• 2D/4D seismic (Contingency)	Regional over AOR	As needed to laterally extend the walkaway imaging
Indirect Reservoir Monitoring	• Passive Seismic Monitoring	Regional over AOR	Continuous recording prior, during and post injection

5.5 Testing Program

5.5.1 Initial Step Rate Injectivity Test

To determine the fracture gradient of the Hackberry Carbon Sequestration Well No. 001, per SWO 29-N-6 ***§617.B.4.a*** [***40 CFR §146.87(d)(1)***] and SWO 29-N-6 ***§617.5.c*** [*40 CFR* ***§146.87(e)(3)***], a step-rate injectivity test will be performed during completion operations prior to injection. A bottomhole pressure gauge and temperature gauge will be run to the bottom of the wellbore. A surface gauge with continuous readout will also be installed. All gauges will be calibrated prior to the test. Initial bottomhole pressure and temperature readings must be taken prior to beginning injection. Refer to the Quality Assurance and Surveillance Plan (QASP) for detailed gauge information.

Brine will be injected at an initial rate of 1.5 barrels per minute (bpm) and held for at least thirty minutes. The injection rates will then be stepped up in 2.0-3.0 bpm stages, with approximately four readings below the estimated formation fracture initiation pressure and four readings above, up to a rate of 20% above the maximum which will be determined once reservoir properties have been determined. Each stage will be maintained at thirty-minute intervals. Once the pressure has stabilized after the final step, the pressures will be recorded at the highest frequency of the gauge for a period as determined from the step-up portion of the test to determine the pressure bleed-off rate.

5.5.2 Pressure Fall-Off Testing

To meet the operational testing requirements in SWO 29-N-6 ***§3625*.A.6** [40 CFR ***§146.90(f)***], HCS will conduct a pressure fall-off test every five years or when moving to new injection interval. These fall-off tests will be used to measure formation properties near the injection well and to monitor for any changes in the near-well bore environment that may impact injectivity and increase pressures.

5.5.2.1 Testing Method

Prior to beginning the pressure fall-off test, injection rate and pressure will be maintained as constant as possible, while continuously recorded. Upon shutting in the well, pressure measurements will be taken continuously within two bottomhole pressure gauges (Sure SENS QPT Elite or equivalent), with one serving as a backup and for verification in cases of questionable data quality. The fall-off period will continue until radial flow conditions are observed, as indicated by a straight line of pressure decay on a semi-log plot.

Injection wells in the State of Louisiana are regulated by LDENR. Form UIC-17 must be submitted, and all activities approved prior to commencing work. The test should also be witnessed by a Conservation Enforcement Specialist. Form UIC-WH1 will be submitted to the LDENR Injection and Mining Division at the conclusion of all tests, along with a report that includes an in-depth analysis of the fall-off Test.

Additionally, Class VI wells are regulated by the EPA. Per the Code of Federal Regulations Title 40 part 146.90 and 146.91, fall-off testing must be performed at least once every five years and an evaluation of the results must be provided within 30 days of the test. A list of submittal requirements can be found in "Underground Injection Control (UIC) Program Class VI Well Testing and Monitoring Guidance" provided by the EPA. The UIC Program Director will evaluate the pressure fall-off test results to assess any changes in characteristics of the near-well bore environment and any indication of fluid leakage during the test. Parameters determined in pressure fall-off tests may be compared to those used in site computational modeling and AOR delineation. Changes in formation permeability values as measured during pressure fall-off tests may also be required by the UIC Program Director to be reflected in an AOR reevaluation.

5.5.2.2 Fall Off Test Detailed Procedure

1. Move in and rig up wireline unit
2. Perform gauge ring run
3. Pick up bottomhole pressure and temperature gauge and run in hole to mid-perforation depth
    a. Use of two pressure gauges is recommended, with one serving as a backup or for data verification
    b. Bottomhole pressure gauge should have continuous surface readout
    c. Ensure gauges are calibrated
4. If not already in place, install surface pressure gauge with a continuous readout
5. Prior to testing, keep injection rate and pressure as constant as practicable and continuously recorded.
    a. This injection rate should be high enough and maintained for a sufficient duration to produce a measurable pressure transient that will result in a valid falloff test.
    b. Offset wells should be shut-in prior to and during the test. If shut-in is not feasible, a constant injection rate should be recorded and maintained during the test and then accounted for in the analysis.

   c. Do not shut-in two wells simultaneously or change the rate in an offset well during the test.
6. Stop injection and shut in well completely
   a. This should occur over the shortest time possible
7. During the shut-in period, continue to record temperature and pressure at the highest obtainable frequency.
   a. The duration of the shut-in period should be long enough to observe a straight line of pressure decay on a semi-log plot (i.e., radial flow is achieved). The radial flow portion of the test is the basis for all pressure transient calculations. Therefore, the falloff portion of the test should be designed not only to reach radial flow, but to sustain a time frame sufficient for analysis of the radial flow period.
   b. A general rule of thumb is to run the test for three to five times the time required to reach radial flow conditions
8. Conclude test
   a. Pull out of hole with bottomhole temperature and pressure gauges
      Rig down and move out wireline unit

5.5.2.3 Analytical Methods

Standard diagnostic log-log and semi-log plots will be generated with observed pressure changes and/or pressure derivative plots. The purpose of these tests is to determine specific near-well bore conditions, such as well skin, the prevailing flow-regimes and hydraulic property and boundary conditions. Comparison of pressure fall-off tests prior to beginning injection operations with those performed subsequently can indicate whether significant changes in the well or reservoir conditions have occurred. Analysis will consider the effects of two-phase flow effects, and parameters determined from the fall-off test will be compared to those used in the site computational modeling and AOR determination. Any significant changes in reservoir properties may result in a reevaluation of the AOR. Results of the pressure fall of test will be reported to the UIC Division within 30 days of the test.

5.5.2.4 Quality Assurance/Control

All field equipment will be inspected and tested prior to use. The SureSENS QPT Elite Gauge or equivalent gauges will be used in the fall-off test and will be calibrated in accordance with manufacturers' recommendations and calibration certificates will be provided with the test results. The use of the second bottomhole pressure gauge will further provide validation of the test results. Refer to Section 12 - QASP for detailed gauge specifications.

5.5.3 Cement Evaluation and Casing Inspection Logs

Casing inspection logs will be run every 5 years or when moving to new injection intervals. The logs will be run through tubing on wireline and if tubing is ever removed during workover operations. The following tools will be run at that time:

- Multiple-armed calipers to measure the inner diameter of the tubing/7-in. casing as the tool is raised or lowered into the well
- Ultrasonic tools to measure wall thickness and provide information about the outer surface of the casing or tubing as well as cement bonding
- Electromagnetic tools that measure magnetic flux of the tubular and can provided mapped circumferential images to indicate potential pitting.

5.5.4 Mechanical Integrity Testing – Annulus Pressure Test

HCS will perform internal mechanical integrity tests (MIT) prior to initial injection and after any subsequent workovers to meet the requirements of SWO 29-N-6 ***§3627.A.2*** [*40 CFR* ***§146.89(b)***].

After the well is completed, an annular pressure test will be performed, prior to the start of injection, to demonstrate mechanical integrity of the casing, tubing and packer. An annulus pressure test will also be performed annually and after any workover operation involving the removal and replacement of the tubing and packer. During the test, the annulus will be pressured to a minimum of 500 psi fluid pressure. A block valve will be used to isolate the test pressure source from the test pressure gauge (Hawk 9000 or equivalent) once the test has begun. All ports into the casing annulus, other than the one monitored by the test pressure gauge will be closed. The test pressure will be monitored and recorded for a minimum of 30 minutes. The test pressure gauge will be of sufficient sensitivity to indicate a loss of 5%. Any loss of test pressure more than 5% during the minimum 30 minutes shall indicate a lack of mechanical integrity. Details on gauge and equipment specifications can be found in Section 12 - QASP.

The test should also be witnessed by a Conservation Enforcement Specialist. The results of the Annulus Pressure Test will be reported to the UIC Division on Form UIC-5 within 30 days of the test.

5.5.5 External Mechanical Integrity Testing – Temperature Log

HCS will perform external mechanical integrity tests (MIT) annually or when moving to new injection interval to meet the requirements of Federal Regulations Tittle 40 part 146.90 & 146.91 and SWO 29-N-6 ***§3627.A.3*** [40 CFR ***§146.89(c)***] by running a temperature log, through tubing. An evaluation of the results will be provided within 30 days of the test. Temperature logs will be run prior to beginning injection operations and will establish the baseline to compare against future logs. Prior to running the temperature logs, the well will be shut in long enough to stabilize temperatures, approximately 36 hours. Correlation between the baseline and subsequent logs will demonstrate mechanical integrity. Temperature logs will be reported to the UIC Division within 30 days of the log run.

5.5.5.1 Temperature Log Procedure

After the completion of the HCS Well No. 001, the well will remain static to achieve temperature equilibrium prior to injection. After the well has been shut in for at least 36 hours, a temperature log will be run in the well to establish a baseline temperature survey. This baseline survey will be compared against temperature surveys throughout the life of the well to determine fluid flow outside pipe. In all future temperature logs, the same 36-hour stabilization period is required to accurately compare any differences in the log. Distributed temperature sensing (DTS) fiber is acceptable for the required temperature analysis.

When conducting a temperature survey via wireline, the tool will log from surface to the total depth of the well. It is important that no logging run precedes the temperature log to ensure static conditions in the wellbore. The recommended logging speed is 30 feet per minute and all depths should be zeroed to the bradenhead flange. The following list highlights the general procedure for the wireline temperature logging operation:

1. Allow well to stabilize for 36 hours.
2. Rig up wireline unit to the wellhead and make up their logging tool (temperature probe and casing collar locator [CCL]).
3. Zero the end of the tool string at the bradenhead flange.
4. Run in the hole while logging from surface to total depth at 30 ft per minute. Correlate collar depths to CCL.
5. Pull out of hole and rig down wireline unit.

Once the temperature log is processed, overlay the data with the baseline temperature log to identify any anomalies in the wellbore. Include the new log and the baseline log on a report as well as a track to calculate the differential temperature.

5.6 Monitoring Programs

The locations of the monitoring and sampling equipment referred to in this section are provided in Figure 5-1.

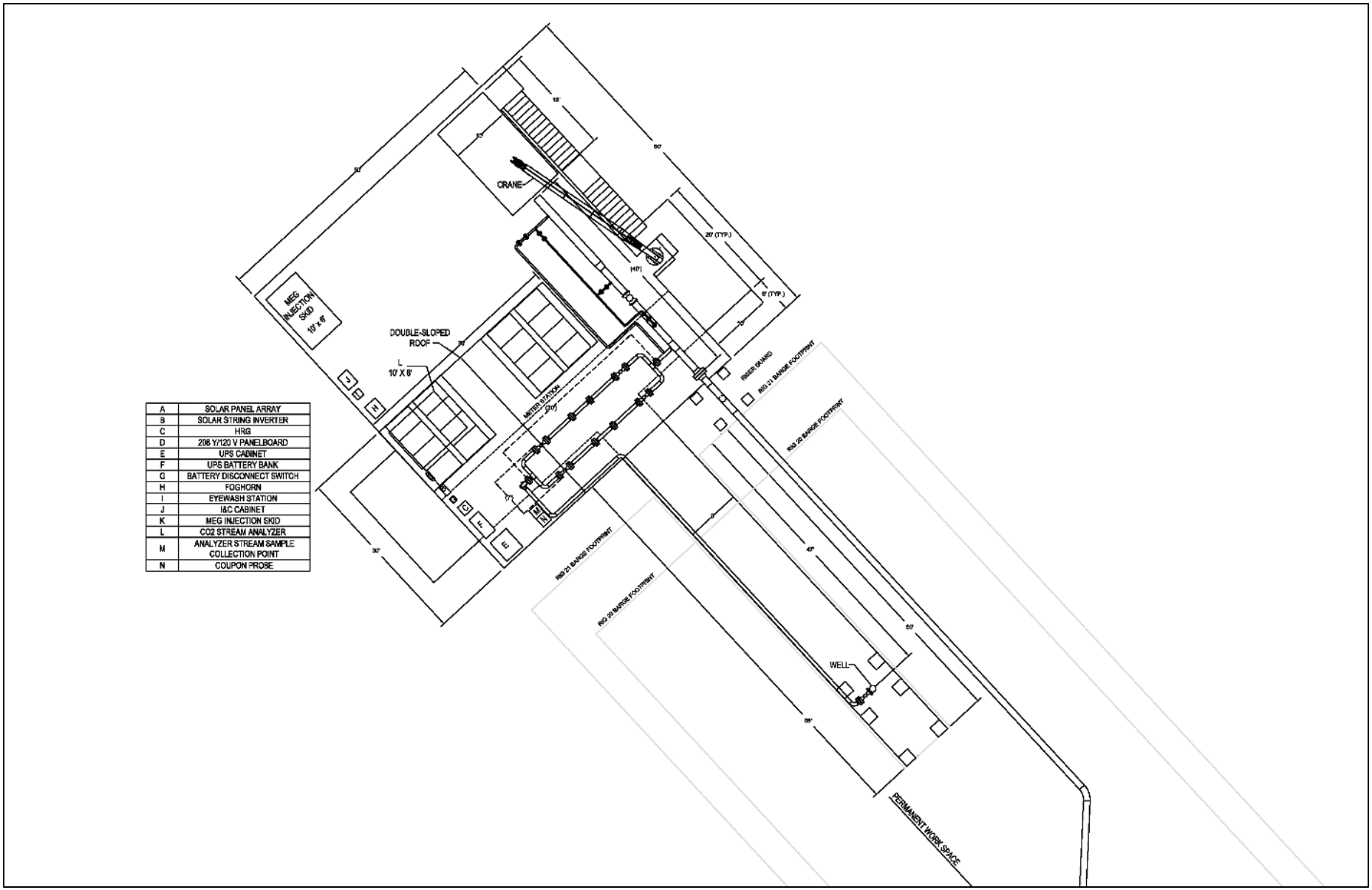


Figure 5-1 – Site Layout with Sampling Locations

5.6.1 Continuous Injection Stream Monitoring

HCS will continuously monitor the injection pressure, rate and volume, plus the annulus pressure to meet the requirements of SWO 29-N-6 ***§3625*.A.2** [40 CFR ***§*146.90(b)**]. To facilitate the collection, monitoring and reporting of operational data, a Supervisory Control and Data Acquisition system (SCADA) will be installed on the site of the injection well.

A change of 10% in the annular pressure will result in a shutdown event. The pressure and temperature of the injected carbon dioxide stream will be continuously monitored using digital pressure gauges installed in the CO_2 pipeline near the pipeline interface with the wellhead and will be connected to the SCADA system on site. A Endress-Hauser Proline Promass O 500 Coriolis flow meter or an equivalent will be installed on the injection well to measure the mass flow rate of CO_2 injected. The flow transmitter will be connected to the site SCADA system to continuously monitor and control the rate of CO_2 injection.

Reservoir temperatures and pressures will be transmitted through gauges installed with a fiber-optic, sDAS (Seismic Distributed Acoustic Sensing), embedded in the cemented annulus behind the long string casing. Possible gauge designs, which are being evaluated, and other monitoring equipment are described in detail in Section 12 - QASP, included in this application.

5.6.2 Injection Stream Composition Monitoring

In accordance with SWO 29-N-6 ***§3625*.A.1** [40 CFR **§146.90(a)**] requirements, HCS will determine the chemical composition of the injection stream, with the objective of understanding potential interactions between CO_2 and other injectate components, as well as with the wellbore materials. This determination is accomplished by quarterly sampling of the injection stream and subsequent laboratory analysis of the parameters listed in Table 5-4, plus continuous pressure and temperature analysis.

5.6.2.1 Testing Method

HCS will collect samples of the CO_2 injection stream and perform analysis to meet the requirements of SWO 29-N-6 ***§3625*.A.1** [40 CFR ***§*146.90(a)**]. Samples of the CO_2 stream will be collected quarterly for the chemical analysis parameters provided below and continuously for pressure and temperature. If a known change to the injection stream chemistry occurs, the sampling will be performed at the time of change and then on a quarterly schedule moving forward. The purpose of analyzing the CO_2 stream is to evaluate potential interactions of carbon dioxide and other components of the injectate with subsurface chemistry compatibilities.

5.6.2.2 Parameters Measured

Table 5-2 – Injectivity Test Parameters Measured and Measurement Frequency

Parameter/Analyte	Frequency
Pressure	Continuous
Temperature	Continuous
pH	Quarterly
CO_2 (%)	Quarterly
Water (lb/mmscf)	Quarterly
Oxygen (%)	Quarterly
Sulfur (ppm)	Quarterly
Methane (%)	Quarterly
Ethane (%)	Quarterly
Other Hydrocarbons (%)	Quarterly
Hydrogen Sulfide (ppm)	Quarterly
Benzene (%)	Quarterly

5.6.2.3 Sampling Methods

Samples of the carbon dioxide stream will be collected from the CO_2 pipeline at a location which represents the injection conditions, with a sampling station connected to the pipeline via a sampling manifold. Sample cylinders will be purged with injectate gas to remove any laboratory-added gas and ensure a quality sample collection.

5.6.3 CO_2 Mass Rate to Volumetric Injection Rate Calculation Methodology

Mass flow rates observed during CO_2 injection can be converted to a volumetric flow rate by considering the density of the fluid. The pressure, temperature, and fluid composition are required to calculate density at specific conditions. Refprop™ or similar fluid property calculation software may be used to determine density.

Output Variables:

Q_{vbh} = Volumetric flowrate at bottomhole (ft^3/day)

Input Variables:

Q_m = Mass flowrate (lb/day)

ρ_{sc} = CO_2 density at standard conditions (lb/ft^3)
T_{bh} = temperature at standard conditions (°F)
P_{bh} = pressure at standard conditions (psi)

ρ_{bh} = CO_2 density at bottomhole Conditions (lb/ft^3)
T_{bh} = Temperature at bottomhole (°F)
P_{bh} = Pressure at bottomhole (psi)

Equations:

(1.0) $Q_{vbh} = \frac{Q_m}{\rho_{bh}} Q_{vbh} = \frac{Q_m}{\rho_{bh}}$

(1.1) $\rho_{bh} = f(T_{BH}, P_{BH}, Fluid\ Composition) \leftarrow REFPROP\ software$

(1.2) $\rho_{sc} = f(T_{sc}, P_{sc}, Fluid\ Composition) \leftarrow REFPROP\ software$

5.6.3.1 Analytical Methods

Continuously monitored parameters will be reviewed and interpreted regularly, to ensure the parameters are within permitted limits. The data will also be reviewed for trends to help identify the need for equipment maintenance or calibration. Monitoring results will be included in the semi-annual reports.

5.6.4 Corrosion Coupon Monitoring

HCS will conduct corrosion monitoring of the tubing and casing materials of the well to meet the requirements of SWO 29-N-6 ***§3625*.A.3** [40 CFR ***§*146.90(c)**]. HCS will implement a corrosion coupon monitoring system, to be evaluated quarterly, as well as casing inspection logs performed every 5 years at the time of permit renewal. If plume surveys indicate it is time to recomplete uphole to a shallower sub-section, then the tubing and packer will be removed and inspected, and a casing inspection logging suite will be run. If abandonment of a sub-section is not warranted at the time of permit renewal, then a through-tubing inspection will be performed.

5.6.4.1 Sampling Methods

Corrosion coupons, made of the same material as the production casing and the injection tubing, will be placed in the CO_2 injection pipeline. The coupons will be removed quarterly and assessed for corrosion using American Society for Testing and Materials (ATSM) standards for evaluating corrosion tests. When the coupons are removed, they will be inspected visually for any signs of corrosion, including pitting. The weight and size of the coupons will be measured each time they are removed. The rate of corrosion will be calculated using a weight loss method where the rate equals the weight loss during the exposure period divided by the duration of the period. Details regarding sample collection and lab testing procedures are provided in Section 12 – QASP.

5.6.5 Ambient Gas Monitoring

A Dräger Polytron® 8720 IR (Figure 5-1) will be utilized to monitor gas concentrations at the wellhead. The gas detection unit will be integrated with the facility's SCADA system. This detection system will continuously monitor ambient gas concentrations and assist with early detection of possible CO_2 leaks at the wellhead and nearby injection systems. Gas detection device maintenance and specifications are provided in the QASP of this application.

Figure 5-2 – Dräger Polytron® 8720 IR

5.6.6 Groundwater Quality Monitoring

HCS will conduct groundwater quality and geochemical monitoring above the confining zone to meet the requirements of SWO 29-N-6 ***§3625.A.4*** [*40 CFR* ***§146.90(c)***]. The purpose of the groundwater monitoring is to detect potential changes that may result from fluid leakage out of the injection zone. Groundwater monitoring will be conducted by two water sample wells, HCS Monitor Well Nos. 001 and 002, drilled and perforated into the 700-Foot Sand formation, above the confining zone. The well locations are shown on Figure 5-2 and the locations are listed in Table 5-3. The locations of the monitor wells were selected to place the wells above the modeled plume migration. The well locations were selected based on our expected dredge path and the location of the nearest artificial penetrations. The USDW monitoring well placed near the injector location is expected to be located approximately 65 ft away from the injector site. The USDW monitoring well placed to the southeast is on the edge of the critical pressure front and along our dredge path in the direction of artificial penetrations. In addition, HCS may include monitoring the USDW through the wells at the Sempra Infrastructure owned LA Storage site

where Sempra plans to have three additional monitoring wells (Figure 5-4). The well schematic as shown in Figure 5-3 represents the construction details for the two wells.

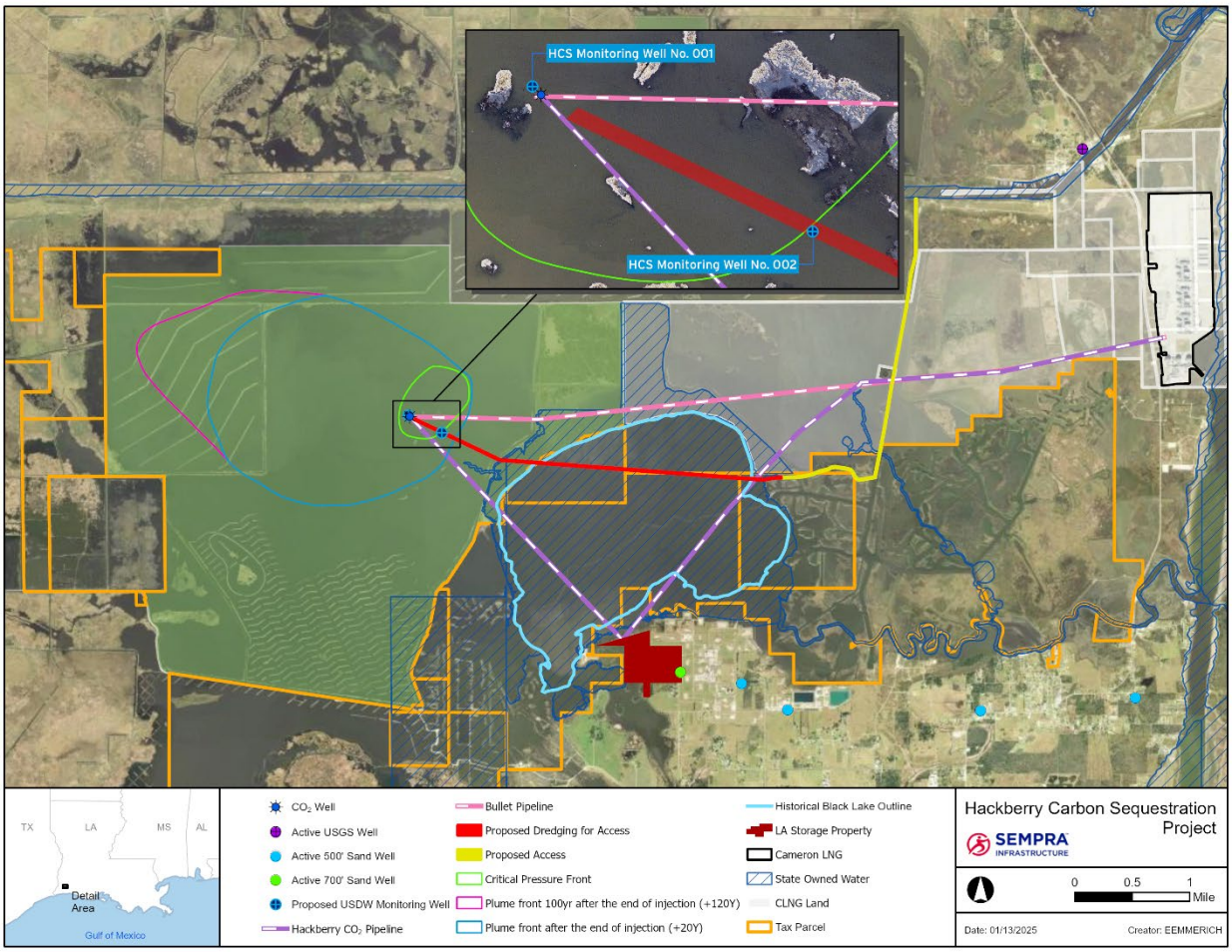
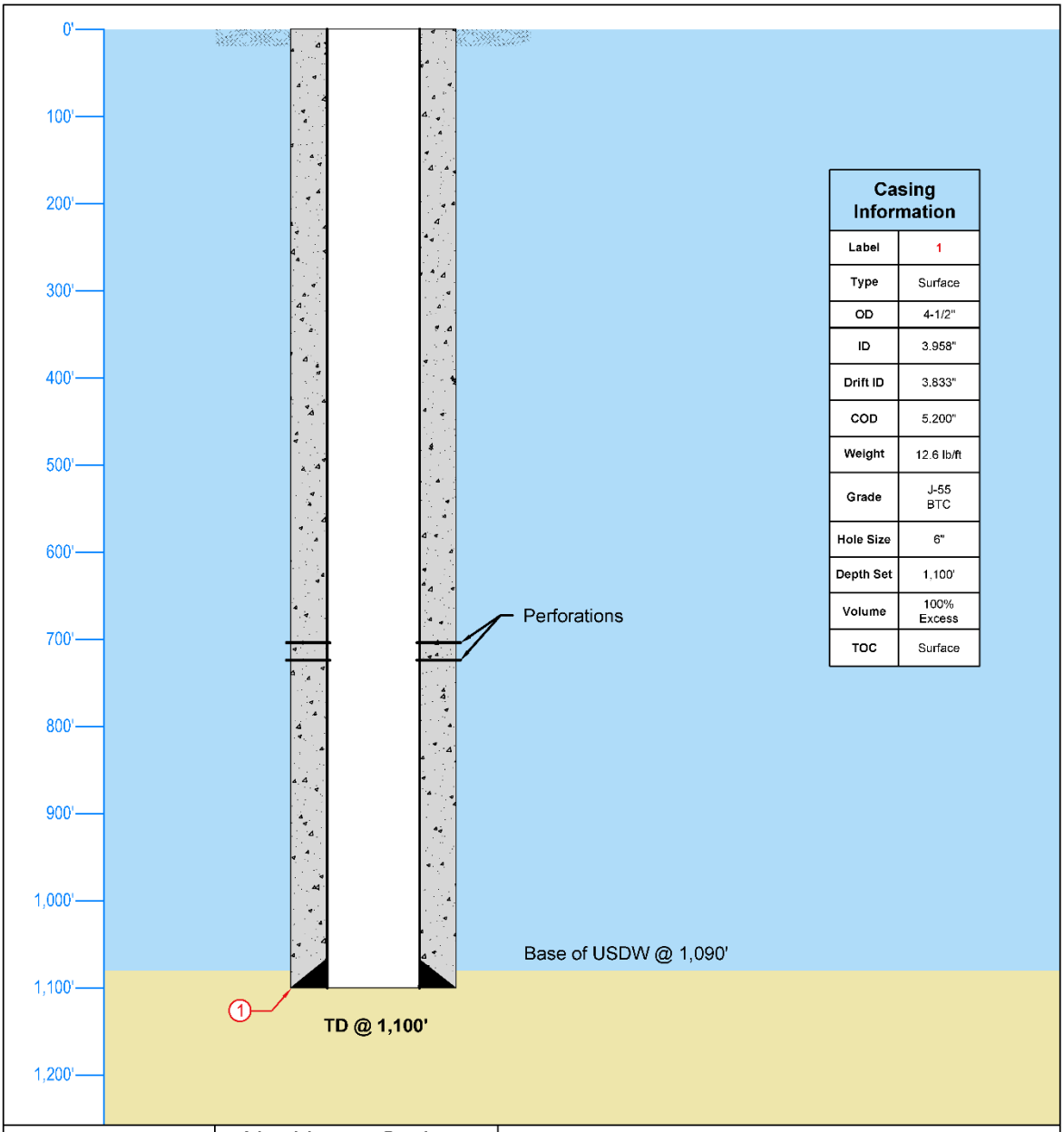


Figure 5-3 – Location of Groundwater Monitoring Wells. These wells are placed within the areas of expected critical pressure and close proximity to the injection well. Final locations will be dependent on surveying and infrastructure needs.

Table 5-3 – HCS Monitor Well Locations

Monitoring Well Location	HCS Monitor Well No. 001	HCS Monitor Well No. 002
Latitude	30° 01' 51.56" N	30° 01' 43.8" N
Longitude	093° 26' 54.73" W	093° 26' 37.31" W
Datum	NAD83	NAD83
Total Depth	1,100 ft	1,100 ft



LONQUIST SEQUESTRATION LLC	Hackberry Carbon Sequestration, LLC	Hackberry Carbon Sequestration Monitor Well Nos. 001-002	
	Country: USA	**State/Province:** Louisiana	**County/Parish:** Cameron
	Location: Multiple	**District:**	**Survey:**
	API No: TBD	**Field:**	**Well Type/Status:** Monitoring Well
Louisiana License EF-7423	**State Gas ID No:**	**Project No:** 2393.4	**Date:** 01/29/2025
12912 Hill Country Blvd. Ste F-200 Austin, Texas 78738 Tel: 512.732.9812 Fax: 512.732.9816	**Drawn:** Jake Coker	**Reviewed:** Joseph Lovewell	**Approved:** Ben H Bergman
	Rev No: 0	**Notes:** Class VI Permit Application - Appendix H2	

Figure 5-4 – HCS Monitor Well Schematic

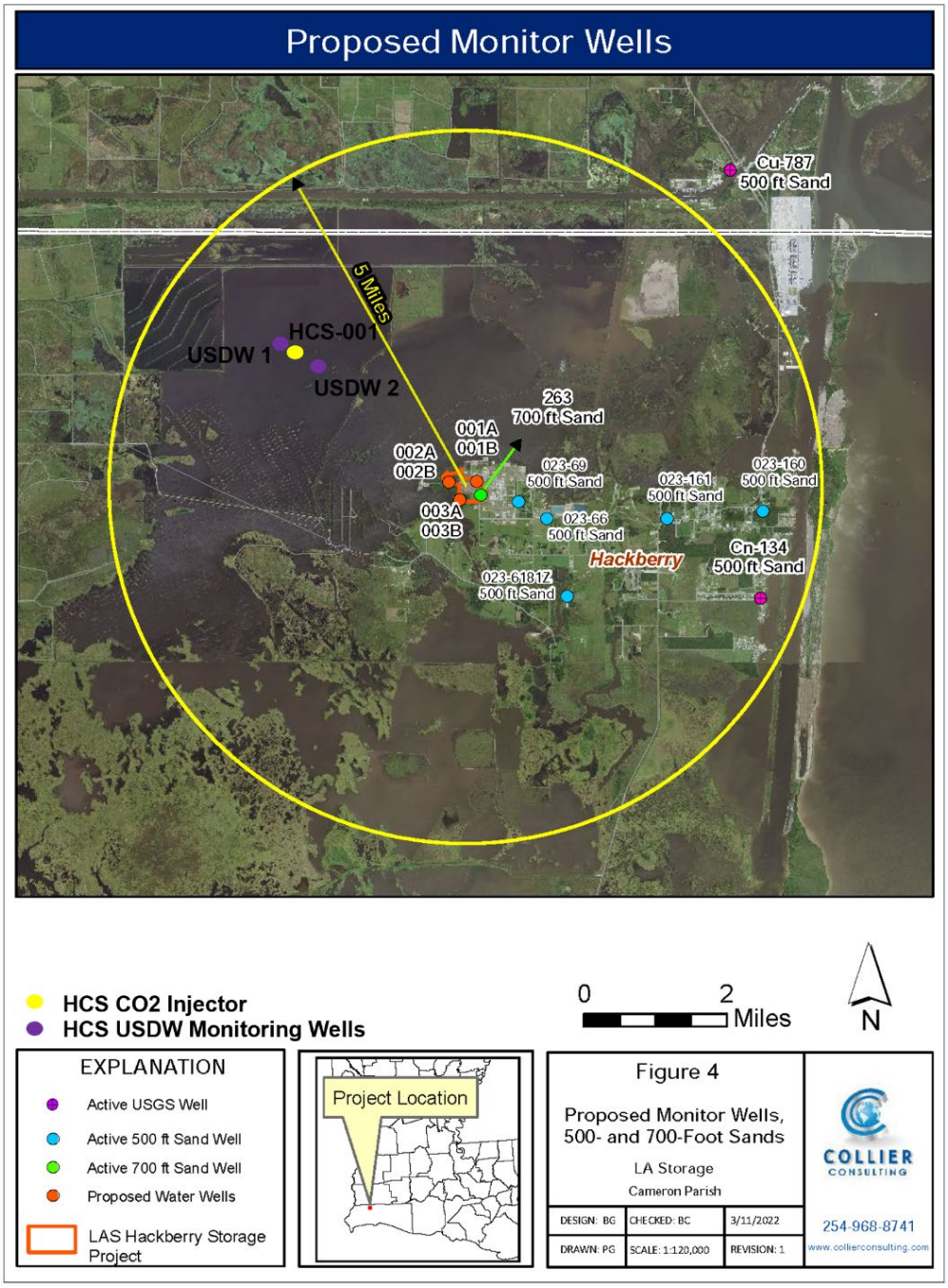


Figure 5-5 – Additional water well locations that Sempra Infrastructure intends to drill for its nearby LA Storage Project – these will be monitored for LA Storage and accessible to be reviewed for HCS as needed. These wells are dependent on LA Storage well permitting.

5.6.6.1 Parameters Measured

Table 5-4 – Groundwater Quality Parameters Measured and Measurement Frequency

Parameter/Analyte	Frequency
Aqueous and pure phase carbon dioxide	Quarterly
Total dissolved solids (TDS)	Quarterly
pH	Quarterly
Specific conductivity (SC)	Quarterly
Temperature	Quarterly
Density	Quarterly
Other parameters including major anions and cations, trace metals, hydrocarbons, and volatile organic compounds)	Quarterly

5.6.6.2 Sampling Methods

Fluid samples in the groundwater monitoring wells will be collected at the monitored formation temps and maintained at the formation pressures within a pressurized sample container to prevent any losses of dissolved gases. Prior to sampling, the well will be purged of any fluid stored in the well bore. Static fluid level and temperature will be measured prior to purging the well. A U-tube sampling system will be lowered to the monitored zone via wireline or slickline and the rate of sample collection should not exceed the rate at which the well was purged.

5.6.6.3 Analytical Methods

Water samples will be tested, and results maintained for the parameters listed above. If any impurities exist in the injectate, they should also be tested for in the groundwater samples to detect any concentrations deviate significantly from the baseline data. Results from the samples will be maintained in an electronic database.

Trends that may indicate fluid leakage include:

- Change in total dissolved solids
- Changing signature of major cations and anions
- Increasing carbon dioxide concentration
- Decreasing pH
- Increasing concentration of injectate impurities
- Increase concentration of leached constituents
- Increased reservoir pressure and/or static water levels

Table 5-5 – Baseline Groundwater Sampling Results

Well No.	Sample No.	Date	CO_2	TDS	pH	SC

5.6.6.4 Laboratory to be Used/Chain of Custody Procedures

Water samples will be submitted to the LDENR/EPA after analysis at a federal- or state-approved laboratory. Standard chain-of-custody procedures will be followed, and records maintained to allow a full reconstruction of how the samples were collected, stored and transported, including any problems encountered.

5.6.6.5 Quality Assurance and Surveillance Measures

Duplicate samples and trip blanks for QA/QC purposes will be collected. These duplicate samples will validate test results and ensure that samples have not been contaminated.

5.6.6.6 Plan for Guaranteeing Access to All Monitoring Locations

As the location will be found entirely under shallow water, access to the well will be extremely restricted. The installation of groundwater monitoring wells is part of the surface-use lease agreements with the landowners across the plume area, thereby ensuring access to the well locations for sampling and maintenance purposes. Unauthorized access will be prevented by capping and locking out the well.

5.6.7 Injectate Plume and Pressure Front Monitoring

To meet the operational monitoring requirements of SWO 29-N-6 ***§3625.A.7*** [*40 CFR* ***§146.90(g)***], HCS is proposing an integrated and complementary monitoring system to track the plume and pressure front evolution. This monitoring system is composed of complementary direct and indirect monitoring techniques.

SWO 29-N-6 ***§3625.A.7*** and *40 CFR* ***§146.90(g)***] require:

> *"testing and monitoring to track the extent of the carbon dioxide plume and the presence or absence of elevated pressure (e.g., the pressure front) by using:*
>
> *a. direct methods in the injection zone(s); and*
>
> *b. indirect methods (e.g., seismic, electrical, gravity, or electromagnetic surveys and/or down-hole carbon dioxide detection tools), unless the commissioner determines that such methods are not appropriate, based on site-specific geology;"*

The proposed direct monitoring techniques at HCS consist of:

- Continuous pressure and temperature sensors along the wellbore to monitor the vertical CO_2 migration and pressures through the successive shale and sandstone layers around the well.
- Rate transient analysis and pressure fall-off tests that will determine the large-scale permeability and volume of the reservoir affected, flow model determination (boundaries to flow), indication on permeability anisotropy Kv/Kh in case of partial penetration.

All this information is mainly used to determine the injectivity potential and to feed the reservoir model for conformance.

The indirect monitoring techniques consist of the combination of the four following complementary geophysical monitoring technologies, one of which is proposed as a contingency.

- Technology 1 (primary): 4D Vertical Seismic Profile (VSP) multi-azimuthal, walkaway profiles. This technique offers the highest spatial and vertical resolution.
- Technology 2: 4D high resolution micro-gravity gradiometry 3D coverage. This technique has a lower resolution but can image the spatial CO_2-saturated zone and image any vertical leak with high CO_2 concentrations.
- Technology 3 (contingency): 2D/4D surface seismic. This technique would be complementary to the VSP proposed in Technique 1, triggered only if the plume migrates beyond the walkaway profile imaging capability.
- Technology 4: Passive seismic monitoring (PSM) network detecting any induced seismicity from or around the storage site.

5.6.7.1 Direct monitoring techniques

Pressure/Temperature Gauges

HCS will employ the use of a permanent downhole monitoring system (PDM). Reservoir temperatures and pressures will be measured through gauges installed with a fiber optic system embedded in the cemented annulus behind the long-string casing.

Equipment Design and Setup

The equipment proposed in this section will be used in the periodic surveys to determine CO_2 plume growth over time. The fiber optic cable, sDAS (Seismic Distributed Acoustic Sensing), used for the time-lapse VSP will be connected to an interrogator box which will be synchronized to the seismic acquisition system that controls both the receiver (fiber optic array cemented in the injection well) and source (air guns from boat or seismic vibrator trucks on land).

Wellbore Overview

The proposed wellbore will have 13-3/8 in. surface casing run below the USDW to a depth of 2,500 ft and cemented in place per EPA Class VI requirements. The production casing will be a 9-5/8 in. long string run to a depth of approximately 3,970 ft in the upper confining zone (UCZ) and then crosses over to 7-in. longstring in the injection interval run to a depth of approximately 10,100 ft. This longstring casing will be cemented back to surface and comprised of CO_2-

compatible cement from TD to above the UCZ. The injection string will be 7 in. CRA material to ensure adequate corrosion resistance for the injection of CO_2. The completion and monitoring assembly consists of a 7 in. x 9-5/8 in. injection packer with releasable Anchor Seal Assembly manufactured from corrosion resistant material. The anchor seal assembly will allow the 7 in. injection string to be released from the packer while maintaining isolation from the injection zones.

Pressure and temperature gauges, and distributed temperature and acoustic sensing with fiber optic cable will be installed on the OD of the 9-5/8 in. crossed over to 7 in. casing to TD. The system will be used to rapidly detect temperature profiles near the casing, as well as to verify cement circulation during the cement job. The pressure gauges will detect pressure changes within the reservoir and above/below the active injection zone. The acoustic fiber will be used to monitor the CO_2 plume growth through seismic processing. The fiber monitoring system enables high-density strain monitoring of the wellbore and surrounding formation, to detect, localize, and classify reservoir compaction, shearing, and integrity issues.

The injection wells will have approximately 10,100 ft of 0.25-in TEC for pressure and temperature gauges and a separate fiber optic line installed. In the primary design, the gauges read pressures and temperatures through the cement to directly monitor the reservoir for the life of the project. In another option being considered, electronic gauges on the OD of the 7 in. production casing could be ported to the ID through gauge carriers. The gauges will be capable of continuous pressure and temperature monitoring of each injection zone, assuming the injector perforations are not squeezed off with cement during plugging operations.

Methods to avoid excessive cable tension at the surface, which could result in cable damage/failure, may include conveying the gauges with clamps to support the cable and gauge weight or similar options. Protective casing clamps will be installed on each of the production casing joints collars to ensure that the cable is securely run to depth. Blast protectors will be installed on each joint in the injection zone, so that the cable location on the 7 in. casing string can be determined to ensure that the fiber optic cable and TEC line are not damaged during oriented wireline perforating. The protectors have added metal in the protector channel to enhance location detection with magnetic resonance tools.

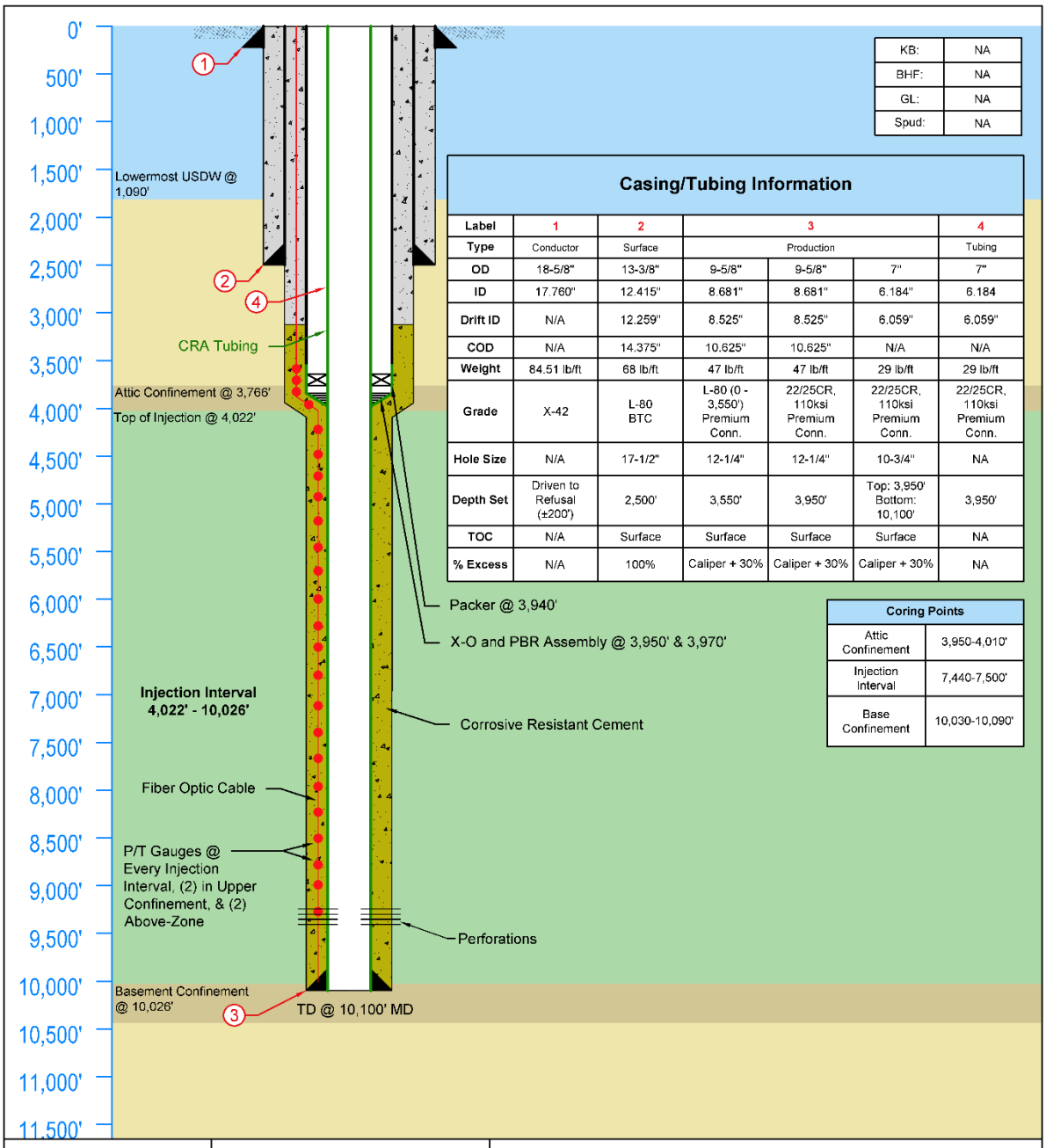


Figure 5-6 – Proposed Wellbore Schematic

Equipment Overview

The following discusses the typical hardware setup and use of in situ monitoring equipment for temperature, pressure, and seismic that will employ fiber optic cable to communicate with a surface-located interrogator box, to record real-time or periodic data. The equipment described represents the technology that could be employed.

Premier Injection Packer with Anchor Seal Assembly

The 831-600 Premier removable production packer is a 7,500-psi rated hydraulic set, large bore retrievable packer. The Premier and its tail pipe assembly are removed from the well on the production tubing by mechanically or chemically cutting the packer mandrel. By incorporating an anchor seal assembly, the wellbore will workover flexibility so the tubing can be disconnected via an anchor-type seal assembly from the upper sealbore of the packer while leaving the packer down hole. Final selection of the packer will meet or exceed these specifications.

Table 5-6 – 831-600 Premier Production Packer Specifications

Casing				Packer					
OD* (in.) (mm)	Weight (lb/ft)	ID** (in.) (mm)	Maximum ID (in.) (mm)	Size	Minimum ID (in.) (mm)	Maximum ID (in.) (mm)	Seal Diameter (in.) (mm)	Elastomers	Temperature Range (°F)
9-5/8 (244.5)	47- 53.5	8.535 (216.8)	8.822 (224.1)	831-588	5.875 (149.2)	8.310 (211.1)	6.871 (174.5)	nitrile, HNBR, and *Aflas®*	100-300†*
				831-600	6.000 (152.4)				150-350**‡

Monitoring Gauges

The following system components and specifications are provided as representative technologies for initial discussion purposes. Final selection of specific monitoring equipment and vendors will be determined prior to commencing drilling operations. Equipment examples are shown for multiple options being evaluated.

Array Pressure Temperature Sensor

The Halliburton Array sensors (Figure 5-6) are welded into the TEC cable when deployed behind casing and have a proven track record of measuring reservoir pressure and temperature through the cement sheath. Between 1 and 25 sensors can be installed on a single TEC line and read independently of each other (e.g., if one sensor is lost the remaining sensors continue reading). (Garcia, E. et al, 2019).

Figure 5-7 – Halliburton Array Pressure Temperature Sensor

SureVIEW with CoreBright Optic Fiber

SureVIEW downhole cable uses CoreBright optical fiber, which leads the industry in resisting hydrogen darkening—the primary cause of failure for fiber optic systems in high-temperature applications. CoreBright is constructed from pure silica—minimizing hydrogen darkening—combined with a layer of hydrogen-absorbing gel. The Baker Hughes and GE Company (BHGE) standard SureVIEW fiber optic cable product is a 0.25-in. OD, heavy wall tubing-armor cable that encloses a 0.125 in. OD, thin wall tubing containing optical fiber. The armor is a corrosion-resistant alloy (CRA) tube, longitudinally welded and cold worked to its final diameter. It contains an extruded plastic filler (belting) that centralizes and provides a level of shock and vibration damping to the inner tube. The inner or fiber-in-metal tube (FIMT) contains up to 12 optical fibers immersed in thixotropic gel. Figure 5-7 illustrates the optical fiber, and Table 5-7 provides the specifications.

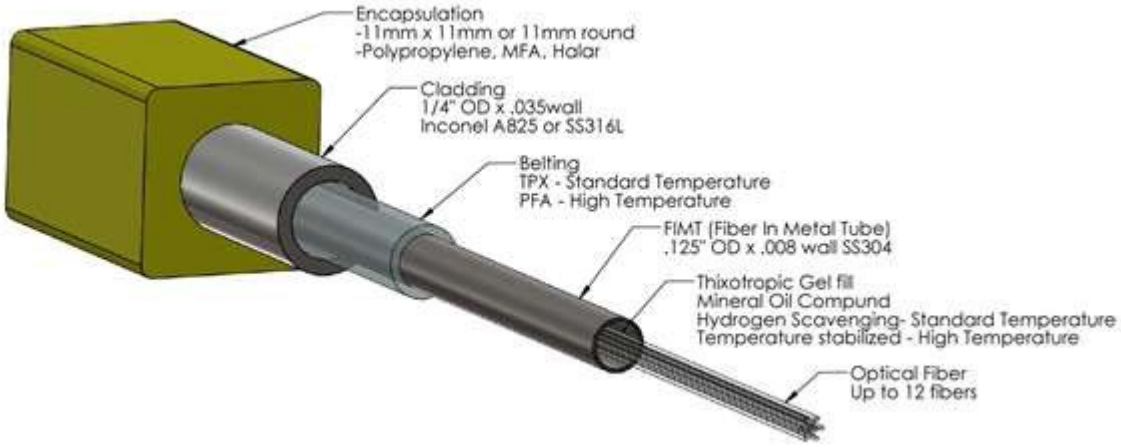


Figure 5-8 – SureVIEW with CoreBright Optical Fiber

Table 5-7 – SureVIEW Downhole Specifications

Description	Value	
Encapsulation	0.433 in.2 (11 mm2) or 0.41 in. round (11-mm OD)	
Cladding	0.250-in. (6.35-mm) OD × 0.035-in. (0.89-mm) wall	
FIMT diameter	0.125-in. (3.18-mm) OD	
Weight with polypropylene 11×11 encapsulation	154 lb/1,000 ft (230 kg/km)	
Weight without encapsulation	101 lb/1,000 ft (150 kg/km)	
Mechanical properties (70°F)*	**A825**	**SS 316L**
Tensile strength (lb)	2,687 (1,219 kg)	2,134 (968 kg)
Yield strength (lb)	2,090 (948 kg)	1,816 (824 kg)
Hydrostatic pressure (kPSI)	25 (17 kg/sq mm)	24 (16.8 kg/sq mm)
Burst pressure (kPSI)	32 (22 kg/sq mm)	22 (15.4 kg/sq mm)
Dynamic bend radius (in.)	14 (355 mm)	25 (635 mm)
Static bend radius (in.)	3 (82 mm)	6.3 (159 mm)
External collapse pressure (kPSI)	24.6 (1729 kg/sq cm)	17 (12.0 kg/sq mm)

*Materials listed should be derated for specific temperature applications. Contact Applications Engineering group for deration factors.

SureVIEW DTS (Distributed Temperature Sensing)

The SureVIEW DTS interrogator provides continuous monitoring, rapidly updating temperature profiles along the length of the completions.

Table 5-8 – SureVIEW DTS Surface Interrogator Specifications

Description	Value
Form Factor	19 in. Rack
Height	2U
Depth (in.)	19.8
Certifications	TUV (US, Can), CE
Public Software Interfaces	OPC/UA, Modbus
Maximum Distance Range (km)	20+
Minimum Spatial Resolution (m)	1.0
Minimum Sampling Interval (m)	0.33
Fastest Acquisition Rate (sec)	3.3
Number of Channels	8 or 16
Internal Data Storage Capability	250 GB
Fiber Types	9/125 µm SMF CoreBright™
Optical Connectors	Fiber Pigtails
Computer Interfaces	Ethernet, DPI, USB
Power Consumption (W)	100 W maximum

SureVIEW sDAS (Seismic Distributed Acoustic Sensing)

The SureVIEW sDAS interrogator offers all of the benefits of fiber optic acoustic monitoring from flow monitoring and optimization, sand detection and stimulation optimization, to seismic and microseismic monitoring, combined in a single interrogator.

Table 5-9 – SureVIEW DAS VSP Specifications

Technical Specifications	
Technology Supported	SureVIEW DAS VSP
Type	Rackmount
Number of Channels	8
Rack Unit Dimensions	6U
Certifications	CE, TUV
Supply Voltage	110–240 Volts AC, 50 or 60Hz
Typical Power Consumption	Up to 400W
Operating Temperature Range	0°C to +40°C / 32°F to +104°F
Optical Connectors	F3000/APC
Interface Connections	Ethernet, GPS, USB (Geophones) DC Trigger Pulse (GPS Synced)
File Formats	PRODML/HDF5/SEG-Y
Data Storage	960GB (Internal) 8TB (NAS)
Maximum Distance Range	Up to 12 miles (20 km) with CoreBright fiber Up to 50 miles (80 km) with CoreBright EBF
Fiber Type	Single Mode
Spatial Resolution	1.5 meter
Minimum Sampling Interval	0.33 meter
Gauge Length	Selectable 3, 7, 15, 31 meters
Maximum Pulse Rate	10 kHz
Dynamic Range	0.24 nε (over full bandwidth) 1.5pε (narrowband) Up to 1 με

SureVIEW WIRE (Well Integrity Real-Time Evaluation)

The SureVIEW WIRE structural integrity management system enables high-density strain monitoring of the wellbore and surrounding formation to detect, localize, and classify issues with reservoir compaction, shearing, and integrity issues. The cable is deployed in the well along the outside of the casing where it is cemented into place and brought online. Once online, data can

be closely observed across the entire geological interface. An illustration of this technology is shown in Figure 5-8, and the technical specifications are provided in Table 5-10.

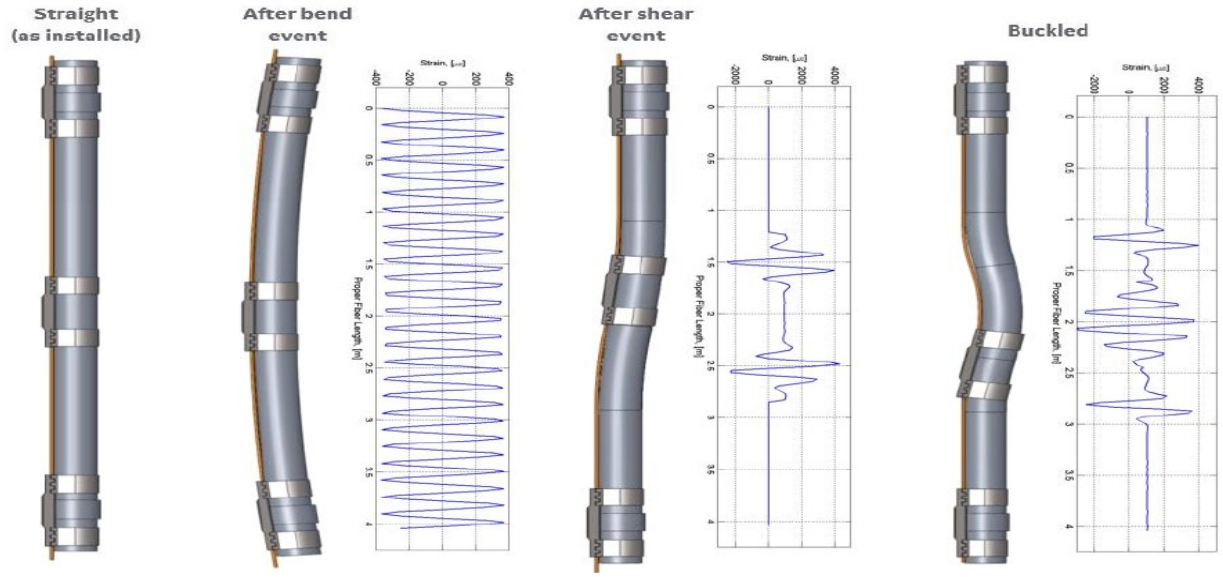


Figure 5-9 – SureVIEW WIRE Well Integrity Evaluation Illustration

Table 5-10 – SureVIEW WIRE Cable Specifications

SureVIEW™ WIRE Cable	
Specifications	

Low Temperature Cable	• 1/4″ OD
	• 0.035″ Wall
	• Alloy 825
	• Specialty Bragg Grating Fibers
	  • One fiber configuration for Axial Strain Only
	  • Two fiber configuration for Axial and Curvature
	• 300m Max Sensor Length*
	• 120 Deg C Temperature Rating
	• 15,000 psi Pressure Rating

High Temperature	• 1/4″ OD
	• 0.035″ Wall
	• Alloy 825
	• Specialty Bragg Grating Fibers
	  • One fiber configuration for Axial Strain Only
	  • Two fiber configuration for Axial and Curvature
	• 300m Max Sensor Length*
	• 225 Deg C Temperature Rating
	• 15,000 psi 15,000 psi Pressure Rating

**may require multiple cables spliced to achieve desired length*	

TEC (Tubing Encapsulated Conductor)

TEC is a proven technology that the oil and gas industry has used reliably for more than 25 years. The TEC is installed to electrically support the QPT Elite gauges and is designed for prolonged life in the most hostile downhole environments. The TEC's primary function is to transmit both electronic digital signals and power between subsurface components and a surface interface module used for reservoir management. The BHGE-standard TEC product is a 0.25-in. OD tubing-armor cable, which includes an insulated 16-American wire gauge (awg) solid conductor. The armor is a metal-clad CRA tube containing filler materials that centralize the core. An encapsulation material specially designed with safe removal components is recommended to be extruded over the TEC, thereby adding to the metal sheath a layer of protection from abrasion while running downhole. Figure 5-9 illustrates the design of the TEC, and the technical specifications are listed in Tables 5-11 and 5-12.

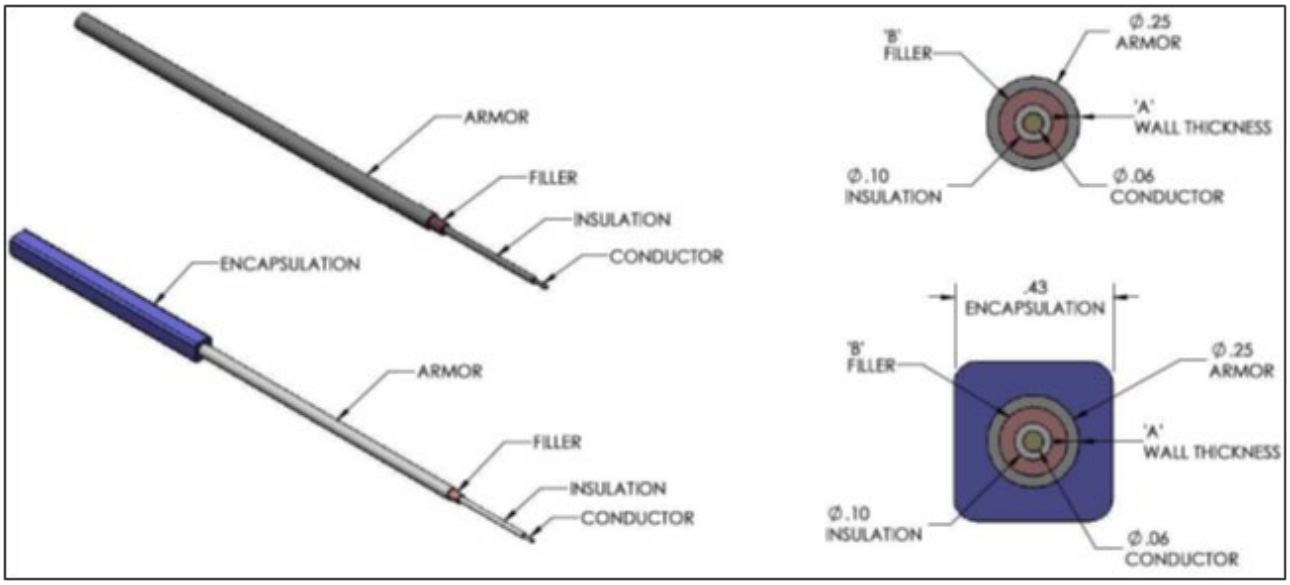


Figure 5-10 – TEC Illustration

Table 5-11 – TEC Specification, Part I

Description	Value	
Size 0.035-in. Wall TEC		
Materials	316L stainless UNS S31603	Alloy 825 UNS N08825
Weight	198 kg/km (133 lb/1,000 ft)	199 kg/km (135 lb/1,000 ft)
Armor resistance at 20°C	51.2 Ohms/km (15.6 Ohms/1,000 ft)	73.9 Ohms/km (22.5 Ohms/1,000 ft)
Capacitance at 20°C	98 pF/m	
Collapse pressure rating (psi)*	30,000	

Table 5-12 – TEC Specifications, Part II

Wall (in.)	Alloy	Tensile (psi)				Yield (psi)			
		Minimum	Maximum	Average	STD	Minimum	Maximum	Average	STD
0.035	316L	122,000	178,000	153,000	6,800	100,000	158,000	125,000	8,200
0.049		141,000	154,000	145,000	5,100	113,000	130,000	119,000	6,400
0.035	A825	123,000	182,000	144,000	8,400	108,000	150,000	126,000	7,100
0.049		113,000	157,000	139,000	7,300	89,000	139,000	122,000	7,500

SureSENS QPT (Quartz Pressure Temperature) Elite Gauge

The SureSENS QPT Elite measures static and dynamic pressures and temperatures and is reliable and accurate. The QPT Elite is highly robust, ensuring mechanical integrity by deep-penetration and high-vacuum, electron-beam fusion welds, without the need for filler material. Only two fittings (the pressure port and the TEC) are required to interface the gauge with the carrier. The fittings can be externally tested in the direction they will experience pressure, eliminating the need for an internal pressure test tool.

Figure 5-11 – SureSENS QPT Elite Gauge Illustration

QPT Elite Pressure Interface – Pressure Testable Manifold

The gauge-pressure interface connection to the carrier is through a pressure-testable manifold interface attached to the mandrel. Triple metal-seal rings are pressure tested to ensure integrity before deployment. The three metal seals provide redundant metal-to-metal sealing, tested in the same direction as the applied pressure in the final installation. This sealing provides a true, unique metal-to-metal design that is bidirectional and dual-testable. Figure 5-11 illustrates the design, and Table 5-13 lists the technical specifications.

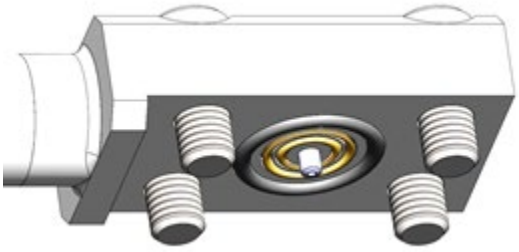


Figure 5-12 – External Sensor Illustration

Table 5-13 – QPT Elite Pressure Interface – Pressure Test Manifold Specifications

Length	25.5 in. to 26.5 in. (64.77 cm to 67.31 cm)					
Height/Width	0.750 in. (19.05 mm) / 1.318 in. to 2.50 in. (33.50 mm to 63.50 mm)					
Seals	Metallic seals and EB welds					
Transducer	Shear mode quartz					
Transducer options	10,000 psi (689.5 bar)	15,000 psi (1103.2 bar)	20,000 psi (1379.0 bar)	25,000 psi (1723.6 bar)	30,000 psi (2068.4 bar)	35,000 psi (2413.7 bar)
Material	Inconel 718	MP35N				
Pressure range	15 psi to 11,000 psi (1 bar to 758.4 bar)	15 psi to 18,000 psi (1 bar to 1241.1 bar)	15 psi to 23,000 psi (1 bar to 1620.3 bar)	15 psi to 28,000 psi (1 bar to 1930.5 bar)	15 psi to 33,000 psi (1 bar to 2275.3 bar)	15 psi to 37,500 psi (1 bar to 2585.5 bar)
Temperature rating (operating)	-99.4°F to 302°F (-73°C to 150°C)	-99.4 to 437°F (-73°C to 225°C)				
Storage temperature	-40°F to 302°F (-40°C to 150°C)					
Temperature shock	5.4°F (3°C) per minute					
Vibration	>10 G, 10 Hz-2 kHz					
Shock	500 G					
Pressure measurement range (calibrated)	200 psi to 10,000 psi (13.8 bar to 689.5 bar)	200 psi to 15,000 psi (13.8bar to 1103.2 bar)	200 psi to 20,000 psi (13.8 bar to 1379.0 bar)	200 psi to 25,000 psi (13.8 bar to 1723.6 bar)	200 psi to 30,000 psi (13.8 bar to 2068.4 bar)	200 psi to 35,000 psi (13.8 bar to 2413.7 bar)
Pressure accuracy	+-0.015% 1.5 psi at full scale	+-0.02% 3.2 psi at full scale	+-0.02% 4.0 psi at full scale	+-0.02% 5.0 psi at full scale	+-0.025% 7.5 psi at full scale	+ -0.03% 10.5 psi at full scale
Pressure resolution	0.0001 psi					
Pressure stability	0.02% full scale, 2.0 psi/year	+-0.02% full scale, 3.2 psi/year	+-0.02% full scale, 4.0 psi/year	+-0.02% full scale, 5.0 psi/year	+-0.02% full scale, 7.5 psi/year	+ -0.03% full scale, 10.5 psi/year
Temperature measurement range (calibrated)	77°F to 302°F (25°C to 150°C)	77°F to 437°F (25°C to 225°C)				
Temperature accuracy	0.27°F (0.15°C)					
Temperature resolution	0.0001°F					
Temperature stability	0.018°F (<0.01°C) per year					
Maximum sample rate/second	>16					
Number of gauges support/TEC	32					
Cable distance transmission	50,000 ft (15,240 m)					

SureSENS QPT Gauge Carriers

The carrier body is machined from a single piece of bar stock with no requirement for welding or heat-treating processes. The gauge assembly is installed into a recessed pocket in the carrier, which provides protection for the gauge without the need for a cover-plate. The uphole end of the gauge is secured to the carrier by a clamp, which is fastened to the carrier by socket head screws. All tubular completions products are designed to meet or exceed the tubing/casing specifications supplied by the customer. All tubular products are individually inspected and tested per API 5CT requirements for drift and pressure.

Figure 5-13 – SureSENSE QPT Gauge Carrier Illustration

Steel Blast Protectors

The blast protectors are installed above and below each zone over the Fiber and TEC lines. The protectors have round steel bars that run the length of and are welded into the channel on both sides of the cables to increase magnetic mass/signature for detection by the HRVRT tool to position the guns away from the cables.

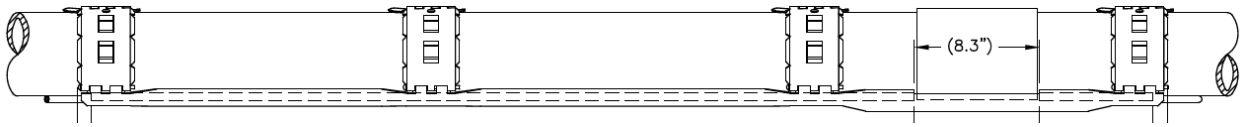


Figure 5-14 – Steel Blast Protector Illustration

Cross Coupling Protectors

To provide protection to the downhole cable, cross-coupling cable protectors which are mounted at each tubing joint coupling to provide protection as the cable transitions across the coupling. There is a potential for the downhole cable to be damaged due to abrasion or crushing between the tubing and casing internal wall during the installation process resulting in the loss of functionality of the associated downhole equipment.

Figure 5-15 – Image of Cross Coupling Protector

5.6.7.2 Rate Transient Analysis

To meet the operation monitoring requirements of SWO 29-N-6 ***§3625.A.7.a*** [*40 CFR* ***§146.90(g)(1)***], The reservoir model built during the site evaluation and permitting phase of the project may be further used to predictively monitor the reservoir conditions during injection operations. Through reservoir engineering and transient flow analyses, the model may be updated with actual temperature, pressure, and rate injection data, to evaluate the injection stream's effect on reservoir conditions and so derive accurate reservoir conditions.

Rate-transient analysis (RTA) using known reservoir characteristics will allow for the calculation of more complex parameters within each injection interval. By using proven and industry-standard flow equations to suit CO_2 injection, RTA is conventionally used to analyze production data and predict future well flow behavior. The forecasting of wells can be determined by the modeling of pressures and rates using Darcy's law combined with equations of state, which are then solved analytically. For use in the geologic storage field, the theory and equations are

altered for injection operations. Several commercially available software packages exist to assist petroleum engineers in these analyses. They are commonly used and are capable of accurately simulating multilayered reservoirs and high-rate gas wells.

Results from the test and known reservoir environment parameters allow for the prediction of the radius of pressure response in the reservoir. Knowing the critical pressure for an injection interval for a project, the radius of investigation (critical pressure front and plume) could be determined. Direct monitoring will be based on continuous pressure, temperature, and injection rate data to verify. The data will be used to refine the dynamic model and calculate the extent of the CO_2 saturation plume and critical pressure front to determine the AOR extent and confirm that the necessary steps to protect to the USDW have occurred.

This proposed direct monitoring method offers significant advantages over in-zone monitoring wells within this portion of the Gulf Coast depositional environment. All reservoir models indicate that pressure build-ups within these high permeability sand packages can be observed for the duration of injection into those sands and then will fall off to nearly in situ reservoir pressures shortly after injection ceases. The entirety of the injection well project includes the active injection and the post-injection monitoring periods. The active injection period of 20 years occurs in discrete time steps, typically only one to three years per designated sand package. The post-injection site monitoring period is approximately 50 years. The continuous monitoring of bottomhole pressures and temperatures, along with the RTA, will confirm that this pressure effect within the reservoir holds true.

Additionally, the total thickness of the proposed gross injection zone, within a typical Gulf Coast depositional environment well, requires that thousands of feet of CRA materials be utilized in the construction of any penetrations into the zone. For Hackberry Carbon Sequestration Well No. 001, the gross injection zone is around 6,000 ft. The design and development of all CCS projects must consider economic feasibility. The pay zone thickness of wells found in this area, as compared to most other geologic regions of the U.S., must be considered. As such, an alternative approach for direct monitoring was deemed necessary.

The most important argument for using RTA is the minimization of artificial penetrations into the gross injection zone. Fewer penetrations allow for greater protection to the USDW and unintentional escape of CO_2 from confinement. If artificial penetrations exist within the injection interval, recompletion to an IZM well would be a reasonable option. Collecting data for only a small time slice of the life of the project by creating artificial penetrations, potentially compromising groundwater resources, prompted the consideration of this alternative method. Continuous pressure and temperature monitoring coupled with RTA accomplishes the goals of (1) appropriate and reasonable data collection to monitoring reservoir effects, (2) protection of groundwater resources, and (3) economic feasibility for project development. This proposed direct monitoring plan is an acceptable and widely used engineering approach in the petroleum industry. Should the data collected from continuous monitoring of downhole conditions indicate limitations to the understanding of the reservoir, an in-zone monitoring well will be considered.

Additionally, any periods of shut-in can be observed and evaluated as a drawdown test. To do this, the shut-in wellhead pressure, downhole tubing pressure, and temperature readings will be recorded and used for pressure transient analysis of the reservoir. Results of the analysis will include the radius and magnitude of pressure buildup and reservoir performance characteristics, such as permeability and transmissibility. Analysis results will then be used to confirm and adjust the previously constructed models.

Through predictive modeling and analysis of recorded pressure and temperature data, the operator can closely monitor the injection well's effect on the subsurface and AOR—to help ensure regulatory compliance and safety while contributing to informed decision-making.

5.6.7.3 Indirect monitoring techniques

Vertical Seismic Profile

To meet the operation monitoring requirements of SWO 29-N-6 ***§3625.A.7.b*** [*40 CFR* ***§146.90(g)(2)***], the primary method of monitoring the extent and development of the CO_2 saturation plume is through the use of a time-lapse Vertical Seismic Profile (VSP).

The VSP walkaway acquisition (geophysical Technology 1) will use a fiber optic cable with sDAS (Seismic Distributed Acoustic Sensing), embedded in the cemented annulus behind the long string casing. This set up will produces a long sensor array from the surface to the reservoir depth that allows real time or periodic monitoring. The sDAS fiber optic can detect very subtle pressure variations induced by acoustic waves and therefore acts like a continuous geophone. Not only will fiber optic collect data from pressure and temperature gauges in the reservoir, it will also be used for the periodic time-lapse VSP walkaway acquisition.

The sDAS fiber optic cable allows seismic measurements at approximately every meter, depending on the interrogator data resampling. This design produces the highest resolution VSP as possible. Using walkaway seismic sources positioned along specified azimuths and offsets, the CO_2 plume can be imaged along multi-azimuthal 2D profiles.

The very shallow water conditions of the site will not allow the use of airgun and vibroseis truck for seismic sources, but most likely dynamite placed in shot-holes will be the best seismic source for such complex transition zone environment. The VSP walkaway baseline will be acquired prior injection and the monitors will be acquired at Year 2 or 3, then at Year 5 and finally every five years after. The VSP techniques aim at evidencing areas where CO_2 plume has flown. Based on the directly acquired data at the well, the reservoir model will be updated and confronted to the VSP image result until the model conformance is achieved.

Time-lapse seismic for the purposes of reservoir monitoring has a long history in tertiary oil and gas recovery. The methodology has been extensively tested in saline aquifers with CO_2. The primary driver of the time-lapse effect is the change in acoustic impedance driven by the compressional velocity changes induced by an increase in the pore space CO_2 saturation.

As illustrated on Figure 5-16, the HCS geophysical monitoring plan includes the acquisition of eight walkaway half-profiles along different azimuthal directions. This technology will be completed with micro-gravity gradiometry acquisition (monitoring Technology 2).

According to the current reservoir model simulation results based on the petrophysical data, which will be revised once the injector well is drilled, and the ray-tracing VSP modeling study, the multi-azimuthal walkaway profiles will be able to image the CO_2 plume for at least the first 10-15 years of injection. Beyond this period, there is a risk that the plume will migrate beyond the walkaway imaging cones. In this case, the subsurface imaging obtained from VSP surveys will be augmented with complementary 2D/4D surface seismic surveys (contingent monitoring Technology 3).

The primary work steps involved in a time-lapse VSP survey design study are:

1. Rock Physics Model
2. Petro-elastic Model
3. Feasibility
4. Baseline Survey (Data acquisition)
5. Repeat/Time-lapse Survey (Data acquisition)
6. Interpretation

A detailed evaluation of the suitability for VSP surveys as the primary method for determining the plume extents is provided in Appendix 5.1.

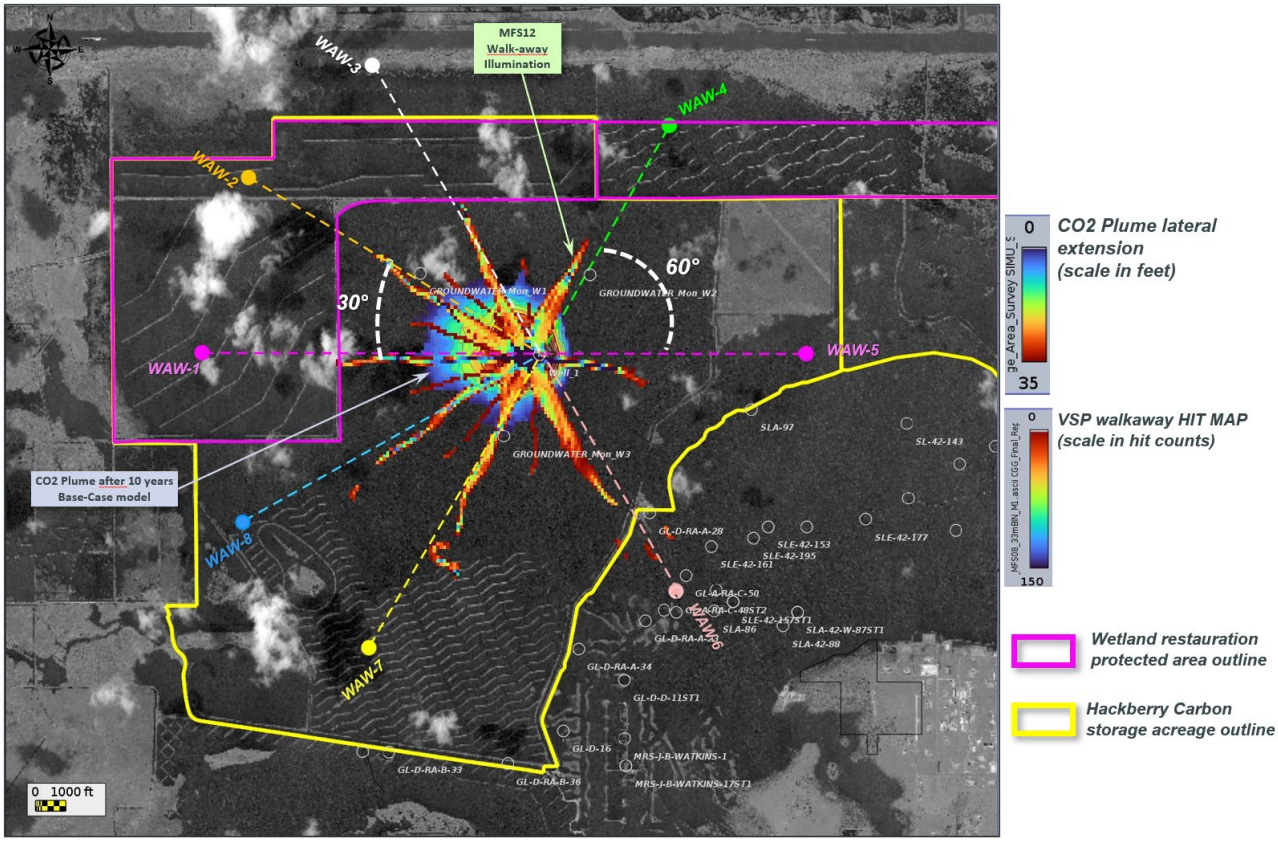


Figure 5-16 – Eight walkaway half-profiles with their illuminations for the MFS12 target.

Processing Workflow and 4D Seismic Volume Determinations

The final interpretation from consecutive surveys will be made by observing gas volume build-ups over time. When 1D, 2D, and 3D seismic surveys are combined with a time component (i.e., surveys conducted at various time periods from one another (Year 1, Year 5, Year 10, etc.), a 4D model is produced). The 4D interpretation of a seismic survey will identify changing volumes of gas build-up which are represented by log shifts on 1D and 2D responses or heat blooms on 3D models.

Inversion Workflow

Baseline surveys will be inverted using post-stack seismic volumes, well log data and a structural model to generate the basic low component model. Subsequent monitor surveys will use the same low component and residual corrections for consistency and the detection of changes over time. These changes over time will be assumed to be due to the injection activities.

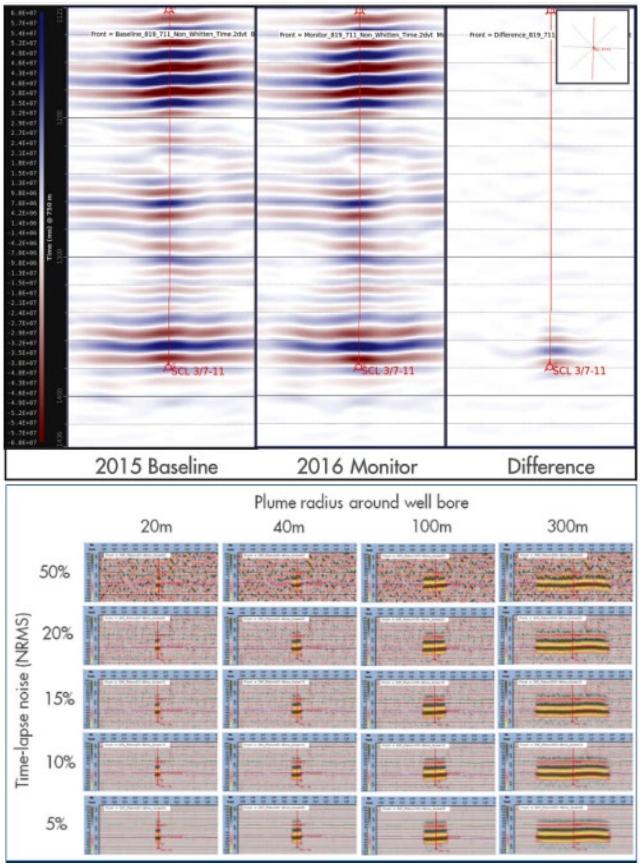


Figure 5-17 – Baseline and subsequent VSP used to determine difference in amplitude attributed to CO_2 injection as measured from the injector well Itself. Estimation of plume growth over time in plot on the right.

Baseline Survey

A quality baseline survey is essential for a quality monitoring program. This survey represents the only opportunity to capture an image of the reservoir before any perturbation of the reservoir occurs due to injection or offset activity (man-made or natural). Without the baseline survey, no interpretation of formation changes can be made. Any errors made in the construction of the baseline image will impair sensitivity and interfere with the sensitivity to which formation changes can be made. Further, the size of the baseline survey determines the extent to which plume can be measured. Given uncertainty in the reservoir models, it is important to acquire a baseline survey with sufficient extent to provide utilization in the event the initial reservoir models are not accurately predicting the plume migration.

An example of a 4D time-lapse model is shown in Figure 5-17 visualized in 3D space with analysis software. Each horizon can be displayed along with a color code for differences in amplitude over time.

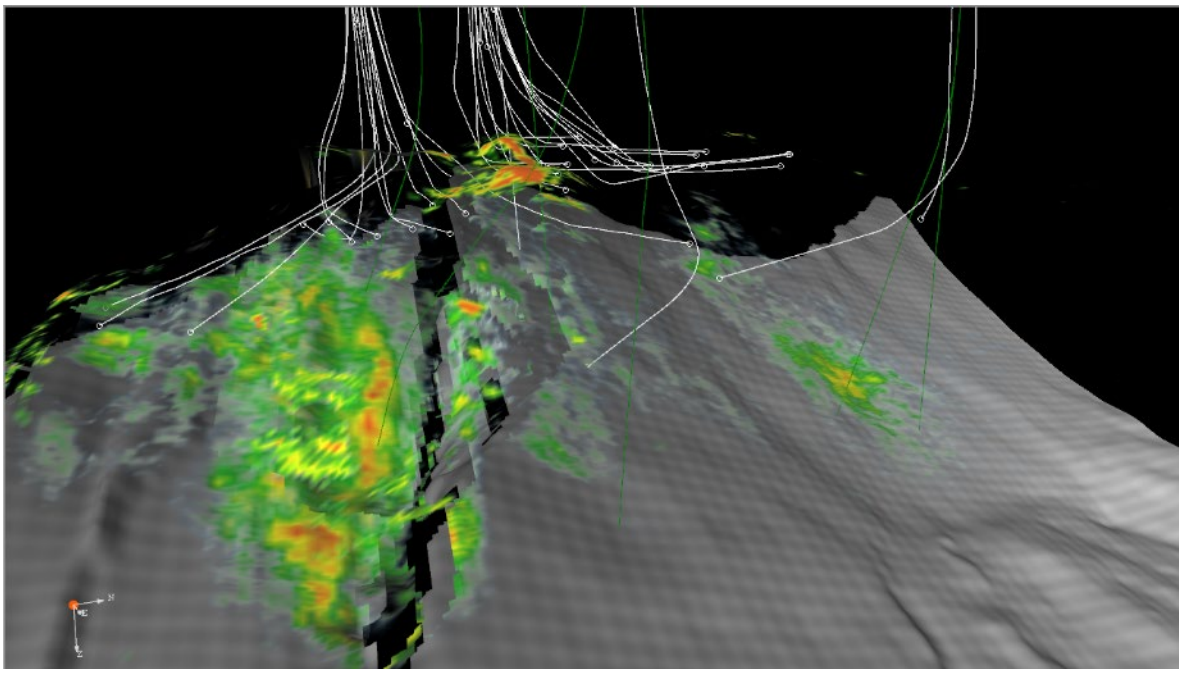


Figure 5-18 – Example of a 4D Output

From the described 4D signal modeling results and overview workflow, different geophysical technologies have been assessed to confirm their usefulness in monitoring both primary and secondary CO_2 saturation front for the HCS project.

Geophysical Monitoring Technology 1: 4D Walkaway Vertical Seismic Profile VSP

As previously described, 4D walkaway VSP is a well-adapted geophysical monitoring technology to perform a cost-efficient tracking of the CO_2 vertical and lateral plume migration. A detailed feasibility study was conducted to determine optimal acquisition design, identify key acquisition challenges and technology limitations for the Hackberry storage site.

Walkaway VSPs consists of acquiring a subsurface seismic image by positioning several receivers in the borehole (i.e., the DAS) and by moving along a straight profile several seismic sources (see figure below). Each shot is recorded and processed to obtain a final high resolution subsurface image.

Additional discussion of the VSP technology is provided in Appendix 5.1.

Geophysical Monitoring Technology 2: 4D Micro-Gravity

The 4D micro-gravity brings the capability to monitoring gravity field azimuthal variations due to fluid density decrease when changing fluids from brine to supercritical CO_2 within the rock pore volume (Gettings et al. 2008). This type of data could be collected and used to history match, validate and extend the VSP monitoring. Gravity field perturbation induced by CO_2 injection is expected to be detectable above 3µGal using state-of-art micro-gravimeter, modeling based on

surface micro-gravity performed over Hackberry demonstrates that the field perturbation will go above this threshold during the injection phase.

Operational Deployments of 4D Micro-gravity Monitoring

A surface gravity survey in the Black Lake context should be relatively straightforward. It requires light logistics and can monitor in 3D the entire concession and more if needed. It has extremely low impacts on the environment. Scouting and monitoring can be performed cost-efficiently in simultaneous operations during the VSP walkaway acquisition. Gravity stations should be to record the field on a 500 x 500 m grid, an estimated time of 20 to 30 minutes field recording per station. Across a square of 50 km^2 this would represent about 200 stations for a one-month duration. The station density can be increased in area of high priority if required to refine the field perturbation monitoring.

Borehole gravity gradiometers (BHGM's) are insensitive to wellbore conditions (e.g., rugosity or casing); however, they cannot be deployed permanently like optic fibers. They could be deployed temporarily in the wellbore simultaneously during the surface gravity surveys, this would constrain the survey on periods of workover (e.g., change of completion etc.) to allow access to the borehole.

The BHGM can also be used to monitor near the wellbore in case there are any suspicions of nearby CO_2 leakage.

5.6.7.4 Plume/Pressure Front Monitoring Summary

Throughout the duration of the injection project, the geophysical indirect monitoring strategy (including multi-azimuthal walkaway VSP, 2D/4D bridging seismic, micro-gravity and passive seismic network) will supplement the direct monitoring efforts (such as monitoring of ground-water wells, pressure, temperature, and geomechanical integrity from the injector).

These techniques are mutually complementary.

Whereas the direct methods installed all along the injector well provide the highest resolution data, vertically, the VSP technique provides the highest resolution data, horizontally.

This leads to build an extremely reliable image of the plume spatial location only based upon:

- The obtained well data including on injection rates, cumulative injected CO_2 volume, BHP, indications on CO_2 vertical migration through reservoir and seal rocks (from pressure and temperature analysis from all gauges)
- Data from the VSP, to determine the shape of the plume evidenced by generated density contrasts. The 2D line set up is only a contingent technique that could be deployed to prolongate the VSP acquisition lines to image the plume beyond a certain size that could be reached after 15 years of injection.

While some results will feed the update of the reservoir model, the others will enable assessing the conformance with the model. Effectively, based on hard data from the direct measurements,

the updated model must reproduce the VSP derived global plume envelope. The only method to define the pressure front associated with the saturated front expansion is the full match of the reservoir simulations with the measured and calculated data.

The other monitoring techniques that are planned to be deployed at the HCS site could be considered as backup techniques. The micro-gravimetry survey, sensitive beyond a certain density variation in the subsurface, will help build the 3D shape of the plume that is first only reconstructed from the VSP 2D lines and prompted also by the proposed fixed offset stations (See VSP design in App. 5.1). In this respect, these two techniques are complementary. Alone, beyond a certain density threshold and despite a poorer vertical resolution, the micro-gravimetry evidences the areal shape of the saturated CO_2 front and thus provides an accurate image of the AOR. Moreover, the micro-gravimetry survey, relatively cheap to deploy, can easily be triggered when necessary and is able to detect any vertical leak where CO_2 will concentrate. In such, for its fast deployment, micro-gravimetry is fundamental for the project.

The other planned complementary technique is the PSM. The PSM alone can detect and locate any “noise” related to underground movements. The PSM are the “ears” of the project. Associated with the VSP and micro-gravimetry plume shape results, it can prove that the detected event is or is not related to the carbon sequestration activity at the HCS site. With the levels of pressure variation induced by the injection in the aquifer reservoir, in the range of 10 to 20 psi only, it is very unlikely that the injection activity will induce any seismic activity. In that respect, PSM is usually set up to ease the public acceptance of the project.

The HCS project is a relatively modest project aiming with a maximum sequestration of 2 MMT/yr from one well that will be implemented in phases, probably starting with 0.7 MMt/yr. Currently, the reservoir modeling is based on data that are relatively dispersed around HCS and there is no data point centered in the acreage. With the additional data from the centered injector well that will be fully logged and abundantly cored, the model with be updated and the associated uncertainties will be greatly reduced. The main uncertain parameters are the heterogeneity of the upper confining unit at the well location and inside the acreage and the petrophysical parameters such as permeability and maximum critical gas saturation (Sgrm). With those greatly reduced uncertainties, plume growth will be reliably simulated and anticipated, especially after the first model calibration with the first VSP monitor planned after two years of injection activity. The sealing efficiency of the intermediate MFS will be firmly assessed from this first monitor and from the continuous measurements of pressure and temperature with gauges dispatched all along the wellbore. With a monitoring program based on multiple complementary techniques, there is no doubt that all possible risks will be anticipated and detected in due time.

Table 5-14 provides a summary of the proposed direct and indirect monitoring strategies and a listing of the pros and cons of each.

Table 5-14 – Hackberry Carbon Storage Proposed Direct/Indirect Monitoring Strategies

Technology	Objective	Pros	Cons
Direct Monitoring			
Injection Well Pressure/ Temperature Measurements	Direct monitoring of reservoir conditions. Results are used to calculate the plume and pressure extents by using rate transient analysis and diffusivity equations.	No additional in-zone monitoring wells are necessary to achieve these results.	If lose communication with downhole sensors, must implement an alternative method.
		Takes advantage of installed equipment used to ensure mechanical integrity exists.	
		Monitoring of targeted conditions is continuous	
		Considerably more cost-effective than in-zone monitoring well.	
Indirect Monitoring			
Walkaway VSP	Identification of changes in formation fluid densities associated with existence of CO_2 concentration.	Most economical seismic data acquisition method.	Has limited technological range.
		Allows operator to detect structural features not accounted for in reservoir simulation model.	Requires interpolation between survey lines.
		Repeatable for time-lapse observation of CO_2 plume movement.	
Gravity Survey	Identification of changes in formation fluid densities associated with existence of CO_2 concentration.	Complementary to walkaway VSP.	Lower accuracy than direct seismic survey.
		Allows full 3D image and doesn't require interpolation between surveys.	Limited range in subsurface depth.
		Does not require significant surface/wetland disturbance.	

5.7 References and Publications

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Underground Injection Control – Class VI Permit Application for Hackberry Carbon Sequestration Well No. 001

Cameron Parish, Louisiana

SECTION 6 – PLUGGING AND ABANDONMENT PLAN

Prepared for *Hackberry Carbon Sequestration, LLC*
Cameron, LA

By

Lonquist Sequestration, LLC
Austin, TX

August 2021
Revised January 2025

SECTION 6 – PLUGGING AND ABANDONMENT PLAN

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6.1 Introduction

This Plugging and Abandonment (P&A) Plan for Hackberry Carbon Sequestration Well No. 001 was prepared to meet the requirements of SWO 29-N-6, **§631** [40 CFR **§146.92**]. *Section 6 – Testing and Monitoring Plan* provides a general description of the steps that will be taken to plug and abandon the planned stages of well development through final abandonment. Complete plugging and abandonment prognoses have been included in *Appendix J* of this application.

As previously described in *Section 4 – Engineering Design and Operating Strategy*, the well will be completed with multiple injection horizons within the gross injection zone. Each injection interval will be utilized for a discrete period of time as identified in the plume model. Once that timeframe has expired, the current injection interval will be plugged to prevent crossflow conditions between new and old injection intervals as well as reduce the likelihood of sand incursion into the well. Once the exhausted sand package has been plugged, a new injection horizon will be opened. This process will repeat until the entire gross injection interval has been fully developed. After approximately 20 years of injection, the well will be permanently plugged.

The following details will outline the procedures for both types of plugs to be installed in this well. In summary, the two types of plugs are:

1. Isolation of the active injection section, or stage, via recompletion operations.
2. Final P&A of the wellbore.

6.2 Zonal Isolation of Injection Stages/ Intermediate Plugback Plan

When the current injection stage has been exhausted of available pore space or the plume migration tracking indicates storage capacity has been reached, the injection stage will be abandoned. The general procedure for zonal isolation will include:

6.2.1 Pre-Plugging Activities

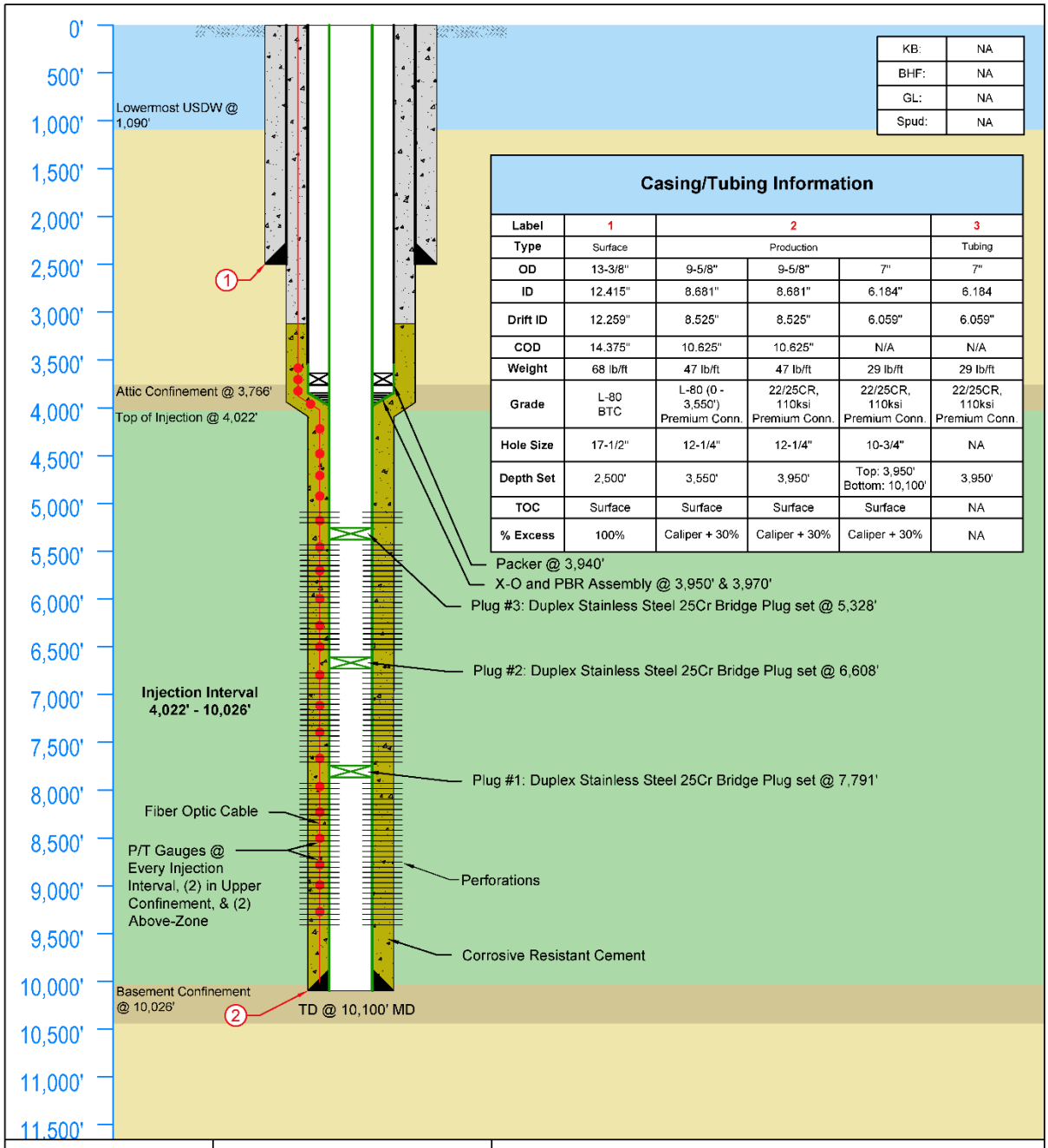
1. Hackberry Carbon Sequestration, LLC (HCS) will comply with all reporting and notification provisions.
    a. EPA UIC Program Director will be notified 60 days in advance of planned plugging efforts. [40 CFR ***§*146.92(c)**]
    b. Notice of Intent to Plug will be communicated to the LDENR by submitting Form UIC-17 with detailed plans. [SWO 29-N-6 ***§*631.A.4**]
2. Bottomhole reservoir pressure will be measured using the fiber optic pressure sensing array permanently installed behind the 9-5/8 in. x 7 in. tapered production casing string. *Section 5 – Testing and Monitoring Plan* provides more information on the pressure measurement systems. [SWO 29-N-6 ***§*631.A.2**; 40 CFR ***§*146.92(a)**]
3. External mechanical integrity will be demonstrated through approved temperature logging methods described in *Section 5 – Testing and Monitoring Plan*. [SWO 29-N-6 ***§*631.A.2**; 40 CFR ***§*146.92(a)**]

4. Casing inspection and cement bond logs will be performed prior to plugging.

6.2.2 Plugging Activities

1. Run in and perform casing inspection and bond log.
2. A corrosion resistant alloy (CRA) bridge plug will be set above the injection stage that is to be isolated.
3. The plug will be qualified by tagging the top and conducting a successful pressure test.
4. The perforations will not be squeezed. This will allow for pressure monitoring of the isolated zone for the duration of the life of the storage project.

The “mono-bore” design of the well will not require any well components to be removed during zonal isolation operations in the permitted injection zone. All intermediate plugging operations can be conducted via wireline services allowing for a more efficient and safer recompletion process.



KB:	NA
BHF:	NA
GL:	NA
Spud:	NA

Casing/Tubing Information

Label	1	2			3
Type	Surface	Production			Tubing
OD	13-3/8"	9-5/8"	9-5/8"	7"	7"
ID	12.415"	8.681"	8.681"	6.184"	6.184
Drift ID	12.259"	8.525"	8.525"	6.059"	6.059"
COD	14.375"	10.625"	10.625"	N/A	N/A
Weight	68 lb/ft	47 lb/ft	47 lb/ft	29 lb/ft	29 lb/ft
Grade	L-80 BTC	L-80 (0 - 3,550') Premium Conn.	22/25CR, 110ksi Premium Conn.	22/25CR, 110ksi Premium Conn.	22/25CR, 110ksi Premium Conn.
Hole Size	17-1/2"	12-1/4"	12-1/4"	10-3/4"	NA
Depth Set	2,500'	3,550'	3,950'	Top: 3,950' Bottom: 10,100'	3,950'
TOC	Surface	Surface	Surface	Surface	NA
% Excess	100%	Caliper + 30%	Caliper + 30%	Caliper + 30%	NA

LONQUIST SEQUESTRATION LLC	Hackberry Carbon Sequestration, LLC	Hackberry Carbon Sequestration Well No. 001	
	Country: USA	**State/Province:** Louisiana	**County/Parish:** Cameron
	API No: TBD	**Field:**	**Well Type/Status:** Class VI CCS
Louisiana License EF-7423	**Permit No:** TBD	**Project No:** 2393.4	**Date:** 01/27/2025
12912 Hill Country Blvd. Ste F-200 Austin, Texas 78738 Tel: 512.732.9812 Fax: 512.732.9816	**Drawn:** Joseph Lovewell	**Reviewed:** Joseph Lovewell	**Approved:** Ben H Bergman
	Rev No: 2	**Notes:**	

Figure 6-1 – Intermediate Plugging Schematic for Hackberry Carbon Sequestration Well No. 001

6.3 Final Plugging and Abandonment

6.3.1 Pre-Plugging Activities

1. HCS will comply with all reporting and notification provisions.
    a. EPA UIC Program Director will be notified 60 days in advance of planned plugging efforts. [40 CFR ***§*146.92(c)**]
    b. Notice of Intent to Plug will be communicated to the LDENR by submitting Form UIC-17 with detailed plans. [SWO 29-N-6 ***§*631.A.4**]
2. Bottomhole reservoir pressure will be measured using the fiber optic pressure sensing array permanently installed behind the 9-5/8 in. x 7 in. tapered production casing string. Please see *Section 5 – Testing and Monitoring Plan* for more information. [SWO 29-N-6 ***§*631.A.2**; 40 CFR ***§*146.92(a)**]
3. External mechanical integrity will be demonstrated through approved temperature logging methods described in *Section 5*. [SWO 29-N-6 ***§*631.A.2**; 40 CFR ***§*146.92(a)**]
4. The injection well will be flushed with a buffer fluid prior to pulling injection tubing and packer. [SWO 29-N-6 ***§*631.A.2**; 40 CFR **§146.92(a)**]
5. All uncemented, non-permanent components of the well will be removed.
6. Casing inspection and cement bond logs will be performed prior to plugging.

Table 6-1 – Description of Casing, Tubing, and Other Well Construction Materials to be Removed

Well Component	Size (in.)	Amount	Notes/Comments
29 lb/ft Alloy Tubing	7	3,970 ft	Tubing and packer will be pulled prior to P&A operations.
Inconel Alloy Packer	9-5/8 x 7	1	

6.3.2 Plugging Activities

1. A CRA bridge plug will be set within the 7-in. production casing above the final injection interval.
2. Tubing and packer will be removed.
3. Final isolation of gross injection interval.
    a. A permanent bridge plug made of CRA will be set at, approximately, the same depth where the tubing packer had previously been set
    b. A plug of epoxy resin or equivalent will be placed on top of the permanent bridge plug and will cover the length of the upper confining zone.
    c. The plug will be qualified by tagging the top and conducting a successful pressure test.
4. Treated fluid will be circulated at least once to achieve a state of static equilibrium.
5. Set 100 ft cement plug, from 50 ft below the surface casing setting depth to 50 ft into the surface casing shoe.
6. Treated fluid will be circulated at least once to achieve a state of static equilibrium.
7. Set 100 ft cement plug, from 50 ft below the base of the lowermost underground source of drinking water (USDW) to 50 ft into the base of the USDW.

8. Treated fluid will be circulated at least once to achieve a state of static equilibrium.
9. Set a 50 ft cement plug from 65 ft to 15 ft.
10. Install a cofferdam around the wellhead
11. Pump out and excavate the area inside the cofferdam to 15 ft below the mudline
12. Cut casing 15 ft below mudline and weld on 0.5 in. steel plate.

Final plugging reports, certified by the operator and the person who performed the plugging operation, will be submitted to the director within 60 days after plugging. Detailed plugging procedures and regulatory forms are included in *Appendix J.*

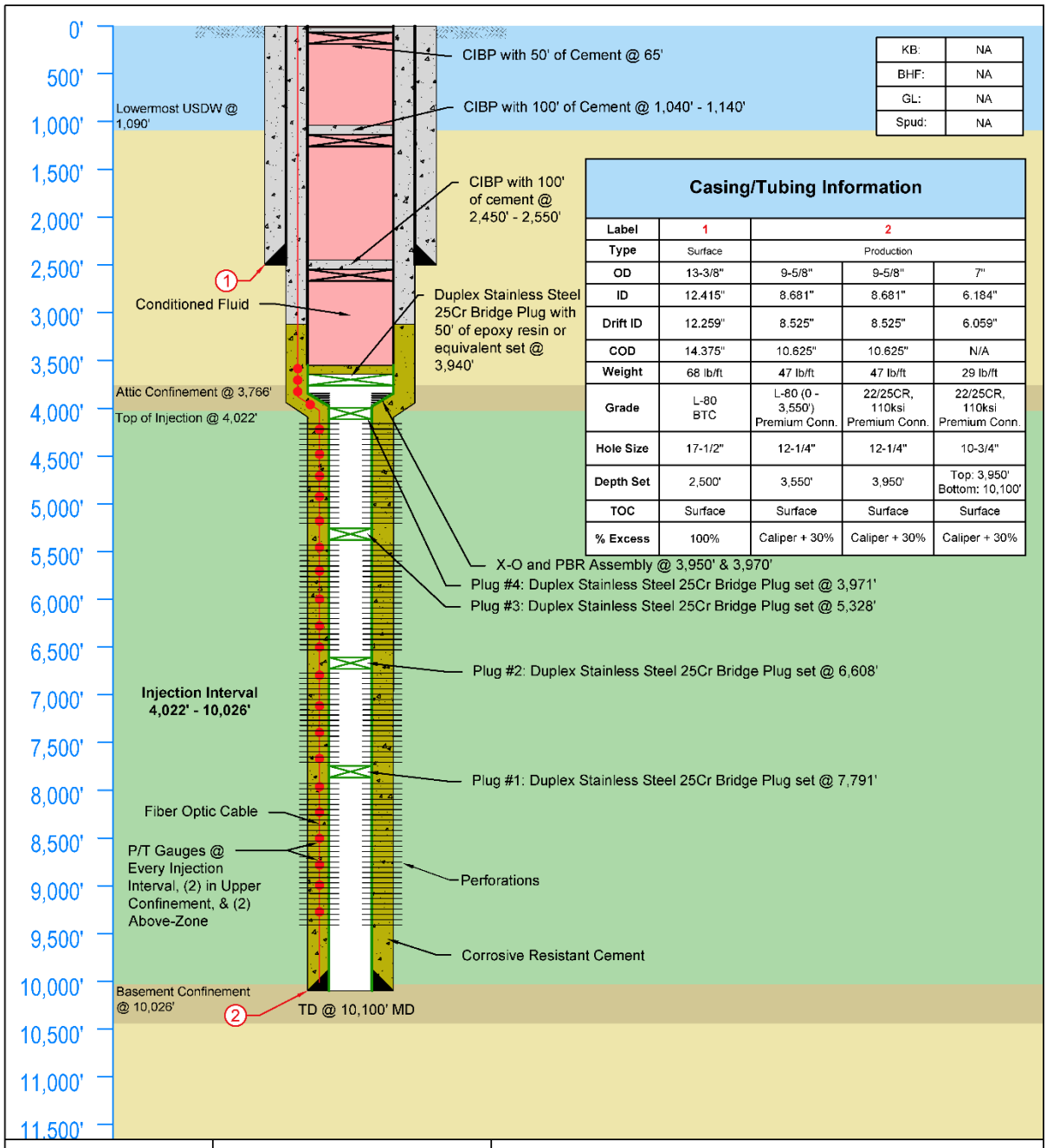
6.3.3 Plug Details

Table 6-2 – Plug Details for Plugs No. 1 – No. 6

Plug Description	Plugback – CRABP	Plugback – CRABP	Plugback – CRABP	Plugback – CRABP	Final P&A – CRABP w/ Resin or Equiv. – Confining Zone Plug	Final P&A – Cmt Plug – Surface Casing Plug
Plug Number	**1**	**2**	**3**	**4**	**5**	**6**
Diameter of Boring in Which Plug Will be Placed (in.)	7	7	7	7	9-5/8	9-5/8
Depth to Bottom of Tubing or Drill Pipe (MD, ft)	7,791	6,608	5,328	3,971	3,940	2,550
Sacks of Cement to be Used (each plug) (sks)	NA	NA	NA	NA	4 bbl	40
Slurry Volume to be Pumped (ft^3)	NA	NA	NA	NA	21	42
Slurry Weight (lb/gal)	NA	NA	NA	NA	10	16.4
Top of Plug (MD, ft)	NA	NA	NA	NA	4,720	2,450
Bottom of Plug (MD, ft)	7,791	6,608	5,328	3,971	3,940	2,550
Type of Cement or Other Material	Corrosion Resistant Alloy Bridge Plug	Corrosion Resistant Alloy Bridge Plug	Corrosion Resistant Alloy Bridge Plug	Corrosion Resistant Alloy Bridge Plug	Corrosion Resistant Alloy Bridge Plug + Epoxy Resin or Equiv. Plug	H
Method of Emplacement	Wireline	Wireline	Wireline	Wireline	Circulation	Circulation
New Plug?	No	No	No	No	Yes	Yes

Table 6-3 – Plug Details for Plugs No. 7 – No. 8

Plug Description	**Final P&A – Cmt Plug – USDW Plug**	**Final P&A – Cmt Plug – Surface Plug**
Plug Number	**7**	**8**
Diameter of Boring in Which Plug Will be Placed (in.)	9-5/8	9-5/8
Depth to Bottom of Tubing or Drill Pipe (MD, ft)	1,140	65
Sacks of Cement to be Used (each plug) (sks)	40	20
Slurry Volume to be Pumped (ft^3)	42	21
Slurry Weight (lb/gal)	16.4	16.4
Top of Plug (MD, ft)	1,040	15
Bottom of Plug (MD, ft)	1,140	65
Type of Cement or Other Material	H	H
Method of Emplacement	Circulation	Circulation
New Plug?	Yes	Yes



KB:	NA
BHF:	NA
GL:	NA
Spud:	NA

Casing/Tubing Information

Label	1	2		
Type	Surface	Production		
OD	13-3/8"	9-5/8"	9-5/8"	7"
ID	12.415"	8.681"	8.681"	6.184"
Drift ID	12.259"	8.525"	8.525"	6.059"
COD	14.375"	10.625"	10.625"	N/A
Weight	68 lb/ft	47 lb/ft	47 lb/ft	29 lb/ft
Grade	L-80 BTC	L-80 (0 - 3,550') Premium Conn.	22/25CR, 110ksi Premium Conn.	22/25CR, 110ksi Premium Conn.
Hole Size	17-1/2"	12-1/4"	12-1/4"	10-3/4"
Depth Set	2,500'	3,550'	3,950'	Top: 3,950' Bottom: 10,100'
TOC	Surface	Surface	Surface	Surface
% Excess	100%	Caliper + 30%	Caliper + 30%	Caliper + 30%

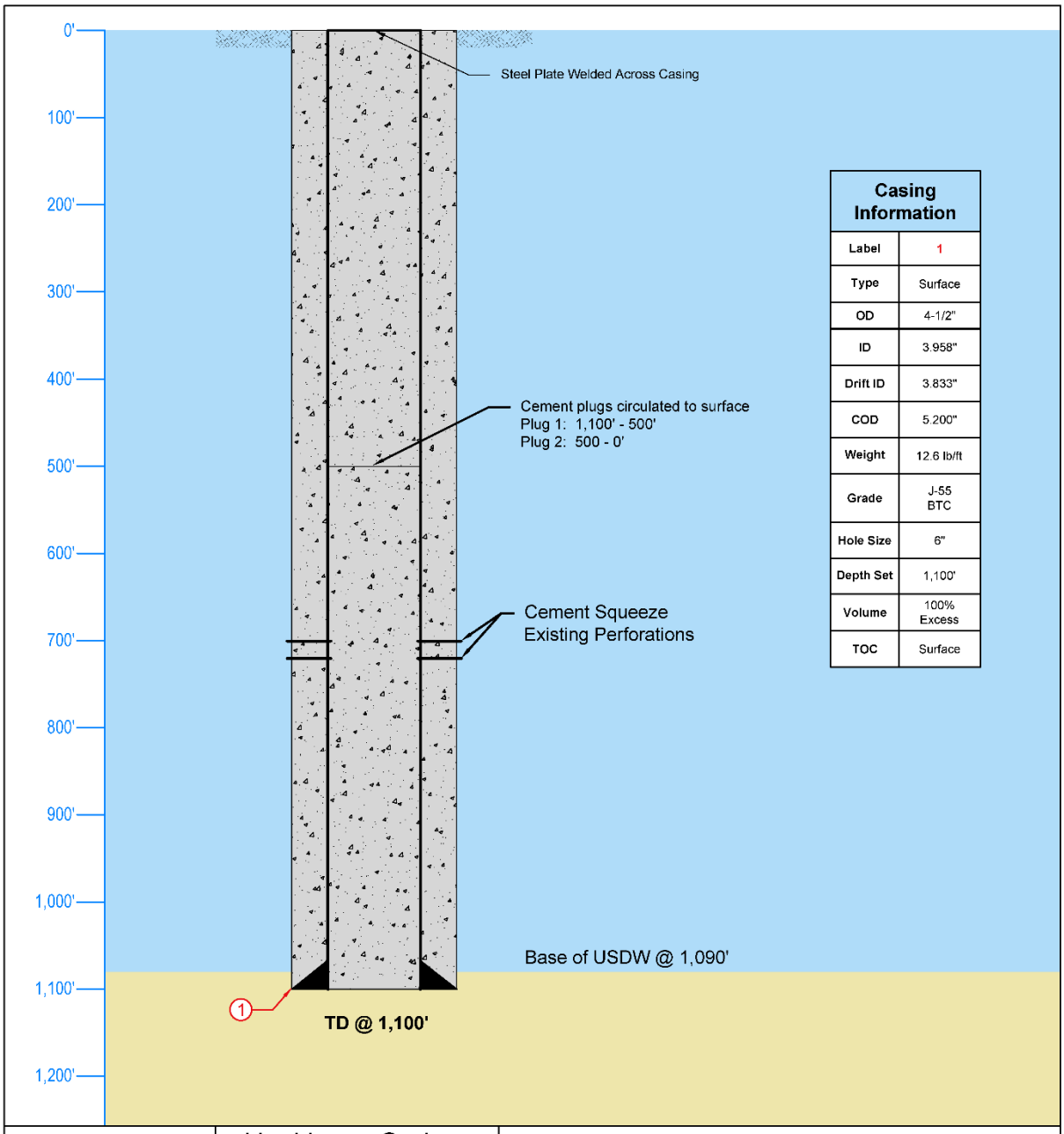
LONQUIST SEQUESTRATION LLC	Hackberry Carbon Sequestration, LLC	Hackberry Carbon Sequestration Well No. 001	
	Country: USA	**State/Province:** Louisiana	**County/Parish:** Cameron
	API No: TBD	**Field:**	**Well Type/Status:** Class VI CCS
Louisiana License EF-7423	**Permit No:** TBD	**Project No:** 2393.4	**Date:** 01/27/2025
12912 Hill Country Blvd. Ste F-200 Austin, Texas 78738 Tel: 512.732.9812 Fax: 512.732.9816	**Drawn:** Joseph Lovewell	**Reviewed:** Joseph Lovewell	**Approved:** Ben H Bergman
	Rev No: 2	**Notes:**	

Figure 6-2 – Final Plugging Schematic for Hackberry Carbon Sequestration Well No. 001

6.3.4 Monitor Well Plugging and Abandonment

Once monitoring of groundwater is no longer needed, the monitoring wells will be plugged and abandoned following Louisiana state guidelines. The details regarding the use of the monitoring well are discussed in Section 5. Ensuring the protection of the USDW is of paramount importance in this project. The plugging of the monitoring well will ensure that existing pathways and exposure to the USDW is restricted. The plugging process for these wells is as follows:

1. All monitoring equipment will be removed from the well.
2. The existing perforations will be squeezed with cement to seal off the USDW.
3. Cement plugs will be circulated from total depth (1,100 ft) to surface.
    a. Plug 1: 1,100 ft – 500 ft
    b. Plug 2: 500 ft – 0 ft
4. A ½ in. steel plate will be welded across the casing, engraved with well serial number, operator name, and plugging date.



LONQUIST SEQUESTRATION LLC	Hackberry Carbon Sequestration, LLC	Hackberry Carbon Sequestration Monitor Well Nos. 001-002	
	Country: USA	**State/Province:** Louisiana	**County/Parish:** Cameron
	Location: Multiple	**District:**	**Survey:**
	API No: TBD	**Field:**	**Well Type/Status:** P & A
Louisiana License EF-7423	**State Gas ID No:**	**Project No:** 2393.4	**Date:** 01/29/2025
12912 Hill Country Blvd. Ste F-200 Austin, Texas 78738 Tel: 512.732.9812 Fax: 512.732.9816	**Drawn:** Jake Coker	**Reviewed:** Joseph Lovewell	**Approved:** Ben H Bergman
	Rev No: 0	**Notes:** Class VI Permit Application - Appendix J6	

Figure 6-3 – Final Plugging Schematic for HCS Monitor Well No. 001

Detailed schematics and procedures are located in Appendix J and contain the following:

- Appendix J-1 Injection Well – First Plugback Schematic
- Appendix J-2 Injection Well – First Plugback Procedure
- Appendix J-3 Injection Well – Final P&A Schematic
- Appendix J-4 Injection Well – Final P&A Procedure
- Appendix J-5 Injection Well – Final P&A Report, LADNR Form UIC-P&A
- Appendix J-6 Monitor Well – Final P&A Schematic

Underground Injection Control – Class VI Permit Application for Hackberry Carbon Sequestration Well No. 001

Cameron Parish, Louisiana

SECTION 7 - POST-INJECTION SITE CARE AND SITE CLOSURE PLAN

Prepared for *Hackberry Carbon Sequestration, LLC*
Cameron, LA

By

Lonquist Sequestration, LLC
Austin, TX

August 2021
Revised January 2025

SECTION 7 – POST-INJECTION SITE CARE AND SITE CLOSURE PLAN

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7.1 Introduction

This Post-Injection Site Care (PISC) and Site Closure Plan for the Hackberry Carbon Sequestration (HCS) Well No. 001 was prepared to meet the requirements of SWO 29-N-6, **§3633** [40 CFR **§146.93**]. The plan describes various activities that will occur once injection has ceased and during the site closure once it is demonstrated that no additional monitoring is needed to ensure that this project does not pose further endangerment to the USDW.

7.2 Post-Injection Pressure Differentials

To meet the requirements of SWO 29-N-6 **§3633.A.1.b** [40 CFR **§146.93(a)(2)**], Figure 7-1 shows the expected pressure differential between pre-injection and post-injection pressures in the injection zone, as determined by the plume model described in Section 2. As discussed in Sections 2 and 3, the HCS Well No. 001 will inject into sequentially shallower intervals over the life of the project, resulting in separate pressure profiles for each interval. The pressure differentials illustrated in Section 3 show that at the end of the injection, a maximum differential of 38 psi from the baseline reservoir pressure is observed. This maximum value is already nearly half of the critical pressure calculated at 77 psi, as described in more detail in Section 3.2 of Section 3 – Area of Review. This delta demonstrates that there is no risk that the brine can percolate upwards to the USDW after injection ceases. The pressure dissipation is such that, 10 years after the end of injection, the maximum excess pressure is only 11 psi, with an average of 7 psi for the whole area.

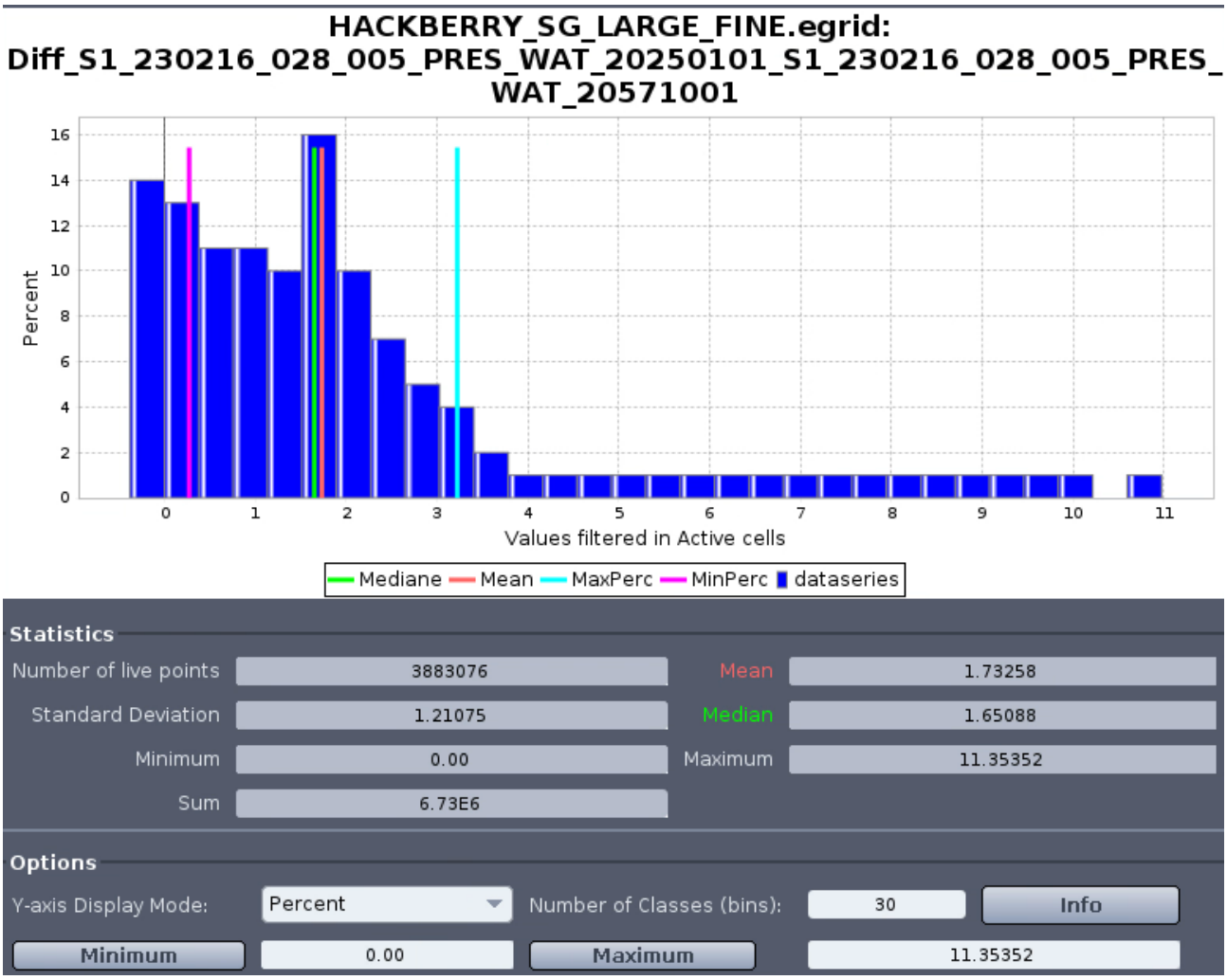
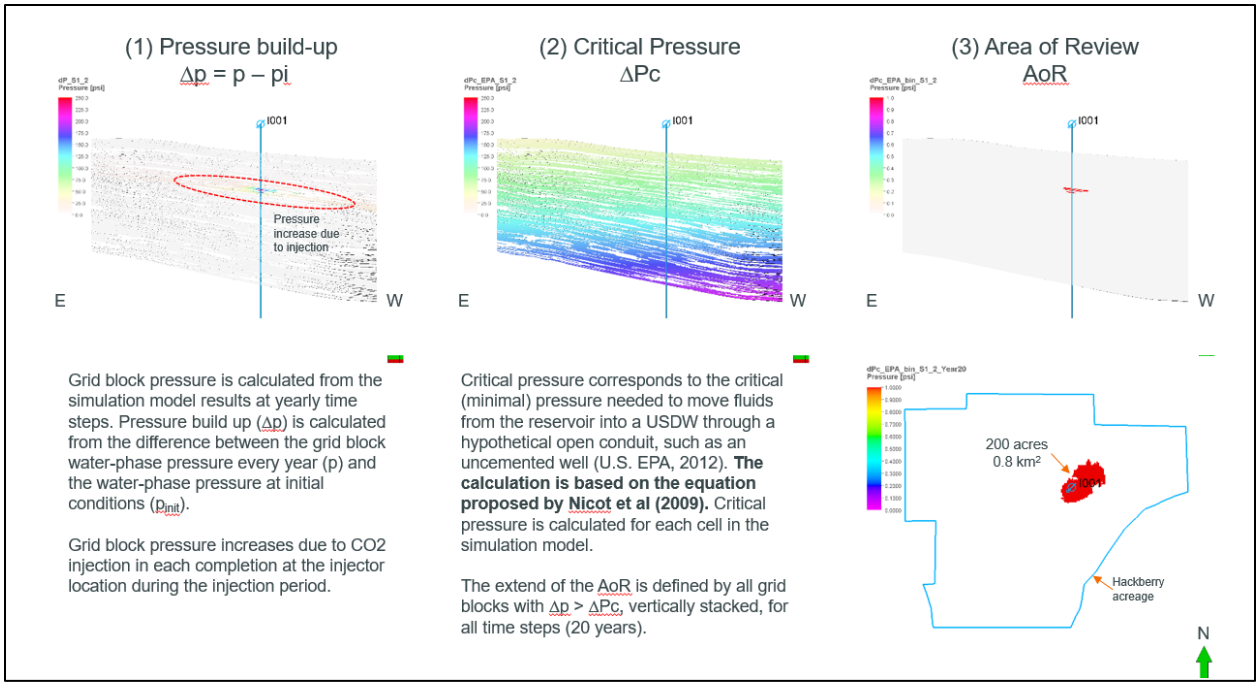


Figure 7-1 – Histogram of Pressure Differential at Year +10 After the End of Injection



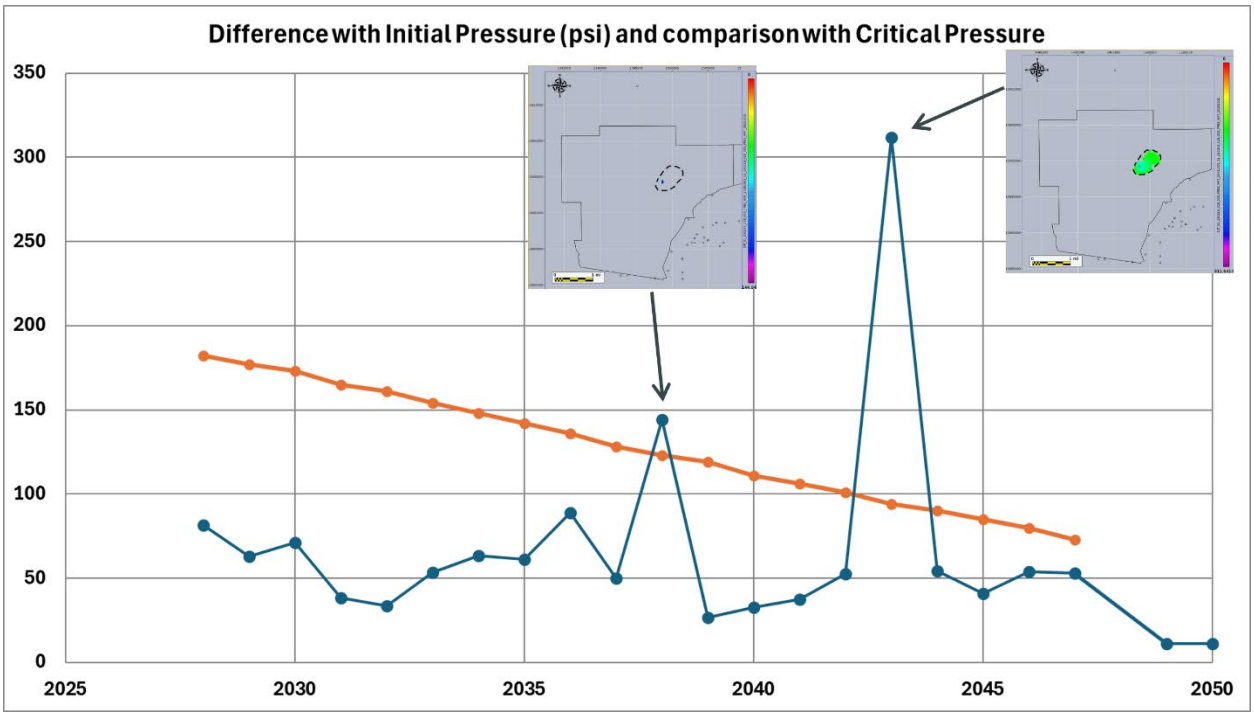


Figure 7-2 –(A) Critical Pressure Front Extent, 2.0 MMT/yr. (B) The plot of generated pressure at the end of each injection period shows the maximum pressure (blue) and the critical pressure (orange). Associated critical pressure fronts are depicted in the above maps. This graph depicts how the pressure decreases post-injection in Year 2048.

Based on the simulation results for the injection scenario of 2.0 MMT/yr, the extent of the critical pressure front covers an area of 200 acres (approximately 0.8 km^2) at the conclusion of the injection phase at Year 20, as shown in Figure 7-2. The spatial extent of the critical pressure is significantly smaller than the actual size of the CO_2 plume, which spreads over a much larger area of 1,989 acres (or 8 km^2). Once the injection phase ceases, pressure begins to dissipate leading to a return towards nearly initial conditions.

7.3 CO_2 Plume Position at End of Injection and at Closure

Section 2.*2.9.13 (Section 2 – Plume Model)* details the changes in the CO_2 plume over the next 100 years post-injection which is affected by the dissolution of CO_2 in water and its trapping due to hysteresis effects. The amount of movable CO_2 decreases over time as described in Figure 7-3.

After the 20-year injection phase, a notable and rapid decrease in CO_2 saturation occurs, leading towards plume stabilization. Approximately 30 years post-injection (around Year 2077), the plume achieves a near-stable state, indicating the diminishing movement of the CO_2 within the injection zone. The rate of saturation change provides a quantitative insight into this stabilizing trend: ten years post-injection (by 2057), the average saturation change is 6.82%, which then sharply decreases to 1.19% by Year 40 (2067), followed by minor changes to 1.16% by Year 50 (2077), and further to 0.81% by Year 60 (2087).

Beyond the 50-year mark post-injection, the saturation change continues to decline very gradually, maintaining an average saturation change of less than 1% from years 70 to 120. This long-lasting period of minimal CO_2 saturation change confirms the effectiveness of the CO_2 trapping mechanisms that contribute to the long-term stability and secure containment of the stored CO_2 in the Hackberry reservoir.

1

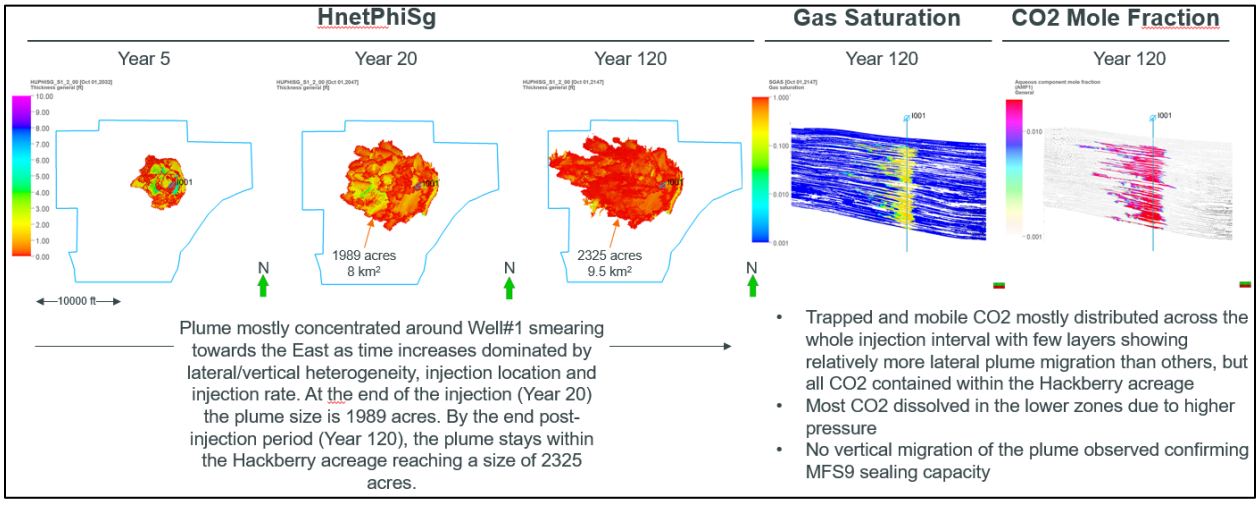


Figure 7-3 – Maximum Extent of CO_2 at End of Injection the Years Prior to End of Injection

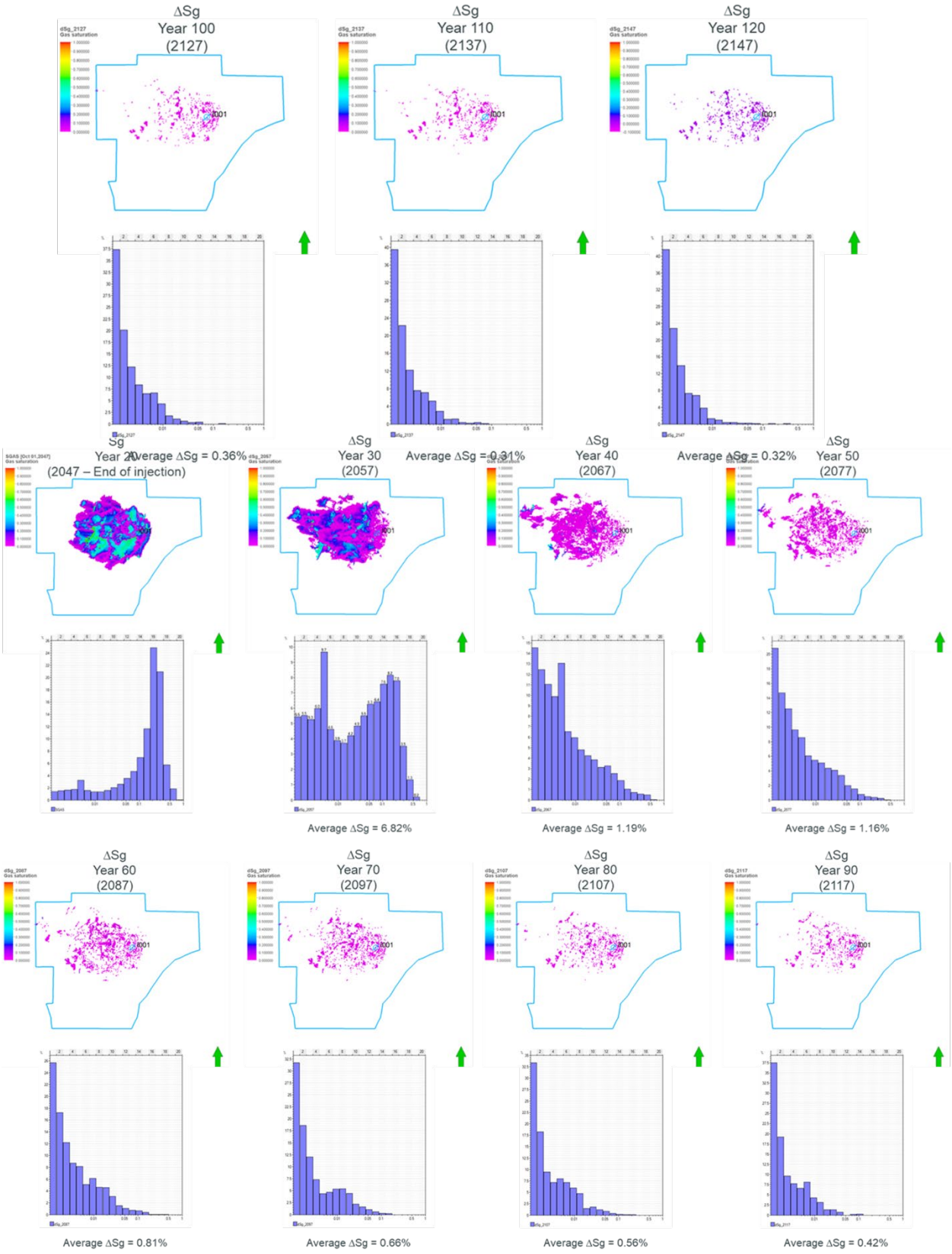

ΔSg
Year 100
(2127)
ΔSg
Year 110
(2137)
ΔSg
Year 120
(2147)
Average ΔSg = 0.36%
Average ΔSg = 0.31%
Average ΔSg = 0.32%
ΔSg
Year 20
(2047 – End of injection)
ΔSg
Year 30
(2057)
ΔSg
Year 40
(2067)
ΔSg
Year 50
(2077)
Average ΔSg = 6.82%
Average ΔSg = 1.19%
Average ΔSg = 1.16%
ΔSg
Year 60
(2087)
ΔSg
Year 70
(2097)
ΔSg
Year 80
(2107)
ΔSg
Year 90
(2117)
Average ΔSg = 0.81%
Average ΔSg = 0.66%
Average ΔSg = 0.56%
Average ΔSg = 0.42%

Figure 7-4 – Plume Dissipation Post-Injection at 2.0 MMT/yr

7.4 Post-Injection Monitoring Plan

As required by SWO 29-N-6 **§3633.A.2** [40 CFR **§146.93(b)**], Hackberry Carbon Sequestration (HCS) will continue to monitor the project site for 50 years or until the carbon front is determined to be a non-threat to the USDW formations. As shown in the model, the pressure differential at the wellbore drops significantly once injection ceases. Without continued pressure, the pressure front loses energy quickly and 99.9% of the CO_2 will be unable to migrate any further by Year 30 (10 years after injection).

Throughout the injection life of the well, the reservoir model will be further calibrated with active injection data. The duration of the PISC timeframe will be re-evaluated alongside area of review (AOR) re-evaluations that are to occur at least once every five years. Upon cessation of injection and at least once every five years, as needed, an amended PISC and Site Closure Plan will be submitted to the Underground Injection Control (UIC) Program Director (UIC Director). The PISC timeframe will be updated based on the latest modeling and monitoring data.

7.4.1 Post-Injection Monitoring Activities

During the monitoring period, the testing and monitoring activities described in Section 5 will be performed and reported at the frequency shown in Table 7-1.

Table 7-1 – Post-Injection Monitoring and Reporting Frequency

Testing/Monitoring Activity	Frequency	Reporting Schedule
Groundwater Monitoring Well Geochemical Analysis	Every five years	Within 30 days after data collection and analysis
Well Pressure and Temperature monitoring	Continuously	Annually
Indirect Plume Front Monitoring (VSP Walk away + micro-gravimetry)	At the end of injection, then at a frequency as determined by model results and in agreement with the UIC Director.	Within 30 days after data collection and analysis

All testing and monitoring activities listed will be performed and analyzed as discussed in Section 5 – Testing and Monitoring Plan, including QA/QC measures.

7.5 Demonstration of Non-Endangerment of USDW

Prior to the approval of the site closure authorization, HCS will provide documentation that the USDW will not be at risk by the CO_2 plume, as required by SWO 29-N-6 **§3633.A.3** [40 CFR **§146.93(c)**]. HCS will submit a report to the UIC Director demonstrating the non-endangerment of the USDW including site-specific conditions, updated plume model, predicted pressure decline within the injection zone and any updates to the underlying geological assumptions used in the original model. While the PISC duration is 50 years, it may be possible to demonstrate USDW non-endangerment earlier.

The non-endangerment report will be compiled and will include project specific information that includes:

- Operational and post-injection phase monitoring data and information
- A current AOR evaluation
- The status of potential conduits for fluid movement within the AOR
- Any other site-specific data of information that may support a demonstration of USDW protection and non-endangerment

The modeling effort will provide a demonstration of USDW non-endangerment. This effort will be accomplished by demonstrating that HCS's injected CO_2 will not migrate out of the injection zone. The data collected throughout the life of the project that was used to delineate the AOR, will be used to support this demonstration. The combination of the model, supporting monitoring history, and operational historical data will demonstrate that the plume has behaved as predicted and will remain stationary, the formation pressures will decline over time, and that the sequestered CO_2 is both vertically and laterally within the injection zone period.

7.6 Site Closure Plan

To meet the requirements of SWO 29-N-6 **§3633.A.3** [40 CFR **§146.93(e)**], the following site closure activities will be performed. These activities include removal of surface equipment, plugging of all wells, site restoration and submittal of final site closure reports.

7.6.1 Pre-Closure

Notice of intent to close the site will be submitted to the UIC Director at least 120 days prior to closure operations. If any changes have been made to the original Post-Injection Site Care and Site Closure Plan, a revised plan must also be submitted. Relevant notifications and applications, such as plugging requests, must be submitted and approved by the appropriate agency prior to commencing such activities.

7.6.2 Injection Well Plugging Activities

HCS Well No. 001 will be plugged as discussed in Section 6 – Plugging and Abandonment Plan.

The planned plug and abandonment procedures are designed to prevent migration of CO_2 or formation fluids in the injection interval from migrating to the USDW. Prior to plugging the injection well, the mechanical integrity of this well will be determined by an annulus pressure test, casing inspection log, temperature log, and a pressure fall-off test as described in Section 5. Plugging schematics and procedures are provided in Appendix J.

7.6.3 Site Closure—Monitoring Well Plugging Activities

Plugging and Abandonment of monitoring wells is discussed in Section 6. Plugging and abandonment objectives of the monitoring wells will ensure that the monitoring wells do not serve as conduits for fluid movement following the cessation of injection and site closure.

7.6.4 Site Restoration

Once the injection well and monitoring wells are plugged and capped below grade, all surface equipment and structures will be removed. The land will be restored to original conditions or to conditions approved by the UIC Program Director.

7.6.5 Documentation of Site Closure

Within 90 days of site closure, a final report must be submitted to the UIC Director, per requirements SWO 29-N-6 **§3633.A.6** [40 CFR **§146.93(f)**], and will include the following:

- Documentation of appropriate injection and monitoring well plugging, including copy of the survey plats
- Documentation of well-plugging report to LDENR
- Records of the nature, composition, and volume of the CO_2 stream over the injection period

A record of notation in the facility property deed will be added to provide, in perpetuity, any potential purchaser of the property the following information:

- The fact the land was used to sequester carbon dioxide
- The name of the State agency (LDENR) with which the survey plat was filed and/or the State Agency to which it was submitted
- The total volume of fluid injected, the injection zones into which it was injected, and the period over which injection occurred

HCS will retain all records collected during the post-injection site care period for 10 years following site closure. At the end of the retention period, HCS will deliver all records to the UIC Director, which will thereafter be retained at a location designation by the Director.

Underground Injection Control – Class VI Permit Application for Hackberry Carbon Sequestration Well No. 001

Cameron Parish, Louisiana

SECTION 8 – EMERGENCY AND REMEDIAL RESPONSE PLAN

Prepared for *Hackberry Carbon Sequestration, LLC*
Cameron, LA

By

Lonquist Sequestration, LLC
Austin, TX

August 2021
Revised January 2025

SECTION 8 – EMERGENCY AND REMEDIAL RESPONSE PLAN

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8.1 Introduction

This Emergency and Remedial Response plan for Hackberry Carbon Sequestration (HCS) Well No. 001 was prepared to meet the requirements of SO 29-N-6, **§623** [40 CFR **§146.94**]. The plan describes potential adverse events that could occur in the development, operation and post-closure phases of the project and the actions to be taken in the event of such an emergency. This plan will be reviewed and updated annually. Any change in key personnel will also cause the Plan to be updated immediately.

A copy of the approved Emergency and Remedial Response Plan and any future updates will be provided to the following agencies and local response personnel:

- Cameron Parish Police Jury President
- Office of Homeland Security
- Cameron Parish Office of Emergency Preparedness

8.2 Resources/Infrastructure in AOR

HCS Well No. 001 is located 2.1 miles northwest of Hackberry, Louisiana. The proposed location is 2.1 miles from the nearest freshwater well and 3.8 miles from the nearest drinking water well. No structures or artificial penetrations of any kind are located within the predicted plume extent. The well and the plume extent are located on and below a brackish body of water. The well location and plume extent are shown in Attachment A.

The lowermost underground source of drinking water (USDW) in the area of review (AOR) is located at approximately 1,100 ft in this area.

8.3 Infrastructure/Resource-Specific Events and Response Plans

The following scenarios represent a high-level concept of potentially significant adverse events, methods of prevention and detection and likely remedial responses. The likely responses are not intended to be exhaustive in nature. Each situation will be evaluated based on the specific event, using best engineering practices.

8.3.1 Event Description – Well Blowout

This event could occur during wellbore drilling if unexpected changes in reservoir pressures cause a sudden release of hydrocarbons.

Risk Level: Low

Prevention and Detection:

- Maintain appropriate mud weights as expected for the area based on offset well data
- Monitor rate of drilling fluid returns versus rates pumped, penetration rates, pump pressures, etc.

Potential Response Actions:

- Stop drilling
- Close the blowout preventer; insert rams into the well.
- Read and record stabilized shut-in pressures
- Stop injection and notify the UIC Program Director within 24 hours.
- Kill the well by pumping fluid down the wellbore that is heavier than the current fluid until the well stops flowing.

Response Personnel: Onsite drilling personnel and supervisors.

Equipment: Drilling rig, mud logging equipment, blowout preventers with annular rams, drilling fluid materials to increase mud weight adequately.

8.3.2 Event Description – Spill

This event could occur during the drilling of the wellbore due to an accidental release of drilling fluids, hydrocarbons, chemicals, etc. during drilling and completion or workover operations.

Risk Level: Medium

Prevention and Detection:

- Properly maintained blowout preventers to prevent accidental release of drilling fluids or hydrocarbons
- Spill prevention equipment on drilling or workover rig

Potential Response Actions:

- Contain spill using available equipment such as absorbents, booms, etc.
- Notify appropriate regulatory authority and supervisory personnel
- Immediately take samples around the point of entry
- Initiate Spill Prevention, Control and Countermeasures Plan for facility

Response Personnel: Drilling/workover crews or operations personnel.

Equipment: Absorbents, containment equipment

8.3.3 Event Description – CO_2 Migration

This event could occur if the plume reaches faults or fractures that allow CO_2 migration into another zone, including the USDW, or to the surface. Failure of the confining zone could also

cause CO_2 to migrate.

Risk Level: Medium

Prevention and Detection: The CO_2 plume will be monitored as described in Section 5 - Testing and Monitoring (Section 5.6.6).

Potential Response Actions:

- Cease injection immediately and notify the UIC Director within 24 hours.
- Use vertical seismic profile (VSP) system to assess location and degree of CO_2 movement, as described in Section 5.
- Resume injection, if able, at a reduced rate.
- Continue monitoring of plume at a more frequent interval to determine if migration continues.
- If groundwater/USDW is impacted:
  - Pump CO_2-contaminated groundwater to the surface and aerate it to remove CO_2..
  - Apply "pump and treat" methods to remove trace elements.
  - Drill wells that intersect the accumulations in groundwater and extract carbon dioxide.
  - Provide an alternative water supply if groundwater-based public water supplies are contaminated.
- If CO_2 plume is detected above the upper confining zone but below the base of the USDW:
  - Cease injection immediately and notify Director within 24 hours.
  - Conduct investigation to determine the most probable source of the leak.
  - Repair source of leak if possible.
  - Conduct a revised area of review for artificial penetrations that could be impacted by the CO_2 plume at the newly detected depth.
  - If required, develop a corrective action plan to address any artificial penetrations identified.
  - If leak has been repaired, notify the UIC Director when injection can be expected to resume.
- If surface water is impacted:
  - Shallow lakes will quickly release dissolved CO_2 back into the atmosphere.
  - Create a hydraulic barrier by increasing reservoir pressure upstream of the leak.
- If the plume continues to migrate out of the zone or beyond the expected plume extent, recomplete up hole into the next planned injection interval.

8.3.4 Event Description – Loss of Mechanical Integrity

This event could occur due to failure of cement behind the casing, improperly seated packer or tubing leak.

Risk Level: Medium

Prevention and Detection: Proper wellbore design, including proper cement and metallurgy of the casing and tubing will be implemented in the construction phase. Pressure and rate monitoring, pressure fall-off tests, annulus pressure tests, etc., will all be performed per the Testing and Monitoring Plan.

Potential Response Actions:

- Stop injection and notify the UIC Program Director within 24 hours.
- Close wellhead valve.
- Monitor well and annulus pressures.
- Determine the cause and severity of failure to determine if any release of the CO_2 stream or formation fluids may have been released into any unauthorized zone.
- Pull and replace the tubing or the packer.
- Install chemical sealant barrier and or attempt cement squeeze to block leaks.
- Demonstrate mechanical integrity per the methods discussed in Section 5.
- Notify the UIC Director when injection can be expected to resume.

8.3.5 Accidents/Unplanned Events (Typical Insurable Events)

Unforeseen events may occur while operating the Hackberry Storage Project, such as surface infrastructure damage, pipeline leak, compressor failure, animal damage, and weather-related events. This applies to FEMA flood hazards and emergencies related to operating a well in a shallow water environment.

Risk Level: Medium

Prevention and Detection: Equipment will be maintained regularly to prevent or minimize damage. Damage prevention infrastructure will be installed, and markers will be placed to alert the public of potential hazards. The markers will include the name of the operator and telephone number. Barricades will be installed to prevent accidental damage to equipment or animals from entering the facility. Weather will be continuously monitored, and during the possibility of an adverse event, precautions will be taken to limit the potential impact.

Potential Response Actions:

- Stop the injection and notify the UIC Director within 24 hours.
- Activate the downhole safety valve if necessary.
- Determine the cause and severity of the failure and initiate repairs.
- Demonstrate mechanical integrity per the methods discussed in *Section 5.*
- Notify the Director when injection can be expected to resume.

8.4 Training

Personnel responsible for implementing this plan shall be trained on their duties and

responsibilities related to these facilities during annual on-site and/or table-top training exercises. All plant personnel, visitors, and contractors must attend a plant overview orientation before obtaining permission to enter any of the facilities. A refresher course on this training is required annually.

Training and/or drill simulations shall include, at a minimum:

- Overview of the HCS Incident Command Structure
- Offensive and defensive roles in various emergency response scenarios and any specific roles for which employees or contractors may be responsible
- Facility communication systems and alternate communication methods
- Critical facility infrastructure
- External agency or media interactions
- Appropriate control, containment, and clean-up procedures

Once the facility construction has been completed and the project is commissioned to go into service, HCS will conduct mock emergency response exercises which will include company personnel, local emergency responders, and third-party contractors. The mock emergency drill will start with a desktop plan for conducting the mock emergency and then be moved to a field exercise. Two mock emergencies are envisioned. The first would be a well-control event where CO_2 and formation fluids are escaping from the injection well. The second event would be a pipeline rupture allowing supercritical CO_2 to escape and vaporize. These mock emergencies would be conducted every three years with the first set done just prior to going into service. The mock emergency will be conducted in conjunction with relevant perish officials. Each mock emergency would be evaluated for not only appropriately addressing the event but also the efficiency of communication with local, state, and federal authorities as well as the nearby public citizenry.

8.5 Communications Plan and Emergency Notification Procedures

Emergency response contacts:

Table 8-1 – Emergency Services – **CALL 911**

Agency	Telephone Number
Cameron Parish Fire Department	911 or (337) 775-7511
Cameron Parish Sheriff	911 or (337) 775-5111
Cameron Parish Health Unit	(337) 775-5368
Cameron Parish Office of Emergency Preparedness	(337) 775-7048
Louisiana Emergency Preparedness Office	(225) 925-7500

Louisiana State Police	(225) 925-6325
Louisiana State Police – Hazardous Material Hotline	(225) 925-6595

Table 8-2 – Government Agency Notification

Agency	Telephone Number
Environmental Protection Agency Region 6	(214) 665-2200
Class VI Contact	(214) 665-8473
Louisiana Department of Natural Resources	(225) 342-4500
Injection Well Incidents	(225) 342-5515
Cameron Parish Local Emergency Planning Committee (LEPC)	(337)-775-7048
National Response Center (NRC)	(800) 424-8802
Louisiana State Police – Hazardous Material Hotline	(225) 925-6595

Table 8-3 – Internal Call List

Name	Title	Telephone Number
Stoney Sportsman	Gas Storage Facility Manager	(337) 527-2260
Michael Hutchinson	Director of Operations	(619) 322-8532
Maurice Gilbert	Chief Engineer	(713) 206-6713
Kelly Oden-Prasser	Senior External Affairs	(619) 696-4230

As appropriate, Hackberry Carbon Sequestration, LLC will communicate with the public regarding events that require an emergency response, including the impact of the event on drinking or the severity of the event, actions taken or planned, etc.

8.6 Flood Risk

Due to its location in shallow open water, the Hackberry Carbon Sequestration Well No. 001 is designated as FEMA flood hazard Zone VE, which corresponds to an area within the one-percent annual chance of flood event with additional hazards due to storm-induced velocity wave action. Floodplain management standards apply.

8.7 Emergency and Remedial Response Plan Review and Updates

This Emergency and Remedial Response Plan will be reviewed and updated annually. Any amendments to the plan must be approved by the UIC Director and will be incorporated into the permit. This plan will also be reviewed and submitted to the UIC Director within one year of an area of review evaluation; following any significant changes to the facility, such as addition of injection or monitoring wells; change in personnel; or when required by the Director.

The following attachments are located in *Appendix I*:

- Appendix I-1 Map of the AOR showing resources and infrastructure
- Appendix I-2 FEMA Flood Zone Hazards Map
- Appendix I-3 Emergency Operations Plan

Underground Injection Control – Class VI Permit Application for Hackberry Carbon Sequestration Well No. 001

Cameron Parish, Louisiana

SECTION 9 – IT DECISION

Prepared for *Hackberry Carbon Sequestration, LLC*
Cameron, LA

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August 2021
Revised September 2024

SECTION 9 – IT DECISION

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9.1 Executive Summary

Large-scale capture of anthropogenic carbon dioxide (CO_2) is increasingly viewed as critical for the United States (U.S.) and global community to meet ambitious goals for greenhouse gas reductions by companies, states, and national governments. For example, the International Energy Agency (IEA) has highlighted a potential need for CO_2 storage to increase from around 40 million metric tons per year today to more than 5,000 million metric tons per year by mid-century. Today, the United States is the global leader in carbon capture, use, and sequestration (CCUS), holding more than 60% of current CCUS capacity and half of all global CCUS capacity under development.[1] To impact global greenhouse gas levels, once carbon, generally in the form of CO_2, is captured from a source, that CO_2 must be safely disposed of in some manner. One of the more common methods of dealing with the captured CO_2 is to inject it into porous formations below the earth's surface.

The U.S. Gulf Coast has long been viewed as suitable for long-term sequestration of CO_2.[2] Hackberry Carbon Sequestration, LLC (HCS) is proposing to develop a carbon sequestration facility in Cameron Parish, Louisiana. HCS was formed to primarily support the capture and permanent sequestration of CO_2 emitted from liquefied natural gas (LNG) export terminals located in the Gulf Coast region. LNG terminals operating and under construction in southwest Louisiana and southeast Texas have enabled the United States to become a global leader in exporting natural gas to foreign customers. Increasingly, these customers seek natural gas sourced through lower-carbon processes to meet their energy needs and are looking to US suppliers to supply this cleaner product.

HCS plans to build a premier carbon sequestration operation in the Gulf Coast region of the US. Through disciplined and innovative processes and engineering designs, HCS will facilitate the sequestration of captured carbon from nearby LNG facilities and other industrial facilities located in the Gulf Coast Region, thereby locking the greenhouse gas away in subsurface geologic structures for all time. In addition, HCS's commitment to facilitate lower-carbon energy and industrial production will help these crucial manufacturers evolve as leaders in the global energy transition.

The Hackberry Carbon Storage Project (Project) is being designed to handle captured from the various industries in southwest Louisiana, and the location for this proposed facility is ideally suited for that purpose. This site was selected for several reasons: favorable geology, controlled pore space storage rights, numerous industrial facilities with sequestration needs, and existing pipeline rights-of-ways to transport the captured gases for disposal. HCS is proposing to drill and complete carbon sequestration well in Cameron Parish, Louisiana. As such, HCS is applying for a Class VI permit to construct and operate the well. The well will be located on surface acreage, with CO_2 injected into and sequestered in subsurface pore space wholly owned by HCS.

[1] The world has vast capacity to store CO2: Net zero means we'll need it – Analysis - IEA

[2] 2010 Carbon Atlas of the United States and Canada, National Energy Technology Laboratory, US Department of Energy

HCS is developing the Project to capture CO_2 from nearby LNG and industrial facilities and sequester it by injecting into porous formations. The Project will capture and compress low-pressure CO_2 and transport it by pipeline to the new Hackberry processing facility. The Hackberry Pump Station will be constructed for this project on land owned by LA Storage, a subsidiary of Sempra Infrastructure. At the Hackberry Pump Station, CO_2 will be compressed and transported to the injection well via the proposed high-pressure pipeline. The injection well will be drilled on land controlled by HCS. The CO_2 will be injected into intervals spanning over the approximately 1,700 net ft of clean, porous, and permeable Miocene sands found under this property at the injection well. The Project will be sized to permanently store up to 2 million metric tons per year of CO_2. Initially, Hackberry Carbon Sequestration, LLC will be working with its affiliate Cameron LNG, LLC (Cameron LNG) to handle and dispose of captured CO_2 from their Cameron, LA export facility. Cameron LNG receives natural gas from various pipelines and compresses the gas into LNG products for export. The process of preparing the natural gas for export generates significant quantities of CO_2. Cameron LNG will be capturing a portion of these resultant emissions and delivering them to HCS for disposal into the carbon sequestration well.

The Project facilities, except the pipelines, will be constructed and operated on the property entirely under the control of HCS.

9.2 Hackberry Pump Station

The Hackberry Pump Station will occupy about 10 acres on property owned by LA Storage (see Figure 9-1). The CO_2 will be delivered to the Hackberry Pump Station at a typical pressure range of 1,200-1,800 pounds per square inch (psi) and a temperature range of 100°F-120°F (38°C-49°C). At these conditions, the injectate stream will be in a supercritical phase. At the Hackberry Pump Station, this fluid will be compressed to a pressure of approximately 3,000 pounds per square inch gage (psig). Then, the pressurized CO_2 will be pumped as a supercritical fluid to the Injection Site, around 5 miles away. Equipment and facilities at the Hackberry Pump Station will likely include:

- Supercritical CO_2 pump, approximately 2,000 to 3,000 horsepower
- Small office, shop, and warehouse
-

9.3 Injection Site

Supercritical CO_2 will be injected into subsurface formations for disposal and sequestration (see Figure 9-1). The facilities installed at the Injection Site will include:

- Injection well
- Pile supported above water well platform (approximately 60 ft by 50 ft)
- Backup solar power and associated batteries
- Meter, valves, and solar power on the platform

Materials and equipment will be transported to the Injection Site by barge, using the water access route shown in Figure 9-1.

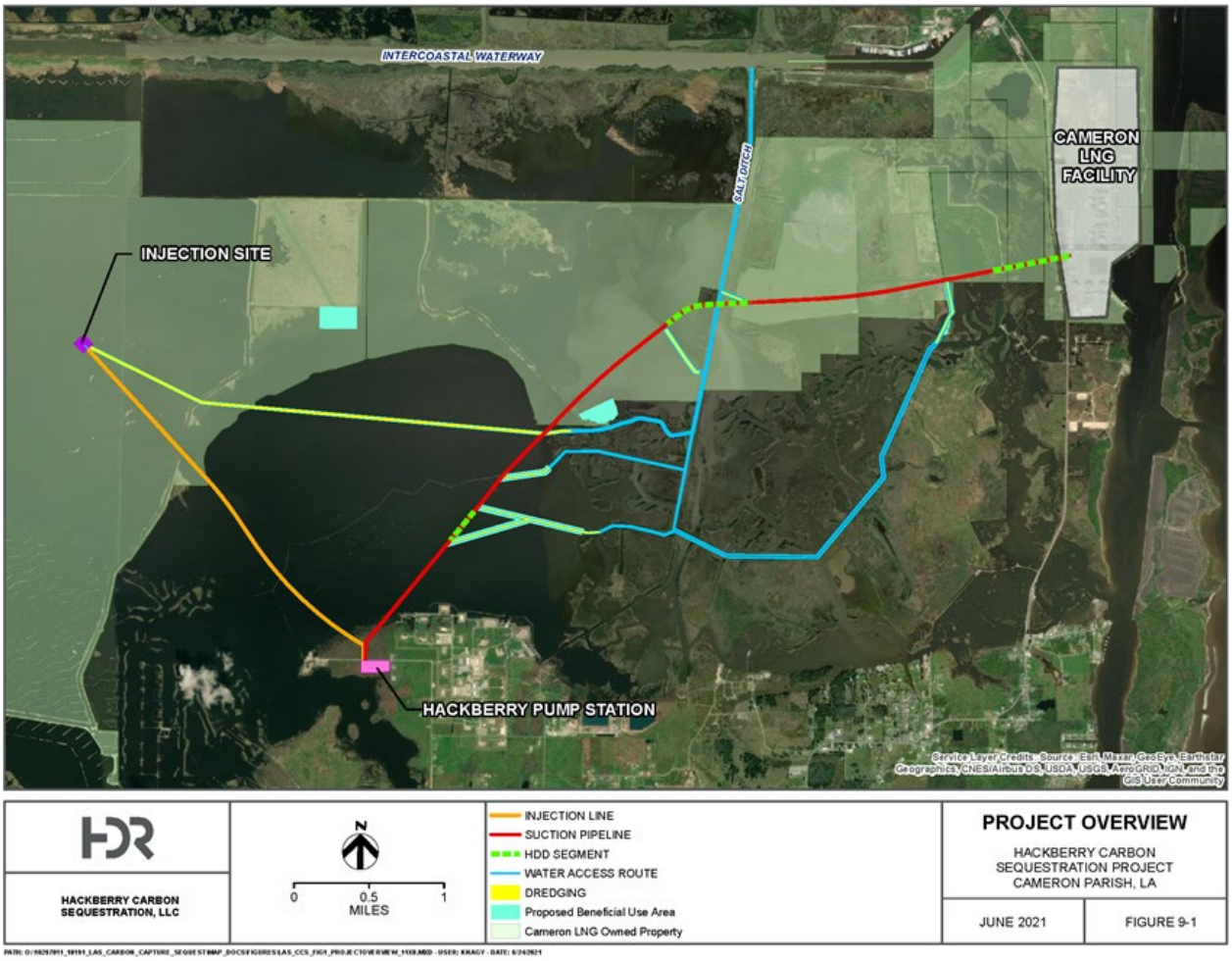

Figure 9-1 – Hackberry Carbon Sequestration Project Overview Map

9.4 Summary of Environmental Impacts of the Project

The Project will provide significant support to reduce global emissions of greenhouse gases by taking CO_2 from LNG and other industrial facilities in the region and sequestering (i.e., permanently storing) it thousands of feet underground. Burning natural gas already emits less CO_2 than coal or fuel oil, and the Project will further reduce the CO_2 associated with natural gas making it an even greener energy source.

The Project includes electric-powered compressors and dehydration facilities to eliminate permitted air emissions. In addition, because of the electric-powered equipment, the Project will not generate emissions of carbon monoxide, volatile organic compounds, formaldehyde, or nitrogen oxides.

The Project will not treat or dispose of any hazardous waste or solid waste. There will be a small quantity of sanitary sewage generated by operations of the Project, but that stream will be treated in accordance with state water quality regulations tying into LA Storage's existing utilities. The discharge will have no impact on water quality.

Due to the size of the Project, transportation is not anticipated to be a concern. Construction materials and process equipment will be delivered to the facility via barges using a water access route (see Figure 9-1). Construction materials and process equipment will be delivered to the pump and compressor stations via trucks on existing roads. Deliveries of any large equipment that could interfere with local traffic will be scheduled during off-peak traffic hours when possible.

Neither threatened and endangered species nor any preferred habitat was found for any listed species within the survey area boundary. The Information for Planning and Consultation (IPaC) consistency letter (Appendix M), which uses the Louisiana Endangered Species Act project review and guidance for other federal trust resources determination key (Louisiana DKey), provides a "may affect – not likely to adversely affect" determination for the Eastern black rail and the West Indian manatee. Due to the lack of preferred habitat at the project site and the temporary nature of the project, HCS does not expect the project to impact any of the potentially occurring protected species. See Appendix M for IPaC study over the area of review (AOR).

The site location has been assessed for impacts to environmental resources. A response to each of the "IT Decision" questions follows.

9.5 IT Questions

I. Have the potential and real adverse environmental effects of the proposed facilitybeen avoided to the maximum extent possible?

Yes. HCS designed the Project to avoid the potential and real adverse environmental effects to the maximum extent possible by placing CO_2 processing facilities on existing developed

property and placing the well on property controlled by HCS. The Project will meet all applicable State and Federal environmental statutes, rules, and regulations. The primary purpose of this facility is for geologic sequestration (permanent storage) of CO_2. Once in operation, safe operating procedures, safety measures, and required monitoring and maintenance practices will be followed to continue to avoid the potential and real adverse environmental effects to the maximum extent possible. No hazardous wastes will be accepted at the site.

Air Quality

The potential air emissions from the Project construction and operation are minimal and will not cause any adverse impacts to air quality.

Air quality impacts associated with the construction of the Project can be generally classified as temporary impacts from the operation of equipment during construction activities and impacts from dust generation. Impacts associated with equipment operation during construction activities, including well drilling, pipeline construction, and dredging, may result in a minor, temporary increase in emissions. Equipment and movement of material for land clearing, grading, excavation, drilling, and concrete work, along with vehicular traffic on paved and unpaved roads, could cause dust. The amount of dust will be based on the area of construction, silt and moisture contents of the soil, wind speed, frequency of precipitation, amount of vehicle traffic, vehicle types, and paved or unpaved roads. Fugitive dust may occur during all phases of construction. Dust will be greater during the drier winter months and in areas of fine-textured soils. During these periods, dust suppression techniques, such as watering, will minimize the impacts of fugitive dust.

The Project does not include any regulated processes by National Emission Standards for Hazardous Air Pollutants (NESHAP) Part 61. The Project will not be a source of federal Hazardous Air Pollutants (HAP). The emergency generator on the well platform will be subject to 40 CFR 63 Subpart ZZZZ, NESHAPs for Stationary Reciprocating Internal Combustion Engines.

Water Quality

During normal operation of the Project facilities, surface water discharge will include stormwater runoff. All stormwater from Hackberry Pump Station will be managed in accordance with HCS's Environmental Plan. In addition, HCS will install all necessary erosion and sedimentation control structures required by the state to minimize potential impacts from stormwater runoff.

Impacts from the project construction and operations to wetlands and waterbodies are authorized in part by the United States Army Corps of Engineers (USACE) – New Orleans District. The Section 404/10 permit No. MVN-2021-01265-WQQ (Appendix N) was issued March 27, 2024. The permit authorizes and provides guidance on the permanent impact of wetland or marsh area affected by the construction of the project. Prior to authorization through this USACE mechanism, the project performed field surveys including a wetland

delineation of the proposed project area to evaluate and determine the amount and type of wetlands that would be impacted by construction and operation. The project will result in a net positive yield of wetlands/marsh, as approximately 20 acres of wetlands/marsh will be generated through the beneficial use of dredge material (BUDM).

The Louisiana Department of Energy and Natural Resources (LDENR) Office of Coastal Management (OCM) was also engaged for a Coastal Use Permit (CUP)/Consistency Determination. This outlines some additional requirements for the permittee on top of what is within the Section 404/10 authorization. The LDENR-OCM issued CUP No. P20210822 (Appendix O) on November 16, 2022.

As part of the interagency review process conducted during the USACE permitting process, The Louisiana Department of Environmental Quality (LDEQ) reviewed the application with regards to compliance with the State Water Quality Standards. LDEQ determined the project met the state standards for preservation of water quality and issued a Water Quality Certification, WQC 211229-01 (Appendix P), on September 21, 2022 authorizing the project.

Temporary soil erosion and sediment control measures will be installed along the proposed pipeline construction right-of-way (ROW) and other work areas, as applicable, in accordance with HCS's Environmental Plan. The Environmental Plan details the Best Management Practices (BMPs) that will be implemented during and after construction to minimize potential impacts to the surrounding environment. The BMPs will be used to minimize erosion of disturbed soils and prevent the transportation of sediment outside of the construction boundary into environmentally sensitive areas such as wetlands and waterbodies. HCS's Environmental Plan provides specifications for the installation, implementation, and maintenance of the BMPs while allowing for flexibility in selecting specific BMPs based on site-specific conditions. This document will be included as part of the construction contract and will provide contractors and environmental inspectors with a reference to specific environmental conditions and associated BMP plans and procedures. The Best Management Practices (BMPs) referenced in the Hackberry Carbon Storage (HCS) Environmental Plan are still under development, as they are project-specific and will be finalized closer to the start of construction. The BMPs will include elements of mitigations required under the USACE Section 404/10 permit, the Coastal Use Permit, and other industry-standard practices for construction designed to minimize off-site impact.

Sensitive Soils and Vegetation

Construction of the Project facilities will not generate waste that could leach into the soil and affect shallow groundwater. Project operations will not cause the destruction of important vegetation or have any impacts on forested lands.

The areas where the Project facilities are to be located consist of open water, existing industrial facilities, or undeveloped marshland. The total disturbance to accommodate these facility components is estimated to be no greater than 10 acres. No permanent wetland impacts are being proposed for the Project. There are no long-term adverse impacts

anticipated on environmentally sensitive areas. The Project, through the beneficial use of dredge material, will create approximately 37 acres of wetland marsh.

Sensitive Wildlife and/or Habitat

HCS consulted with the U.S. Fish and Wildlife Service and the National Marine Fisheries Service to determine the potential for the occurrence of federally listed species and their critical habitat that are known or expected to be in the vicinity of the Project. HCS conducted habitat and wetland surveys of the entire proposed Project area, and no endangered or threatened species or critical habitat were observed during the field surveys.

The USACE permitting process includes interagency collaboration and consultation with multiple other agencies to address potential adverse impacts to threatened and endangered (T&E) species. These communications include:

- A consultation held with United States Fish and Wildlife Service (USFWS) by the project team on August 17, 2021, to introduce the project. As part of the interagency collaboration with USACE, USFWS determined no threatened or endangered species are expected to be impacted as a result of this project. The USACE Section 404/10 reflects the inclusion of standard permit language for Manatees, which is standard for projects with an in-water work component.

- National Oceanic and Atmospheric Administration's National Marine Fisheries Service (NOAA's NMFS) sent a concurrence (Appendix Q) dated February 21, 2022 explaining their reception of the Joint Public Notice under the USACE permitting process and determined the project had minimal impact while noting the marsh creation through beneficial use of dredge material. The NMFS does not object to the project as currently proposed and offers no conservation recommendations pursuant to the EFH provisions of the Magnuson-Stevens Fishery Conservation and Management Act or the Fish and Wildlife Coordination Act.

- The Louisiana Department of Wildlife and Fisheries (LDWF) provided comments regarding erosion control and vegetative maintenance in a communication (Appendix R) dated February 2, 2022.

The impact to threatened and endangered species within the AOR was not directly evaluated during the permitting process. However, per the LDENR's suggestion, HCS performed a desktop evaluation of the AOR. Using the IPaC tool, a determination was able to be made that there are no T&E species that are within the AOR or at risk due to project activity in the AOR. Considering the AOR will not have any additional above surface impacts other than where it coincides with pipeline, well pad, or temporary access (which were all evaluated in the USACE 404/10 permit process), it can be sufficiently determined that there is no additional risk to T&E species.

Archaeological and Historic Resources

HCS performed a Phase I Archaeological Survey of the entire proposed Project area to identify archaeological and historic resources. No archaeological or historic resources were identified within the proposed Project survey areas.

HCS performed surveys of the impacted areas for archaeological and cultural resources consistent with the Louisiana State Historic Preservation Office (SHPO) and coordinates with the Tribal Historic Preservation Offices (THPO). The SHPO provided a concurrence (Appendix S) on October 11, 2021, agreeing that there are no properties in or eligible for listing in the National Register of Historic Places and that no archaeological or cultural resources would be adversely affected by the construction and operation of the project. Surveys were not conducted in the AOR, apart from the surface impacts surveyed originally, but it is reasonable to conclude that there would be no impacts in areas where work was not being conducted and the ground/water not disturbed.

Accidental Releases

The Project facilities are designed to meet or exceed all existing environmental regulations in a manner that minimizes the potential for accidental releases using the best available technology, best equipment, and best management practices.

The potential for a release of CO_2 to the surface or into a USDW will be monitored continuously, and the possibility of any impact from such release will be kept to a minimum by operating the well in accordance with Statewide Order 29-N-6 and EPA's regulations for Class VI CO_2 geologic sequestration injection wells found in 40 CFR Part 146, Subpart H. Well design, construction, and continuous monitoring requirements in federal and state regulations are written to protect USDWs. However, in the event of a suspected release to a USDW, HCS will shut in the system, begin an assessment of the area possibly affected, and begin evaluation of the possible source of the release. Notification to those listed in the facility Emergency Action Plan, including the Office of Conservation, will be initiated, and additional actions will be planned based on the results of the assessment. In the event of any leak or spill of drilling fluid or fuel during construction, the system will be shut-in, and HCS will implement the directives set forth in its Emergency Action and Spill Prevention Plans.

The risk of mechanical failure of the well will be minimized by routine visual inspections, preventive maintenance, and monitoring. Periodic demonstration of mechanical integrity of all wells is required by the Office of Conservation and as set forth in Statewide Order 29-N-6. HCS will establish mechanical integrity prior to commencing injection and on a schedule as set forth in the Order. In addition, HCS will maintain mechanical integrity as defined in §3627 of the Louisiana Administrative Code, Title 43, Part XVII (January 2021). These measures will include:

- Performance of an annulus pressure test after initial well construction as part of the pre-operating requirements; and at least once every 12 months witnessed by an agent of the Office of Conservation; and after performing any well remedial work that

involves unseating the tubing or packer.

- Continuous monitoring of injection pressure, rate, injected volumes; pressure on the annulus between tubing and long-string casing; and annulus fluid volume as specified in **§3621.A.6.**

In addition, as described in Statewide Order 29-N-6, HCS will monitor the predicted extent of the injected CO_2 plume and any mobilized fluids that may result in degradation of water quality over the lifetime of the project, as informed by computational modeling, in order to ensure that the proposed injection operation will not at any time endanger USDWs including non-exempted portions of the injection formation. At least once every 12 months, HCS will determine the absence of significant fluid movement by using an approved tracer-type survey such as a radioactive tracer, oxygen-activation log, or similar tool; or a temperature or noise log. HCS is considering monitoring alternatives, including the use of 4-D seismic monitoring or a proprietary process for continuous reservoir surveillance using fiber-optic downhole equipment connected to the wellbore.

In the event that a well fails a mechanical integrity test, HCS will immediately take the well out of service and notify the Office of Conservation. Written procedures for correcting the well failure will be submitted within 60 days, and the well will be rehabilitated upon approval by the Office of Conservation. In addition to adhering to the measures specified in §3627, HCS will also adhere to the reporting and recordkeeping measures defined in §3629.

No land-based treatment or disposal of solid or liquid waste is planned for the Project. HCS will design, construct, and operate the Project, including the well, pipelines, pump station, and other facilities in accordance with good engineering practices. These practices ensure systems provide maximum safeguards for the protection of the groundwater and surrounding environment. No adverse effects on groundwater resources are anticipated from the placement of foundations for the well pad, pipelines, or Project facilities.

BMPs will be followed to prevent and control the discharge of pollutants from accidental release incidents. HCS will develop contingency plans, operating procedures, and BMPs to prevent the discharge of pollutants resulting from accidental release events.

The Project facilities will have highly trained and dedicated staff to operate the facility, and HCS will utilize experienced personnel to form the core of its operating staff. Operations, maintenance, and support personnel will be thoroughly trained and periodically tested in the proper use and operation of appropriate equipment and will be familiar with the potential hazards of operating the Project facilities. Combining properly designed facilities and thoroughly trained personnel accomplishes the goal of minimizing the potential for accidental releases.

II. Does a cost-benefit analysis of the environmental impact costs balanced against the social and economic benefits of the proposed facility demonstrate that the latter outweighs the former?

Yes. The purpose of the Project is to provide beneficial environmental impacts by sequestering CO_2 emissions that would otherwise be released to the environment. This environmental benefit, along with the social and economic benefits, more than balances the minor adverse impacts associated with the construction and operation of the Project.

The Project will provide important economic and social benefits to Cameron Parish and the State of Louisiana. Construction of the Project will create jobs, additional earnings for households, and rising business activity throughout the Louisiana economy. An increase in employment will be realized because of the Project. The Project estimates an average of approximately 310 workers will be needed during construction. HCS anticipates that the workforce will be composed of 15% local residents, 75% commuters, and 10% who will temporarily relocate to the area. The operations phase of the Project is expected to create approximately two full-time employment positions. The Project will result in increased business activity associated with the construction, as measured by sales and personal earnings. Additionally, during construction, there will be an increase in tax revenue to local Parishes. The operation of the Project facilities will positively affect local tax revenue based on tax revenue projections.

The economic benefits and spillovers from the construction of the Project are substantial but temporary. The economic benefits and spillovers from the ongoing operation of the Project facilities are both substantial and permanent. These economic benefits will accrue to the State of Louisiana and the Cameron Parish region for the duration of facility operations. HCS intends to be a good corporate citizen involved in employee/community partnerships in Cameron Parish and surrounding communities. HCS will make an effort to buy goods and services locally and hire locally for the construction and implementation of the Project. Employment opportunities are provided to all aspects of the Louisiana workforce. As a result, the Project will result in a net social benefit to the community in the vicinity of the proposed Project.

Geologic carbon sequestration is the process of capturing CO_2, the most commonly produced greenhouse gas, and storing it underground in deep geologic formations. Carbon sequestration is one method of reducing the amount of CO_2 in the atmosphere with the goal of reducing global climate change.

In conclusion, because HCS anticipates no potential negative economic effects on the community and no additional costs to the community for police, fire, school, or medical services, HCS believes that the benefits of the Project, coupled with the economic benefits that the Project will bring to the area, outweigh the minimal adverse environmental impacts as described in the response to Question 1.

III. Are there alternative projects which would offer more protection to the environment than the proposed facility without unduly curtailing non-environmental benefits?

No. There are no alternative projects which would offer more protection to the environment than the proposed facility without unduly curtailing non-environmental benefits. The primary goal of this Project is to sequester CO_2 captured from nearby LNG facilities by permanently storing it in subsurface geologic formations. The Project will support the delivery of green LNG products to foreign customers for their energy needs and provide the environmental benefit of reducing greenhouse gas emissions. Carbon sequestration has only recently become economically feasible. Based on publicly available information, no other such projects planned would serve the same purpose in this area. The project is designed to maximize co-location with other facilities, minimize the footprint of surface facilities, and minimize environmental impacts within the Louisiana coastal zone. As explained in the response to Question 1, the Project will have minimal adverse environmental impacts, which will be outweighed by its environmental benefit.

IV. Are there alternative sites which would offer more protection to the environment than the proposed facility site without unduly curtailing non-environmental benefits?

No. There are no alternative sites that would offer more protection to the environment than the proposed facility site without unduly curtailing non-environmental benefits or the environmental benefits that are the Project's primary purpose. HCS considered a number of factors in selecting the proposed facility location including proximity to the CO_2 source (Cameron LNG), control (ownership or lease) of the surface area overlying the proposed extent of the CO_2 plume, avoidance of artificial penetrations (e.g., oil and gas wells) in the plume area, and subsurface geologic conditions suitable for CO_2 sequestration. A large contiguous area of surface and subsurface control is needed for the carbon capture and sequestration project. Sempra Infrastructure and its subsidiaries own and control the pore space on over 8,000 acres in the area of the proposed facility, which is ideal for this type of project. Sempra Infrastructure owns a 160-acre parcel of land in Cameron Parish, which is situated near Cameron LNG, one of the initial sources of CO_2 for this proposed HCS sequestration project. The parcel is also the proposed site of the Hackberry Storage Project, which will be developed for natural gas storage by LA Storage, LLC. LA Storage, LLC and HCS are both subsidiaries of Sempra Infrastructure. HCS will construct the compression and dehydration facilities on 10 acres within the 160-acre industrial property. This co-location of facilities will serve to minimize environmental impacts.

The 160-acre property cannot be used for the injection well itself because it overlies the West Hackberry Salt Dome, which has displaced the Miocene sand layers that will be used for the CO_2 sequestration. The salt dome is approximately 4 miles long (east-west) and 2 miles wide

(north-south). Numerous oil wells, both active and plugged, are present along the flanks of the salt dome. Oil wells would be undesirable in the sequestration area because they would present a potential vertical pathway for CO_2 to migrate out of the storage zone. The location of the proposed CO_2 injection well avoids these issues and meets all regulatory siting requirements. The plume will also be entirely contained within surface and subsurface areas controlled by Sempra Infrastructure or its subsidiaries.

HCS assessed the feasibility of collocating the facility with the saltwater disposal wells proposed for the Project. This location would be east of the West Hackberry Salt Dome and close to Cameron LNG, which would result in shorter pipelines. However, the CO_2 plume associated with an injection well at this location would extend beyond the Gulf Intracoastal Waterway and onto other land not controlled by Sempra Infrastructure or its subsidiaries. This would not be a viable alternative to offer more protection to the environment than the proposed facility site.

HCS considered drilling its injection well on dry land rather than the proposed injection site. However, to keep the CO_2 plume within lands owned by Sempra Infrastructure or its subsidiaries, the well would have to be directionally drilled to inject CO_2 at the desired point. The Louisiana Department of Energy and Natural Resources (LDENR) requires a vertical borehole from the upper confining zone through the injection zone to the lower confining zone. Directional drilling would increase the risk of hole failure from the pipe getting stuck, as well as increase the potential for problems with well integrity. Furthermore, a longer injection pipeline might be needed. Therefore, this alternative would not offer more protection to the environment than the proposed facility site.

The proposed route for this pipeline is the most feasible. The suction pipeline will be installed beneath sensitive surface water bodies using horizontal directional drilling (HDD) to avoid impacts to the water bodies and adjoining area. Additionally, the suction pipeline will be co-located with the proposed pipelines associated with the Hackberry Storage Project for about 3.2 miles (about 60% of the total length), which will also reduce impacts.

In conclusion, HCS has not identified an alternative that would result in a significant environmental advantage compared to the proposed Project.

V. Are there mitigating measures which would offer more protection to the environment than the facility as proposed without unduly curtailing non-environmental benefits?

No. There are no mitigating measures that would offer more protection to the environment than the facility as proposed without unduly curtailing non-environmental benefits or the environmental benefits that are the Project's primary purpose. Specific discussions of the mitigating measures are included in the responses to the previous questions. These mitigating measures include:

- The existing Cameron LNG facility and the 10-acre site for the Hackberry Pump Station within the LA Storage facility are both suitable for industrial development. Numerous oil wells and pipelines currently exist in open water outside the sequestration area, and the proposed injection well will not represent an unusual element to the current use or the viewshed of the area.

- The suction pipeline will be co-located with other pipelines for over half of its route, and HDD will be used to construct the suction pipeline beneath sensitive water bodies and State Highway 27.

- Transfer of construction materials and process equipment will occur primarily by barges using a water access route through open water and trucks using existing roads. HDD will be used to construct the suction pipeline beneath sensitive water bodies and State Highway 27. Also, when possible, arrivals of large or oversized shipments will be scheduled during non-peak traffic hours to the extent practical. No significant impact on traffic patterns is expected from the Project.

- To the extent feasible, the water access route will align with previous water access features to minimize the amount of dredging required.

- There is no treatment or disposal of solid or hazardous waste associated with the Project.

- There will be no significant adverse impacts on historical, archaeological, wetland, estuarine, wildlife habitat, or prime agricultural areas as a result of the Project.

- There will not be any permanent filling of wetlands.

- The Project will create approximately 37 acres of wetland marsh through the beneficial use of dredge material.

- The Project provides increased economic and social benefits to the local and regional areas.

- Groundwater resources are protected to the maximum extent possible.

- Wastewater and stormwater discharges from the Project will have minimal impacts to receiving waters. Only stormwater runoff will be discharged to local drainage.

- The injection well will be operated in such a fashion as to meet the state requirements of Statewide Order 29-N-6 and federal requirements of 40 CFR 146.88. These requirements include limiting injection pressures, maintaining mechanical integrity, and monitoring.

- The compressors/pumps and dehydration equipment will be powered by electricity. Solar energy is currently planned to be the primary source to power communication systems at the injection wellhead with battery storage.

HACKBERRY
CARBON SEQUESTRATION

Stakeholder Engagement Plan

Rev	Date	Status	Review	Approval
1	12/4/2023	Original Draft	K. Prasser / J. Trahan	R. Tomaski / P. Frederick
2	1/18/2024	EPA Upload	K. Prasser / J. Trahan	R. Tomaski / P. Frederick
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1.0 SUMMARY

1.1 HACKBERRY CARBON SEQUESTRATION

Sempra Infrastructure Partners, LP (Sempra Infrastructure or SI), along with its Cameron LNG Partners, is developing the Hackberry Carbon Sequestration (HCS) project, a proposed carbon capture storage facility designed to sequester carbon dioxide (CO_2) from the Cameron LNG project and other industrial sources. SI or its Affiliate is a majority owner of Cameron LNG, a liquefaction facility in Cameron Parish, Louisiana.

1.1.1 SITE DEVELOPMENT

Located in west Hackberry, Louisiana, the facility is being designed to advance the company's net-zero solutions goal by producing cleaner liquefied natural gas (LNG) for Cameron LNG customers. HCS intends to utilize the federal 45Q tax credit to create economic value. HCS is expected to be one of the first world-class carbon sequestration operations in North America.

This facility will be constructed primarily for the storage of carbon dioxide (CO_2) from Cameron LNG and potentially other industrial sources. The proposed project will include a compression and processing facility and pipelines to transport the CO_2 to the sequestration well.

In September 2021, HCS initiated the permitting process by filing a Class VI injection well permit application with the U.S. Environmental Protection Agency (EPA). Applications were also filed with the U.S. Army Corps of Engineers (USACE), the Louisiana Department of Natural Resources (LDNR) and other agencies.

Development of the Hackberry Carbon Sequestration project remains subject to definitive agreements, obtaining the necessary permits, and all partners reaching final investment decision.

1.2 PROJECT DESCRIPTION

Sempra Infrastructure is developing the Hackberry Carbon Sequestration project (HCS), a carbon capture storage facility designed to sequester CO_2 from industrial sources. The project will include a compression and processing facility and pipelines to transport the CO_2 to the sequestration well.

As part of the development of this project, CO_2 would be captured at the Cameron LNG facility and transported by pipeline to land owned by LA Storage, a subsidiary of Sempra Infrastructure. It will be permanently stored in a saline aquifer using an injection well

approximately 5,000 to 10,000 feet under the earth's surface with a maximum capacity of up to 4.5 million tonnes of CO_2 per year.

The initial well will be permitted to sequester up to 2 million tonnes of CO_2 annually and the project can be expanded to accommodate additional sources. The initial volumes from Cameron LNG are estimated at approximately 600,000 tonnes per year based on the CO_2 removed from the natural gas feedstock of a 17 million tonnes per year LNG export facility.

The expertise required to develop and operate carbon sequestration facilities is similar to that for natural gas storage facilities. The experience of Sempra Infrastructure and its Affiliates includes developing and operating two natural gas storage facilities in the U.S. Gulf Coast.

1.3 CAMERON LNG

Located in Hackberry, Louisiana, the Cameron LNG export facility includes three liquefaction trains with an export capacity of 14 million tonnes per annum (Mtpa) of LNG or approximately 1.7 billion cubic feet per day (Bcfd). The company commenced commercial operations for Train 1 in August 2019, Train 2 in March 2020, and Train 3 in August 2020, respectively.

Sempra Infrastructure, through its development of Cameron LNG has been in Cameron Parish as an active community partner and neighbor since 2002. The Hackberry Carbon Sequestration facility is being constructed as part of the company's commitment to sustainability and once operational, will help to reduce Cameron LNG's CO2 emissions by up to 15%.

1.4 LA STORAGE

Once constructed, Sempra Infrastructure's LA Storage project will be a new high-deliverability natural gas storage facility in Hackberry with associated pipelines running through Cameron and Calcasieu Parishes. This project is being built to meet the growing operational needs of LNG facilities in the region.

The project will consist of four storage caverns located on a 160-acre parcel of company-owned land. Upon completion of this facility, LA Storage will be able to provide approximately 25.5 billion cubic feet (Bcf) of natural gas storage capacity.

Part of Hackberry Carbon Sequestration's facilities will be located on the LA Storage facility site. The proposed Hackberry Carbon Sequestration pipeline will run approximately 6 miles from Cameron LNG to the LA Storage site. The LA Storage site will allow for future sources of CO_2 or other required CCS facilities. The CO_2 will then be transported to the injection well, located about 3 miles away.

2.0 PROJECT BENEFITS

Hackberry Carbon Sequestration (HCS) is part of Sempra Infrastructure's Southwest Louisiana Energy Hub. Positioning Cameron Parish as a flagship hub for the energy transition, the company will leverage the integrated capabilities of its business segments to develop projects including HCS to serve Cameron LNG.

SI's Southwest Louisiana Energy Hub represents a multibillion-dollar infrastructure investment that will support manufacturing, small businesses and the local community by creating jobs and contributing to the regional community. Construction of the HCS project would provide significant economic benefits including:

1. **Advancing the Energy Transition:** HCS is part of an initiative focused on sustainability as the world transitions to a low carbon future. The development of HCS will help lower greenhouse gas emissions at LNG and other industrial facilities while working to provide decarbonization solutions to customers in North America and global energy markets.

2. **Regional Economic Benefits:** The project will have positive economic benefits to Hackberry, Cameron Parish and the surrounding region through procurement of materials and services, and through the generation of tax revenues. It is estimated that more than $30 million of annual taxable revenue per year will be generated by HCS providing carbon sequestration services in Cameron Parish.

3. **Job Creation:** The project would support the creation of up to approximately 215 on-site engineering and construction jobs over a two-year time period. HCS estimates that at least 8 full-time jobs would be created to operate and maintain the facility on a long-term basis.

4. **Local Environmental Enhancements:** As part of the construction of the HCS facility, approximately 37 acres of new wetland marsh will be created through beneficial use of dredge material.

5. **Community Investment:** Sempra Infrastructure companies are committed to the communities where our employees live and work. The company invests its time, talent and financial resources to help improve the quality of life for our customers, neighbors and employees. Since 2015, SI has contributed nearly $3 million to Southwest Louisiana community partners that are providing vital programs and services in the areas of environmental stewardship and sustainability, emergency preparedness and safety, education, and economic prosperity.

3.0 COMMUNITY ENGAGEMENT

Community involvement, stakeholder engagement and feedback are critical components of this project. HCS also recognizes that effective communication with its stakeholders may address and reduce community concerns, help build trust and transparency, and contribute to the project's overall success. As part of the HCS Stakeholder Engagement Plan, the project team is committed to:

- Conducting a community assessment to help identify and validate concerns and opportunities related to the development and operations of energy and net-zero infrastructure projects in the area. This assessment will also help to identify if the project is in an environmental justice community and opportunities for meaningful social investment.
- Implementing stakeholder engagement activities in which the team actively solicits feedback from the community and property owners about the project. This includes, but is not limited to, conducting open house events, making presentations to local groups, coordinating feedback roundtables, and participating in community events. This also includes utilizing the Cameron LNG Community Advisory Committee (CAC) which has been active since 2004 and is comprised of local citizens that represent the diversity of the area.
- Providing regular project updates to local stakeholders during the calendar year with key project milestones and community investment highlights.
- Maintaining communication channels for stakeholders to include a dedicated toll-free phone line, email address, website and social media channels to allow for two-way communication and response to community questions or concerns.
- Providing a dedicated outreach team to address community questions and concerns and deliver project updates.
- Coordinating contributions of the company and individual employee's time, talent, and funding to support community investment initiatives and events in Cameron Parish communities with a focus on Hackberry, where the HCS project will be located.

3.1 COMMUNITY DESCRIPTIONS

The proposed HCS project will be located in Hackberry, Louisiana. Outlined below are community descriptions for this region of Louisiana, Cameron Parish and the town of Hackberry.

3.1.1 LOUISIANA AND GULF COAST

According to the U.S. Energy Information Administration, the Gulf of Mexico, both onshore and offshore, is one of the most important regions for energy resources and infrastructure in the United States. More than 30 percent of the total U.S. natural gas processing plant capacity is located along the Gulf Coast.

The petroleum and gas industry boomed in the 1970s, and with it, so did Louisiana's economy. Many jobs that operate or provide logistical support to the U.S. Gulf of Mexico crude oil-and-gas industry are within Louisiana. Additionally, approximately 51 percent of the total U.S. natural gas processing plant capacity is located along the Gulf Coast in Louisiana and Texas.

Additionally, according to Global Energy Hub, over 80% of the LNG exported by the United States comes from four Gulf Coast facilities located in Louisiana and Texas.

Carbon sequestration will enable industry to operate while emitting fewer greenhouse gases, making it a powerful tool for reducing emissions. This technology allows Louisiana an opportunity to take the lead in a new generation of energy production, boost the economy and create more high-paying jobs.

3.1.2 CAMERON PARISH

Cameron Parish has a total area of 1,932 square miles, of which 1,313 square miles is land and 619 square miles is water. The Parish is in the southwest corner of Louisiana with major industries including oil, gas and LNG, fisheries, agriculture, cattle, alligator, and trapping.

According to the U.S. Census in 2022, Cameron Parish has approximately 4,900 residents. Cameron Parish Public Schools contain four schools with 1,142 students. The district's minority enrollment is 10% and 70.2% of students are economically disadvantaged.

3.1.3 TOWN OF HACKBERRY

The community of Hackberry is technically an island surrounded by lakes, streams and bayous in the north-central part of Cameron Parish. Known for its wildlife, fishing and cattle, the land where the Cameron LNG facility sits was once used for cattle grazing and oil production. Hackberry High School, a primary and secondary school with curriculum for grades Pre-kindergarten through 12, serves approximately 200 students and is part of

the Cameron Parish School Board. Cameron Parish Public Library operates the Hackberry branch located on Main Street. The Hackberry Volunteer Fire Department provides emergency services.

Situated approximately 20 miles from the Gulf of Mexico, Hackberry has also weathered multiple hurricanes and other natural disasters. After every disaster the town has rebuilt with the help of many volunteers, federal assistance and donations from industry. Nearly 1,300 Southwest Louisiana residents call the community of Hackberry home.

3.2 POLITICAL GOVERNANCE

With the State motto of "Union, Justice and Confidence," Louisiana became the 18th state admitted to the union in April 1812. The Pelican State is home to nearly 4.6 million people with Baton Rouge serving as the state's capital.

3.2.1 LOUISIANA - FEDERAL

Louisiana's federal delegation is comprised of two U.S. senators, six members of the U.S House of Representatives and eight electoral votes. U.S. Senators serve a six-year term while U.S. Representatives each serve a two-year term.

A list of key federal elected stakeholders representing Cameron Parish has been included in the attached appendix.

3.2.2 LOUISIANA - STATE

The State Constitution of 1974 provides for three branches of government: Executive, Judicial and Legislative. The Executive Branch is headed by the Governor who is elected for a four-year term. Governor Jeff Landry (R) recently took office on January 8, 2024. The Louisiana Supreme Court leads the Judicial Branch.

The State of Louisiana has a bicameral legislature that includes a Senate and House of Representatives. The Legislative Branch consists of 39 State Senators and 105 State Representatives. All are elected to a four-year term. Republicans hold a majority in both the Senate and the House.

3.2.3 LOUISIANA - LOCAL

Cameron Parish is governed by a police jury, which is made up of district representatives. In Louisiana, police juries serve as the elected body for the parish. A police jury is a regional form of government, much like a county, and has responsibilities including land use authority, public safety and some public services.

Separately, elected and appointed officials serve on special districts, boards, commissions, and other groups to provide specific services for a designated area within their parish. Each of these districts and boards governs its own activities, has its own

budget and collects property taxes and fees to provide services including school boards, port authorities and other special districts.

Cameron Parish is the largest parish in the state and is known for its abundance of wildlife, marshlands and beachfront. The parish is governed by an elected, 7-member police jury that provides essential public services through its staff to approximately 4,900 Cameron Parish residents.

A list of local government representatives can be found in the attached appendix.

3.2.4 SOVEREIGN NATIONS

According to the Louisiana Department of Culture, Recreation and Tourism, there are four federally recognized tribes in the state: the Jena Band of Choctaw Indians, the Tunica-Biloxi Tribe of Louisiana, the Coushatta Tribe of Louisiana and the Chitimacha Tribe of Louisiana. There are no sovereign nations or tribal communities located in Cameron Parish.

3.3 PUBLIC SAFETY AND EMERGENCY SERVICES

At Sempra Infrastructure, we put the health, safety and security of our workforce, customers and communities at the center of everything we do. We reinforce a safety-first culture for our employees and contractors. We also seek continuous improvement through measurement and learning from daily activities, events and observations.

The project's emergency preparedness and safety plans will be coordinated with local public safety and emergency services, including the Office of Homeland Security, Office of Emergency Preparedness, and locally with sheriff, fire and ambulance districts.

A list of local and regional public safety and emergency services agencies is included in the appendix.

4.0 STAKEHOLDER ENGAGEMENT PLAN

Community and stakeholder engagement is essential to developing, siting, building and operating energy infrastructure. Sempra Infrastructure has a long-standing history in Louisiana of engaging stakeholders early in the development process and has a strong track record of developing, building and operating major energy infrastructure. The company continues to maintain and grow its commitment to the community through a robust stakeholder engagement process.

4.1 BACKGROUND

A partner in Southwest Louisiana and the community of Hackberry for over 20 years, Sempra Infrastructure is committed to giving back and making a positive difference in the communities where we live and work.

Our social investment strategy is aligned with our company culture and values to champion responsible local growth and development, and to support resilient and safe communities. We provide funding and resources to community programs in the following priority areas: Environmental Stewardship and Sustainability, Emergency Preparedness and Safety, Education – Science, Technology & Innovation, Engineering, and Math (STEM) and Economic Prosperity and Leadership Development.

As a company dedicated to enhancing the economic prosperity and resilience of an area that hurricanes and other weather events have significantly impacted, Sempra Infrastructure has also contributed to several community emergency preparedness and safety initiatives over the years. This includes contributing to the construction of a new, $6.3 million community center in Hackberry, which serves as the area's local Emergency Operations Center and a shelter for residents. It also served as an office for FEMA following hurricanes Laura and Delta in 2022.

Additionally, as part of the Stakeholder Engagement Plan (SEP), Sempra Infrastructure's due diligence process includes consultations with stakeholder groups to identify and gain understanding of environmental and social risks. The company strives to mitigate any impacts of our operations and collaborates with the community on ways to contribute to the economic prosperity for all people regardless of race, color, national origin or income with respect to the development, implementation and enforcement of environmental laws, regulations and policies.

At Sempra Infrastructure, we encourage and applaud employee involvement in our communities. Through the ***My Energy*** program, employees can voluntarily participate in a payroll deduction program supporting qualified nonprofit charitable organizations of their choice. Donations by eligible employees are matched up to a limit of $1,500 by the company's corporate foundation.

4.2 STAKEHOLDER COMMUNICATIONS AND CONSULTATIONS

The company's values of ***do the right thing, championing people,*** and ***shape the future*** are at the foundation of developing relationships and ties to the communities where we do business and have employees. Relationships are established before formal permitting for the project begins and extend throughout the development, construction and operation of the facility.

As part of the pre-development phase of the project, a community assessment is completed to gain a better understanding of the area and identify potential issues and concerns. During the permitting phase of the project, particular attention is paid to conveying a coordinated, consistent and clear messaging regarding the proposed project, as well as listening to and addressing issues within the local neighborhoods.

Throughout the development process, the company is proactive in the community, both with community leaders and in consultation with federal, state, and local officials, and agencies. In addition, the company establishes several mechanisms to stimulate community feedback including a local Community Advisory Committee (CAC) made up of a diverse group representative of the area.

As part of the Hackberry Carbon Sequestration project, the company has a developed a robust Stakeholder Engagement Plan (SEP) as a framework to coordinate communications activities, engagement, advocacy, and commitments.

In early 2024, upon completion of the community assessment, this SEP will be expanded to include an overview of community concerns and issues to help advise new or updated elements that may be needed during the different phases this project.

4.3 ENVIRONMENTAL JUSTICE

As a Sempra Infrastructure company, HCS and its employees are committed to a high-performance culture and focused on delivering energy with purpose. Our strength as a company comes from a mosaic of different perspectives, cultures and experiences, and is grounded in the shared values of: ***do the right thing, champion people and shape the future*****.** We are dedicated to building a diverse and inclusive workplace that empowers its employees to reach their full potential in a sustainable manner.

As part of our Stakeholder Engagement Plan, our due diligence process includes consultations with stakeholder groups to identify and gain an understanding of environmental and social risks. We strive to mitigate any impacts of our operations and collaborate with the community on ways to contribute to the economic prosperity for all people regardless of race, color, national origin or income with respect to the

development, implementation and enforcement of environmental laws, regulations and policies.

Demonstrating our values, and to ensure social and environmental justice concerns related to the project are understood and addressed, HCS will collaborate with local and regional stakeholders to continue our focus on:

- Partnerships with local nonprofits, NGO's and other community-based organizations representing the diversity of the community of Hackberry.

- Coordination with local groups focused on education, workforce development and training. This includes:

  - workforce organizations that help provide a pipeline for qualified applicants
  - local and regional high schools, colleges and technical institutions

- Coordination with local groups focused on economic and business development including:

  - chambers
  - economic and business development agencies
  - local contractor groups and unions

- Partnerships with local, regional and state environmental organizations, NGO's and agencies dedicated to habitat and coastal restoration efforts in our local communities.

- Demonstrating the company's commitment to the enhancement of the local environment by evaluating science-based, emission reduction technologies and processes. This is part of Sempra's net-zero value chain emission reduction targets.

- Utilizing our diverse employee ambassadors as spokespeople and mentors to provide project updates and plans.

Helping to advance the global energy transition, the HCS project represents a significant investment in critical infrastructure to help bring cleaner energy sources to the region. SI believes this is essential to powering new solutions for society's climate challenges, as well as building a healthy economy and better quality of life for our communities.

In addition, HCS utilized the EPA's EJScreen to help identify any social or environmental justice concerns. HCS selected a 3-mile buffer around our Class VI Area of Review ("AOR") and the tool allocated a population of 116 residents based on Census information. HCS has identified only 2 permanent residents within the proposed 3-mile buffer and both are over 2 miles away from AOR.

4.4 GOALS AND OBJECTIVES

The goal of the SEP is to provide transparent, two-way communication to stakeholder audiences to build trust and credibility. The plan also ensures that there are structures and mechanisms in place for stakeholders to express any comments or concerns that may arise so that they can be addressed and resolved in a timely manner. By completing the activities detailed in this plan, we will:

- Broaden the knowledge base of stakeholders on topics related to carbon sequestration and its role in helping minimize GHG emissions associated with the natural gas liquefaction process.
- Demonstrate compatibility of the carbon sequestration process with the surrounding environment.
- Communicate the project's safety attributes and emergency preparedness plans.
- Position the company and its employees as safe and responsible clean-energy developers committed to the community long-term.
- Communicate the economic benefits of the proposed project.
- Communicate local content messaging including job and vendor opportunities with the project and its contractors.
- Contribute to charitable and community organizations that align with efforts in the company's key pillar areas of environmental stewardship and sustainability, emergency preparedness and safety, education, and economic prosperity.
- Communicate construction activities and provide feedback or grievance mechanisms for the public.
- Educate and engage employees and project contractors on aspects of the Stakeholder Engagement Plan. This includes reviewing and addressing any community concerns or issues on the project.

4.5 STAKEHOLDER AUDIENCES

The SEP involves extensive interaction with different stakeholder groups using approaches designed to suit each group. Our stakeholders can be divided in the following seven major categories, which represent a detailed, but not exhaustive list:

4.5.1 COMMUNITY:

- Individual stakeholders, such as property owners and neighbors, and community and business leaders

- Educational institutions including school districts, colleges and universities and trade schools
- Groups representing traditionally underserved audiences including:
  - Minority, cultural and diversity
  - Disabled and special needs
  - Senior citizens
  - Veterans
- Community health, first responders and emergency service providers including police, fire and sheriff
- Religious-based organizations serving community needs, such as places of worship
- Environmental nonprofits, ENGO's and local agencies
- Civic groups and non-governmental organizations (NGO's)

4.5.2 INDUSTRIAL NEIGHBORS

- Texas Petroleum
- Targa
- Strategic Petroleum Reserve (SPR)

4.5.3 BUSINESS ADVOCACY:

- Chambers of Commerce
- Economic Development Organizations
- Workforce Development Organizations

4.5.4 GOVERNMENT:

- Federal, state and local elected officials and staff
- Federal, state and local permitting agencies
- Waterway agencies
- Local Port & Navigation Districts

4.5.5 MEDIA:

- National
- Regional and Local

- Industry Publications

4.5.6 TRADE ASSOCIATIONS:

- International and Trade Organizations
- Energy Trades including LNG and pipelines

4.5.7 INTERNAL:

- Project Partners and Investors
- Employees
- Construction Contractors and Subcontractors
- Project vendors

4.6 COMMUNITY ENGAGEMENT AND TACTICS

To effectively reach a diverse array of stakeholders, a number of activities and tactics are utilized as part of the Stakeholder Engagement Plan (SEP). These community engagement actions have been outlined below.

4.6.1 COMMUNITY OUTREACH AND FEEDBACK

Outreach and engagement activities are utilized to broaden community knowledge on topics related to the project and its benefits. Feedback from these efforts include identifying any concerns or issues early on and addressing them. Tactics include:

- Hosting informational meetings and open houses for the community and partnering with local organizations to provide project updates and information
- Engaging and conducting feedback roundtables with project neighbors and local groups representing the needs of the community
- Developing project fact sheets and other communication materials to provide stakeholders with information on the project
- Establishing two-way communication mechanisms for community input, including a toll-free phone number, project email, website and social media channels
- Participating in the region's business advocacy groups to better identify and understand key community issues
- Engaging with the project's Community Advisory Committee (CAC) to gage community opinions and concerns, and involve them in education efforts

- Developing regular consultations with community and business leaders to build a strong foundation for maintaining long-term relationships and creating an atmosphere of collaboration
- Conducting project tours when appropriate
- Hosting job fairs and other recruitment opportunities when appropriate
- Hosting community/company events to celebrate milestones

4.6.2 PUBLIC AFFAIRS

Engaging and informing government officials and agencies about project activities is done early in the project development phase with regular updates provided as the project progresses. As such, government leaders are an essential stakeholder group in getting input and feedback on the project and can be helpful in the resolution of potential community concerns. Tactics include:

- Building relationships with local, state and federal government officials
- Holding regular meetings with public officials, staff and permitting agencies to provide project information and updates, and garner feedback
- Coordinating meetings with parish administrators including water and drainage districts to share project updates and construction activities
- Conducting site tours (when appropriate) and presentations
- Working with public officials and involving them in education and advocacy activities when appropriate

4.6.3 COMMUNITY PARTNERSHIPS

Living our values of ***doing the right thing*** and ***shaping the future***, building strong community partnerships is paramount to developing trust and transparency. Community groups have expertise on local issues, can be sounding boards, and serve as conduits for consulting with other residents to find opportunities that help meet community needs. Efforts in this area include:

- Engaging the Cameron LNG Community Advisory Committee (CAC) to assist in the identification of community partners helping to meet the needs of the community
- Coordinating opportunities to connect with community partners and their constituencies to provide project updates, address and questions or concerns, and solicit feedback on other community engagement opportunities
- Implementing an annual community investment plan that outlines the project's involvement in initiatives that provide vital programs and services in the focus areas of Environmental Stewardship and Sustainability, Emergency Preparedness and Safety, Education, and Economic Prosperity and Leadership Development

- Creating opportunities for community and employee engagement

4.6.4 MEDIA COMMUNICATIONS

The company provides project information and updates via media channels including local area newspapers, television news stations and social media channels. This includes:

- Developing press releases/press kits to distribute to media
- Creating and continuously updating message points and a message platform about the project
- Creating project materials, including a project frequently asked questions (FAQ)
- Providing materials on the project website and social media channels when appropriate
- Holding press briefings and media interviews, as appropriate
- Conducting site tours for media when appropriate
- Monitoring media activities relating to the CCS and liquefaction projects

4.6.5 EMPLOYEE ENGAGEMENT

Living the values of ***championing people*** and ***shaping the future***, employees are encouraged to energize their local communities by giving their time, talent and resources to local causes and groups. Efforts in this area include:

- Educating employees on the Stakeholder Engagement Plan and providing opportunities for local engagement as employee ambassadors
- Featuring local employees in informational pieces on their engagement in the project and in the community
- Providing resources including a matching gifts program, to support employee charitable donations and time donated to eligible nonprofit organizations

4.6.6 COMMUNICATIONS MATERIALS

To provide information to the community and other stakeholders on the project and community engagement efforts, many different communications channels are utilized. This also includes two-way communication channels where the community has an opportunity to provide feedback. Tactics in the area include

- Developing a project website/web presence specifically for the project and with regular updates
- Creating and distributing project communications (i.e. factsheets, brochures)

- Creating and distributing project updates/newsletters (print and electronic) during construction to keep the community informed on any new developments, community partnerships and programs
- Communicating project developments and milestones via social media
- Securing ad and advertorial opportunities to highlight project milestones as appropriate
- Providing visual renderings on the project, when available
- Communicating project messages as part of participation in industry leadership groups, conferences, forums and trade shows
- Supporting career and vendor recruitment activities with ads, open houses and job fairs
- Supporting project permitting activities with ads, open house events, agency briefings and community feedback meetings
- Creating internal news articles and features to educate and engage employees on the project

4.7 ADDRESSING POTENTIAL PROJECT ISSUES AND CONCERNS

Construction activities can generate issues that may impact our neighbors and the surrounding community. Issues such as increased traffic, noise, dust and population increases from temporary workers can also be a concern. To help address this, HCS will have a variety of methods available to stakeholders to communicate any questions or concerns. Below is a summary of these methods:

4.7.1 PUBLIC COMMENT AND FEEDBACK METHODS:

- **Dedicated Project E-mail and Phone Number:** A project specific toll-free phone line and dedicated email address will be established upon receiving the Class VI permit to construct. Additionally, once construction activities begin, these communication channels will be promoted in project materials and with community partners and project neighbors.
- **Project Webpage:** A project webpage will be developed to include information on how to contact appropriate project representatives, as well as provide other ways to connect directly with the company.
- **Correspondence:** HCS plans to distribute correspondence on activities affecting project neighbors and other community members.
- **Open House Events:** The HCS team is planning to host open house events allowing community members a chance to engage with project team and provide

feedback. Additional open house events or meetings will be planned and implemented closer to the commencement of construction activities.

- **Community Feedback Roundtables:** The HCS team will also host smaller consultations with representatives from the community to garner input on the project and address any questions or concerns.
- **Regulatory and Permitting process:** Federal and state regulatory and permitting processes have continually encouraged public comment and feedback on projects. HCS will incorporate changes to the project as needed to address any potential concerns.
- **Communication Tools**: HCS will provide updates on construction and other activities via press releases/advisories, website, social community newsletter and paid inserts in local papers.
- **Community Advisory Committee:** Sempra Infrastructure already has an established Community Advisory Committee (CAC) which has been active since 2004. The CAC meets a minimum of two times per year, as well as participates in project-driven community engagement activities throughout the year for Cameron LNG and other company projects in the Cameron Parish community.

4.7.2 AGENCY PUBLIC COMMENT AND FEEDBACK METHODS

The U.S. Environmental Protection Agency's (EPA's) permitting process for the Class VI application includes a technical review after the permit application is deemed complete. The technical review period is projected to be approximately 24 months. When the project passes the EPA's technical review, a new Class VI carbon storage permit will be drafted and published for public review. This will trigger a public comment period of a minimum of 30 days.

Communities are notified of this public comment period through local newspaper postings and property owners living within a 2-mile radius also receive a project mailing when draft permits are issued. There are several opportunities for public participation including submitting comments on the draft permits, attending public meetings or agency public hearings. Public comments are evaluated before a final permit decision is rendered by the agency.

Louisiana's Department of Natural Resources (DNR), through its Office of Conservation – Injection & Mining Division, issues a public notice for Underground Injection Control (UIC) well permit applications in accordance with the State of Louisiana laws and provisions adopted by the Office of Conservation. All interested parties are giving the opportunity to submit written comments to the state. A permit decision is made after the public comment period closes.

The HCS team works in coordination with both the EPA and LDNR to attend and participate at the agency events.

4.8 GRIEVANCES AND RESOLUTIONS

As part of the Stakeholder Engagement Plan, HCS will establish and manage a Grievance Management System. As part of this effort, the following activities will be instituted:

- All grievances made known to the project team via the methods described in the Agency Comment and Feedback section above are recorded in the company's Community Feedback Mechanism. This is also referenced internally as our Grievance Record Log tool.
- This record log will be maintained to document the individual's name and contact information, the type of grievance, responsible department and resolution.
- Each grievance will be considered and promptly reviewed. A resolution or explanation will be issued via the appropriate communication channel in a timely manner.

4.9 EVALUATION METRICS

Successful implementation and effectiveness of the SEP will be measured by:

- Continually reviewing goals and assessing the results
- Seeking community feedback with a focus on immediate project neighbors, especially during the construction phase of the project
- Conducting feedback sessions with project employees and contractors
- Conducting surveys and public opinion polling, as appropriate
- Monitoring the media for positive vs. negative news on the project
- Maintaining a calendar of all outreach activities, including all meetings and presentations
- Evaluating the Community Feedback Mechanisms to evaluate any trends or reoccurring issues and identifying mitigation measures that can be taken
- Implementation and measurement of any Community Benefits Agreements negotiated as part of the project

5.0 DETAILED ACTIVITIES

5.1 PRE-DEVELOPMENT PHASE

Objective: The pre-development phase of the project focuses on activities done prior to or in conjunction with the submission of the project's permit application process. During this phase, the team will garner information about the community and validate project stakeholders. Additionally, the team will seek feedback to better understand key stakeholder positions on the project in order to address questions and mitigate community concerns.

Key Considerations:

- Educate and seek initial feedback from stakeholders about the project
- Gain understanding of key priorities and concerns in the community
- Gain an understanding of priority community issues relating to infrastructure projects and construction activities
- Coordinate activities required by the EPA, LDNR or other permitting agencies as part of the application and community feedback process

Key Activities:

- Conduct a regional community assessment to identify and understand new socio-economic considerations in the region and key stakeholders. The community survey is expected to be completed in Q1 2024.
- Develop informational materials about the project that can be made available to stakeholder groups. Materials will include:
    - A fact sheet on the HCS project
    - Background information on the company
    - Schematic of how the facility operates
    - Photos of the site / project rendering
    - Informational videos (as available) on CCS technology
    - An overview highlighting the economic development benefits of the project for the local community
- Develop and manage the HCS project webpage
- Secure project community contact mechanisms including phone line, dedicated email

- Conduct initial key stakeholder feedback consultations with representatives from the following groups:
  - State and local elected officials from Cameron and Calcasieu Parishes
  - Safety agencies (e.g., fire, sheriff and emergency response teams)
  - Project neighbors
  - Local leadership from organizations including:
    - Educational institutions
    - Environmental groups
    - Business advocacy (chambers and economic development)
    - NGO's representing local environmental justice issues
- Seek feedback from the company's local Community Advisory Committee (CAC)
    - CAC was established and has been active since 2004
    - Comprised of ten representatives and is utilized to assist the company in providing feedback in the following areas:
      - Construction activities including traffic issues, jobs and vendor procurement
      - Environmental stewardship including wetlands protection
      - Emergency and Safety Preparedness Plan
      - Community Engagement activities and Stakeholder Engagement Plan
- Other activities as identified

5.2 DEVELOPMENT PHASE

Objective: The project's development phase focuses on activities conducted during the permitting process. During this phase, the team will increase its outreach to the broader community to gain a better understanding of key community concerns and issues, seek feedback on the project and gain community support. In understanding the community's position on the project, the team will be able to better address questions and minimize or mitigate concerns.

Key Considerations:

- Educate and seek continuous feedback from the local community about the project
- Gain understanding of the community's key priorities and concerns regarding the project
- Coordinate opportunities with local community organizations to disseminate project information to their constituencies

- Continue coordination of activities required by the EPA, LDNR or other permitting agencies as part of the application and community feedback process

Key Activities:

- Update project materials based on initial stakeholder consultations and concerns
- Conduct community feedback roundtables or open house events to present the project and seek feedback from a broader group of stakeholders
- Coordinate briefings with the media on the project with particular attention on local media channels
- Educate company employees and develop internal news stories about the project
- Implement community feedback mechanisms to include a toll-free phone line, dedicated email and webpage
- Finalize local community assessment and create a stakeholder map.
- Outline activities related to any Community Benefits Plans secured as part of the project. This can result from tax abatement or other local agreements and is often focused on the incorporation of a Local Content Plan.

5.3 ADVANCED DEVELOPMENT PHASE

Objective: The advanced development phase of the project focuses on activities done after the project permits have been received and prior to the start of construction. During this phase, the team will focus on working with project contractors, project employees and local stakeholders to ensure two-way communication with the community and begin implementing the local content plan.

Key Considerations:

- Educate project neighbors on construction schedule and key activities
- Educate project employees and contractors on the company's commitments to the community and the stakeholder engagement and community investment plans
- Coordinate opportunities with neighborhood-based organizations to disseminate project construction information to their constituencies
- Validate and prioritize community issues relating to infrastructure projects and construction activities

Key Activities:

- Conduct community or neighborhood open house events to connect local stakeholders to the project construction team and contractors
- Activate and actively promote community feedback mechanisms to include a toll-free phone line, dedicated email and webpage
- Evaluate and implement regular neighborhood feedback sessions to help identify any new potential concerns or issues that may arise during construction activities
- Continue stakeholder engagement roundtables to seek feedback on local content opportunities to include local hiring and procurement opportunities and initiatives
- Educate company employees and develop internal news stories about the project

6.0 STAKEHOLDER OUTREACH ACTIVITIES AT-A-GLANCE

Activities	Q1 2024	Q2 2024
Community Assessment	• Conduct a regional community assessment to identify and understand new socio-economic considerations in the region and key stakeholders. Community survey is expected to be completed by April 2024. (In Progress)	• Complete stakeholder mapping (April)

Communication Materials & Mechanisms	• Development and/or update of Project Materials (In Progress)
	  ○ Project fact sheet
	  ○ Company information
	  ○ Schematic of how a CCS facility operates
	  ○ Project rendering / photos
	  ○ Informational videos (as available) on CCS technology
	  ○ Overview addressing environmental and safety aspects of the project
	• Develop project webpage (Completed)
		• Identify and secure project Community Feedback Mechanisms (CFM) including phone number, dedicated email, social media channels, local outlets (e.g., newspaper, library or community center, post office)
		• Create CFM materials for various channels (May)

Stakeholder Outreach & Engagement	• Conduct initial key stakeholder feedback consultations with representatives from the following groups (Feb – Mar)
	  ○ State and local elected officials from Cameron and Calcasieu Parishes
	  ○ Safety agencies
	  ○ Project neighbors
	  ○ Local leadership from organizations including:
	  • Educational institutions
	  • Environmental groups
	  • Business advocacy
	  • NGO's representing local environmental justice constituencies
	• Seek feedback from the company's local Community Advisory Committee (CAC)
		• Support / participate in proposed EPA or LDNR community meeting or open house events (Apr – May)
		• Identify opportunities for project updates via key stakeholder groups (June)

7.0 APPENDICES AND PROJECT MATERIALS

7.1 APPENDIX 1 - CONTACT INFORMATION

Houston – Corporate Headquarters:
Sempra Infrastructure
1500 Post Oak Blvd, Suite 1000
Houston, TX 77056

SWLA – Local Office:
1500 Holbrook Park Road
Sulphur, LA 70663

Email:
contact@semprainfrastructure.com

Media Line:
1-877-855-7887

Dedicated Project Email:
To be developed – Q1 2024

Community Toll-free Number:
To be developed – Q1 2024

Sempra Infrastructure

External Affairs and Communications Team Contacts

Kelly Prasser Director, External Affairs M: +1-619-507-9692 KPrasser@SempraGlobal.com	Craig Lewellyn Public Affairs Manager M: +1-713-825-1841 CLewellyn@SempraGlobal.com
Jeanne Trahan Community Outreach Specialist M: +1-337-304-0388 JTrahan@SempraGlobal.com	Jackie Drake Communications Advisor M: +1-832-370-0931 JDrake@SempraGlobal.com

Louisiana Federal & State Delegation

- Governor of Louisiana (Jeff Landry)
- Lieutenant Governor (Billy Nungesser)
- US Senators – District 6 (Bill Cassidy)
- US Senator – District 4 (John Kennedy)
- US Representative – District 3 (Clay Higgins)
- US Representative – District 4 (Mike Johnson)
- US Representative – District 5 (Julia Letlow)
- US Representative – District 1 (Steve Scalise)
- State Senator – District 25 (Mark Abraham)
- State Senator – District 27 (Jeremy Stine)
- State Senator – District 30 (Mike Reese)
- State Senator – District 32 (Heather Cloud) – CCS Forums
- State Senator – District 33 (Les Farnum)
- State Representative – District 32 (Dewith Carrier)
- State Representative – District 34 (Wilford Carter)
- State Representative – District 35 (Brett Geyman)
- State Representative – District 36 (Phillip Tarver)
- State Representative – District 47 (Ryan Bourriaque)

Local Louisiana Delegation

- Cameron Parish Police Jury
  - Ronald Nunez – Parish President
  - Curtis Fountain / Michael Fewell – District 2 Police Juror
- Cameron Parish Administration
  - Tom Barrett – District Attorney
  - Scott Lavergne – Tax Assessor
  - Katie Armentor – Parish Administrator
- Calcasieu Parish Policy Jury
  - Chris Landry – Parish President
  - Judd Bares - District 12 Police Juror
- Calcasieu Parish Administration
  - Stephen Dwight – District Attorney
  - Wendy Aguillard – Tax Assessor
  - Bryan Beam – Parish Administrator
- Cameron Parish Water Works District #2

Cameron Parish Emergency Preparedness & Safety Agencies

- Cameron Parish Office of Emergency Preparedness (Danny Lavergne, Director)
- Cameron Parish EMS – Ambulance District 2 (Rhonda Coleman, Director)
- Hackberry Volunteer Fire Department (Mark Grange, Chief)
- Cameron Parish Sheriff's Office (Ron Johnson, Sheriff)

Community Stakeholders

Name	Organization	Stakeholder Group Type
Brent Clements	Performance Contractors and Retired Calcasieu Parish Police Juror	Cameron LNG Community Advisory Committee and Business /Industrial
Byron Gibbs	Hackberry High School	Cameron LNG Community Advisory Committee and Education / Workforce / School
Charley Lemons	Cameron Parish School Board	Cameron LNG Community Advisory Committee and Education / Workforce / School
Chris Savoie	Cameron Parish Sheriff's Office	Cameron LNG Community Advisory Committee and Safety Agency
Curtis Fountain	Retired, Strategic Petroleum Reserve and former Cameron Parish Police Juror	Business / Industry
Danny Lavergne	Cameron Parish Office of Emergency Preparedness (OEP)	Safety Agency
Dawn LeBato	Hackberry Duck-off	Non-profit / Community Organization
Deborah Cloud	Project Neighbor	Neighbor
Dick Gremillion	Calcasieu Parish Office of Emergency Preparedness (OEP)	Safety Agency
Dinah Landry	Cameron Council on Aging	Non-profit / Community Organization
Gregory Gray	The Marshland Festival	Non-profit / Community Organization
Gwen Poole	Targa Resources	Cameron LNG Community Advisory Committee and Business / Industrial
Gwen Reasoner Vanzile	Project Neighbor Gwen & Pat Vanzile – 125 Arthur Ln	Neighbor
Jim Rock	Lake Area Industry Alliance (LAIA)	Chamber / Business Advocacy / Trade
Jody Farnum	Care Help of Sulphur	Non-profit / Community Organization
Julie Trahan	Cameron Parish Lion's Club	Non-profit / Community Organization
Katie Armentor	Cameron Parish Administration	Cameron LNG Community Advisory Committee and Local Delegation / Government
Kayla Connor	Cameron Parish Sheriff's Office	EP&S – Safety Agency
Kim Montie	West Cameron Port Commission	Business / Industry
Kirk Stansel	Hackberry Duck-off	Non-profit / Community Organization
Kitty Askew	Retired Teacher, Community Volunteer	Cameron LNG Community Advisory Committee and Non-profit / Community Organization
Mae Doris Little	Immediate Project Neighbor 150 Ernie Ln	Neighbor
Mark McMurry	Consultant and Retired Cal Parish Administrator	Cameron LNG Community Advisory Committee and Business / Industrial
Molly Reasoner Richard	Neighbor: Molly & Roger Richard – 105 Arthur Ln	Neighbor
Regina Aucoin	St. Peter's Catholic Church	Religious / Place of Worship
Sheron Faulk	Ship-to-Shore LLC	Cameron LNG Community Advisory Committee and Business / Industrial
Stephanie Rodrique	Community Volunteer - Education Former School Superintendent, Cameron Parish ISD	Cameron LNG Community Advisory Committee and Education / Workforce / School
Tommy Faucheux	Louisiana Mid-Continent Oil & Gas Association (LMOGA)	Chamber / Business Advocacy / Trade
William Aucoin	Project Neighbor: Will & Regina Aucoin – 165 Arthur Ln	Neighbor

HCS Project Fact Sheet

Hackberry Carbon Sequestration

Sempra Infrastructure

CONFIDENTIAL
February 22, 2021

PROJECT DESCRIPTION

Sempra Infrastructure is developing the Hackberry Carbon Sequestration project ("Hackberry CS"), a carbon capture storage facility designed to sequester CO2 from industrial sources. Hackberry CS intends to utilize the federal 45Q tax credit in capturing CO2 to create economic value. This project will be among the first commercial carbon sequestration operations in North America.

The project will transport CO2 once it has been initially compressed and dehydrated to a CO2 compression facility on land owned by LA Storage, a subsidiary of Sempra Infrastructure. The CO2 will then be transported at high pressure to a CO2 Injection well, located in an undeveloped area without oil & gas production activities to minimize geological integrity risk.

The initial well will be permitted to sequester up to 2,000,000 tonnes of CO2 annually and the project can be expanded for additional sources of C02. This initial CO2 volumes are estimated at ~600,000 tonnes per year which is based on the CO2 removed from the natural gas feedstock of a 17 million tonnes per year LNG export facility.

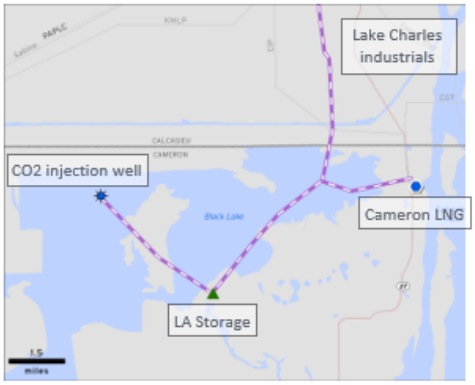
The expertise required to develop and operate carbon sequestration facilities is similar to that for natural gas storage facilities. Sempra's experience includes developing and operating two natural gas storage facilities in the US Gulf Coast. It is currently developing a new high injection gas storage facility, LA Storage, to serve LNG export facilities.

PROJECT DEVELOPMENT UPDATE

- ✓ Sempra owns a suitable site on the West Hackberry Salt Dome for a proposed natural gas compression and dehydration facility
- ✓ Sempra received all required permits and land and initiated drilling of a UIC Class V stratigraphic test well in December 2020
- ✓ Completed drilling of test well and analyzed the well data in Q1 2021
- ✓ Prepared and submitted a UIC Class VI sequestration well application in Q3 of 2021
- ✓ Prepared and submitted applications for all other required state and federal long-lead permits in Q3 of 2021
- ▪ Final investment decision targeted 2023–2024
- ▪ Commercial operation targeted 2026-2027

PROJECT LOCATION

Hackberry, Louisiana



CARBON SEQUESTRATION

Carbon sequestration is the process of capturing and permanently storing carbon. For several decades, the U.S energy industry has safely injected CO2 in underground geological formations in enhanced oil recovery projects

45Q TAX CREDIT

US Internal Revenue Code 45Q provides a tax credit of $50 per tonne for a period of up to 12 years for geological CO2 sequestration. Congress recently extended the qualifying in service date to 2026 with the Consolidation Appropriations Act of 2021.

CO2 SOURCES

Industry accounts for 22% of the total US greenhouse gas emissions. Hackberry CS is initially targeting LNG export facilities as a supply of CO2 from two major sources: i) a concentrated CO2 steam from the acid gas removal unit which processes the natural gas feedstock prior to liquefaction, and ii) a larger, but less concentrated source of CO2 from the liquefaction compressor gas turbine exhaust.

2022 Sempra Infrastructure Community Impact Report

Community Impact Report | 2022

SEMPRA INFRASTRUCTURE

OUR COMMITMENT

Active involvement in the communities in which we operate is fundamental to the success of our organization. Sempra Infrastructure has been a proud community partner in Southwest Louisiana for more than 20 years. We invest our time, talent and resources to help improve the quality of life for our customers, neighbors and employees. At Sempra Infrastructure, we believe that by partnering with local organizations and leadership, we contribute to making a positive impact in the communities where we do business.

OUR GIVING PRIORITY AREAS

Sempra Infrastructure contributed nearly $160,000 in charitable contributions to community partners in Cameron, Calcasieu, and Beauregard parishes in 2022. We are proud of the partnerships we have built with community members and seek to enhance those relationships every year by focusing on efforts in our four Giving Priority Areas which include:

COMMUNITY INVESTMENT BY PRIORITY AREAS

Economic Prosperity & Leadership Development | Education – Science, Technology & Innovation, Engineering, and Math (STEM) | Emergency Preparedness & Safety | Environmental Stewardship

CAMERON LNG – COMMITTED TO OUR COMMUNITY

Our Cameron LNG facility in Hackberry was developed to meet the growing demand for safe, sustainable and reliable natural gas worldwide. This world-class facility is focused on its local roots in Southwest Louisiana, and we are proud of our partners' and employees' daily commitment to safe operations and protecting the environment. Cameron LNG is a dedicated community partner, contributing nearly $350,000 in 2022 to organizations serving the needs of Cameron and Calcasieu parishes and more than $3.6 million since 2004. In addition to its charitable contributions program, Cameron LNG's Employee Giving Fund has distributed $180,850 in grants to various nonprofits within the community since its inception in 2016.

Our Community Partners

Beauregard Parish Fire Protection District • Cameron's Lion Club • Care Help of Sulphur • Coalition to Restore Coastal Louisiana • DeQuincy Elementary School • DeRidder Police Officer Association • Ducks Unlimited • Hackberry Duck-Off • Louisiana Chamber of Commerce Foundation • Louisiana United Methodist Children & Family Services • Louisiana Wildlife and Fisheries • Marshland Festival • Ragley Historical Society • Second Harvest Food Bank of Greater New Orleans • Squyres United Methodist Church • SWLA Alliance • The Chamber SWLA • West Cal-Cam Chamber of Commerce • West Calcasieu Cameron Hospital Foundation

2022 COMMUNITY PARTNERSHIP HIGHLIGHTS

ENVIRONMENTAL STEWARDSHIP

Sempra Infrastructure strives to do the right thing by working to mitigate the environmental impact of our operations. We are committed to environmental stewardship and work with partners that promote and help advance the preservation and restoration of the coastal zone's marsh, wetland areas, and wildlife habitats.

photo by: John Hoffman, Ducks Unlimited

Habitat Restoration Effort with Ducks Unlimited

A $15,000 grant to Ducks Unlimited from Sempra Infrastructure supported efforts to enhance the wetland habitat at Cameron Prairie National Wildlife Refuge in Cameron Parish, LA. Ducks Unlimited is using these funds to replace the pumping system with a new electric power unit and to install new water control structures which will benefit migrating and wintering waterfowl and other migratory birds.

ECONOMIC PROSPERITY AND LEADERSHIP

A thriving community is supported by healthy economic conditions. At Sempra Infrastructure, we contribute to economic prosperity by investing in programs to help support the growth of diverse businesses and contribute to leadership development. Our relationships with organizations focused in this area help support local economies as well as enhance the resiliency of the communities where we operate.

Minority Business Initiative with the Louisiana Chamber of Commerce Foundation

In 2022, Sempra Infrastructure partnered with Louisiana Chamber of Commerce Foundation to help drive the continued recovery and economic growth of the region by empowering and sustaining the minority business community. Our partnership with the Foundation helped them launch a Technical Assistance Initiative in Lake Charles which provided valuable technical support and training to minority-owned, small businesses.

EDUCATION | STEM

Today's students are tomorrow's workforce and leaders who will shape our future. As part of our efforts to champion people and grow a diverse, inclusive and high-performance workforce, we partner with local schools, technical colleges, and universities to promote learning and continued development.

Innovative Educators Initiative with Hackberry High School

At Sempra Infrastructure, we believe teachers are one of our greatest resources - helping to develop the next generation of innovators, leaders, and game-changers. In 2022, we launched our Innovative Educators Initiative to support teachers in enhancing classroom activities in the areas of science, technology, engineering, and math (STEM) at all education levels. We distributed $11,000 to Hackberry High School teachers through this effort.

EMERGENCY PREPAREDNESS & SAFETY

We put the health, safety, and security of our workforce, customers, and communities at the center of everything we do. As an industry leader, we champion health, safety, and security programs that protect our people, projects and operations. Our partnerships with organizations that provide local safety and emergency preparedness programs and services are imperative in maintaining safe and resilient communities.

Combatting Food Insecurity with Care Help

Sempra Infrastructure has been a longtime supporter of Care Help, Inc. of Sulphur's program to address food insecurity in the area and provide for emergency needs after a disaster. In 2022, we helped fund holiday food boxes and gift cards distributed to over 500 households, many of which were senior citizens. Additionally, we were proud to support the "Kids Give" Shopping Day providing an opportunity for nearly 200 children to shop for gifts for their family members at no cost.

Sempra Infrastructure is not the same company as the California utilities, San Diego Gas & Electric company (SDG&E) or Southern California Gas Company (SoCalGas), and Sempra Infrastructure is not regulated by the California Public Utilities Commission.

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SEMPRA™ INFRASTRUCTURE

2022 Cameron LNG Community Impact Report

Cameron LNG

Community Impact Report 2022

OUR COMMITMENT

Together with our partners, we have created a global business with local roots in Southwest Louisiana that delivers cleaner energy around the world.

A partner in the community for nearly 20 years, Cameron LNG is committed to giving back and making a positive difference in the communities where we live and work.

Since 2004, more than $3.6 million in charitable contributions has been awarded to nonprofit and business organizations benefitting this region. Our charitable giving strategy aligns with our company culture and values to champion local growth and development, and to support resilient and safe communities.

OUR GIVING PRIORITY AREAS

In 2022, Cameron LNG contributed more than $340,000 in community partnerships with organizations serving the needs of Cameron and Calcasieu parishes. In alignment with our community investment priorities, we provided funding and resources to efforts in the following areas:

- Economic Prosperity & Leadership Development
- Education – Science, Technology & Innovation, Engineering, and Math (STEM)
- Emergency Preparedness & Safety
- Environmental Stewardship

COMMUNITY INVESTMENT BY PRIORITY AREAS

Cameron LNG Employee Giving Fund

Cameron LNG's Employee Giving Fund (EGF) makes giving charitable contributions to 501(c)(3) nonprofit organizations quick and easy for our employees. Employees can enroll in voluntary payroll deductions and pool the money with other employee contributions to increase giving power. The Fund has distributed $180,850 in grants to various nonprofits within the community since its inception in 2016. Nonprofit organizations are nominated by employees, and fund allocations are voted on quarterly by a committee of employees representing both our Hackberry and Houston offices.

COASTAL RESTORATION AWARD

In May 2022, the Coalition to Restore Coastal Louisiana (CRCL) selected Cameron LNG to receive the 2022 Hurricane Laura Coastal Stewardship Award for our contributions to restoring coastal beaches, wetlands and wildlife habitats. CRCL works at the state, local and federal levels to ensure that restoring and protecting coastal Louisiana are top priorities for our state and the nation.

2022 COMMUNITY PARTNERSHIP HIGHLIGHTS

ENVIRONMENTAL STEWARDSHIP

Cameron LNG is committed to sustainable stewardship and environmental preservation. Through our annual community partnership program, we are proud to partner in efforts that preserve and protect wildlife habitats, wetland areas and support beautification efforts in our communities.

Hackberry Cemetery Earth Month Project
In recognition of Earth month, Cameron LNG partnered with the Hackberry Cemetery Association to restore the landscaping at this community landmark. Cameron LNG employees and community members planted 50 crape myrtle trees to replace pine trees destroyed by Hurricane Laura in 2020. This two-phase project will be completed in 2023 with additional tree plantings and other beautification efforts.

EDUCATION | STEM

Our education initiatives are focused on helping to prepare future generations and grow a vibrant workforce. This is achieved by supporting programs at local schools and colleges focused on promoting learning and teacher development in the fields of Science, Technology, Engineering and Math (STEM).

Cameron LNG Graduating Senior and Continuing Education Programs
In 2012, Cameron LNG launched a competitive scholarship program for students graduating from one of the four high schools in Cameron Parish. Four years later, the Continuing Education Scholarship program was announced, allowing previous winners to apply for funds that could be applied to their advanced education. Both programs support students pursing degrees at educational institutions including trade schools, technical colleges, community colleges, four-year colleges or universities.

To date, more than $140,000 has been awarded to 96 Cameron Parish graduates through our Graduating Senior Program. Additionally, awards totaling $92,000 have helped 21 students continue to pursue their higher education goals.

ECONOMIC PROSPERITY AND LEADERSHIP

As a company dedicated to enhancing the economic prosperity and resiliency of the region where we operate, Cameron LNG works alongside community and business leaders to invest time and resources to support local economies and help build thriving communities.

Port Wonder Project
Cameron LNG is proud to be one of the first LNG companies to support the City of Lake Charles' iconic new education complex featuring the Children's Museum of Lake Charles and the Louisiana Department of Wildlife and Fisheries Science Center and Educational Complex (SCEC). In June, city and state officials celebrated the groundbreaking of Port Wonder, a $20+ million lakefront development project. This economic development partnership grant will help fund STEM-based, hands-on interactive exhibits and an immersive, live-animal Louisiana coast experience.

EMERGENCY PREPAREDNESS & SAFETY

At Cameron LNG, safety is a core value of our organization and the top priority of our employees. Our relationships with law enforcement agencies and emergency responders in Cameron and Calcasieu parishes support our commitment to emergency preparedness and safety. Our Safe Communities initiative makes a significant impact on communities with partnerships focused on eradicating hunger, providing healthcare screenings and delivering other critical services to improve quality of life for all.

Second Harvest – South Cameron Food Pantry
Through our annual partnership with Second Harvest Food Bank, we helped launch a new food pantry at South Cameron High School. Operating twice a month, this school pantry has become an important resource to students and their families. Over the course of the year, the canned-food pantry was transformed into an on-site grocery store offering meat, produce, dairy and household items and is now the closest grocery store within a 40-minute drive for residents of the Cameron community.

Our Community Partners

Boy Scouts of America-Lake Charles Group • Calcasieu Area Boy Scouts of America • Calcasieu Cameron 4-H Foundation • Calcasieu Community Clinic • Cameron Community Charity • Cameron Council on Aging • Cameron Lions Club • Cameron Parish Council on Aging • Cameron Parish Dare Program • Cameron Parish Head Start • Cameron Parish School Board • Cameron Preservation Alliance • Care Help of Sulphur • Coastal Conservation Association - Louisiana • Christus St. Patrick's Hospital Foundation • Community Foundation of SWLA • Ducks Unlimited | Louisiana • Ethel Precht Hope Breast Cancer Foundation • Friends of Cameron Parish Beach Sweep • Fur and Wildlife Festival • Future Business Leaders Assn/ Hackberry High School • Grand Lake Elementary • Grand Lake FFA • Hackberry Duck Off • Louisiana Association of Business & Industry • Louisiana Chemical Industry Alliance • Louisiana Wildlife and Fisheries Foundation • Marshland Festival • McNeese State University • Moore-Odom Wildlife Foundation • Port Wonder • Propeller Club • Sacred Harvest Food Bank • SOWELA Technical Community College • St. Nicholas Center • SWLA Economic Development Alliance • The Chamber of SWLA • West Calcasieu Cameron Hospital Foundation • West Calcasieu Chamber of Commerce • Women's Commission of Southwest Louisiana

COMMUNITY OUTREACH CameronLNG.com | CameronLNG

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Cameron LNG

Underground Injection Control – Class VI Permit Application for Hackberry Carbon Sequestration Well No. 001

Cameron Parish, Louisiana

SECTION 10 – FINANCIAL ASSURANCE

Prepared for *Hackberry Carbon Sequestration, LLC*
Cameron, LA

By

Lonquist Sequestration, LLC
Austin, TX

August 2021
Revised January 2025

SECTION 10 – FINANCIAL ASSURANCE

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10.1 Introduction

This financial assurance section for Hackberry Carbon Sequestration (HCS) Well No. 001 was prepared to meet the requirements SWO 29-N-6 **§607.C.2.m** and **§609.C.1** [40 CFR **§146.82(a)(14)** and **§146.85(a)**]. This section outlines the instruments and associated costs for the well.

10.2 Financial Assurance

A surety bond will be secured and used to provide sufficient funding for the purposes of demonstrating financial responsibility for the life cycle of the Hackberry Sequestration Project. In compliance with SWO 29-N-6 **§609.C.4.c** [40 CFR **§146.85(a)(4)]**, this instrument may not be terminated except due to failure to make payment and may not be final until 120 days after receipt. The total estimate for all sequestration activities requiring financial assurance at the Hackberry site is $19,598,000 and will reflect the minimum amount of funding to cover the costs of the closure plan, post-injection site care and emergency response/remediation plans. Table 10-1 summarizes the total estimated project costs by activity. These estimates are based on cost estimates developed through the permit application process. These costs assume that third party contractors would be hired to perform these services.

Table 10-1 – Summary of Geologic Sequestration Activity Project Costs

Activity	Cost
Corrective Action	N/A
Well Plugging	$1,523,000
Post-Injection Site Care and Site Closure	$8,250,000
Emergency and Remedial Response	$9,825,000
TOTAL	**$19,598,000**

A bond for $1,523,000 will be provided to LDENR prior to construction to cover the potential well plugging costs associated with HCS No. 001. A commercial General Liability Insurance policy of $2,000,000 and marine liability of not less than $20,000,000 will be in place prior to construction. Prior to receiving Authority to Inject, a rider to the bond, bringing the total to $19,598,000, will be obtained and provided to LDENR. Additionally, HCS agrees to obtain an insurance policy to cover any potential, immediate impacts to the project that could be experienced during the life of the project.

10.3 Corrective Action Plan

No corrective action plan is required for the HCS Well No. 001 project, as there are no wellbores within the area of review (AOR). The AOR will be reevaluated every five years to determine if any new penetrations have occurred.

10.4 Injection Well Plug and Abandonment

Plug and abandonment (P&A) of HCS Well No. 001, and the associated monitoring wells, will meet the requirements of SWO 29-N-6 **§631** [40 CFR **§146.92**]. The P&A of the injection well will be designed such that no movement of fluids will occur from the injection interval. A more detailed P&A plan is discussed in Section 6. Funds will be guaranteed, via a surety bond, to ensure that P&A operations are properly managed. These funds include costs for logs/wireline to be run in the wellbore before cementing occurs. Acid-resistant cement will be used in the initial plug for the well to ensure the cement does not react with the injected fluid, so a higher cement expense than usual is to be expected. All expenses relating to personnel and equipment have been accounted for in Table 10-2. Pressure test costs are also included in order to prove the integrity of the well.

Table 10-2 – Summary of Well Plugging Costs

Activity	Cost Per Well	Total
Injection Well P&A		***$982,000***
Workover Rig	$108,000	
Kill/Buffer Fluid	$12,000	
Personnel	$60,000	
Wireline	$30,000	
Cast Iron Bridge Plug	$200,000	
Other Services	$72,000	
Cement and Pumping Services	$200,000	
Equipment Rentals	$65,000	
Miscellaneous/Contingency	$235,000	
Above-Zone Monitoring Well P&A (one well)		***$436,000***
Workover Rig	$75,000	
Kill/Buffer Fluid	$8,000	
Personnel	$25,000	
Wireline	$80,000	
Downhole Tools	$25,000	
Other Services	$50,000	
Cement and Pumping Services	$50,000	
Equipment Rentals	$40,000	
USDW Monitoring Well P&A (three wells)		***$105,000***
Workover Rig	$20,000	
Cement Services	$10,000	
Auxiliary Services	$5,000	
TOTAL		**$1,523,000**

10.5 Post-Injection Site Care and Site Closure

The post injection site care and site closure plan will be designed to meet the requirements of SWO 29-N-6 **§633** [40 CFR **§146.93**]. The costs associated with the plan have been highlighted in Table 10-3**.** The site care and closure plan is discussed in Section 7.

Table 10-3 – Summary of PISC/Site Closure Costs Associated with Financial Security

Activity	Cost	Total
Post-Injection Monitoring		***$7,000,000***
Indirect Plume Monitoring (VSP)	$5,000,000	
Other Monitoring (e.g., fluid sampling and analysis, pressure/temperature monitoring)	$2,000,000	
Site Closure		***$1,250,000***
Waste Removal	$150,000	
Clean/Gas-Free Certification of Storage Vessels	$50,000	
Dismantle Surface Facilities	$950,000	
Site Restoration	$100,000	
TOTAL		**$8,250,000**

10.5.1 Post-Injection Monitoring

As discussed in Section 5, VSP monitoring will be conducted at the end of injection, then at a frequency as determined by model results and in agreement with the UIC Director to ensure the integrity of the well and to track the migration of the plume. Groundwater sampling will take place every five years. Well pressure and temperatures will be monitored continuously. The monitoring costs will continue until the owner is released from post injection site duties.

10.5.2 Site Closure

When the director has released the owner from all post-injection site duties, site closure will occur. The costs in Table 10-3 reflect the expected amount to close the site and restore the facility to its natural state. Dismantling of surface facilities includes removing storage vessels, piping, pumps, and surface equipment, etc. Concrete and debris removal are also included in surface facilities costs. Funds will be allocated for site restoration to leave minimal environmental impact.

10.6 Emergency and Remedial Plan

The emergency and remedial plan is referenced in Section 8 and is designed to be in compliance with SWO 29-N-6 **§623.A.1** [40 CFR **§146.94**]. The remediation costs associated with an unlikely release of CO_2 into the groundwater determine the final amount of funds required for the surety bond. This bond will help ensure the operator will have sufficient funds in place to handle all scenarios. The following is a discussion on the costs associated with remediation if a CO_2 released were to occur during CO_2 sequestration operations.

The potential remediation activities include the following and are discussed in more detail in the

Remediation Work Plan provided in *Appendix O – Financial Assurance*:

- Drilling of a CO_2 groundwater capture well to remove CO_2 from the aquifer. This well will remediate the impacted aquifer and provide a capture zone to limit the areal migration of CO_2.
- Installation of a wellhead CO_2 separator. Contaminated groundwater would be pumped to a wellhead separator system to allow the venting of CO_2 to the atmosphere and allow the treated water to be pumped into up to three groundwater reinjection wells.
- Drilling of three groundwater barrier injection wells. The purpose of these wells is to limit the areal extent of contaminated groundwater by creating a hydraulic barrier to CO_2 movement. The injected groundwater will push contaminated groundwater back toward the CO_2 capture well for extraction and treatment.
- Installation of a manifold pipeline system

Costs for each of these activities are included in Table 10-4. These cost estimates are based on quotes from drilling companies, oil field service companies and equipment manufacturers and are shown in 2023 dollars.

Table 10-4 – Summary of Costs Associated with Emergency and Remedial Response Plan

Activity	Cost	Total
Emergency Remedial Response		***$9,825,000***
Installation of CO_2 Extraction Well	$1,830,000	
Groundwater Extraction Well Pump	$400,000	
Install Groundwater Reinjection Wells (3 wells)	$4,095,000	
CO_2 Wellhead Separator	$200,000	
Groundwater Injection Well Pipelines	$3,300,000	

10.7 Updates to Financial Assurance

During the active life of this project, HCS will adjust the cost estimate for inflation in conjunction with the required AOR review cycle (at least every five years) and provide this adjustment to the Director. HCS will also provide written updates of adjustments to the cost estimate within 60 days of any amendments to the area of review and corrective action plan, the injection well plugging plan, the post-injection site care and site closure plan, and the emergency and remedial response plan. If the updated cost estimate increases to an amount greater than the face value of the surety bond in use, HCS will obtain an increase in the surety bond at an amount at least equal to the current cost estimate or obtain other financial responsibility instruments to cover the increase and supply evidence of such to the Director.

Underground Injection Control – Class VI Permit Application for Hackberry Carbon Sequestration Well No. 001

Cameron Parish, Louisiana

SECTION 11 – ENVIRONMENTAL JUSTICE

Prepared for *Hackberry Carbon Sequestration, LLC*
Cameron, LA

By

Lonquist Sequestration, LLC
Austin, TX

August 2021
Revised September 2024

SECTION 11 – ENVIRONMENTAL JUSTICE

According to the CEQ environmental justice guidance under NEPA and EPA's *Promising Practices for EJ Methodologies in NEPA Reviews*, minorities are those groups that include American Indian or Alaskan Native; Asian or Pacific Islander; Black, not of Hispanic origin; or Hispanic. Minority populations are defined where either; (a) the minority population of the affected area exceeds 50 percent or (b) the minority population of the affected area is meaningfully greater (10 percent greater) than the minority population percentage in the general population or other appropriate unit of geographic analysis. The CEQ guidance further recommends that low-income populations in an affected area should be identified using data on income and poverty from the U.S. Census Bureau and considered in the analyses. According to the U.S. Census Bureau, low-income populations are populations where households have an annual household income below the poverty threshold, which is $26,500 for a family of four in 2021.

Rates of households below the poverty level and percentages of minority residents are significantly lower in Cameron Parish than for Louisiana as a whole. U.S. Census data shows that in the State of Louisiana in 2020, 42.8 percent of the population was minority, while in Cameron Parish, 12.8 percent of the population was minority. Similarly, 19.4 percent of Louisiana households were below the poverty threshold. Poverty rates were lower in Cameron Parish, where only 10.3 percent of households fell below the poverty threshold.

Potentially adverse environmental effects associated with the Project will be minimized and/or mitigated, as applicable, and are not characterized as high and adverse. Beneficial environmental effects of the Project will extend beyond Cameron Parish and the State of Louisiana. The Project will not cause a disproportionate share of high and adverse environmental or socioeconomic impacts on any racial, ethnic, or socioeconomic group.

Stakeholder Engagement Plan

The following document provides details regarding the Stakeholder Engagement Plan that Hackberry Carbon Sequestration, LLC (HCS) and Sempra Infrastructure Partners, LP has developed to ensure that the community is informed about the Hackberry project, has methods to communicate with HCS to express their questions and concerns, receives project updates, etc.

Underground Injection Control – Class VI Permit Application for Hackberry Carbon Sequestration Well No. 001

Cameron Parish, Louisiana

SECTION 12 – QUALITY ASSURANCE AND SURVEILANCE PLAN

Prepared for *Hackberry Carbon Sequestration, LLC*
Cameron, LA

By

Lonquist Sequestration, LLC
Austin, TX

August 2021
Revised September 2024

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1. Introduction

Large-scale capture of anthropogenic carbon dioxide (CO_2) is increasingly critical for the United States and the global community to meet ambitious goals for greenhouse gas reductions by companies, states, and national governments. The costs associated with CCUS technologies have historically made carbon injection and sequestration projects uneconomical without substantial governmental assistance or revenue from utilizing CO2 in an enhanced oil recovery application. However, the expansion of the 26 U.S Code **§45Q** tax credit through the Bipartisan Budget Act of 2018, which was further expanded by the Inflation Reduction Act of 2022, and the implementation of the associated guidance and regulations by the U.S. Department of Treasury has now created a framework where more carbon capture and sequestration projects can be economically feasible.

This Quality Assurance and Surveillance Plan (QASP) is created to meet the requirements in **CFR 40 146.90(k)**. This plan sets forth the data collection methods and guidelines that will be followed while operating the Hackberry Carbon Sequestration project. The program describes the standards and procedures used to maintain high quality data. These measurements will provide a level of confidence that injection operations are operating as permitted and not endangering the underground sources of drinking water.

2. Project Organization

The Hackberry Carbon Sequestration Project Manager will be the responsible party for this QASP. In addition, external organizations with unique expertise will be secured as necessary.

- A third-party provider will perform CO2 and groundwater analysis. They will be responsible for performing sample collection and laboratory measurements.
- A third-party provider will be responsible for providing expertise and equipment to collect deep monitoring well fluids. They will provide tools, equipment, and internal standard operating procedures.
- A third-party lab will provide corrosion coupon monitoring. They will be responsible for performing sample collection and laboratory analysis.
- A third-party provider will provide well integrity testing services or equipment. They will be responsible for all measurement and analysis that is related to integrity evaluation.
- Third-party Logging services will provide tools to measure physical parameters. They will be responsible for providing data validation, tool calibration and internal standard operating procedures.
- A core laboratory will provide measurements and testing for core sample analysis. The laboratory will provide analytical measurements related to the confining zones and the injection interval.

Hackberry Sequestration Project Manager will be responsible for the supervision of data collection for continuous monitoring, sampling design, testing and well logging carried out at the

Hackberry Carbon Sequestration Project (HCS Project). Prior to commencing data collection, the project manager will coordinate with the laboratory, testing, and logging entities to review field, laboratory, and testing roles and responsibilities. This review will also include the documentation and chain-of-custody requirements to minimize potential problems during the project. The project manager will also be responsible for ensuring that any changes to this plan will be communicated with relevant parties and a copy is submitted to the appropriate regulatory bodies for approval.

2.1 Problem Definition/Background

The HCS Project is located in Cameron Parish in southwest Louisiana. The location is ideal as the source of CO_2 is located near LNG export facilities, and the subsurface provides ideal geologic conditions. HCS plans to sequester 2 million metric tons per year (MMT/yr) of CO_2. To ensure the safety of the environment and as validation that the project is operating as planned, a system of testing and monitoring will be applied. The data collected will be used by engineers, operators, and regulators. Engineers will use the data to confirm the development of the plume and verify the validity of the model. The operators will use the data to ensure injection is operating within the planned operating window. Regulators will use the data to ensure the project is operating as permitted and verify the safety of the impacted public.

2.2 Project/Task Description and Schedule

For the purpose of this plan, the data collection at HCS facility has been subdivided into six major data collection systems:

- Continuous Monitoring
- Corrosion Monitoring
- Sampling and Analysis
- Integrity Testing
- Well Logging

A continuous monitoring system will collect real-time data. The corrosion monitoring system will provide a method that will collect data that is representative of the metallurgy of the system that will encounter the injection stream. The sampling program will include groundwater and CO_2. The sampling of ground water will provide confidence that the injection project is not interfering with the underground source of drinking water. The CO_2 sampling program will provide information that will be used to verify the quality of the CO_2 and will be used in the simulation of behavior of the underground plume. The sampling and analysis program will characterize and monitor changes in fluid chemistry and lithology. Lastly, data collected from pressure testing and logging programs will be used to verify the integrity of the well and the integrity of the injection zone. This plan will remain in effect throughout the life of the geologic sequestration project, to include post injection and site closure phases. This QASP will be submitted to the Director for approval. Additionally, this plan will be reviewed annually. Any

changes or modifications to any gauges, meters, flowmeters, testing or analytical techniques will require this plan to be amended and submitted to the Director for approval. Once approved, copies will be distributed to all personnel involved in the data collection operations.

3. Instrumentation Summary

Table 12-1 provides a summary of the data collection efforts during the operation of the Hackberry Carbon Sequestration (HCS) project. Instruments selected are based on HCS's data quality objectives.

Table 12-1—Hackberry Instrumentation Library

Monitoring Location	Instrument Type	Monitoring Target (Formation or Other)	Explanation
CO_2 Facility	Injection Pressure Gauge	CO_2 Stream	Injectate pressures will be monitored and recorded using a Supervisory Control and Data Acquisition system.
	Temperature Gauge	CO_2 Stream	Injectate temperatures will be monitored and recorded using a SCADA system.
	Coriolis Meter	CO_2 Stream	Injectate flow rates and volumes will be monitored and recorded using a SCADA system.
	Corrosion Coupon System	Corrosion	Corrosion coupons will be collected quarterly and sent to an independent laboratory for metal loss analysis.
	Surface CO_2 Detection	CO_2	Monitor CO_2 Concentrations
Third-Party	Pressure Gauge	Pressure	Monitor Pressure
	Temperature Gauge	Temperature	Monitor Temperature
	CBL	Cement Bond	Monitor cement bond
	Casing Inspection	Casing Thickness	Measure metal loss
	Pump pressure	Pressure	Monitor pump
Injection Well	Distributed Temperature Sensing	Subsurface	Measure Subsurface temperature profile
	Seismic Distributed Acoustic Sensing	Subsurface	Monitor plume growth
	Well Integrity Real-	Casing Integrity	Monitor Casing

Monitoring Location	Instrument Type	Monitoring Target (Formation or Other)	Explanation
	Time Evaluation		Integrity
	Pressure Temperature Gauge	Miocene Sands	Monitor Injectate temperature
Monitoring Well	Fluid Sampling System- U-Tube	USDW	Ground Water Quality Monitoring

4. Continuous Monitoring

SWO 29-N-6 ***§3625.A.2*** [40 CFR ***§146.90(b)***], requires the use of continuous recording devices. The devices provide information that ensures injection operations are operating within permitted parameters. The information collected also is used to validate the growth of the plume and ensure containment within the permitted zone.

4.1.1 Summary of Data Collection

Temperature, pressure, flowrates and volumes are measured at the surface. Field gauges and meters will be used to collect this data. Table 12-2 provides a summary of the data collection efforts for the continuous monitoring requirements.

Table 12-2—Surface Continuous Monitoring Data Collection Instruments

Activity	Location(s)	Purpose
CO_2 stream analysis	Coupon System	Monitor CO_2 Quality
Injection rate and volume	Injection flow line	Mass Flow Measurement
Injection pressure	Injection Tree	Monitor injection pressures
Annular pressure	Annulus Access	Monitor Annular Pressures
Downhole pressure/ temperature	Outside of 9/5 in. casing	Monitor injection zone pressure and temperature
CO_2 Gas Detection	Wellhead	Monitor Ambient CO_2 Concentrations

4.1.2 Downhole Continuous Monitoring Instruments

Permanent downhole monitoring gauges will be installed. Downhole gauges will provide real-time data of the pressure and temperature of the in-situ conditions. Table 12-3 provides gauge specifications for the monitoring instruments. The selected gauges meet and set the standards for data quality objectives. The data quality parameters meet or exceed the requirements for

precision, accuracy, measurement range, representativeness, comparability, and completeness of the HCS Project.

Table 12-3—Downhole Gauge Precision, Accuracy, and Measurement Range

Parameter	Value
Model	SureSENS QPT (Quartz Pressure Temperature) Elite Gauge or equivalent
Calibrated working pressure range	200 – 10,000 Psi
Initial pressure accuracy	+/- 0.015% 1.5 psi at full scale
Pressure resolution	0.0001 psi
Pressure drift stability	0.02% full scale, 2.0 psi/year
Model	SureSENS QPT (Quartz Pressure Temperature) Elite Gauge or equivalent
Calibrated working temperature range	14 °F - 302°F
Initial temperature accuracy	0.27 °F
Temperature resolution	0.0001°F
Temperature drift stability	0.018°F
Max temperature	-
Instrument calibration frequency	-
Model	SureVIEW DTS or equivalent
Calibrated working temperature range	0°C-250°C
Initial temperature accuracy	+/-2 °C
Temperature resolution	See SureVIEW DTS Spec Sheet Attached or equivalent
Temperature drift stability	-
Max temperature	-
Instrument calibration frequency	-
Model	SureVIEW DAS or equivalent
Operating temperature (°C)	0°C-40°C
Storage temperature (°C)	-40°C-80°C
Operating relative humidity (%)	10%-70%
Sensing temperature (°C)	0°C-300°C
Operating altitude (m)	0m-2,000m
Fiber Types	9/125 µm CoreBRIGHT EBF or equivalent 9/125 µm CoreBRIGHT SMF or equivalent

4.1.3 Surface Continuous Monitoring Instruments

Gauges and meters will continuously monitor pressure, temperature, rate and volume, parameters at surface. Tables 12-4 through 12-8 provide the gauge and meter specifications for the monitoring instruments at surface. The selected gauges meet and set the standards for data quality objectives. The data quality parameters meet or exceed the requirements for precision,

accuracy, measurement range, representativeness, comparability, and completeness of the HCS Project.

Table 12-4—Injection Tubing Pressure Gauge, Precision, Accuracy, and Measurement

Parameter	Value
Model	Hawk 9000 or equivalent
Calibrated working pressure range	0.00-3,500.00 psi
Initial pressure accuracy	+/-0.8400 psi
Pressure resolution	0.0105 psi
Pressure drift stability	To be determined

Table 12-5—Annulus Pressure Gauge Precision, Accuracy, and Measurement Range

Parameter	Value
Model	Hawk 9000 or equivalent
Calibrated working pressure range	0.00-3,500 psi
Initial pressure accuracy	+/-0.8400 psi
Pressure resolution	0.0105
Pressure drift stability	To be determined

Table 12-6—Injection Tubing Temperature Gauge Precision, Accuracy, and Measurement Range

Parameter	Value
Model	Hawk 9000 or equivalent
Calibrated working temperature range	-20.00-80.00 °C
Initial temperature accuracy	+/- 0.40 °C
Temperature resolution	+/-0.001 °C
Temperature drift stability	To be determined

Table 12-7—Mass Flow Rate Meter Precision, Accuracy, and Measurement Range

Parameter	Value
Model	Endress-Hauser Proline Promass O 500 Coriolis Flow Meter or equivalent
Calibrated working flow rate range	0-2,200,000 kg/hr
Initial mass flow rate accuracy	+/-.10%
Mass flow rate resolution	-
Mass flow rate drift stability	To be determined

Table 12-8—CO_2 Gas Detection

Parameter	Value
Model	Dräger Polytron® 8720 IR or equivalent
Gases	CO_2
Measuring Range	• 0 to 10 vol. % (Standard) • 0 to 2,000 ppm to 30 vol. % (configurable) • Up to 100 vol. % possible with decreased linearity.
Sensitivity	≤± 0.01 % vol.
Response Time	4 seconds (w/o splash guard)

4.1.4 Data Representativeness

Every location has been selected to best collect a representative measurement of the injection operation.

4.1.5 Data Completeness

Gauge and meter data will be collected continuously.

4.1.6 Training Requirements and Certifications

HCS will provide training and qualification for any personnel performing covered tasks during the operation of the facility. Qualification records will be kept and maintained and will be made available for audit.

4.1.7 Documentation and Records

All calibration and maintenance records will be kept on file in paper and digital format. The continuous monitoring data stream will be collected, transmitted to central site to carry out necessary analysis and control and will be preserved digitally. As required by 40 CFR **146.91(f)(3)** [SWO 29-N-**6 §3629.A.4.c**], all continuous monitoring data will be retained for at least 10 years after collection. Record will be made available upon request during an audit.

4.1.8 Instrument/Equipment Testing, Inspection, and Maintenance Requirements

All instruments used will be tested, maintained, and inspected as described in Table 12-9.

Table 12-9—Instrument Testing, Inspection, and Maintenance Requirements

Equipment Type	Inspection Frequency	Type of Inspection	Maintenance	Testing
Gauge	Quarterly	Visual	Quarterly	Quarterly
Meter	Quarterly	Visual	Quarterly	Quarterly

4.1.9 Instrument Calibration and Frequency

All instruments will be calibrated as described in Table 12-10. Example of a gauge calibration certificates is provided in §10.3 of this plan.

Table 12-10—Instrument Calibration and Frequency

Equipment Type	Calibration Frequency	Standard Or Calibration Instrument Used
Gauge	Annual	Manufacturer recommendation or equivalent industry standard
Meter	Annual	Manufacturer recommendation or equivalent industry standard

Data is reviewed in real time. Any data found to be outside of normal operating ranges will raise an alarm. The source of the alarm will be immediately investigated, and a determination will be made if the data collected is valid or will need to be rejected.

4.1.10 Data Management

Surface and downhole data will be collected and managed using a Supervisory Control Data and Data Acquisition (SCADA) system. Figure 12-1 displays the data collection arrangement for the downhole monitoring system. The continuous monitoring data stream will be collected, transmitted to central site to carry out necessary analysis and control and will be preserved digitally.

Application

This example shows the typical connections for the system from configuration to real-time data communications.

Figure 1: Applications example.

Figure 12-1—Example of system configuration to real-time data

4.1.11 Reports

Continuous monitoring reports will be compiled monthly. The reports will be distributed to all relevant management parties, and the subsurface CO_2 plume and pressure front modelling team. The reports will be used to adjust the data collection and validation efforts.

5. Corrosion Monitoring

A corrosion monitoring system will be implemented where any metal encountering the injection stream will be tested. The coupons will be sent to Stress Engineering Services (or equivalent third-party laboratory) to be tested. Sections below describe QA/QC procedures that will be utilized to collect data that will meet the standards of quality.

5.1 Data Precision, Accuracy, and Measurement Range

Once received by the laboratory, the coupons shall be carefully inventoried and photo documented. Coupons shall be nondestructively cleaned and weighed to determine mass loss. Mass shall be measured to the nearest 0.1 mg, and dimensions shall be measured to the nearest 0.025 mm (0.001 in.). Measuring and weighing equipment shall have been calibrated no longer than one year prior to the date of use.

Chemical cleaning may be employed if needed to remove scale and shall be done in accordance with established laboratory procedures. Coupons shall then be examined under optical microscopy for evidence of localized corrosion (such as pitting or crevice corrosion), which shall be documented if present.

5.2 Training Requirements and Certifications

Contractors will be trained in handling and examining corrosion coupons.

5.3 Documentation and Records

As required by 40 CFR 144.51(j)(3), any records collected will contain:

- The date, exact place and time of sampling or measurements
- The individual(s) who performed the sampling or measurements
- The date(s) analyses were performed
- The individual(s) who performed the analyses
- The analytical techniques or methods used
- The results of such analyses

As required by 40 CFR **146.91(f)(1)** [SWO 29-6-N **§3629.A.4.a**]**,** reports will be kept as physical and digital formats throughout the life of the geologic sequestration project and for the 10 years following site closure.

5.4 Sampling Process Design

Field coupons will be of representative metallurgy as the equipment being monitored. All coupons will be newly prepared, uniquely and indelibly marked (etched or stamped), and their initial masses will be measured. Prior to installation, a record will be started for each coupon that includes as a minimum the serial number, installation date, installed location in the system, and orientation. The total number of coupons, coupon sizes, and coupon locations will be determined based on the final system design, targeting portions of the system that are at greatest risk of liquid water being present. Coupon holders will be designed such that they are resistant to degradation in the CO2 stream, regardless of whether water is present. All corrosion coupons are to be individually packaged and carefully handled during both shipment and installation to avoid damage that may affect results.

5.5 Sampling Method Requirements

The project manager will coordinate with the laboratory and sampling collection entities to review field, laboratory, and testing roles and responsibilities. This review will also include the documentation and chain-of-custody requirements to minimize potential problems during the project.

5.6 Sample Handling and Custody Procedures

Coupon holders will be designed such that they are resistant to degradation in the CO_2 stream, regardless of whether water is present. All corrosion coupons are to be individually packaged and carefully handled during both shipment and installation to avoid damage that may affect results.

Coupons are planned to be removed and replaced on a quarterly basis in accordance with 40 CFR 146.90(c). Like with installation, coupon removal will be done carefully to avoid damage. No coupon cleaning or coating is to be done in the field. Upon removal, the corrosion coupon report for each coupon will be updated with the removal date, initial observations, and any pertinent information about

operations during the time the coupon was in place. Coupons will be individually photographed, protected in moisture-free packaging, and immediately shipped to the test laboratory for evaluation.

Standard chain-of-custody procedures will be followed, and records maintained to allow a full reconstruction of how the samples were collected, stored and transported, including any problems encountered.

5.7 Analytical Methods Requirements

Table 12-11—Corrosion Coupon Analysis

Activity	Location(s)	Method	Analytical Technique	Lab/Custody	Purpose
Corrosion monitoring	Corrosion Coupon Monitoring System	Weight Loss Calculation	ASTM G4, NACE International (NACE) Recommended Practice RP- 0775 (NACE, 2005), or equivalent industry standard	Stress Engineering Services or equivalent	Monitor metal loss that may lead to loss of mechanical integrity

5.8 Quality Control Checks

Measuring and weighing equipment shall have been calibrated no longer than one year prior to the date of use.

5.9 Reports

Stress Engineering Laboratories, or other third-party lab, will generate a corrosion coupon report. HCS will review the report and verify that no significant metallurgic changes have been observed. If significant changes are observed, an investigation into the source will be launched and remediation efforts will begin. Mass loss should be considered for information only, and any evidence of localized corrosion warrants review by a subject matter expert to provide recommendations. The CRA portions of the system are designed to resist corrosion damage entirely, so if there is pitting on the coupons, it will need to be reviewed. Tightening up test frequency would not be helpful and may even mask the damage since there is a nucleation time associated with the pitting mechanism. The report will be submitted to the required regulatory bodies along with the semi-annual reports.

5.10 Sampling Process

Corrosion coupons, made of the same material as the production casing and the injection tubing, will be placed in the CO_2 injection pipeline. The coupons will be removed quarterly and assessed for corrosion using American Society for Testing and Materials (ATSM) standards for evaluating corrosion tests. When the coupons are removed, they will be inspected visually for any signs of corrosion, including pitting. The weight and size of the coupons will be measured each time they are removed. The rate of corrosion will be calculated using a weight loss method where the rate equals the weight loss during the exposure period divided by the duration of the period.

5.11 Laboratory Analysis

Once received by the laboratory, coupons will be carefully inventoried and photo-documented. Coupons will be nondestructively cleaned and weighed to determine mass loss. Chemical cleaning may be employed if needed to remove scale and shall be done in accordance with established laboratory procedures. Coupons will then be examined under optical microscopy for evidence of localized corrosion (such as pitting or crevice corrosion), which will be documented if present. Results will be reviewed by subject matter experts, documented on the corrosion coupon reports, and delivered to the operator for review. Mass loss should be considered for information only, and any evidence of localized corrosion warrants review by a subject matter expert to provide recommendations. Any additional examinations of the coupons will be considered on a case-by-case basis.

5.12 Record Keeping

Results will be reviewed by subject matter experts, documented on the corrosion coupon reports, and delivered to the operator for review. Any additional examinations will be considered on a case-by-case basis.

All coupon sampling history and analysis will be kept on file. They will remain active during the life of the project.

6. Groundwater and CO_2 Sampling and Analysis

Table 12-12—HCS Sampling Summary

Activity	Location(s)	Method	Analytical Technique	Lab/Custody	Purpose
Ground Water analysis	Monitoring Well No. 001	U-Tube Sampling System	Lab	Element Materials Technology or equivalent	Detection of water quality deterioration
Ground Water analysis	Monitoring Well No. 002	U-Tube Sampling System	Lab	Element Materials Technology or equivalent	Detection of water quality deterioration

Activity	Location(s)	Method	Analytical Technique	Lab/Custody	Purpose
CO2 Analysis	Injection Stream Sampling Manifold	Sampling Cylinders	Lab	Element Materials Technology or equivalent	Ensure Quality of Injectate
Formation Sample Analysis	Injection Well No. 001	Formation Tester	Lab	TBD Element Materials Technology	Characterize and monitor formation

6.1 CO_2 Stream Analysis

CO_2 stream analysis will be conducted by Element Laboratories or equivalent third-party lab. The sections below describe QA/QC procedures that will be utilized to collect data that will meet the quality standards

Table 12-13 – CO_2 Precision, Analysis, and QC Requirements

Parameters	Analytical Methods	Detection/limit Range	Typical Precisions	QC Requirements
Oxygen	GPA 2261-20 can do low level oxygen test or mole sieve analysis	Low level oxygen: 1ppm- 1% Mole sieve analysis up to 10% oxygen	Approx 10- 20ppm	Run mole sieve standard to generate response factors for unknown sample
Nitrogen	GPA 2261-20	0.001-99.999%	Approx. 1%	Run daily check, must pass gpa 2261-20
Carbon Monoxide	GPA 2261-20 mole sieve analysis	10ppm-1%	Approx 10- 20 ppm	Run mole sieve standard to generate response factors for unknown sample
Total Hydrocarbons	GPA 2261-20 regular run GPA 2286 extended analysis	0.001-99.999%	Approx. 1%	Run daily check, must pass gpa 2261-20
Methane	GPA 2261-20	0.001-99.999%	Approx. 1%	Run daily check, must pass gpa 2261-20
Hydrogen Sulfide	GPA 2377 stain tube GPA 2261-20 gas analysis of H_2S	0.2ppm-4% using stain tube Gas analysis – 0.1%-20%	For staintube approx. 10-20 ppm For gas analysis approx. 1%	Run daily check, must pass gpa 2261-20

Parameters	Analytical Methods	Detection/limit Range	Typical Precisions	QC Requirements
CO_2 Purity	Test CO_2 quantity but not purity GPA 2261-20	0.001-99.999%	Approx. 1%	Run daily check, must pass gpa 2261-20

6.1.1 Training Requirements and Certifications

An EPA-Certified laboratory will be used for all sample analysis.

6.1.2 Documentation and Records

As required by 40 CFR 144.51(j)(3), any records collected will contain:

- The date, exact place and time of sampling or measurements
- The individual(s) who performed the sampling or measurements
- The date(s) analyses were performed
- The individual(s) who performed the analyses
- The analytical techniques or methods used
- The results of such analyses

6.1.3 Sampling Method Requirements

The project manager will coordinate with the laboratory and sampling collection entities to review field, laboratory, and testing roles and responsibilities. This review will also include the documentation and chain-of-custody requirements to minimize potential problems during the project.

6.1.4 Sample Handling and Custody Procedures

Water samples will be sent to an EPA approved laboratory. Standard chain-of-custody procedures will be followed, and records maintained to allow a full reconstruction of how the samples were collected, stored and transported, including any problems encountered.

6.1.5 Analytical Methods Requirements

Analytical Methods are presented in Table 12-13.

6.1.6 Quality Control Checks

QC Methods are presented in Table 12-13.

6.1.7 Reports

Element Laboratories, or equivalent lab will generate a report t hat HCS will review and verify that no significant geochemical changes have been observed. The report will be submitted to the required regulatory bodies along with the semi-annual reports.

6.1.8 Sampling Procedures

The project manager will coordinate with the laboratory, sampling collection, and formation tester service representatives, to review field, laboratory, and testing roles and responsibilities. This review will also include the documentation and chain-of-custody requirements to minimize potential problems during the project.

6.1.9 Record Keeping

As required by 40 CFR **146.91(f)(1)** [SWO 29-N-6 **§3629.A.4.a**]**,** reports will be kept on physical and digital formats throughout the life of the geologic sequestration project and for the 10 years following site closure.

6.2 Water Analysis

6.2.1 Formation Fluid Analysis

A wireline formation tester services will be acquired. Valid calibration certificates and tool specifications will be requested before selecting the service.

Table 12-14—Formation Sample Precision and Analysis

Analyte	Method	Reporting Limit	MDL	Precision*	QC requirements
Aluminum	6020	20.0 ug/L	4.94 ug/L	80-120%	Initial Calibration and Verification Continuing calibration ICP Interference Check Samples Internal Standards Method Blank Lab Control Sample/Lab Control
Antimony	6020	0.25 ug/L	0.0086 ug/L	80-120%	
Arsenic	6020	0.25 ug/L	0.0179 ug/L	80-120%	
Barium	6010	0.01 mg/L	0.001 mg/L	80-120%	
Cadmium	6010	0.005 mg/L	0.00078 mg/L	80-120%	Sample Dup Matrix Spike/Matrix Spike Dup
Calcium	6010	0.5 mg/L	0.1 mg/L	80-120%	
Chromium	6010	0.01 mg/L	0.00048 mg/L	80-120%	
Copper	6010	0.01 mg/L	0.00064 mg/L	80-120%	

Analyte	Method	Reporting Limit	MDL	Precision*	QC requirements
Iron	6010	0.01 mg/L	0.005 mg/L	80-120%	
Lead	6010	0.01 mg/L	0.0049 mg/L	80-120%	
Magnesium	6010	0.5 mg/L	0.1 mg/L	80-120%	
Manganese	6010	0.01 mg/L	0.0028 mg/L	80-120%	
Potassium	6010	5 mg/L	0.126 mg/L	80-120%	
Selenium	6010	0.02 mg/L	0.005 mg/L	80-120%	
Sodium	6010	5.0 mg/L	2.32 mg/L	80-120%	
Titanium	6010	0.01 mg/L	0.00033 mg/L	80-120%	
Silica (Dissolved)	6010	0.1 mg/L	0.0056 mg/L	80-120%	
Bromide	9056	0.1 mg/L	0.00044 mg/L	80-120%	Initial Calibration and Verification Continuing calibration Method Blank Lab Control Sample/Lab Control Sample Dup Matrix Spike/Matrix Spike Dup
Chloride	9056	0.25 mg/L	0.0166 mg/L	80-120%	
Fluoride	9056	0.05 mg/L	0.00199 mg/L	80-120%	
Nitrate	9056	0.025 mg/L	0.0026 mg/L	80-120%	
Sulfate	9056	0.25 mg/L	0.0145 mg/L	80-120%	
Dissolved CO2	RSK 175	880 ppb	220 ppb	80-122%	Calibration, Method Blank, LCS, Duplicate, MS, MSD.
Total Dissolved Solids	2540C	10 mg/L	5.57 mg/L	85-115%	Method Blank Lab Control Sample/Lab Control Sample Dup Matrix dup
Alkalinity, Total	SM2320 B	20 mg/L	2.43 mg/L	80-120%	Method Blank Lab Control Sample Matrix dup
pH	4500H-B	1.68 S.U.	NA	97-103%	Lab Control Sample Matrix dup
Specific Conductance (@25C)	E120.1	10 mg/L	0.512 mg/L	90-110%	Method Blank Lab Control Sample Matrix dup

Precision*= LCS control limits

Additional sample volume required for Field Duplicate, Matrix Spike, Matrix Spike Duplicate samples.

6.2.1.1 Training Requirements and Certifications

An EPA-Certified laboratory will be used for all sample analysis.

6.2.1.2 Documentation and Records

As required by 40 CFR 144.51(j)(3), any records collected will contain:

- The date, exact place and time of sampling or measurements
- The individual(s) who performed the sampling or measurements
- The date(s) analyses were performed
- The individual(s) who performed the analyses
- The analytical techniques or methods used
- The results of such analyses

As required by 40 CFR **146.91(f)(1)** [SWO 29-6-N **§3629.A.4.a**]**,** reports will be kept on physical and digital formats throughout the life of the geologic sequestration project and for the 10 years following site closure.

6.2.1.3 Sampling Process Design

Prior to setting the production casing string, samples of the formation fluid will be obtained by running an open hole fluid recovery tool (RDT). Recovery sections will be determined based on open hole evaluations. Two samples will be taken per section as described in the Drilling and Completion Prognosis, Appendix F.

6.2.1.4 Sampling Method Requirements

The project manager will coordinate with the laboratory, sampling collection, and formation tester service representatives, to review field, laboratory, and testing roles and responsibilities. This review will also include the documentation and chain-of-custody requirements to minimize potential problems during the project.

6.2.1.5 Sample Handling and Custody Procedures

Formation fluid samples will be sent to an approved laboratory. Standard chain-of-custody procedures will be followed, and records maintained to allow a full reconstruction of how the samples were collected, stored and transported, including any problems encountered.

Table 12-15—Container, Preservation Methods, and Holding Times

Analyte	Container	Preservation	Holding Time
Aluminum	8 oz plastic	pH < 2 via Nitric Acid	6 Months
Antimony	Same	Same	Same
Arsenic	Same	Same	Same
Barium	Same	Same	Same
Cadmium	Same	Same	Same
Calcium	Same	Same	Same
Chromium	Same	Same	Same
Copper	Same	Same	Same
Iron	Same	Same	Same

Analyte	Container	Preservation	Holding Time
Lead	Same	Same	Same
Magnesium	Same	Same	Same
Manganese	Same	Same	Same
Potassium	Same	Same	Same
Selenium	Same	Same	Same
Sodium	Same	Same	Same
Titanium	8 oz plastic	Same	Same
Silica (Dissolved)	8 oz plastic	None	Same
Bromide	8 oz plastic	Cool 0 - 6 C	28 Days
Chloride	Same	Cool 0 - 6 C	28 Days
Fluoride	Same	Cool 0 - 6 C	28 Days
Nitrate	Same	Cool 0 - 6 C	48 Hours
Sulfate	Same	Cool 0 - 6 C	28 Days
Dissolved CO2	2 unpreserved 40 ml vials, zero headspace	Cool 0 - 6 C	7 Days
Total Dissolved Solids	1 Liter plastic	Cool 0 - 6 C	7 Days
Alkalinity, Total	500 ml plastic	Cool 0 - 6 C	14 Days
pH	4 oz plastic		Onsite/15 minutes
Specific Conductance (@25C)	4 oz plastic	Cool 0 - 6 C	28 Days

6.2.1.6 Analytical Methods Requirements

Formation fluid analysis is presented in Table 12-16.

6.2.1.7 Quality Control Checks

Formation fluid QC is presented in Table 12-16.

6.2.1.8 Reports

Element Laboratories, or equivalent third-party lab, will generate a report that HCS will review and verify that no significant geochemical changes have been observed. The report will be submitted to the required regulatory bodies along with the semi-annual reports.

6.2.1.9 Groundwater Monitoring Analysis

Above zone monitoring will be conducted using a deep monitoring well. The following sections describe the QA/QC procedures that will be utilized to collect data that will meet the standards of quality.

Table 12-16—Groundwater Sample Precision and Analysis

Analyte	Method	Reporting Limit	MDL	Precision*	QC requirements
Aluminum	6020	20.0 ug/L	4.94 ug/L	80-120%	Initial Calibration and Verification Continuing calibration ICP Interference Check Samples Internal Standards Method Blank Lab Control Sample/Lab Control Sample Dup Matrix Spike/Matrix Spike Dup
Antimony	6020	0.25 ug/L	0.0086 ug/L	80-120%	
Arsenic	6020	0.25 ug/L	0.0179 ug/L	80-120%	
Barium	6010	0.01 mg/L	0.001 mg/L	80-120%	
Cadmium	6010	0.005 mg/L	0.00078 mg/L	80-120%	
Calcium	6010	0.5 mg/L	0.1 mg/L	80-120%	
Chromium	6010	0.01 mg/L	0.00048 mg/L	80-120%	
Copper	6010	0.01 mg/L	0.00064 mg/L	80-120%	
Iron	6010	0.01 mg/L	0.005 mg/L	80-120%	
Lead	6010	0.01 mg/L	0.0049 mg/L	80-120%	
Magnesium	6010	0.5 mg/L	0.1 mg/L	80-120%	
Manganese	6010	0.01 mg/L	0.0028 mg/L	80-120%	
Potassium	6010	5 mg/L	0.126 mg/L	80-120%	
Selenium	6010	0.02 mg/L	0.005 mg/L	80-120%	
Sodium	6010	5.0 mg/L	2.32 mg/L	80-120%	
Titanium	6010	0.01 mg/L	0.00033 mg/L	80-120%	

Analyte	Method	Reporting Limit	MDL	Precision*	QC requirements
Silica (Dissolved)	6010	0.1 mg/L	0.0056 mg/L	80-120%	
Bromide	9056	0.1 mg/L	0.00044 mg/L	80-120%	Initial Calibration and Verification Continuing calibration Method Blank Lab Control Sample/Lab Control Sample Dup Matrix Spike/Matrix Spike Dup
Chloride	9056	0.25 mg/L	0.0166 mg/L	80-120%	
Fluoride	9056	0.05 mg/L	0.00199 mg/L	80-120%	
Nitrate	9056	0.025 mg/L	0.0026 mg/L	80-120%	
Sulfate	9056	0.25 mg/L	0.0145 mg/L	80-120%	
Dissolved CO2	RSK 175	880 ppb	220 ppb	80-122%	Calibration, Method Blank, LCS, Duplicate, MS, MSD
Total Dissolved Solids	2540C	10 mg/L	5.57 mg/L	85-115%	Method Blank Lab Control Sample/ Lab Control Sample Dup Matrix dup
Alkalinity, Total	SM2320 B	20 mg/L	2.43 mg/L	80-120%	Method Blank Lab Control Sample Matrix dup
pH	4500H-B	1.68 S.U.	NA	97-103%	Lab Control Sample Matrix dup
Specific Conductance (at 25C)	E120.1	10 mg/L	0.512 mg/L	90-110%	Method Blank Lab Control Sample Matrix dup

Precision*= LCS control limits
Additional sample volume required for Field Duplicate, Matrix Spike, Matrix Spike Duplicate samples.

6.2.1.10 Training Requirements and Certifications

An EPA-Certified laboratory will be used for all sample analysis.

6.2.1.11 Documentation and Records

As required by 40 CFR 144.51(j)(3), any records collected will contain:

- The date, exact place and time of sampling or measurements
- The individual(s) who performed the sampling or measurements
- The date(s) analyses were performed
- The individual(s) who performed the analyses
- The analytical techniques or methods used
- The results of such analyses

Additionally, required by 40 CFR **146.91(f)(1)** [SWO 29-6-N **§3629.A.4.a**]**,** reports will be kept on physical and digital formats throughout the life of the geologic sequestration project and for the 10 years following

site closure.

6.2.1.12 Sampling Process Design

Fluid samples in the groundwater monitoring well will be collected at the monitored formation temps and maintained at the formation pressures within a pressurized sample container to prevent any losses of dissolved gases. Prior to sampling, the well will be purged of any fluid stored in the well bore. Static fluid level and temperature will be measured prior to purging the well. A U-tube sampling system will be lowered to the monitored zone via wireline or slickline and the rate of sample collection should not exceed the rate at which the well was purged.

Class VI Solutions, Inc. has been contracted to provided sampling services. The detailed sampling process can be found in **§10.6** of this document.

The project manager will coordinate with the laboratory and sampling collection entities to review field, laboratory, and testing roles and responsibilities. This review will also include the documentation and chain-of-custody requirements to minimize potential problems during the project.

6.2.1.13 Sampling Method Requirements

The project manager will coordinate with the laboratory, sampling collection, and formation tester service representatives, to review field, laboratory, and testing roles and responsibilities. This review will also include the documentation and chain-of-custody requirements to minimize potential problems during the project.

6.2.1.14 Sample Handling and Custody Procedures

Table 12-17—Container, Preservation Methods, and Holding Times

Analyte	Container	Preservation	Holding Time
Aluminum	8 oz plastic	pH < 2 via Nitric Acid	6 Months
Antimony	Same	Same	Same
Arsenic	Same	Same	Same
Barium	Same	Same	Same
Cadmium	Same	Same	Same
Calcium	Same	Same	Same
Chromium	Same	Same	Same
Copper	Same	Same	Same
Iron	Same	Same	Same
Lead	Same	Same	Same
Magnesium	Same	Same	Same
Manganese	Same	Same	Same
Potasium	Same	Same	Same
Selenium	Same	Same	Same
Sodium	Same	Same	Same
Titanium	8 oz plastic	Same	Same

Analyte	Container	Preservation	Holding Time
Silica (Dissolved)	8 oz plastic	None	Same
Bromide	8 oz plastic	Cool 0 - 6 C	28 Days
Chloride	Same	Cool 0 - 6 C	28 Days
Fluoride	Same	Cool 0 - 6 C	28 Days
Nitrate	Same	Cool 0 - 6 C	48 Hours
Sulfate	Same	Cool 0 - 6 C	28 Days
Dissolved CO2	2 unpreserved 40 ml vials, zero headspace	Cool 0 - 6 C	7 Days
Total Dissolved Solids	1 Liter plastic	Cool 0 - 6 C	7 Days
Alkalinity, Total	500 ml plastic	Cool 0 - 6 C	14 Days
pH	4 oz plastic		Onsite/15 minutes
Specific Conductance (@25C)	4 oz plastic	Cool 0 - 6 C	28 Days

6.2.1.15 Analytical Methods Requirements
Formation fluid analysis is presented in Table 12-17.

6.2.1.16 Quality Control Checks
Formation fluid QC is presented in Table 12-17.

6.2.1.17 Reports
Element Laboratories will generate a report. HCS will review the report and verify that no significant geochemical changes have been observed. The report will be submitted to the required regulatory bodies along with the semi-annual reports.

7. Integrity Testing

Temperature, pressure, flowrates and volumes will be measured. Field gauges and meters will be used to collect this data. The following sections provide instrumentation specifications and operating details. The selected gauges meet and set the standards for data quality objectives. The data quality requirements will cover:

- Annulus Pressure Testing
- Pressure Fall-off Testing
- Step-Rate Injectivity Testing

The data quality parameters meet or exceed the requirements for precision, accuracy, measurement range, representativeness, comparability, and completeness of the HCS Project.

7.1 Data Precision, Accuracy, Measurement Range

Table 12-18—Tubing Pressure Testing Precision, Accuracy, and Measurement

Parameter	Value
Model	Hawk 9000 or equivalent
Calibrated working pressure range	0.00-3,500.00 psi
Initial pressure accuracy	+/-0.8400 psi
Pressure resolution	0.0105 psi
Pressure drift stability	To be determined

Table 12-19—Annulus Pressure Testing Precision, Accuracy, and Measurement Range

Parameter	Value
Model	Hawk 9000 or equivalent
Calibrated working pressure range	0.00-3,500 psi
Initial pressure accuracy	+/-0.8400 psi
Pressure resolution	0.0105
Pressure drift stability	To be determined

Table 12-20—Downhole Pressure Gauge Precision, Accuracy, and Measurement Range

Parameter	Value
Model	Tandem Downhole Pressure Gauge or equivalent
Calibration Date	TBD
Serial Number	TBD
Certificate Number	TBD
Pressure Range	0-15 Ksi
Pressure Accuracy	± .05% Full Scale
Temperature Range	0°F to 300°F (0°C to 150°C)
Temperature Accuracy	Temperature ± 3°F
Sample Rate	1.875 seconds/gauge

7.2 Training Requirements and Certifications

Training and qualification for any personnel performing covered tasks will be provided before participating in operations. Qualification records will be kept and maintained and will be made available for audit.

7.3 Instrument/Equipment Testing, Inspection, and Maintenance Requirements

Table 12-21—Instrument Testing, Inspection, and Maintenance Requirements

Equipment Type	Inspection Frequency	Type of Inspection
Gauge	Quarterly	Visual
Meter	Quarterly	Visual

7.4 Instrument Calibration and Frequency

Table 12-22—Testing Instrument Calibration

Equipment Type	Calibration Frequency	Standard Or Calibration Instrument Used
Gauge	Annual	Manufacturer recommendation or equivalent industry standard
Meter	Annual	Manufacturer recommendation or equivalent industry standard

7.5 Reports

Reports will be compiled after testing. The reports will be kept on file in physical and digital formats. Complete reports will be distributed to management and required regulatory bodies.

7.6 Data Review, Validation, and Verification

The data collected from any integrity testing will be reviewed by the responsible third-party using company and equipment standard operating procedures internal data validation and verification process.

The project manager will coordinate with the testing service representatives to review field and testing roles and responsibilities. This review will also include the documentation and chain-of-custody requirements to minimize potential problems during the project.

7.7 Calibration Procedures

Service companies will provide gauges that will be used for testing. All gauges that will be used in testing will need to have current calibration records. These records will be kept on file and will remain active during the life of the project.

7.8 Record Keeping

All records pertaining to integrity testing will be kept in physical and digital format. As required by 40 CFR

146.91(f)(1) [SWO 29-N-6 **§3629.A.4.a**]**,** reports will be kept on physical and digital formats throughout the life of the geologic sequestration project and for the 10 years following site closure.

8. Well Logging

Logging services will be secured through a selection process that will be determined by availability, current technology, and expertise. All logging services will be assessed for data quality standards conformance before selection.

Table 12-23—Well Logging Methods to be Employed

Activity	Location(s)	Method	Purpose
Mechanical integrity—External	Injection Well	Wireline Conveyed Temperature Survey	Demonstration of Mechanical Integrity
Mechanical integrity—Cement Evaluation	Injection Well	Wireline Conveyed Cement Evaluation	Monitor casing-cement bonding
Mechanical integrity— Casing Inspection	Injection Well	Wireline Conveyed Casing Inspection	Monitor casing corrosion

8.1 Data Precision, Accuracy, Measurement Range

Logging tool service providers will provide tool precision, accuracy and measurement ranges upon solicitation of services.

An example of logging tools specifications is provided in **§8.5**

The project manager will coordinate with the laboratory, testing, and logging entities to review field, laboratory, and testing roles and responsibilities. This review will also include the documentation and chain-of-custody requirements to minimize potential problems during the project.

8.2 Instrument/Equipment Testing, Inspection, and Maintenance Requirements

Logging tool service providers will be responsible for maintaining equipment, testing, and inspecting of measurement devices. Certification of these activities will need to be provided from the service provider before commencing data collection activities at the HCS project.

8.3 Instrument Calibration and Frequency

Logging tool service providers will be responsible for calibration of measurement devices. Certificates of calibration will need to be provided from the service provider before commencing data collection activities

at the HCS project.

8.4 Data Acquisition Requirements

Logging tool service providers will be responsible for data acquisition requirements. Standard industry practices will be applied.

8.5 Reports

Reports will be compiled after logging. The reports will be kept on file in physical and digital formats. Complete reports will be distributed to management and required regulatory bodies. The report will be submitted to the required regulatory bodies along with the semi-annual reports.

8.6 Data Review, Validation, and Verification

The data collected from any logging activities will be reviewed by the responsible third-party using company and equipment standard operating procedures and internal data validation and verification process.

8.7 Record Keeping

A copy of all instrument certification and calibration will be kept on file. Reports generated from data collection activities will be compiled and disseminated to all interested parties. As required by 40 CFR **146.91(f)(1)** [SWO 29-N-6 **§3629.A.4.a**]**,** reports will be kept on physical and digital formats throughout the life of the geologic sequestration project and for the 10 years following site closure.

9. Coring

40 CFR **146.87(b)** [SWO 29-N-6 **§3617.B.2**] requires cores to be taken form the injection zone and the confining system. Cores will be taken from zones in Table 12-24**.**

Table 12-24—Coring Plan

Activity	Location(s)	Method	Purpose
Above Injection zone Confining Interval	Amphistegina B	60 ft whole Core	Formation Evaluation
Injection Zone	Miocene Sands	60 ft whole Core	Formation Evaluation
Below Injection Zone Confining Interval	Anahuac Shale	60 ft whole Core	Formation Evaluation

Tables 25 and Table 26 describe the analysis and the testing standards that will be implemented.

Table 12-25—Injection Interval Core Analyses

Whole Core Analysis / Injection Intervals	Corelab Service Standards or equivalent
Absolute and relative permeability (x,y,z directions)	API RP40
Klinkenberg parameter "b" (Pa^{-1}) where $K_{gas} = k * (1 + (\frac{b}{p}))$	API RP40
Porosity	API RP40
Formation heat conductivity under fully liquid-saturated conditions (W/m-°C)	ASTM D5334
Formation heat conductivity under desaturated conditions (W/m-°C)	ASTM D5334
Rock grain density (kg/m^3)	API RP40
Rock grain specific heat (J/kg-°C)	ASTM D5334
Pore compressibility (Pa^{-1})	API RP40
Pore expansivity (1/°C)	API RP40
Capillary pressure	API RP40
Tortuosity factor for binary diffusion	API RP40
Geochemistry	No Standard (Interpretive)
XRD	No Standard (Interpretive)
XRF	No Standard (Interpretive)
Fracture pressure / gradient	

Table 12-26—Confining Interval Core Analyses

Whole Core Analysis / Confining Intervals	Corelab Service Standards or equivalent
Absolute and relative permeability (x,y,z directions)	API RP40
Porosity	API RP40
Rock grain density (kg/m^3)	API RP40
Pore compressibility (Pa^{-1})	API RP40
Pore expansivity (1/°C)	API RP40
Capillary pressure	API RP40
Tortuosity factor for binary diffusion	API RP40
Geochemistry	No Standard (Interpretive)
XRD	No Standard (Interpretive)
XRF	No Standard (Interpretive)
Fracture pressure / gradient	

9.1 Reports

As required by 40 CFR **146.87(b)** [SWO 29-N-6 **§3617.B.2**], a detailed report prepared by a log analyst. The report includes: (1) Well Log analyses, core analyses, and formation fluid sampling.

9.2 Record Keeping

A copy of all instrument certification and calibration will be kept on file. Reports generated from data collection activities will be compiled and disseminated to all interested parties. As required by 40 CFR **146.91(f)(1)** [SWO 29-N-6 **§3629.A.4.a**]**,** reports will be kept as physical and digital formats throughout the life of the geologic sequestration project and for the 10 years following site closure.

10. Packer

A Weatherford UltraPak™ or equivalent Permanent Seal-Bore Packer will be utilized in the construction of the HCS Well No. 001. Figure 12-2 provides the specifications for the packer.

10.1 Instrument/Equipment Testing, Inspection, and Maintenance Requirements

UltraPak™ Permanent Seal-Bore Packer

Specifications

Casing				Packer[1]			
OD (in./*mm*)	Weight (lbm/ft, *kg/m*)	Minimum ID (in./*mm*)	Maximum ID (in./*mm*)	Bore (in./*mm*)	Maximum OD (in./*mm*)	Basic Part	Elastomer
4-1/2 *114.3*	11.6 to 13.5 *17.3 to 20.1*	3.853 *97.87*	4.069 *103.35*	2.688 *68.28*	3.750 *95.25*	173369	NBR[2]
						747092	HNBR[3]
						742725	Aflas®
	15.1 to 16.6 *22.5 to 24.7*	3.669 *93.19*	3.904 *99.16*	2.390 *60.71*	3.574 *90.78*	166863	Nitrile
5-1/2 *139.7*	14.0 to 17.0 *20.8 to 25.3*	4.778 *121.36*	4.950 *125.73*	2.688 *68.28*	4.600 *116.84*	742814	Nitrile
				3.000 *76.20*		168508	NBR
						231098	Nitrile
						742805	Aflas
	17.0 to 23.0 *25.3 to 34.2*	4.670 *118.62*	4.892 *124.26*		4.435 *112.65*	167058	NBR
					4.440 *112.78*	166879	Nitrile
						896333	Aflas Kalrez® Teflon® Ryton®
7 *177.8*	23.0 to 32.0 *34.2 to 47.6*	5.900 *149.86*	6.466 *164.24*	3.250 *82.55*	5.875 *149.23*	168371	NBR
						747098	HNBR
						173510	Nitrile
						173309	Aflas
						747096	Aflas
				4.00 *101.60*	5.860 *148.84*	747100	Aflas
					5.875 *149.23*	718580	Nitrile
						762924	HNBR
						718580	Nitrile
	32.0 to 35.0 *47.6 to 52.1*	5.892 *149.66*	6.208 *157.68*		5.794 *147.17*	290138	HSN[4]
	35.0 to 38.0 *52.1 to 56.6*	5.801 *147.35*	6.123 *155.52*		5.710 *145.03*	742891	Aflas
						711054	HNBR
7-5/8 *193.7*	29.7 *44.2*	6.510 *165.35*	6.875 *174.63*	3.250 *82.55*	6.250 *158.75*	737016	NBR
	33.7 to 39.0 *50.2 to 58.0*		6.882 *174.80*			168563	NBR
				4.000 *101.60*	6.375 *161.93*	277814	WE-216
	29.7 *44.2*	6.781 *172.24*	6.987 *177.47*	3.250 *82.55*	6.250 *158.75*	737016	NBR
9-5/8 *244.5*	40.0 to 53.5 *59.5 to 79.6*	8.405 *213.49*	8.968 *227.79*	4.750 *120.65*	8.319 *211.30*	745634	Aflas
						173978	Nitrile
						743146	HNBR
	47.0 to 53.5 *69.9 to 79.6*	8.535 *216.79*	8.681 *220.50*	3.250 *82.55*	8.125 *206.38*	728071	NBR
				4.000 *101.60*		728191	NBR

[1]Has a wireline-guide bottom connection
[2]Nitrile butadiene rubber
[3]Hydrogenated nitrile butadiene rubber
[4]Highly saturated nitrile

Figure 12-2—Packer Specifications example.

11. Instrument Specification Sheets

11.1 Example – Gauge Calibration Records

Cal-scan Services Ltd.
4188-93 Street
Edmonton, Alberta, Canada
T6E 5P5
Phone: (780) 944-1377 Fax: (780) 944 - 1406

Calibration Certificate

Model :	Hawk 9000	**Range :**	3,500.00 psi
Serial Number :	60961	**Last Cal. Date :**	31-October-2019

Specifications

Calibration Pressure Range:		0.00	3,500.00 psi
Calibration Temperature Range:		-40.00	60.00 ° C
Pressure:	Accuracy	±	0.8400 psi (0.024 %FS)
	Resolution	±	0.0105 psi (0.0003 %FS)
Temperature:	Accuracy	±	0.400 ° C (0.40 %FS)
	Resolution	±	0.001 ° C (0.001 %FS)

Calibration Summary

Pressure: Accuracy (maximum error)	0.28 psi
Temperature: Accuracy (maximum error)	0.19 ° C

Traceability Statement

All working standards are traceable to national or internationally recognized standards.
Calibrated with Cal-Scan DWG # 5

Calibrated by:

Ed Arnold

11.2 Dräger Polytron® 8720 IR

Dräger

Dräger Polytron® 8720 IR
Detection of carbon dioxide

The Dräger Polytron® 8720 IR is an advanced explosion proof transmitter for the detection of carbon dioxide in percent volume or ppm. It uses a high performance infrared Dräger PIR 7200 sensor, which can be submerged in water without damage. Besides a 3 wire 4 to 20 mA analog output with relays, it also offers HART®, Modbus and Fieldbus making it compatible with most control systems.

Dräger. Technology for Life®

Benefits

Efficient, stable and robust – the Dräger PIR 7200

With its stainless steel 316L enclosure and drift free optics, the Dräger PIR 7200 is built for the harshest industrial and commercial outdoor environments. The unique 4 beam signal stabilizing system makes the sensor resistant to dust or dirt deposits on the optical surfaces. Environmental and ageing effects are compensated ensuring long term, drift free operation. The measuring range can be freely adjusted between 0 – 2,000 ppm and 0 – 30 % volume enabling a wide variety of applications.

Easy device management via digital communication

The Dräger Polytron 8720 is equipped with digital interfaces allowing for quick and easy remote interrogation of the transmitter's state. Integration with existing asset management systems such as PACTware™ is possible via DTM. In addition to the common HART® communication system, the fieldbus interfaces PROFIBUS® PA, FOUNDATION fieldbus™ H1, and Modbus RTU are also available.

Same design, same operating principle

The Dräger Polytron 8720 belongs to the Polytron 8000 series. All transmitters in this series have the same design and user interface. This allows for uniform operation with reduced training and maintenance requirements. The large graphic backlit display shows status information clearly and in an easy to use format. The measured gas concentration, selected gas type, and measuring unit are displayed during normal operation. Colored LEDs (green, yellow and red) provide additional alarm and status information. The Polytron 8720 is operated by means of a magnetic wand over contact surfaces.

Three relays for controlling external equipment

Upon request, the Dräger Polytron 8720 can also be supplied with three integrated relays. This enables you to use it as an independent gas detection system with two arbitrarily adjustable concentration alarms and one fault alarm. Audible alarms, signal lights or similar devices can thus be controlled locally without an additional cable between the transmitter and central controller.

Safe, robust housing for every application

Polytron 8720 features a Class I, Div. 1 rated explosion proof enclosure made from aluminium or stainless steel, making it suitable for a wide range of environmental conditions. The included splash guard features a chimney effect that actively draws ambient air inside enabling gases to be detected in under 10 seconds.

Make the impossible possible with the remote sensor

A remote explosion proof junction allows installation of the sensor up to 100' away from the transmitter in difficult to access areas. A convenient flow cell allows for remote bump testing or calibration from the Polytron display by using permanently attached tubing that takes the calibration gas to the sensor.

Benefits

Data logger

The Polytron 8720 has a data logger, which records measuring and event data from the past years. A graph function displays the history of the past 15 minutes on a time/concentration graph.

System Components

D-6806-2016

Dräger REGARD® 7000

The Dräger REGARD® 7000 is a modular and highly expandable control system for monitoring various gases and vapors. Ideal for gas warning systems with various levels of complexity and numbers of transmitters, the Dräger REGARD® 7000 delivers exceptionally reliability and efficiency. An additional benefit is the controller's backward compatibility with the REGARD®.

D-1130-2010

Dräger REGARD® 3900 Series

The devices of the Dräger REGARD® 3900 series can be used as standalone controllers. You can configure up to 16 measuring channels. In addition, the modular setup enables you to customise the control units to the demands of your plant. You can also embed further features to existing alarms.

Accessories

ST-11680-2007

Splash guard

The Splash guard protects the sensor against splash water and dirt. Every Polytron® 8720 ships with the splash guard and an LED status indicator preinstalled.

D-883346-2013

Duct mount kit

The duct mount kit enables gas monitoring inside ventilation ducts while keeping the transmitter outside.

D-16985-2014

Process cuvette SGR

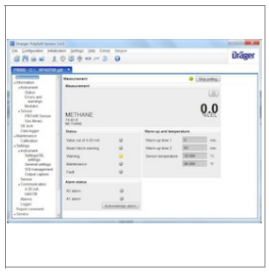
For sampling and in-line applications – reduces the inner volume of the measuring cuvette, thus providing a faster speed of response under flow conditions – made of stainless steel

ST-11699-2007

Flow Cell

Function test/calibration of the transmitter during high wind forces and/or high test gas concentration, including status display, suitable for process applications.

Accessories



D-4316-2019

Dräger Polysoft software

The optional Dräger Polysoft Windows® software is used for configuration, firmware upgrades, diagnostics, and downloading the Polytron's built in datalogger. All from the comfort of your control room using the digital HART® signal that rides on top of the analog 4 to 20 mA signal. Out in the field, an available non intrusive IR dongle easily connects Polytron® to Polysoft.

D-2950-2018

Remote Sensor Junction Box

The explosion-proof junction box allows remote mounting of CatEx sensor with cabling lengths over 300 feet. A plug and play sensor interface makes installation easy.

D-8536-2013

Pole Mounting Kit

Attach Polytron® 5000/8000 series to a pole or pipe using clamps (not included)

Polytron® Calibration Kit

Basic calibration kit with zero gas cylinder and space for a span gas cylinder. Includes all the needed accessories in a convenient carrying case.

Technical Data

Dräger Polytron® 8720 IR

Type	Explosion proof / flameproof enclosed transmitter ("d")		
Gases	Carbon dioxide		
Measuring range	0 to 10 vol. % (Standard)		
	0 to 2,000 ppm to 30 vol. % (configurable)		
	Up to 100 vol. % possible with decreased linearity.		
Display	Backlit graphic LCD; 3 Status LEDs (green/yellow/red)		
Performance Characteristics	Accuracy/repeatability	Sensitivity	≤± 0.01 % vol.
		Long term drift	≤± 0.03 % vol. after 12 months
	Response time	T90	4 seconds (w/o splash guard)
Electrical data	Signal output analog	Normal operation	4 to 20 mA, 3- or 4-wire, sink or source
		Maintenance	Constant 3.4 mA (adjustable)
		Fault	< 1.2 mA
	Signal output digital	HART® w/ 3- or 4-wire, PROFIBUS® PA, FOUNDATION fieldbus™ H1 and Modbus RTU w/ 5-wire	
	Power supply	10 to 30 V DC	
	Power consumption (max.)	w/o relay, non-remote	330 mA at 24 V
		w/ relay, remote	350 mA at 24 V
	Relay specification (option)	2 alarm relays and 1 fault relay, SPDT 5 A @ 230 VAC, 5 A @ 30 VDC	
Environmental conditions(see sensor data sheet)	Temperature	-40 to +171 °F (-40 to +77 °C) without relay	
		-40 to +70 °C (-40 to +158 °F) with relay	
	Pressure	20.7 to 38.4 inch Hg / 700 to 1,300 mbar	
	Humidity	0 to 100 % r. h., non-condensing	
Housing	Transmitter housing	Epoxy coated copper-free aluminium or stainless steel SS316 L	
	Sensor housing	Stainless steel SS316 L	
	Enclosure protection type	NEMA 4X & 7, IP65/66/67	
	Cable entry point	3/4" NPT threaded holes or M20 cable gland	
	Dimensions (H x W x D), approx.	11.0" x 5.9" x 5.1" / 280 × 150 × 130 mm	
	Weight, approx.	8.6 lbs / 3.9 kg	
		12.6lbs / 5.7 kg	
Approvals	UL/CSA	Class I, Div 1, Groups A, B, C, D;	
		Class I, Zone 1, Group IIC;	
		T-Code T6/T4	
		CSA C22.2 No. 152	
	IECEx	Ex db IIC T6/T4 Gb, -40 ≤ Ta ≤ +40/+80 °C;	
	ATEX	II 2G Ex db IIC T6/T4 Gb, -40 ≤ Ta ≤ +40/+70 °C;	
	CE markings	ATEX (Directive 2014/34/EU)	
		Electromagnetic Compatibility (Directive 2014/30/EU)	
		Low Voltage (Directive 2014/35/EU)	
	Shipping approvals	DNV GL, ABS, LR, CCS, RMRS	
	MED approval	Certificate No. MEDB0000411	
	DEKRA Performance approval	PFG 14 G 001XSI	
	L 2 certified by TUEV Sued	Certificate no. Z10 053474 0023	

11.3 Tandem Downhole Pressure Gauge (TSRO) Specifications Sheet

Tandem Downhole Pressure Gauge (TSRO)

The **TSRO** downhole pressure gauge system is utilized when your job application requires dual real-time, SRO (Surface Read Out) data acquisition and the flexibility of a multiplexed, tandem gauge system. It is flexible enough to operate on a wide variety of mono-conductor electric lines; including cobalt. The sophisticated multiplexing control circuits are in the top instrument or master gauge. The bottom slave unit is a standard **TSRO** gauge design. Each gauge alternates sending data up the line to the surface data acquisition system. Data is received every 0.9375 seconds, first from the master unit and then the slave unit. This method provides an overall sampling rate of 1.875 seconds. One **TSRO** system can be connected to the surface wireline receiver.

Applications & Features

- Tandem downhole SRO gauges allows immediate verification of pressure anomalies
- Top gauge can be ported via tubing to another zone (i.e. bottom of packer, etc.) while bottom gauge measures a separate zone
- Bottom gauge can be hung below the top gauge using any length of Electric-Line cable to measure at a different depth
- Application flexibility due to system design
- Standard ASCII data storage format
- Gauge system connects to a standard 1-3/16" G-O pin cable head

Wireline Receiver Power	120/220/240 VAC
Temperature	0°F to 300°F (0°C to 150°C)
Length	91 in. (2.31 m) (both instruments)
Weight	29 lbs (13.15 Kg)
Resolution	Pressure - .03 psi Temperature - .04° F
Accuracy	Pressure ± .05% Full Scale Temperature ± 3°F
Pressure Range	5-15Ksi (34,000 - 103,000 kPa)
Sample Rate	1.875 seconds/gauge
Outside Diameter	1.45 in. (3.68 cm) max diameter

11.4 Flow Meter Specifications

Products Solutions Services

Proline Promass O 500
Coriolis flowmeter

Robust high-pressure flowmeter, as remote version with up to 4 I/Os

More information and current pricing:
www.endress.com/8O5B

Benefits:

- Maximum safety – highest resistance to stress corrosion cracking
- Fewer process measuring points – multivariable measurement (flow, density, temperature)
- Space-saving installation – no in/outlet run needs
- Full access to process and diagnostic information – numerous, freely combinable I/Os and fieldbuses
- Reduced complexity and variety – freely configurable I/O functionality
- Integrated verification – Heartbeat Technology

Specs at a glance

- **Max. measurement error** Mass flow (liquid): ±0.10 % (standard), 0.05 % (option) Volume flow (liquid): ±0.10 % Mass flow (gas): ±0.35 % Density (liquid): ±0.0005 g/cm³
- **Measuring range** 0 to 2 200 000 kg/h (0 to 80 850 lb/min)
- **Medium temperature range** −40 to +205 °C (−40 to +401 °F)
- **Max. process pressure** PN 250, Class 1500
- **Wetted materials** Measuring tube: 25Cr duplex (Super Duplex), 1.4410 (UNS S32750) Connection: 25Cr duplex (Super Duplex), 1.4410 (F53)

Field of application: Promass O is designed for premium accuracy of liquids and gases at the highest process pressures in the oil and gas industry. The sensor is fully suitable for offshore conditions and resistant to stress corrosion cracking. With its innovative remote transmitter Promass O 500 maximizes installation flexibility and operational safety in demanding environments. Heartbeat Technology ensures safe processes.

Endress+Hauser

APPL NUM 45026

Features and specifications

Liquids

Measuring principle
Coriolis

Product headline
Robust high-pressure flowmeter, as remote version with up to 4 I/Os. For premium accuracy at highest process pressures, fully suitable for offshore conditions.

Sensor features
Maximum safety – highest resistance to stress corrosion cracking. Fewer process measuring points – multivariable measurement (flow, density, temperature). Space-saving installation – no in-/outlet run needs.
Measuring tube in 25Cr Duplex, 1.4410 (UNS S32750). Process pressure up to PN 250 (Class 1500). Nominal diameter: DN 80 to 250 (3 to 10").

Transmitter features
Full access to process and diagnostic information – numerous, freely combinable I/Os and fieldbuses. Reduced complexity and variety – freely configurable I/O functionality. Integrated verification – Heartbeat Technology.
Remote version with up to 4 I/Os. Backlit display with touch control and WLAN access. Standard cable between sensor and transmitter.

Nominal diameter range
DN 80 to 250 (3 to 10")

Wetted materials
Measuring tube: 25Cr duplex (Super Duplex), 1.4410 (UNS S32750)
Connection: 25Cr duplex (Super Duplex), 1.4410 (F53)

Measured variables
Mass flow, density, temperature, volume flow, corrected volume flow (API tables), reference density, concentration

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Liquids

Max. measurement error
Mass flow (liquid): ±0.10 % (standard), 0.05 % (option)
Volume flow (liquid): ±0.10 %
Mass flow (gas): ±0.35 %
Density (liquid): ±0.0005 g/cm³

Measuring range
0 to 2 200 000 kg/h (0 to 80 850 lb/min)

Max. process pressure
PN 250, Class 1500

Medium temperature range
–40 to +205 °C (–40 to +401 °F)

Ambient temperature range
Standard: –40 to +60 °C (–40 to +140 °F)
Option: –50 to +60 °C (–58 to +140 °F)

Sensor housing material
1.4404 (316L), highest corrosion resistance
Sensor connection housing (standard): AlSi10Mg, coated
Sensor connection housing (option): 1.4301 (304); 1.4404 (316L); 1.4409 (CF3M) similar to 316L

Transmitter housing material
AlSi10Mg, coated; 1.4409 (CF3M) similar to 316L; Polycarbonat

Degree of protection
Sensor remote version (standard): IP66/67, type 4X enclosure
Sensor remote version (option): IP69. Transmitter remote version: IP66/67, Type 4X enclosure

Display/Operation
4-line backlit display with touch control (operation from outside)
Configuration via local display and operating tools possible

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Liquids

Outputs
4 outputs:
4-20 mA HART (active/passive)
4-20 mA WirelessHART
4-20 mA (active/passive)
Pulse/frequency/switch output (active/passive)
Double pulse output (active/passive)
Relay output

Inputs
Status input
4-20 mA input

Digital communication
HART, PROFIBUS DP, PROFIBUS PA, FOUNDATION Fieldbus, Modbus RS485, Profinet, Ethernet/IP, OPC-UA

Power supply
DC 24 V
AC 100 to 230 V
AC 100 to 230 V / DC 24 V (non-hazardous area)

Hazardous area approvals
ATEX, IECEx, cCSAus, NEPSI, INMETRO, EAC

Product safety
CE, C-tick, EAC marking

Functional safety
Functional safety according to IEC 61508, applicable in safety-relevant applications in accordance with IEC 61511

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Liquids

Metrological approvals and certificates
Calibration performed on accredited calibration facilities (acc. to ISO/IEC 17025)
Heartbeat Technology complies with the requirements for measurement traceability according to ISO 9001:2015 – Section 7.1.5.2 a (TÜV SÜD attestation)
MI-005 Liquids other than water (Hydrocarbons)
MI-002, PTB

Marine approvals and certificates
LR approval, DNV GL approval, ABS approval, BV approval, CCS approval

Pressure approvals and certificates
PED, CRN, AD 2000

Material certificates
3.1 material
NACE MR0175/MR0103, PMI; welding test acc. to EN ISO, ASME, NORSOK

Gas

Measuring principle
Coriolis

Product headline
Robust high-pressure flowmeter, as remote version with up to 4 I/Os. For premium accuracy at highest process pressures, fully suitable for offshore conditions.

Sensor features
Maximum safety – highest resistance to stress corrosion cracking. Fewer process measuring points – multivariable measurement (flow, density, temperature). Space-saving installation – no in-/outlet run needs. Measuring tube in 25Cr Duplex, 1.4410 (UNS S32750). Process pressure up to PN 250 (Class 1500). Nominal diameter: DN 80 to 250 (3 to 10").

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APPL NUM 45026

Gas

Transmitter features
Full access to process and diagnostic information – numerous, freely combinable I/Os and fieldbuses. Reduced complexity and variety – freely configurable I/O functionality. Integrated verification – Heartbeat Technology.
Remote version with up to 4 I/Os. Backlit display with touch control and WLAN access. Standard cable between sensor and transmitter.

Nominal diameter range
DN 80 to 250 (3 to 10")

Wetted materials
Measuring tube: 25Cr duplex (Super Duplex), 1.4410 (UNS S32750)
Connection: 25Cr duplex (Super Duplex), 1.4410 (F53)

Measured variables
Mass flow, density, temperature, volume flow, corrected volume flow (API tables), reference density, concentration

Max. measurement error
Mass flow (liquid): ±0.10 % (standard), 0.05 % (option)
Volume flow (liquid): ±0.10 %
Mass flow (gas): ±0.35 %
Density (liquid): ±0.0005 g/cm^3

Measuring range
0 to 2 200 000 kg/h (0 to 80 850 lb/min)

Max. process pressure
PN 250, Class 1500

Medium temperature range
–40 to +205 °C (–40 to +401 °F)

Ambient temperature range
Standard: –40 to +60 °C (–40 to +140 °F)
Option: –50 to +60 °C (–58 to +140 °F)

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APPL NUM 45026

Gas

Sensor housing material
1.4404 (316L), highest corrosion resistance
Sensor connection housing (standard): AlSi10Mg, coated
Sensor connection housing (option): 1.4301 (304); 1.4404 (316L); 1.4409 (CF3M) similar to 316L

Transmitter housing material
AlSi10Mg, coated; 1.4409 (CF3M) similar to 316L; Polycarbonat

Degree of protection
Sensor remote version (standard): IP66/67, type 4X enclosure
Sensor remote version (option): IP69. Transmitter remote version: IP66/67, Type 4X enclosure

Display/Operation
4-line backlit display with touch control (operation from outside)
Configuration via local display and operating tools possible

Outputs
4 outputs:
4-20 mA HART (active/passive)
4-20 mA WirelessHART
4-20 mA (active/passive)
Pulse/frequency/switch output (active/passive)
Double pulse output (active/passive)
Relay output

Inputs
Status input
4-20 mA input

Digital communication
HART, PROFIBUS DP, PROFIBUS PA, FOUNDATION Fieldbus, Modbus RS485, Profinet, Ethernet/IP, OPC-UA

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APPL NUM 45026

Gas

Power supply
DC 24 V
AC 100 to 230 V
AC 100 to 230 V / DC 24 V (non-hazardous area)

Hazardous area approvals
ATEX, IECEx, cCSAus, NEPSI, INMETRO, EAC

Product safety
CE, C-tick, EAC marking

Functional safety
Functional safety according to IEC 61508, applicable in safety-relevant applications in accordance with IEC 61511

Metrological approvals and certificates
Calibration performed on accredited calibration facilities (acc. to ISO/IEC 17025)
Heartbeat Technology complies with the requirements for measurement traceability according to ISO 9001:2015 – Section 7.1.5.2 a (TÜV SÜD attestation)
MI-005 Liquids other than water (Hydrocarbons)
MI-002, PTB

Marine approvals and certificates
LR approval, DNV GL approval, ABS approval, BV approval, CCS approval

Pressure approvals and certificates
PED, CRN, AD 2000

Material certificates
3.1 material
NACE MR0175/MR0103, PMI; welding test acc. to EN ISO, ASME, NORSOK

Steam

Measuring principle
Coriolis

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11.5 Downhole Distributed Temperature Sensing

Baker Hughes

L3 - Instruction / T1 - Global
Tech Unit
Well Monitoring Services
TU 101507
Rev. A
Effective Date: 27 Sep 2021

SureVIEW DTS S2

Product Family H30760

Last Four Revisions					
Rev.	RDR	Amendment Detail	Reviewer	Approver	Effective Date
A	/RM	Initial Release	Baker, Mark	Raggio, John	27 Sep 2021

BHOSCMS

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1 Introduction

The **Baker Hughes Company SureVIEW™ DTS S2**-series is an optoelectronic surface instrument used to measure temperature continuously along the length of an optical fiber. The SureVIEW DTS can interrogate fibers well beyond 10km in length and is capable of spatial temperature resolution of less than 0.15°C and down to 1 meter spatial resolution.

2 Description

The SureVIEW DTS is a single-mode Raman-based Optical Time Domain Reflectometry (OTDR) distributed temperature sensing interrogator. The unit operates by sending optical laser pulses into an optical fiber. As these pulses propagate through the fiber, light is backscattered toward the source in a phenomenon known as Raman Scattering. The SureVIEW DTS analyzes the intensity of the backscattered light at specific wavelengths to derive temperature measurements along the entire length of the fiber.

An OTDR technique is used to derive the distance along the fiber sensor from which the backscatter originated. Similar to radar echo location, the SureVIEW DTS monitors the elapsed time from when the laser pulse enters the fiber to when the backscattered light is received. Since the velocity of light in the fiber is known, the distance to backscatter location can be derived.

The SureVIEW DTS is available in a 2U rack mount form factor. It can be connected to up to 16 individual downhole fiber-optic cables – or wells – which each act as linear temperature sensors. The SureVIEW DTS will interrogate the fiber sensor for a user specified measurement time (ranging from 3 seconds to 1 hour) and produce temperature measurements as arrays of temperature vs. fiber length. DTS measurements will repeat continuously.

Figure 1: SureVIEW DTS S2.

Figure 2: SureVIEW DTS front panel.

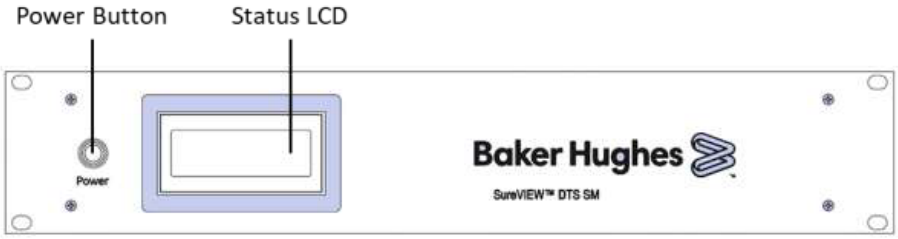


Figure 3: SureVIEW DTS rear panel.

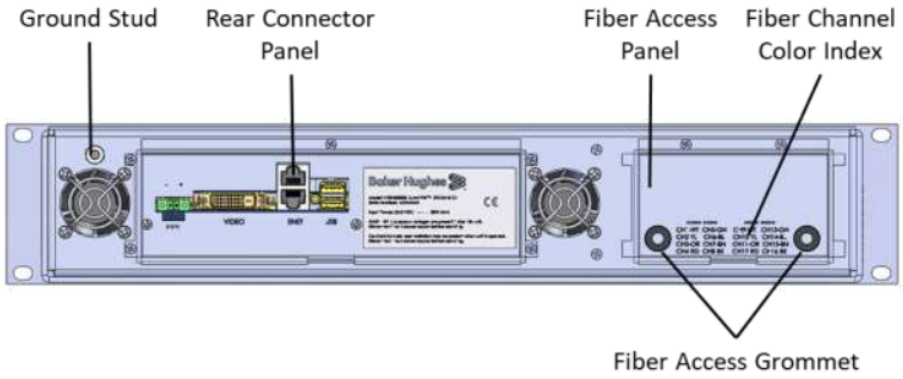
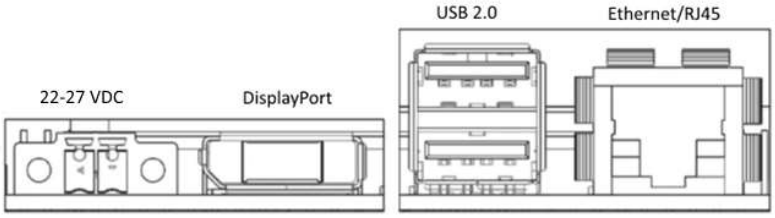


Figure 4: Close-up of rear connectors.



3 Application

The SureVIEW DTS provides a distributed temperature measurement, with temperature measurements spaced regularly along the downhole sensing fiber. These temperature measurements can be used in many applications, including:

- Production or injection logging
- Fracture monitoring
- SAGD steam injection/break through
- Leak detection/thief zones
- Gas-lift surveillance
- Fluid breakthrough (water/oil/gas)
- Fluid levels (stable conditions)
- Measure geothermal
- Recirculation
- Cement curing monitoring (slurry, voids, exothermic)
- Flow monitoring
- Behind casing flow

- Cross-zonal flow
- Gas lift valve monitoring
- Steam monitoring
- Flow assurance (hydrate formation detection)
- Flow meter and allocation (interpretation)
- Gas/oil/water production (interpretation)

4 Features and Benefits

- SureVIEW™ DTS automatically corrects for differential attenuation
  - Produces accurate temperature measurements even in hydrogen-rich environments.
- SureVIEW DTS/DAS have configurable laser pulse width
  - Allows trade-off of spatial resolution vs. temperature/acoustic resolution
- Up to 16 optical channels
  - One SureVIEW DTS can interrogate up to 16 cables/wells.
  - SureVIEW DAS can interrogate up to 8 cables/wells.
- Designed for unattended remote service
  - Once configured, the SureVIEW DTS/DAS will continue to operate without operator input.
- Communicates with data center over Ethernet
  - OPC UA used for transferring full DTS traces, configuration data, and status data.
  - *Modbus®* (RTU or TCP/IP)[1] for transferring decimated data.
- Optical-based measurements
  - Immune to electromagnetic interference.

5 Engineering Tables and Information

Specification Guide

Table 1: Operating Conditions

Description	Range	
	Minimum	Maximum
Operating temperature (°C)	0	40
Storage temperature (°C)	-40	80
Operating relative humidity (%)	5	95
Sensing temperature – standard calibration range (°C)	0	250
Sensing temperature – full range* (°C)	-50	350

*Contact IPS product line technical support if non-standard calibration range required.

[1] Modbus is a registered trademark of MODICON, Inc.

Table 2: Features

Description	Value
Form factor	19-in. rack
Height	2U
Depth (in.)	19.8
Certifications	TUV (US, Can), CE
Public software interfaces	OPC/UA, *Modbus*
Maximum distance range (km)	20+
Minimum spatial resolution (m)	1.0
Minimum sampling interval (m)	0.33
Fastest acquisition rate (sec)	3.3
Absolute temperature accuracy (°C)	±2
Number of channels	1, 8 or 16
Internal data storage capability	250 GB
Fiber types	9/125 µm SMF *CoreBRIGHT™*
Optical connectors	Fiber pigtails
Computer interfaces	Ethernet, DPI, USB
Voltage input	22-27 VDC
Power consumption	100 W (maximum)
Differential attenuation compensation	Yes
Fiber configuration	Single-ended or J-type
Sensing temperature range (°C)	0–300
Operating temperature (°C)	0–40
Storage temperature (°C)	-40 to 80
Operating relative humidity (%)	5–95

Table 3: Rear Connectors

Connector	Function
22-27 VDC	Provides power to the SureVIEW DTS. Connect as described in the assembly instructions (Section 13).
DisplayPort	For Baker Hughes diagnostics only.
USB 2.0	For Baker Hughes diagnostics only.
Ethernet/RJ45	For connection to the customer network. Connect as described in the assembly instructions (Section 13).

Ordering Guide

SureVIEW DTS S2-Series interrogators are produced by Baker Hughes, refer to models (Table 4) for all available options.

Table 4: Models

Model	Description
H307600008	Rackmount, safe area, 8 channel, TUV and CE marks
H307600009	Rackmount, safe area, 16 channel, TUV and CE marks
H307600016	Rackmount, safe area, 1 channel, no certification

Accessory Equipment

Not applicable.

Product Selection Chart

Not applicable.

Theory of Operation

A brief introduction to the physics of Raman-based distributed temperature sensing is presented here. A practical knowledge of these concepts will be helpful to understand how to properly select, configure, and troubleshoot a SureVIEW DTS for a given application.

Raman-based Distributed Temperature Sensing

Raman-based DTS systems derive the temperature of a fiber-optic sensor by utilizing a phenomenon known as Raman scattering. As a pulse of light propagates through an optical fiber the light will collide with the vibrating lattice structure of the fiber and produce localized scatter sites. The scattered light spectrum contains three intensity peaks: Rayleigh, Raman Anti-Stokes, and Raman Stokes.

The Raman peaks are the result of an energy exchange during the collision with the fiber lattice which shifts the wavelength of the scattered light. A decrease in wavelength is known as an Anti-Stokes shift while an increase in wavelength is called Stokes shift. Rayleigh scattering occurs when no energy exchange takes place and therefore the Rayleigh scatter remains at the same wavelength as the incident light.

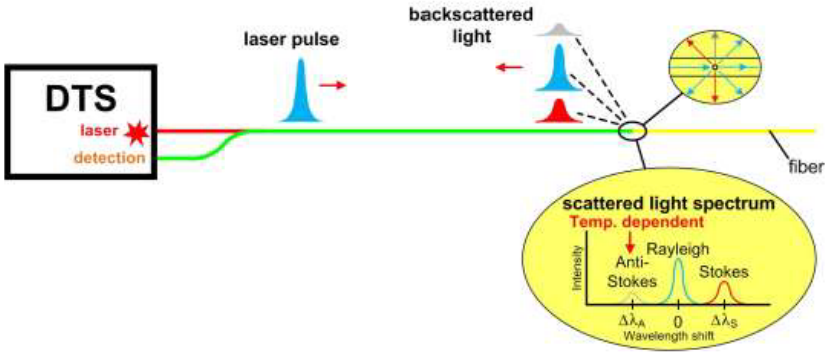
Within the scattered light spectrum, the intensity of the Anti-Stokes wavelength is dependent on the local fiber temperature at the scatter site while the intensity of the Stokes and Rayleigh wavelengths are relatively independent of temperature. The intensity of light received at the detector is also affected by attenuation intrinsic to the fiber between the scatter site and the detector. Analyzing backscatter at the Anti-Stokes wavelength alone is therefore insufficient for separating the effects of temperature variation and fiber attenuation on the measured Anti-Stokes intensity. The SureVIEW DTS S2-Series uses a proprietary technique to compensate for attenuation, described below.

As the light pulse propagates through the fiber, backscatter is continuously produced. These backscatter signals are detected and analyzed by the SureVIEW DTS interrogator to generate a continuous temperature profile along the entire length of the fiber-optic sensor.

An OTDR technique is used to derive the location along the fiber sensor, from which the backscatter originated. With this technique, the SureVIEW DTS monitors the elapsed time from when the laser pulse enters the fiber to when the backscattered light is received at the

interrogator. Since the velocity of light in the fiber is known, time measurements are used to calculate the distance to the scatter location.

Figure 5: DTS operational schematic.



Differential Attenuation Correction

Optical attenuation, measured in dB/km and often represented symbolically as α (Greek letter alpha), is the gradual loss of intensity light experiences as it propagates through an optical fiber. Attenuation varies with wavelength; therefore light at two different wavelengths propagating through an optical fiber will be attenuated at different rates.

Attenuation of the anti-stokes signal is comprised of two phases: attenuation of the outgoing laser pulse – as it travels to a backscatter location – and attenuation of the returning backscatter signal. Several effects can cause attenuation at these two different wavelengths (outgoing and incoming/backscattered) to differ; among these are hydrogen in the fiber, splices, and connectors. The SureVIEW DTS S2-series measures the attenuation at these multiple wavelengths by measuring Rayleigh backscatter at the outgoing 1550nm wavelength and the return anti-Stokes 1470nm wavelength. Using the anti-stokes data and these Rayleigh attenuation measurements, a temperature can be calculated.

Depth Calibration

The S2-Series DTS inherently measures distances in fiber length; conversion from fiber length to well measured depth (MD) – or other customer preferred scale – is managed by either the interrogator's configuration client (SureVIEW Configuration Client) or by the customer's visualization package (such as SureVIEWer).

Conversion from fiber length to MD generally requires two adjustments: one to offset the desired zero point from the DTS laser to, for example, the rotary Kelly bushing (RKB). The second adjustment involves accounting for excess fiber length (EFL), as there is generally more fiber length than physical length (MD) in a deployment, due to the overstuffing of fiber within the cable at manufacture.

Temperature Calibration

Older DTS units require temperature calibration in the field, using downhole temperature measurements as a reference. This is caused by uncertainties due to differential attenuation or connectors. The automatic attenuation correction feature of S2-series DTS allows accurate temperature measurements without the need for downhole reference points. The DTS is delivered

to the wellsite capable of producing accurate distributed temperature measurements using only factory calibration.

Description of Terms

This section defines terms related to the SureVIEW DTS.

Spatial Temperature Resolution

The (spatial) temperature resolution is the random variation in calculated temperature with fiber distance, in a single temperature trace. It is determined from twice the standard deviation of adjacent temperature sample points, with the fiber held at constant temperature *(SEAFOM-MSP-01, 2016)*.

In a DTS measurement, the temperature resolution obtained at a given fiber location is a function of the optical power received at the detector from the backscattering location. Losses in optical power cause the temperature resolution to degrade. Temperature resolution is therefore dependent on measurement time (input power), distance from the DTS unit and other optical losses present in the system such as splices, connectors, couplers, switches, etc. Because some of these quantities are variable, the exact temperature resolution cannot be truly known until the system is deployed.

A spatial temperature resolution performance plots for ideal conditions (i.e., continuous fiber with no splices, connectors, etc.) is presented in SureVIEW DTS spatial temperature resolution against time (Fig. 9).

Technical support should be consulted when making spatial temperature resolution estimates for a particular application.

Temperature Repeatability

The temperature repeatability is the random variation in calculated temperature between successive temperature traces, at a given fiber distance. It is determined from twice the standard deviation of corresponding temperature sample points in each temperature trace, with the fiber held at constant temperature *(SEAFOM-MSP-01, 2016)*.

A temperature repeatability performance plot is presented in SureVIEW DTS spatial temperature repeatability against time (Fig. 10).

Temperature Accuracy

Temperature accuracy refers to the absolute error between a reported temperature measurement and the actual environmental temperature at that location. The temperature accuracy quoted within this service unit (±2°C) assumes that the interrogator acquisition has been configured with a spatial temperature resolution and temperature repeatability that is less than 2°C.

For any given application, the temperature accuracy performance reflects the largest of these performance figures:

- Spatial temperature resolution
- Temperature repeatability
- ±2°C (optimum performance figure based interrogator's hardware)

differential attenuation. Since the measurement technique used by the SureVIEW DTS S2-series is superior to double-ended measurement, being able to automatically compensate for differential attenuation, the S2 supports only a single-ended measurement.

Troubleshooting

Table 5: Common Problems With Possible Causes and Solutions

Problem	Cause	Solution
DTS trace immediately drops to -273°C	Failed splice at pigtail	Resplice fiber to downhole cable.
	Fiber properties improperly configured	1. Stop DTS scanning using DTS configuration client. 2. Reconfigure channel using SureVIEW configuration client. 3. Transmit configuration to DTS. 4. Restart DTS scanning.
High reflection at end of fiber	Bad fiber terminations	5. Ensure fibers are terminated with end termination fiber (ETF).
No network connectivity	Bad cable or cable not connected	Ensure network cable is connected properly.
Reported temperatures within the reference coil are nonsensical (not close to 40°C)	Reference coil may not have reached stable operating temperature yet	6. Ensure environment meets with specified environmental operating range of SureVIEW DTS. 7. Wait for up to 1hr after powering on the SureVIEW DTS to allow sufficient time for reference coil to reach operating temperature. 8. If problem persists, contact IPS product line for technical support.
	Unknown component failure	Contact IPS product line for technical support.
No power	Bad power connection	Ensure power cable is connected properly.
	Fuse blown	Return device for service.

Measurement Time

The measurement time is the period between successive independent temperature measurements, when making continuous measurements on a single fiber. Equivalently, it is the time interval between successive temperature trace timestamps, under these conditions *(SEAFOM-MSP-01, 2016)*.

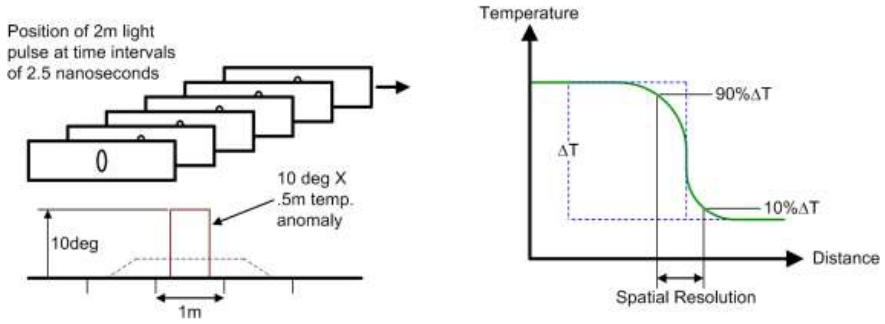
The SureVIEW DTS interrogates the fiber sensor by firing short pulses of light into the fiber and monitoring the backscattered signal. The backscattered signal from one pulse of light is too weak to produce an accurate temperature profile. Therefore, thousands or millions of pulses are fired and the backscattered signal is averaged over time to improve the signal-to-noise ratio. The number of pulses which can be averaged is dictated by the measurement time of the SureVIEW DTS.

Measurement time is configured by the user and should be carefully chosen for the application. A longer measurement time will improve temperature resolution while a shorter measurement time will decrease signal-to-noise ratio and degrade temperature resolution. When specifying a measurement time, it is important to consider the magnitude of the thermal event(s) being monitored (i.e., temperature resolution required) and the rates at which downhole temperatures are changing (i.e., measurement time limitations). For example, if small changes in temperature need to be measured, a longer measurement time will be required to improve temperature resolution. If the application is for transient event detection where events will be occurring quickly and producing large temperature signatures, a shorter measurement time is required to detect the events and prevent an averaging out of transient temperature changes.

Spatial Resolution

The spatial resolution of a DTS interrogator is the distance of fiber taken to fully respond to a step change in temperature. A temperature anomaly acting on a distance of fiber shorter than the spatial resolution will not be measured as full magnitude.

Figure 6: Spatial smearing of temperature features due to finite interrogation pulse width.



Single-ended and Double-ended Measurement Configurations

There are two common configurations for deploying a DTS system: single-ended (SE) and double-ended (DE). SE measurements make use of a single fiber, along which the temperature is measured; Whereas DE measurements require two fibers that are looped together, with both fibers connected to the DTS interrogator. This requires the use of twice as many channels on the DE DTS interrogator – and twice as much fiber length – when compared to SE DTS measurements. DE measurement is used by older DTS systems to try to compensate for

differential attenuation. Since the measurement technique used by the SureVIEW DTS S2-series is superior to double-ended measurement, being able to automatically compensate for differential attenuation, the S2 supports only a single-ended measurement.

Troubleshooting

Table 5: Common Problems With Possible Causes and Solutions

Problem	Cause	Solution
DTS trace immediately drops to -273°C	Failed splice at pigtail	Resplice fiber to downhole cable.
	Fiber properties improperly configured	1. Stop DTS scanning using DTS configuration client. 2. Reconfigure channel using SureVIEW configuration client. 3. Transmit configuration to DTS. 4. Restart DTS scanning.
High reflection at end of fiber	Bad fiber terminations	5. Ensure fibers are terminated with end termination fiber (ETF).
No network connectivity	Bad cable or cable not connected	Ensure network cable is connected properly.
Reported temperatures within the reference coil are nonsensical (not close to 40°C)	Reference coil may not have reached stable operating temperature yet	6. Ensure environment meets with specified environmental operating range of SureVIEW DTS. 7. Wait for up to 1hr after powering on the SureVIEW DTS to allow sufficient time for reference coil to reach operating temperature. 8. If problem persists, contact IPS product line for technical support.
	Unknown component failure	Contact IPS product line for technical support.
No power	Bad power connection	Ensure power cable is connected properly.
	Fuse blown	Return device for service.

6 HSE&S

Read, understand and follow all Baker Hughes Company instructions and specifications in this unit while assembling, disassembling, maintaining or repairing this equipment. Failure to do so may result in property damage, serious injury or fatality.

- The SureVIEW DTS contains a high power laser, operating as class 1. The laser radiation is not visible but may cause damage to the eye if magnification is used. Ensure proper termination, and do not operate the DTS with unterminated fibers.
- The recommended power supply is a Safety Class 1 Product (provided with protective earth). The mains plug shall only be inserted in a socket outlet provided with a protective earth contact. Any interruption of the protective conductor inside or outside of the instrument is likely to make the instrument dangerous. Intentional interruption is prohibited.
- To prevent electrical shock, disconnect the instrument from mains before cleaning. Use a dry cloth or one slightly dampened with water to clean the external case parts. Do not open the card cage inside the SureVIEW DTS, or attempt to clean it internally.
- The SureVIEW DTS complies with IEC Pollution Degree 2.
- When installing the SureVIEW DTS using power supply, make sure the detachable power cord is readily identifiable and is easily reached by the operator.
- Do not connect a light source - such as a VFL or OTDR - to the optical output, or connected fiber, to prevent potential interference or damage of internal optical or opto-electrical components.
- To power the instrument for operation, use a 24 Volt, 100 Watt DC power supply. Acceptable input voltage range is 22 to 27 V DC. The mating connector for the power input is a Phoenix Contact 1847055. Although the connector accepts 28-16 AWG wire, 16 AWG wire should be used to connect to the power supply. Positive DC voltage and ground should be attached as indicated on the back panel.
- Please pay attention to the following laser safety warnings:
  - Though the laser power of the SureVIEW DTS instrument does not generate direct danger to eyesight, it is recommended to not look into the end of an optical cable attached to the optical output when the device is operational.
  - The use of optical focusing instruments with this product will increase the hazard to your eyes.
  - Refer servicing only to qualified and authorized personnel.
- Do not operate the SureVIEW DTS in the presence of flammable gases or fumes. Operation of any electrical instrument in such an environment constitutes a safety hazard.
- Do not dispose the SureVIEW DTS in household waste.
- Do not open the enclosure of the SureVIEW DTS. Internally, the SureVIEW™ DTS uses class 3B laser sources. Opening the enclosure could result in exposure to these sources:
  - Oclaro/Bookham LC94-350: 974 nm, 350 mW pump laser diode, CW
  - Fitel FOL1402PMH: 1474 nm, 240 mW peak power, pulsed laser, < 0.11% duty cycle
  - Thorlabs FPL1009S: 1550 nm, 100 mW peak power, pulsed laser, < 0.11% duty cycle

⚠ WARNING

Invisible laser radiation

- Class 1M laser product
- IEC 60825-1:2014
- Maximum pulse duration: 60 ns, 0.5% duty cycle
- Average 20 mW @1550 nm, 1 mW @1470 nm
- All optical output fibers emit class 1 laser radiation

- Complies with FDA performance standards for laser products except for deviations pursuant to *Laser Notice No. 50, dated June 24, 2007*.

NOTICE

If the SureVIEW DTS is operated in a manner not specified in this manual then the protection provided by the equipment may be impaired.

7 Preservation of Product

For preservation of product requirements refer to the global procedure for *OFS Preservation of Product (QA-GLB-En-100042)* located on Baker Hughes Operating System (BHOS).

Storage Recommendations

The SureVIEW DTS should be stored at temperatures defined for the particular model under storage temperature [refer to specification guide (Section 5)]. Do not expose bare units to the elements. The SureVIEW DTS should be handled with care. Do not subject units to shock and vibration. The SureVIEW DTS should be stored in appropriate packaging, off of the floor. Store away from exposure to dust and/or fluids.

Shipping Recommendations

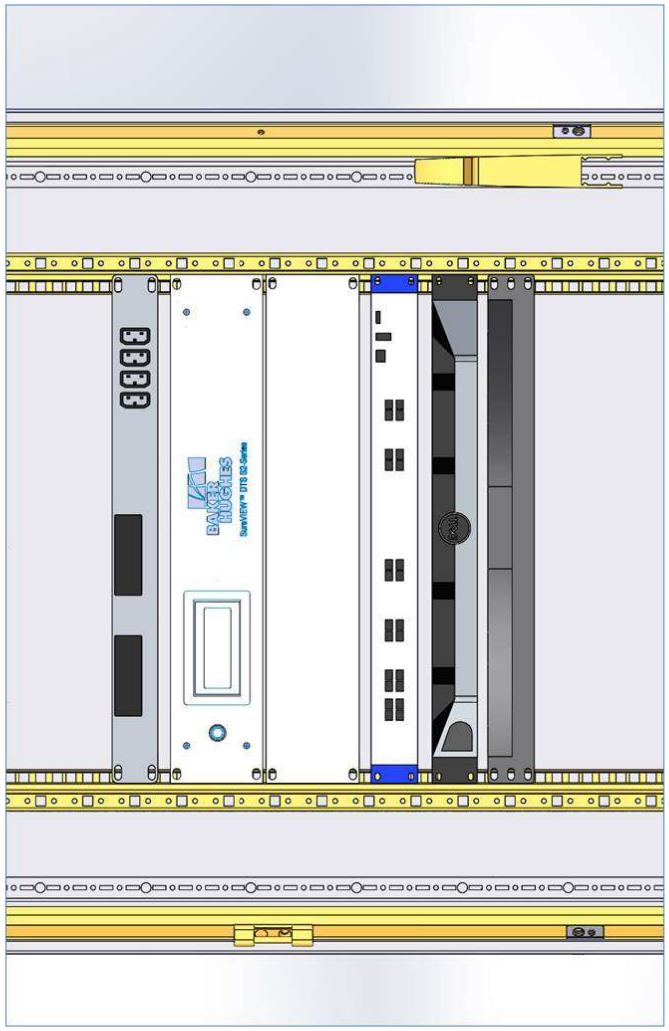
The SureVIEW™ DTS should be shipped in the Pelican Model 1730 Transport Case (SAP # 10503908) in which the DTS was originally delivered.

8 Assembly and Dimensional Information

SureVIEW DTS S2

Figure 7: Assembly Drawing (Inserting DTS into Rack)

APPL NUM 45026



SureVIEW DTS S2

Figure 8: Assembly Drawing (DTS in Rack)

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STATE EXHIBIT NO. 6; DOCKET NO. IMD 2025-04; PAGE 545 of 1181

9 Appendices

Appendix A – SureVIEW DTS S2-Series Performance

Typical performance shown below. Curves families shown with different calibrated spatial resolutions.

Figure 9: SureVIEW DTS spatial temperature resolution against time.

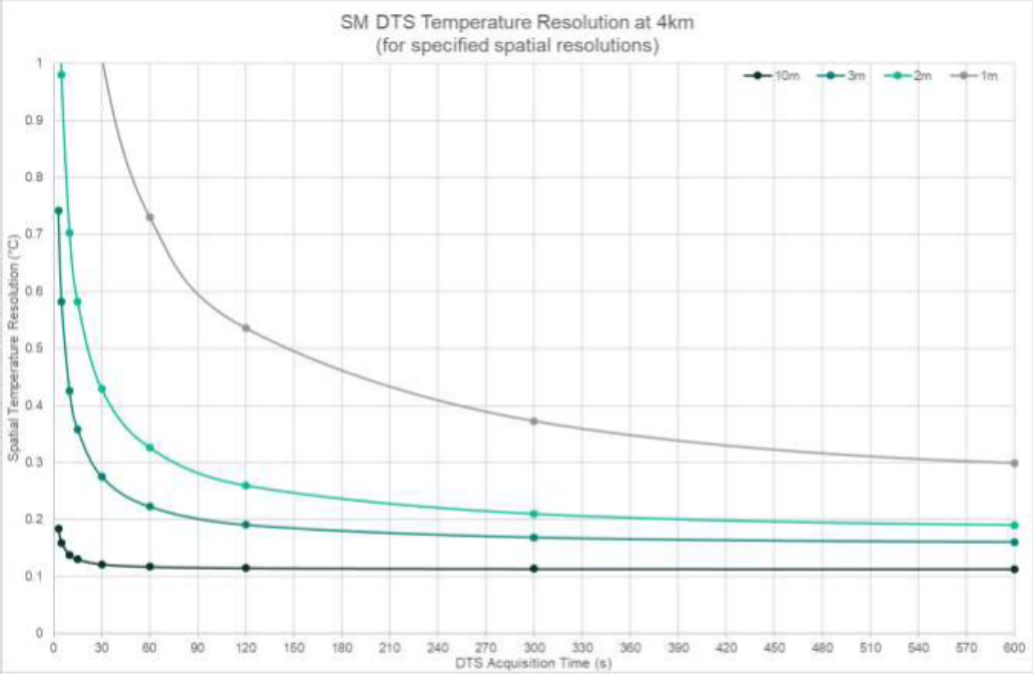
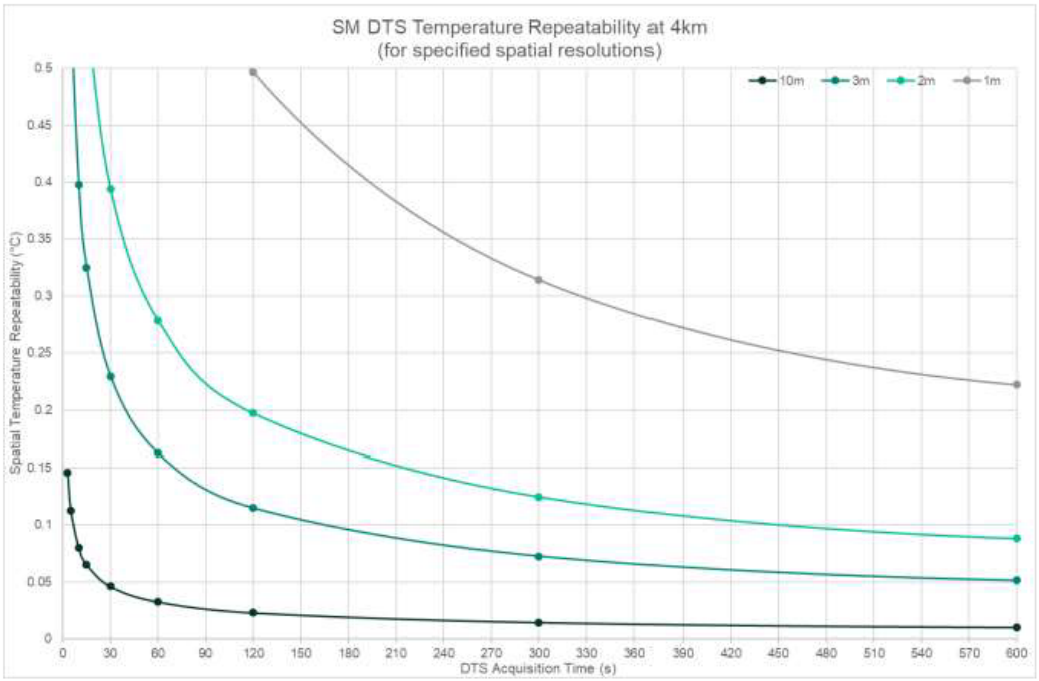


Figure 10: SureVIEW DTS spatial temperature repeatability against time.



11.6 SureVIEW Distributed Acoustic Sensor Fiber-Optic-based Distributed Acoustic Senson Interrogator

Baker Hughes

L3 - Instruction / T1 - Global
Tech Unit
Well Monitoring Services
TU 101991
Rev. A
Effective Date: 21 Oct 2021

SureVIEW Distributed Acoustic Sensor Fiber-Optic-based Distributed Acoustic Sensor Interrogator

Product Family H30760

Last Four Revisions					
Rev.	RDR	Amendment Detail	Reviewer	Approver	Effective Date
A	—/RM	Initial Release	Soliman, Ashraf	Raggio, John	21 Oct 2021

BHOSCMS

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1 Introduction

The Baker Hughes Company SureVIEW™ distributed acoustic sensor (DAS) is a distributed acoustic sensor: an optoelectronic instrument used to measure acoustic signals continuously along the length of an optical fiber. The SureVIEW DAS can interrogate fibers up to 80km in length and is capable of multiplexing measurements between several wells.

Hereafter, the term SureVIEW DAS may be used interchangeably with distributed acoustic sensor, or just DAS.

Figure 1: SureVIEW DAS.

Figure 2: SureVIEW DAS (front panel).

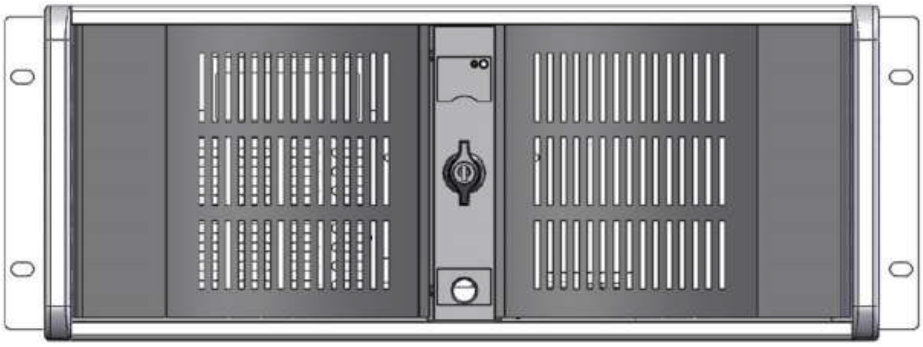
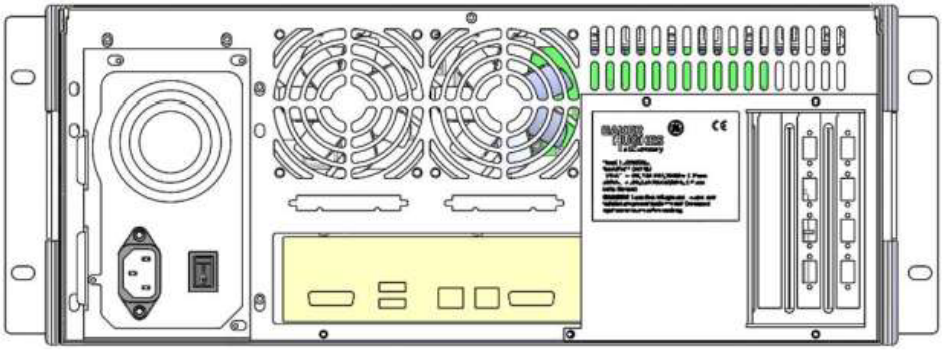


Figure 3: SureVIEW DAS (rear panel).



2 Description

The SureVIEW DAS is an Optical Time Domain Reflectometry (OTDR) distributed acoustic sensing interrogator. The unit operates by sending optical laser pulses into an optical fiber. As these pulses propagate through the fiber, some of the light is backscattered toward the source in a phenomenon known as Rayleigh scattering. The SureVIEW DAS analyzes the intensity of the backscattered light to derive acoustic measurements.

An OTDR technique is used to derive the distance along the fiber sensor from which the backscatter originated. Similar to radar echolocation, the SureVIEW DAS monitors the elapsed time from when the laser pulse enters the fiber to when the backscattered light is received. Since the velocity of light in the fiber is known, the distance to scatter site can be derived.

The SureVIEW DAS is available in a 4U rack mount form factor. It is connected to up to eight downhole fiber-optic cables. These cables, when stimulated by the SureVIEW DAS, act as acoustic sensors. The SureVIEW DAS will interrogate the fiber sensor for a user specified measurement time (ranging from 1 second to indefinite) and produce acoustic measurements as arrays of acoustic phase vs. fiber length. Measurements will repeat continuously or until stopped.

3 Application

The SureVIEW DAS provides a distributed acoustic measurement, with acoustic measurements spaced regularly throughout the downhole sensing fiber. These acoustic measurements can be used in many applications, including:

- Production profiling
- Fracture monitoring
- SAGD steam injection/break through
- Leak detection/thief zones
- Gas-lift surveillance
- Fluid breakthrough (water/oil/gas)
- Fluid levels (stable conditions)
- Vertical seismic profiling (VSP)
- Recirculation
- Cementing monitoring
- Flow monitoring
- Behind casing flow
- Cross-zonal flow
- Gas lift valve monitoring
- Steam monitoring
- Flow assurance (hydrate formation detection)
- Flow meter and allocation (Interpretation)
- Gas/oil/water production (interpretation)

4 Features and Benefits

- Phase sensitive measurement
  - Avoids harmonic distortion that occurs in amplitude DAS.
- Four configurable gauge lengths
  - Allows trade-off of spatial resolution vs. acoustic sensitivity.
- Can multiplex up to eight optical channels
  - One SureVIEW DAS unit can interrogate multiple fibers/wells.
- Designed for unattended remote service
  - Once configured, the SureVIEW DAS will continue to operate without operator input.
- Communicates with data center over Ethernet
  - HDF5/PRODML native data formats.
- Can support streaming HDF5 phase data to storage at 10 kHz, 1 meter resolution, 4 km sensing range
  - Allows for real-time visualization and analysis of high-density acoustic data.

Table 2: Operating Conditions

Description	Range	
	Minimum	Maximum
Operating temperature (°C)	0	40
Storage temperature (°C)	-40	80
Operating relative humidity (%)	10	70
Sensing temperature (°C)	0	300
Operating altitude (m)	0	2,000

Table 3: Rear Connectors

Connector	Function
110-240 VAC, IEC C13	Provides power to the SureVIEW DAS. Connect as described in the assembly instructions (Section 13).
VGA port	For Baker Hughes diagnostics only.
USB 3.0	For Baker Hughes diagnostics only.
Ethernet/RJ45	For connection to the customer network. Connect as described in the assembly instructions (Section 13).

Ordering Guide

SureVIEW DAS interrogators are produced by Baker Hughes. Currently a single configuration is available: rack-mount, 8-channel, single-mode fiber.

Table 4: Models

Model	Description
H307600012	SureVIEW DAS, 8-channel

Accessory Equipment

Not applicable.

Product Selection Chart

Not applicable.

Theory of Operation

A brief introduction to the physics of distributed acoustic sensing is presented here. A practical knowledge of these concepts will be helpful to understand how to properly select, configure, and troubleshoot a SureVIEW DAS for a given application.

Distributed Acoustic Sensing

DAS systems derive the acoustic phase of a fiber-optic sensor by utilizing a phenomenon known as Rayleigh scattering. As a pulse of light propagates through an optical fiber, the light will collide with the vibrating lattice structure of the fiber and produce localized scatter sites. Rayleigh scattering occurs when no energy exchange takes place and therefore the Rayleigh scatter remains at the same wavelength as the incident light. Rayleigh scattering is the strongest scattering phenomenon.

Troubleshooting

Table 5: Common Problems with Possible Causes and Solutions

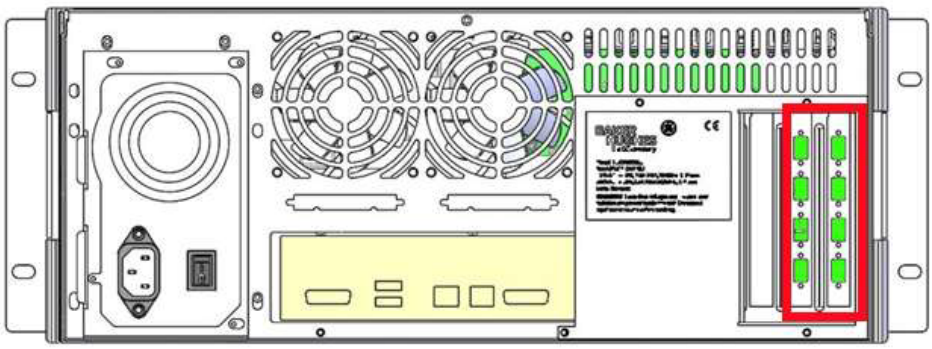
Problem	Cause	Solution
DAS RMS traces too small	Failed optical connector	Clean fiber connector. If this is unsuccessful, new fiber connectors may need to be spliced.
	Fiber properties improperly configured	1. Stop DAS scanning using DAS configuration client. 2. Re-configure channel using configuration client. 3. Transmit configuration to DAS. 4. Restart DAS scanning.
No network connectivity	Bad cable or cable not connected	Ensure network cable is connected properly.
No power	Bad power connection	Ensure power cable is connected properly.
	Fuse blown	Return device for service.

6 HSE&S

Read, understand and follow all Baker Hughes Company instructions and specifications in this unit while assembling, disassembling, maintaining or repairing this equipment. Failure to do so may result in property damage, serious injury or fatality.

- The SureVIEW DAS contains a high power laser, operating as class 1. The laser radiation is not visible but may cause damage to the eye if magnification is used. Ensure proper termination, and do not operate the DAS with unterminated fibers.
- The SureVIEW DAS emits light at 1550 nm from the connectors (Fig. 4).

Figure 4: Location of laser apertures.



The DAS interrogator sends the received light through a Mach-Zehnder interferometer using a configurable gauge length. The two legs of the interferometer interfere with each other, producing a beat pattern. Using a quadrature detector, the phase difference between the legs of the interferometer is computed. This phase difference is the extracted acoustic signal.

As the light pulse propagates through the fiber, backscatter is continuously produced. These backscatter signals are detected and analyzed by the SureVIEW DAS interrogator to generate a continuous acoustic along the entire length of the fiber-optic sensor.

An OTDR technique is used to derive the location along the fiber sensor, from which the backscatter originated. With this technique, the SureVIEW DAS monitors the elapsed time from when the laser pulse enters the fiber to when the backscattered light is received at the interrogator. Since the velocity of light in the fiber is known, time measurements are used to calculate the distance to the scatter site.

Depth Calibration

The SureVIEW DAS does not currently support depth correction. All depths are reported as fiber offset, with capability of correcting for lead-in (surface cable) offsets.

Description of Terms

This section defines terms related to the SureVIEW DAS.

Phase Resolution

The phase resolution of a DAS unit is the smallest phase change that can be discriminated from background noise.

Measurement Time

The measurement time is the length of time the DAS interrogates a fiber channel before moving to the next configured fiber channel. For single fiber configurations, the DAS will interrogate that channel continuously.

Spatial Resolution

The spatial resolution of a DAS interrogator is the distance of fiber taken to respond fully to a step change in acoustic excitation. An acoustic anomaly acting on a distance of fiber shorter than the spatial resolution will not be measured as full magnitude.

- To prevent electrical shock, disconnect the instrument from mains before cleaning. Use a dry cloth to clean the external case parts. Do not open the card cage inside the SureVIEW DAS, or attempt to clean it internally.
- The SureVIEW DAS complies with IEC Pollution Degree 2.
- Do not connect a light source to the optical output or the connected fiber to prevent potential interference or damage of optical or opto-electrical components.
- To power the instrument for operation, use a 110-240 Volt, 400 Watt AC power source using an IEC-C13 power cable.
- When installing the SureVIEW DAS using uninterruptible power supply (UPS), make sure the detachable power cord is readily identifiable and is easily reached by the operator.
- Please pay attention to the following laser safety warnings:
  - Though the laser power of the SureVIEW DAS instrument does not generate direct danger to eyesight, it is recommended to avoid looking into the end of an optical cable attached to the optical output when the device is operational.
  - The use of optical instruments with this product will increase the hazard to your eyes.
  - Refer servicing only to qualified and authorized personnel.
- Do not operate the SureVIEW DAS in the presence of flammable gases or fumes. Operation of any electrical instrument in such an environment constitutes a safety hazard.
- Do not dispose the SureVIEW DAS in household waste.
- Do not open the enclosure of the SureVIEW DAS. Internally, the SureVIEW DAS uses class 3B laser sources. Opening the enclosure could result in exposure to these sources:
  - ThorLabs BL976-SAG300: 976 nm, 300 mW pump laser diode, CW
  - NKT Koheras BASIK MIKRO Laser: 1550.12 nm, 12 mW, CW
  - ThorLabs SOA1013SXS: 1550 nm optical amplifier

⚠ WARNING

Invisible laser radiation

- Class 1M laser product
- IEC 60825-1:2014
- Average <1 mW at 1550 nm
- Average 20 mW @1550 nm, 1 mW @1470 nm
- All optical output fibers emit class 1 laser radiation

- Complies with FDA performance standards for laser products except for conformance with IEC 60825-1 Ed. 3., as described in Laser Notice No. 56, dated May 8, 2019.
- The SureVIEW DAS emits pulsed laser light with a maximum duty cycle of 0.25%, with a maximum pulse width of 50 ns, and maximum pulse rate of 50 kHz.
- The SureVIEW DAS is intended for indoor use only.

- The SureVIEW DAS exceeds 18 kg. When lifting the unit, use two or more people to lift the load.

NOTICE	
	If the SureVIEW DAS is operated in a manner not specified in this manual then the protection provided by the equipment may be impaired.

7 Preservation of Product

For preservation of product requirements refer to the global procedure for *OFS Preservation of Product (QA-GLB-En-100042)* located on Baker Hughes Operating System (BHOS).

Storage Recommendations

The SureVIEW DAS should be stored at temperatures defined for the particular model under *Storage Temperature*, refer to specification guide (Table 1). Do not expose bare units to the elements. The SureVIEW DAS should be handled with care. Do not subject units to shock and vibration. The SureVIEW DAS should be stored in appropriate packaging, off the floor. Store away from exposure to dust and/or fluids.

Shipping Recommendations

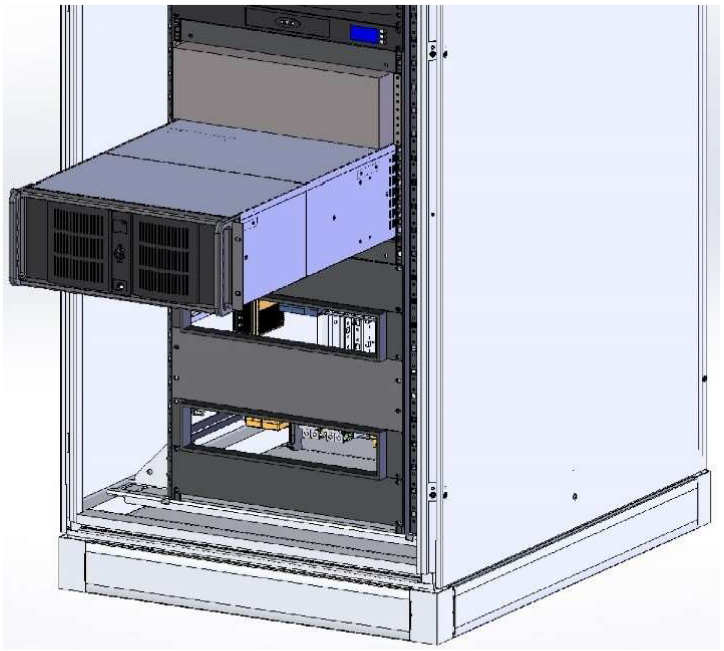
The SureVIEW DAS should be shipped in the *Pelican*™ 1730 Transport Case[1] (SAP # 10503908) in which the DAS was originally delivered.

[1] Pelican is a trademark of Pelican Products, Inc.

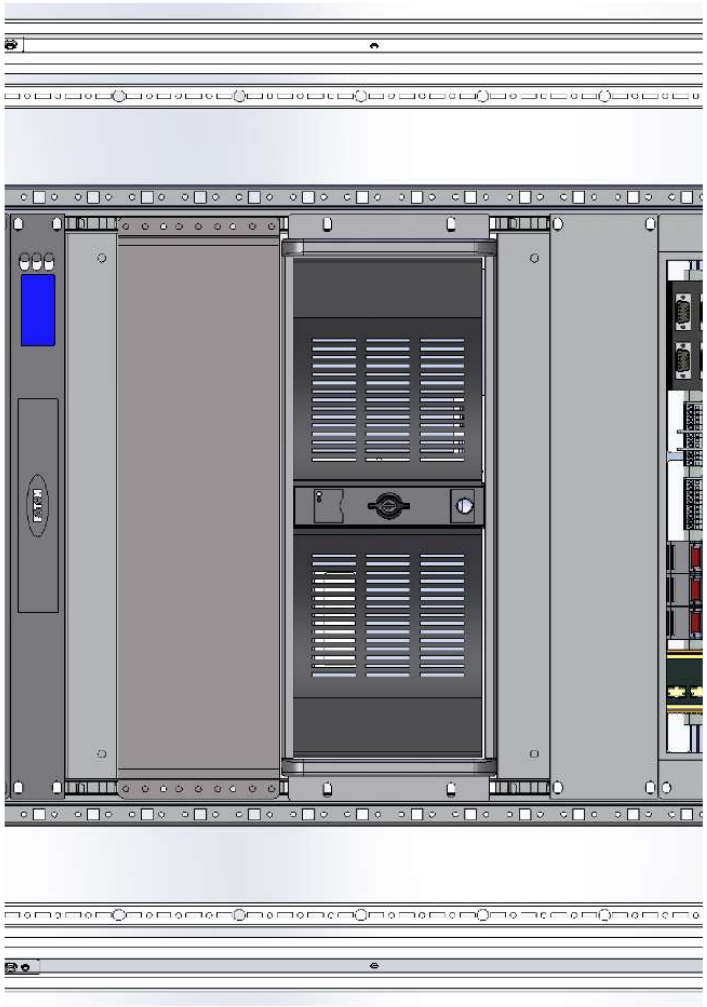
8 Assembly and Dimensional Information

SureVIEW Distributed Acoustic Sensor

Figure 5: Assembly Drawing (Inserting Unit into Rack)



APPL NUM 45026



SureVIEW Distributed Acoustic Sensor
Figure 6: Assembly Drawing (Unit in Rack)

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11.7 Downhole Pressure/Temperature Gauges

Baker Hughes

L3 - Instruction / T1 - Global
Tech Unit
Well Monitoring Services
TU 100950
Rev. F
Effective Date: 18 May 2022

SureSENS QPT ELITE Downhole Pressure Temperature Gauge

Product Family H30757

Last Four Revisions					
Rev.	RDR	Amendment Detail	Reviewer	Approver	Effective Date
F	4996/RM	Updates throughout document; revision level is being aligned to reflect master document/document family for SU 100950.	Rendall, Lorn	Lake, Ben	18 May 2022
E	3236/RM	Updates throughout document	Freeman, Joe	Scott, Thomas M	27 Sep 2018
D	—/RM	The content of this document has not been effected; revision level is being aligned to reflect master document/document family for SU 100950.	Freeman, Joe	Scott, Thomas M	13 Apr 2018
C	/RM	The content of this document has not been effected; revision level is being aligned to reflect master document/document family for SU 100950.	L Rendall	T.M. Scott	12 May 2017

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APPL NUM 45026

1 Introduction

The SureSENS™ QPT ELITE tools are pressure/temperature gauges suitable for single or multipoint reservoir monitoring in either single or multiple-gauge configurations. The gauge is highly robust, ensuring mechanical integrity by deep-penetration and high-vacuum, electron-beam fusion welds, without the need for filler material.

2 Description

The Baker Hughes Company SureSENS QPT ELITE gauge for permanent downhole installations measures static and dynamic pressures and temperatures with introducing a step change in reliability and accuracy. The gauge is qualified for operation at pressures less than 35,000 psi (2,413.1 bar) and temperatures up to 437°F (225°C).

The static pressure information obtained can be used to determine production performance, calculate reserves, and provide input to reservoir simulations. The dynamic pressure data can help determine reservoir characteristics and optimize production rates.

The SureSENS QPT ELITE gauge includes the new ELITE electronics package, built upon our industry leading STAR hybrid electronic package design. The ELITE electronics package incorporates an application specific integrated circuit (ASIC), providing a new level of reliability to the industry.

3 Application

The cost-effectiveness and flexibility of the SureSENS system enables deployment in single- or multiple-gauge applications and is especially suited to downhole applications, which have bottomhole pressures of less than 35,000 psi (2,413.1 bar) and bottomhole temperatures of less than 437°F (225°C). The applications can be tied back to a surface or floating facility, or interfaced with a subsea infrastructure. The flexibility of the system enables the selection of a number of parameter measurements, including single-point zonal pressure measurements to multiple-point pressure measurements (multiple zones or intelligent applications), as well as applications where differential pressure measurements are required (e.g., fluid characterization or flowmeter applications).

4 Features and Benefits

- ELITE electronics package
  - Provides superior reliability in demanding high-pressure/high-temperature (HP/HT) conditions.
- Flexible, compact design
  - Easily change gauge and pressure porting configurations without modifying the carrier.
  - Multiple gauge combinations can be deployed on single standardized carrier.
- Unique construction configurations with less connections
  - Eliminates the need for additional splices.
  - Increases reliability.
  - Reduces installation time.

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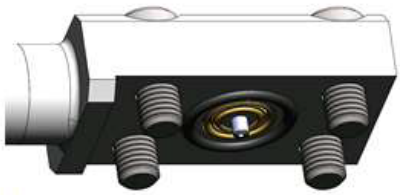
- Supports multiple monitoring devices on single tubing encapsulated conductor (TEC) cable
  - Deploys multiple gauges, flowmeters, and valve positions to provide redundant readings.
  - Serves as platform for future developments.
- Proprietary counting method and broad sample gate duration
  - Derives finest P/T measurement resolution attainable.

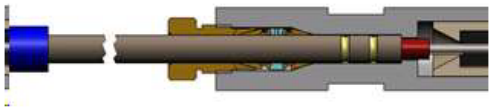
Pressure Interface Manifold

The gauge pressure interface connection to the carrier are dual metal C-rings that can be externally tested in the direction which it will experience pressure, eliminating the need for an internal pressure test tool.



Cable Head

The TEC's primary seal is a dual metal-to-metal pressure-testable interface, and the mechanical package is completely integrated into the gauge assembly, which eliminates the requirement for external Y-block components.



Gauge Addressing

The SureSENS QPT ELITE gauge supports multiple node addresses that range from 1–32 with a maximum of 32 gauges in multidrop applications. For these applications, the bottom gauge will not require a feed through. All other gauges above the bottom gauge deployment will require a TEC feedthrough which connects each gauge in the well without the use of a Y-splice assembly.

Each gauge has its own unique address expressed in the nomenclature T1, T2, T3, etc. Default tool addressing will be Single – T1, Dual – T1/T2, Triple – T1/T2/T3.

Example: If three dual gauges were to be deployed in the same well, all six tools must have an individual tool address, this would require three different material numbers to be ordered* as shown in address designation for multidrop application (Table1).

Table 1: Address Designation for Multidrop Application

Example Configuration	Tool Address
Dual gauge 3 with feedthrough	T5/T6
Dual gauge 2 with feedthrough	T3/T4
Dual gauge 1	T1/T2

Note: Tools with the same addresses cannot be run on a single TEC system.

*Refer to product selection chart (Table 6) for information on tool addresses.

5 Engineering Tables and Information

Table 2: Specification Guide

Description	Value					
Length (in.)	25.5 to 26.5 (60.96 cm to 67.31 cm)					
Diameter (in.)	0.75 to 2.50 (19.05 mm to 57.15 mm)					
Seals	Metallic seals and EB welds					
Transducer	Shear mode quartz					
Transducer options (psi)	10,000 (689.5 bar)	16,000 (1,103.2 bar)	20,000 (1,379.0 bar)	25,000 (1,723.6 bar)	30,000 (2,068.4 bar)	35,000 (2,413.7 bar)
Material	*Inconel*® 718		MP35N			
Pressure range (psi) (operating at 150°C)	15–11,000 (1–758.4 bar)	15–18,000 (1–1,241.1 bar)	15–23,500 (1–1,620.3 bar)	15–28,000 (1–1,930.5 bar)	15–33,000 (1–2,275.3 bar)	15–37,500 (1–2,585.5 bar)
Temperature rating (operating)	-99 to 302°F (-73 to 150°C)	-99.4 to 437°F (-73 to 225°C)				
Storage temperature (°F)	-40 to 302 (-40 to 150°C)					
Temperature shock (°F)	5.4 (3°C) per minute					
Vibration	>10 G, 10 Hz - 2 kHz					
Shock	500 G					
Pressure measure range (calibrated)	200–10,000 psi (13.8–689.5 bar)	200–16,000 psi (13.8–1,103.2 bar)	200–20,000 psi (13.8–1,379.0 bar)	200–25,000 psi (13.8–1,723.6 bar)	200–30,000 psi (13.8–2,068.4 bar)	200–35,000 psi (13.8–2,413.7 bar)
Pressure accuracy	±0.015% 1.5 psi (at full scale)	±0.02% 3.2 psi (at full scale)	±0.02% 4.0 psi (at full scale)	±0.02% 5.0 psi (at full scale)	±0.025% 7.0 psi (at full scale)	±0.03% 10.5 psi (at full scale)
Pressure resolution (psi)	0.0001					
Pressure stability	±0.02% full scale, 2.0 psi/year	±0.02% full scale, 3.2 psi/year	±0.02% full scale, 4.0 psi/year	±0.02% full scale, 5.0 psi/year	±0.02% full scale 7.0 psi/year	±0.03% full scale 10.5 psi/year
Temperature measurement range (calibrated)	77 to 302°F (25 to 150°C)	77 to 437°F (25 to 225°C)				
Temperature accuracy (°F)	0.27 (0.15°C)					
Temperature resolution (°F)	0.0001					
Temperature stability	0.018°F (<0.01°C) per year					
Maximum sample rate/second	>16					
Number of gauges support/TEC	32					
Cable distance transmission (ft)	50,000 (15,240 m)					

Inconel is a registered trademark of Special Metals Corporation.

Ordering Guide

Deliverables

All orders for SureSENS QPT ELITE gauges will have the following items delivered:

- SureSENS QPT ELITE gauge
- Certificate of conformance (COC)

Note: All installation kits and redress kits are ordered separately.

Note: Coefficient files and calibration information are available at go/gauge.

Table 3: Accessory Equipment

Material	Description
10456966	Opposing ferrule seal (OFS) install kit
10456879	Manifold install kit
H0J0324100*	OFS blanking plug assembly
H0J1236900**	External pressure testing fixture

*To be used in applications where the lowest gauge in the completion has been ordered with electrical feedthrough and requires to be blanked off.

**For applications where OFS seals require to be tested in the direction of pressure

Table 4: Opposing Ferrule Seal Install Kit Bill of Material

Description	Qty. Req'd	Material
1/4-in. Front Ferrule	2	10369916
1/4-in. Rear Ferrule	2	10369914
Activator	1	H0J0145801
Expansion Ring	1	H0J0145100
Gland Nut	1	H0J0145201
Spring Insert	1	10372093
Test Port Plug	1	H0J0385400
Tungrease CF-33E	1	H0J0626700

Table 5: Manifold Install Kit Bill of Materials

Description	Qty. Req'd	Material
0.375-in. OD Crush Ring	1	10452446
0.436-in. OD Crush Ring	1	10452447
Port Block Seal	1	P630-0035-ZZ
2-017 *Kalrez*® O-ring	1	10599692
Blanking Plugs	2	H0J0385400

Kalrez is a registered trademark of DuPont Performance Elastomers L.L.C.

Figure 1: Configuration examples.

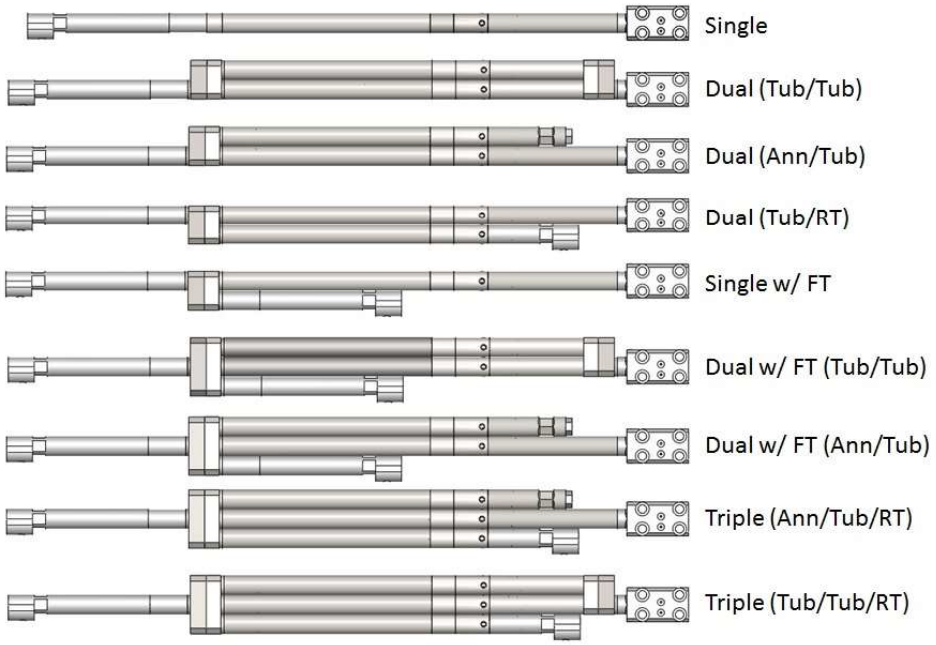


Figure 2: Sensor placement in multisensor assembly.

Table 6: Product Selection Chart

Tool Address	Pressure Rating (psi)						OFS Install Kit	Manifold Install Kit
	10,000	16,000	20,000	25,000	30,000	35,000	Qty Required	Qty Required
Single (Tubing)								
T1	H307570100	H307570150	H307570200	H307570250	H307570300	–	1	1
Single with Feedthrough (Tubing)								
T1	H307570101	H307570151	H307570201	H307570251	H307570301	–	2	1
T2	H307570102	H307570152	H307570202	H307570252	H307570302	–	2	1
T3	H307570103	H307570153	H307570203	H307570253	H307570303	–	2	1
T4	H307570104	H307570154	H307570204	H307570254	H307570304	–	2	1
T5	H307570105	H307570155	H307570205	H307570255	H307570305	–	2	1
T6	H307570106	H307570156	H307570206	H307570256	H307570306	–	2	1
T7	H307570107	H307570157	H307570207	H307570257	H307570307	–	2	1
T8	H307570108	H307570158	H307570208	H307570258	H307570308	–	2	1
T9	H307570109	H307570159	H307570209	H307570259	H307570309	–	2	1
T10	H307570110	H307570160	H307570210	H307570260	H307570310	–	2	1
T11	H307570111	H307570161	H307570211	H307570261	H307570311	–	2	1
T12	H307570112	H307570162	H307570212	H307570262	H307570312	–	2	1
T13	H307570113	H307570163	H307570213	H307570263	H307570313	–	2	1
T14	H307570114	H307570164	H307570214	H307570264	H307570314	–	2	1
T15	H307570115	H307570165	H307570215	H307570265	H307570315	–	2	1
T16	H307570116	H307570166	H307570216	H307570266	H307570316	–	2	1
T17	H307570117	H307570167	H307570217	H307570267	H307570317	–	2	1
T18	H307570118	H307570168	H307570218	H307570268	H307570318	–	2	1
T19	H307570119	H307570169	H307570219	H307570269	H307570319	–	2	1
T20	H307570120	H307570170	H307570220	H307570270	H307570320	–	2	1
T21	H307570121	H307570171	H307570221	H307570271	H307570321	–	2	1
T22	H307570122	H307570172	H307570222	H307570272	H307570322	–	2	1
T23	–	–	–	–	–	–	2	1
T24	–	–	–	–	–	–	2	1
T25	–	–	–	–	–	–	2	1
T26	–	–	–	–	–	–	2	1
T27	–	–	–	–	–	–	2	1
T28	–	–	–	–	–	–	2	1
T29	–	–	–	–	–	–	2	1
T30	–	–	–	–	–	–	2	1
T31	–	–	–	–	–	–	2	1
T32	–	–	–	–	–	–	2	1
Dual (Tubing/Tubing)								
T1/T2	H307570123	H307570173	H307570223	H307570273	H307570323	–	1	1
Dual with Feedthrough (Tubing/Tubing)								
T1/T2	H307570124	H307570174	H307570224	H307570274	H307570324	–	2	1
T3/T4	H307570125	H307570175	H307570225	H307570275	H307570325	–	2	1
T5/T6	H307570126	H307570176	H307570226	H307570276	H307570326	–	2	1
T7/T8	H307570127	H307570177	H307570227	H307570277	H307570327	–	2	1
T9/T10	H307570128	H307570178	H307570228	H307570278	H307570328	–	2	1
T11/T12	H307570129	H307570179	H307570229	H307570279	H307570329	–	2	1
T13/T14	H307570130	H307570180	H307570230	H307570280	H307570330	–	2	1
T15/T16	H307570131	H307570181	H307570231	H307570281	H307570331	–	2	1
T17/T18	H307570132	H307570182	H307570232	H307570282	H307570332	–	2	1
T19/T20	H307570133	H307570183	H307570233	H307570283	H307570333	–	2	1

Tool Address	Pressure Rating (psi)						OFS Install Kit	Manifold Install Kit
	10,000	16,000	20,000	25,000	30,000	35,000	Qty Required	Qty Required
T21/T22	H307570134	H307570184	H307570234	H307570284	H307570334	–	2	1
T23/T24	–	–	–	–	–	–	2	1
T25/T26	–	–	–	–	–	–	2	1
T27/T28	–	–	–	–	–	–	2	1
T29/T30	–	–	–	–	–	–	2	1
T31/T32	–	–	–	–	–	–	2	1
Dual (Annulus/Tubing)								
T1/T2	H307570135	H307570185	H307570235	H307570285	H307570335	–	1	1
Dual with Feedthrough (Annulus/Tubing)								
T1/T2	H307570136	H307570186	H307570236	H307570286	H307570336	–	2	1
T3/T4	H307570137	H307570187	H307570237	H307570287	H307570337	–	2	1
T5/T6	H307570138	H307570188	H307570238	H307570288	H307570338	–	2	1
T7/T8	H307570139	H307570189	H307570239	H307570289	H307570339	–	2	1
T9/T10	H307570140	H307570190	H307570240	H307570290	H307570340	–	2	1
T11/T12	H307570141	H307570191	H307570241	H307570291	H307570341	–	2	1
T13/T14	H307570142	H307570192	H307570242	H307570292	H307570342	–	2	1
T15/T16	H307570143	H307570193	H307570243	H307570293	H307570343	–	2	1
T17/T18	H307570144	H307570194	H307570244	H307570294	H307570344	–	2	1
T19/T20	H307570145	H307570195	H307570245	H307570295	H307570345	–	2	1
T21/T22	H307570146	H307570196	H307570246	H307570296	H307570346	–	2	1
T23/T24	–	–	–	–	–	–	2	1
T25/T26	–	–	–	–	–	–	2	1
T27/T28	–	–	–	–	–	–	2	1
T29/T30	–	–	–	–	–	–	2	1
T31/T32	–	–	–	–	–	–	2	1
Dual (Tubing/Remote Tap)								
T1/T2	H307570147	H307570197	H307570247	H307570297	H307570347	–	2	1
Triple (Annulus/Tubing/Remote Tap)								
T1/T2/T3	H307570148	H307570198	H307570248	H307570298	H307570348	–	2	1
Triple (Tubing/Tubing/Remote Tap)								
T1/T2/T3	H307570149	H307570199	H307570249	H307570299	H307570349	–	2	1

Only the single and dual configurations can be deployed with a feedthrough, for configurations not listed contact product line.

6 HSE&S

Read, understand and follow all Baker Hughes Company instructions and specifications in this unit while assembling, disassembling, maintaining or repairing this equipment. Failure to do so may result in property damage, serious injury or fatality.

7 Preservation of Product

For preservation of product requirements refer to the global procedure for *OFS Preservation of Product (QA-GLB-En-100042)* and *CWI Storage and Preservation Guidelines (AMO-GLB-En-101887)* located on Baker Hughes Operating System (BHOS).

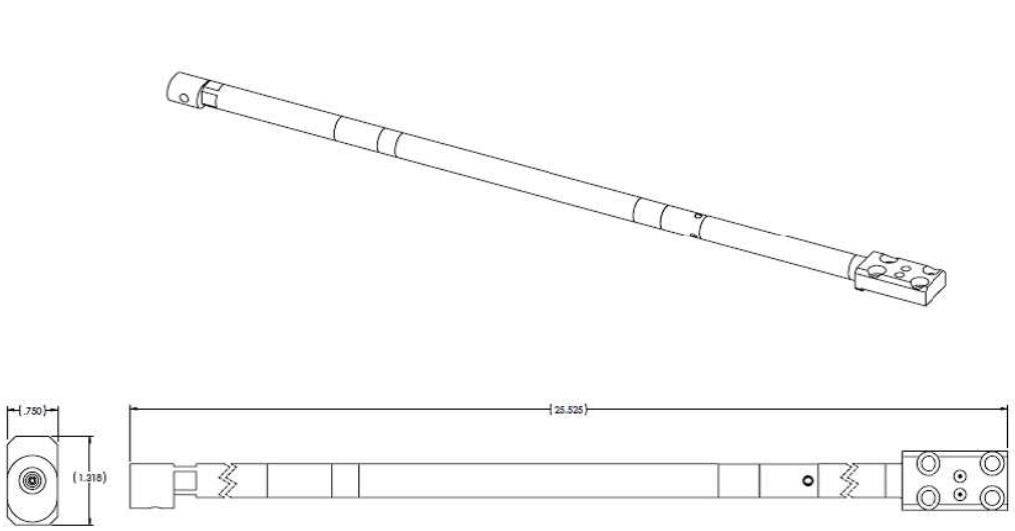
Storage Recommendations

Adequate storage facilities must be established for equipment to prevent inadvertent damage due to moisture, humidity, vibration, shock and handling. Equipment will be appropriately protected during transport and handling.

8 Assembly and Dimensional Information

SureSENS QPT ELITE Downhole Pressure Temperature Gauge

Figure 3: Assembly Drawing J06-522-00 (single tubing)



SureSENS QPT ELITE Downhole Pressure Temperature Gauge

Figure 4 : Assembly Drawing J06-526-00 (tubing with feedthrough)

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9 Appendix

Hand Tools Required

- Encapsulation stripping tool
- 12-in. steel rule or dial calipers
- Tubing cutter
- Triangular file
- Large vise grips
- 3/16-in. through 5/16-in. coaxial cable stripper (IDEAL 45-165)
- 1/8-in. coaxial cable stripper (IDEAL 45-162)
- 12-20 AWG wire stripper
- DMC AF8 crimp tool
- Swaging tool (Material PGA-80-09000)
- 12-in. adjustable wrench
- Torque wrench ft.lb scale with interchangeable head (Snap-on QC2I75 or CDI 75MFIMHSS)
- Jam nut torque wrench head (BH Material H0J0531502 or Snap-on QJRXS16A)
- 5/8-in. wrench
- Torque wrench (in.lb scale)
- 3/16-in. hex socket bit

If deploying the external pressure testing fixture the following will be required:

- Clamp assembly (Material H0J1237000)
- Modified drive adapter (Material H0J1166900 or CDI TCQJRXS12A)
- 3/8-in. crows foot Wwench (Material 10601424 or Snap-on FRH120S) not required if using CDI TCQJRXS12A

Consumables Required

- P600 emery paper
- Silicone grease DC111
- TUNAP Tungrease CF-33 grease paste

Pressure Test Equipment Required

- Hand pump or HPU with transformer oil (Shell *DIALA* or equivalent)
- Chart recorder or pressure recording digital gauge
- High pressure lines with 1/4-in. autoclave high-pressure connections
- High-pressure T-piece
- High-pressure needle valve
- Pressure test adaptor (Material H0J0419300)

11.8 CoreBright Optical Fiber

Ensure industry-leading protection against hydrogen darkening in high-temperature applications

SureVIEW™ downhole cable by Baker Hughes uses CoreBright™ optical fiber, which leads the industry in hydrogen darkening resistance, the primary cause of failure for fiber optic systems in high- temperature applications. CoreBright fiber is constructed from pure silica that minimizes hydrogen darkening. The cable also includes a layer of hydrogen- absorbing gel. This combination provides the industry's best protection against hydrogen darkening.

Fabricating a downhole optical cable with the performance and reliability demanded by the oil and gas industry requires a sophisticated understanding of fiber design, fiber coatings, cable manufacturing processes, and cable construction. Optical, chemical, and physical disciplines are combined with extensive oilfield experience to offer a superior cable.

CoreBright fiber offers its extended lifetime through a simple principle: Rather than attempt to avoid hydrogen damage by trying to block hydrogen (a near impossibility in enhanced oil recovery operations due to high temperatures), CoreBright optical fiber avoids the hydrogen damage by preventing the reaction between SiO2 structure of the optical fiber and the hydrogen. Thus, CoreBright fiber tolerates the presence of hydrogen without suffering lifetime limiting damage.

In this way, our solution is unique: The fiber will never darken, and reliable readings over the full life of the installation are assured. Independent testing has concluded that CoreBright optical fiber is the only fiber in the industry that is suitable for oil and gas environments over a long duration; it is the only known fiber designed for, and has demonstrated, long-term immunity to first and second-order hydrogen darkening effects.[1]

Applications

- Downhole fiber optic monitoring systems

Features and Benefits

- Industry leading reliability
- Proprietary glass composition delivers industry-leading resistance to hydrogen darkening
- Extreme temperature rating
- 100% dynamically proof-tested before cabling

Multiple applications

- CoreBright fiber can be used in a variety of applications from SAGD to Leak Detection to Acid Stimulation and many more

Baker Hughes

Technical Specifications - SureVIEW Downhole	
Description	**Specifications**
Maximum Pressure	25,000 psi
Overpressure	1.2x maximum pressure
Operating Temperature	• 150°C / 302°F for standard • 250°C / 482°F for high temperature • Higher temperature solutions available upon request
Sheath Material	A825, 316LSS
Crush	>5,000lbf
Fibers	Maximum of 12, any combination of SM and MM
Fiber Protection	• Standard Temperature: Hydrogen-scavenging gel, carbon coating, acrylate buffer • High Temperature: High-temperature stabilized gel, polyimide buffer, optional carbon coating
Dimensions	0.25 inch outside diameter (excluding encapsulation)
Encapsulation Options	• 0.43 inch square encapsulation • 0.41 inch round encapsulation • Variety of encapsulation materials can be utilized

Call your local Baker Hughes representative today to learn more about how SureVIEW fiber optic monitoring solutions can reliably monitor and deliver the downhole wellbore and reservoir data you need, when you need it.

1. van Rooyen, A. (Royal Dutch Shell), "Fibre Testing at Elevated Temperatures Under Hydrogen Conditions", SEAFOM Industry Meeting (Dec. 2012)

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11.9 SureVIEW Tubing Encapsulated Fiber (TEF)

BAKER HUGHES a GE company

L3 - Instruction / T1 - Global
Tech Unit
Well Monitoring Services
TU 100698
Rev. A
Effective Date: 01 Aug 2019

SureView Tubing Encapsulated Fiber (TEF)

Product Family H30761

Last Four Revisions					
Rev.	RDR	Amendment Detail	Reviewer	Approver	Effective Date
A	3823/RM	Updates throughout document; imported content to CMS	McGowan, Melina	Raggio, John	01 Aug 2019
New	–	Initial Release	J. Jones	R.G. Duncan	01 Feb 2016

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1 Introduction

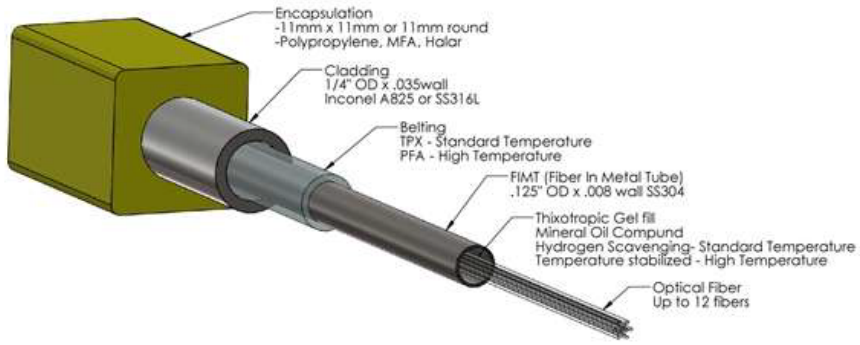
SureVIEW™ tubing encapsulated fiber (TEF) by Baker Hughes, a GE company (BHGE) uses CoreBright™ optical fiber, which leads the industry in hydrogen darkening resistance, the primary cause of failure for fiber optic systems in high-temperature applications. CoreBright fiber is constructed from pure silica that minimizes hydrogen darkening. The cable also includes a layer of hydrogen-absorbing gel. This combination provides the industry's best protection against hydrogen darkening.

CoreBright fiber offers its extended lifetime through a simple principle: Rather than attempt to avoid hydrogen damage by trying to block hydrogen (a near impossibility in enhanced oil recovery operations due to high temperatures), CoreBright optical fiber avoids the hydrogen damage by preventing the reaction between SiO_2 structure of the optical fiber and the hydrogen. Thus, CoreBright fiber tolerates the presence of hydrogen without suffering lifetime limiting damage.

2 Description

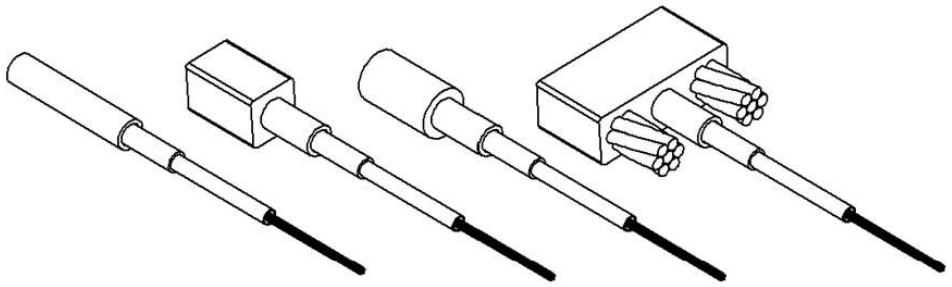
The BHGE standard SureView fiber-optic cable product is a 0.25-in. outside diameter (OD) heavy wall tubing-armor cable which encloses a 0.125-in. OD thin wall tubing containing optical fiber **(Fig. 1)**. The armor is a corrosion resistant metal alloy (CRA) tube, longitudinally welded and cold worked to its final diameter. It contains an extruded plastic filler (belting) that centralizes, and provides a level of shock and vibration damping, to the inner tube. The inner tube, referred as the fiber in metal tube (FIMT), contains up to 12 optical fibers immersed in thixotropic gel.

Figure 1: Tubing encapsulated fiber example.



The SureView fiber-optic cable can be run bare, jacketed in plastic encapsulation (11-mm × 11-mm, or 11-mm OD) for additional protection, or for maximum protection in a flat pack configuration comprised of SureView fiber-optic cable and wire rope in a rectangular cross-section plastic encapsulation (

Figure 2: Fiber-optic cable configuration options.



The BHGE standard manufactured SureView fiber-optic cable has alloy 825 cladding with a wall thickness of 0.035 inches. The cable is also available with 316 stainless steel cladding. The mechanical properties and cost of the SureView fiber-optic cable vary considerably with the choice of alloy.

The SureView fiber-optic cable is available in two temperature ranges: low temperature cable has a maximum continual use temperature of 150°C (302°F), high temperature cable has a maximum continual use temperature of 250°C (482°F). Higher temperature solutions available upon request.

All fibers utilize carbon coating to minimize the effects of hydrogen at temperatures below 150°C (302°F), where higher molecular hydrogen induced losses can occur. Additionally, the low temperature cable contains a hydrogen scavenging gel. The carbon coating also provides added security against liquid ingress from the downhole environment in all cables.

Excess fiber length (EFL) is incorporated in the designs to compensate for the thermal expansion mismatch between the optical fiber and the cable materials, and to allow the cable to stretch without stretching the fiber itself, minimizing optical fiber strain.

3 Application

The SureView tubing encapsulated fiber (TEF) supports permanent fiber-optic pressure gauges, and distributed temperature sensing (DTS) fiber. The primary function of the SureView cable is to transmit optical signals between subsurface components and a surface interface module used to conduct reservoir management.

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4 Features and Benefits

- Proprietary glass composition
  - Industry-leading resistance to hydrogen darkening.
- Multiple applications
  - CoreBright fiber can be used in a variety of applications from SAGD to leak detection to acid stimulation and many more.
- Suitable for high temperatures applications
  - High-temperature stabilized gel, polyimide buffer, optional carbon coating.
- Different encapsulation options
  - Variety of encapsulation materials can be utilized depending on application.

5 Engineering Tables and Information

Table 1: Specification Guide

Description	Value	
Encapsulation	0.433 in.2 (11 mm2) or 0.41 in. round (11-mm OD)	
Cladding	0.250-in. (6.35-mm) OD × 0.035-in. (0.89-mm) wall	
FIMT diameter	0.125-in. (3.18-mm) OD	
Weight with polypropylene 11×11 encapsulation	154 lb/1,000 ft (230 kg/km)	
Weight without encapsulation	101 lb/1,000 ft (150 kg/km)	
Mechanical properties (70°F)*	**A825**	**SS 316L**
Tensile strength (lb)	2,687 (1,219 kg)	2,134 (968 kg)
Yield strength (lb)	2,090 (948 kg)	1,816 (824 kg)
Hydrostatic pressure (kPSI)	25 (17 kg/sq mm)	24 (16.8 kg/sq mm)
Burst pressure (kPSI)	32 (22 kg/sq mm)	22 (15.4 kg/sq mm)
Dynamic bend radius (in.)	14 (355 mm)	25 (635 mm)
Static bend radius (in.)	3 (82 mm)	6.3 (159 mm)
External collapse pressure (kPSI)	24.6 (1729 kg/sq cm)	17 (12.0 kg/sq mm)

*Materials listed should be derated for specific temperature applications. Contact Applications Engineering group for deration factors.

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Ordering Guide

Table 2: Standard Cable Options

Material	Operating Temperature (°C)	Single Mode CoreBright	Multimode Vhm 3000	Cladding Material	Encapsulation	
					Material	Color
H307610002	150	2	1	A825	PP	Yellow
H307610015		4	2	A825	None	—
H307610033		4	2	A825	PP	Yellow
H307610040		4	2	316SS	None	—
H307610089	200	4	0	A825	FEP	Blue
H307610095		2	0	A825	FEP	Blue
H307610069	250	4	0	A825	None	—
H307610036		4	2	316SS	None	—

Contact Applications Engineering group or submit a technical support portal (TSP) for other nonstandard cable options.For other standard cable options, search SAP, T-code Zih09 (Product Family H30761).

Accessory Equipment

Not applicable.

Table 3: Product Selection Chart

Application	Minimum Fiber Required	Temperature	Fiber Types
SureVIEW P/T gauges	1 SM per gauge	Below 150°C	SM CoreBright
		Above 150°C	
SureVIEW DAS	1 SM per well	Below 150°C	SM CoreBright
		Above 150°C	
SureVIEW DTS	Single Ended 1 SM or 1 MM per well Double ended 2 MM or 2 SM per well	Below 150°C	SM CoreBright MM VHM 3000
		Above 150°C	SM CoreBright
SureVIEW wire	2 SM per wire	Below 150°C Above 150°C	SM CoreBright

Table 4: Abbreviations and acronyms

Term	Definition	Abbreviation/Acronym
American wire gauge	—	AWG
As required	—	A/R
Baker Hughes	—	BH
Cladding	Cable outer protective metal tubing	—
Fiber in metal tube	Cable inner metal tubing containing optical fibers	FIMT
Meter	—	m
Millimeter	—	mm

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Term	Definition	Abbreviation/Acronym
Not applicable	—	N/A
Polyimide	—	PI
Gauge	SureView fiber-optic P/T gauge	—
Teflon® (trade name)	—	PTFE
Tubing encapsulated fiber, plastic filler	—	TEF-P
Multimode	—	MM
Single mode	—	SM
Primary reference mark	—	PRM

Teflon is a registered trademark of DuPont.

Encapsulation

Encapsulation is the layer of plastic jacket extruded onto the cladding. Its purpose is to provide an extra level of protection to the cable and ease cable installation.

- **PP or polypropylene (Yellow)** is the least costly and thus most commonly used encapsulation. In water base annular fluid wells use polypropylene when bottomhole temperature <100°C and gas with CO2 is present, or when gas is present but CO2 is not present, or when bottomhole temperature >90°C and no gas or CO2 is present. Minimum installation temperature -10°C.
- **Nylon (Black)** is more expensive, can withstand higher temperatures and has better chemical resistance. Nylon is also harder and thus is more difficult to work with. In oil and gas base annular fluid wells, use when bottomhole temperature is <150°C and no water is present. In water base annular fluid wells, use when bottomhole temperature < 125°C and no gas or CO2 is present. Minimum installation temperature -40°C.
- **ETFE or ethylene tetrafluoroethylene (Blue)** has higher temperature and chemical resistance. In oil and gas base annular fluid wells, use when bottomhole temperature is 150 to 175°C. In water base annular fluid wells, use when bottomhole temperature >125°C and gas with CO2 is present. Minimum installation temperature -60°C.
- **PFA or perfluoroalkoxy (White)** has the highest temperature and chemical resistance. Use PFA when bottomhole temperature is up to 260°C. Minimum installation temperature -100°C.

Table 5: Application Conditions for Encapsulation Materials

Material	Operating Temperature Limits (°C)	H_2O Present	Presence of		Minimum Installation Temperature (°C)
			CO_2	Gas	
PP	90–100	Yes	No	Inquire	-10
	<100		Yes		
Nylon	<125		No	No	-40
	<150	No		Yes	
ETFE	>125	Yes	Yes		-60
	150–175	No			
PFA	<260	DNM	DNM	DNM	-100

DNM = Does not matter.

6 HSE&S

Read, understand and follow all Baker Hughes, a GE company (BHGE) instructions and specifications in this unit while assembling, disassembling, maintaining or repairing this equipment. Failure to do so may result in property damage, serious injury or fatality.

HSE, part of our DNA – HSE is who we are. We integrate HSE in business decisions, our management system and everything we do. Through our culture of HSE we protect our people, customers, and the environment.

High standards – All employees comply with HSE standards and procedures, policies, laws, regulations, and requirements. We are able to articulate these standards to anyone in our business from leadership, to our suppliers, contractors and customers. We are all accountable to maintaining the same high standards.

Immediate action – We identify and stop any unsafe acts before they happen. Everyone is responsible and empowered to observe, intervene, and report unsafe conditions and behaviors immediately.

It is every person's responsibility to:

- Read, understand, and follow all BHGE instructions and specifications in this unit while assembling, disassembling, maintaining, or repairing this equipment.
- Complete any and all risk assessments (and any other associated assessments, documentation, etc), both BHGE and customer-specific, as necessary to ensure safe working conditions at the wellsite.

⚠ WARNING

Substantial energy stored in spooled cable

Serous bodily injury may result in personnel are struck by an uncontrolled cable end

- Grip cable end tightly by hand before unsecuring cable end. Work gloves are required
- Wear safety glasses and safety gloves

⚠ CAUTION

Cut hazard

Cut to hand or fingers

- Take precaution while using any encapsulation removal tool, such as double handled knife, to remove the downhole cable's encapsulation
- Use *Kevlar®* cutting gloves[1]
- Cut away from the body

[1] Kevlar is a registered trademark of DuPont.

7 Preservation of Product

For preservation of product requirements refer to the global procedure for *Preservation of Product (QA-GLB-En-100042)* located on Baker Hughes Operating System (BHOS).

Storage Recommendations

Reels should be stored in an area accessible to forklifts and trucks, but away from constant traffic. Reels should be stored in an area where they will not be damaged by falling objects, chemicals, open flames, welding operations, or excessive heat. Reels should always be stored with their flanges vertical. Reels should never be stored horizontally.

If possible, store reels indoors to provide maximum protection. If the cable must be stored outside, the reels should be placed on a hard, well-drained surface. For long-term storage, it is recommended that cable have overhead protection or be covered with a canvas or opaque polyethylene tarp to avoid prolonged exposure to sunlight.

If a portion of the cable is used, the open end of the cable should immediately be resealed. After re-sealing, the cut end should be reattached to the inside edge of the reel flange.

When cable is to be installed during cold weather at temperatures of less than -10°C, it is recommended that it be stored in a heated building for at least 24 hours prior to installation.

8 Assembly and Dimensional Information

Not applicable.

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11.10 Cement/Casing Inspection

USI UltraSonic Imager Tool

Schlumberger

The USI* UltraSonic Imager tool (USIT) uses a single transducer mounted on an Ultrasonic Rotating Sub (USRS) on the bottom of the tool. The transmitter emits ultrasonic pulses between 200 and 700 kHz and measures the received ultrasonic waveforms reflected from the internal and external casing interfaces. The rate of decay of the waveforms received indicates the quality of the cement bond at the cement/casing interface, and the resonant frequency of the casing provides the casing wall thickness required for pipe inspection. Because the transducer is mounted on the rotating sub, the entire circumference of the casing is scanned. This 360° data coverage enables the evaluation of the quality of the cement bond as well as the determination of the internal and external casing condition. The very high angular and vertical resolutions can detect channels as narrow as 1.2 in. [3.05 cm]. Cement bond, thickness, internal and external radii, and self-explanatory maps are generated in real time at the wellsite.

Applications

- Cement evaluation
- Casing inspection
  - Corrosion detection and monitoring
  - Detection of internal and external damage or deformation
  - Casing thickness analysis for collapse and burst pressure calculations

Measurement Specifications

	USIT
Output	Acoustic impedance, cement bonding to casing, internal radius, casing thickness
Logging speed	1,800 ft/hr [549 m/h]
Range of measurement	Acoustic impedance: 0 to 10 MRayl [0 to 10 MPa.s/m]
Vertical resolution	Standard: 6 in. [15.24 cm]
Accuracy	Less than 3.3 MRayl: ±0.5 MRayl
Depth of investigation	Casing-to-cement interface
Mud type or weight limitations†	Water-base mud: Up to 15.9 lbm/gal Oil-base mud: Up to 11.2 lbm/gal
Combinability	Bottom-only tool, combinable with most tools
Special applications	Identification and orientation of narrow channels

†Exact value depends on the type of mud system and casing size.

Mechanical Specifications	
	USIT
Temperature rating	350°F [177°C]
Pressure rating	20,000 psi [138 MPa]
Casing size—min.	4½ in [11.43 cm]
Casing size—max.	13⅜ in [33.97 cm]
Outer diameter†	3.375 in [8.57 cm]
Length†	19.75 ft [6.02 m]
Weight†	330 lbm [151 kg]
Tension	40,000 lbf [177,950 N]
Compression	4,000 lbf [17,790 N]

† Excluding the rotating sub

USIT Rotating Sub Mechanical Specifications					
	USRS-AB	USRS-A	USRS-B	USRS-C	USRS-D
Outer diameter	3.41 in [8.66 cm]	3.58 in [9.09 cm]	4.625 in [11.75 cm]	6.625 in [16.83 cm]	8.625 in [21.91 cm]
Length	9.8 in [24.89 cm]	9.92 in [25.20 cm]	9.8 in [24.89 cm]	8.3 in [21.08 cm]	8.3 in [21.08 cm]
Weight	7.7 lbm [3.5 kg]	7.7 lbm [3.5 kg]	10.6 lbm [4.8 kg]	15.0 lbm [6.8 kg]	18.3 lbm [8.3 kg]

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11.11 U-tube Sampling

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JOURNAL OF GEOPHYSICAL RESEARCH, VOL. 110, B10203, doi:10.1029/2005JB003735, 2005

The U-tube: A novel system for acquiring borehole fluid samples from a deep geologic CO_2 sequestration experiment

Barry M. Freifeld,[1] Robert C. Trautz,[1] Yousif K. Kharaka,[2] Tommy J. Phelps,[3] Larry R. Myer,[1] Susan D. Hovorka,[4] and Daniel J. Collins[5]

Received 17 March 2005; revised 26 June 2005; accepted 12 July 2005; published 11 October 2005.

[1] A novel system has been deployed to obtain geochemical samples of water and gas, at in situ pressure, during a geologic CO_2 sequestration experiment conducted in the Frio brine aquifer in Liberty County, Texas. Project goals required high-frequency recovery of representative and uncontaminated aliquots of a rapidly changing two-phase fluid (supercritical CO_2 and brine) fluid from 1.5 km depth. The data sets collected, using both the liquid and gas portions of the downhole samples, provide insights into the coupled hydrogeochemical issues affecting CO_2 sequestration in brine-filled formations. While the basic premise underlying the U-tube sampler is not new, the system is unique because careful consideration was given to the processing of the recovered two-phase fluids. In particular, strain gauges mounted beneath the high-pressure surface sample cylinders measured the ratio of recovered brine to supercritical CO_2. A quadrupole mass spectrometer provided real-time gas analysis for perfluorocarbon and noble gas tracers that were injected along with the CO_2. The U-tube successfully acquired frequent samples, facilitating accurate delineation of the arrival of the CO_2 plume, and on-site analysis revealed rapid changes in geochemical conditions.

Citation: Freifeld, B. M., R. C. Trautz, Y. K. Kharaka, T. J. Phelps, L. R. Myer, S. D. Hovorka, and D. J. Collins (2005), The U-tube: A novel system for acquiring borehole fluid samples from a deep geologic CO_2 sequestration experiment, *J. Geophys. Res., 110*, B10203, doi:10.1029/2005JB003735.

1. Introduction

[2] The Frio Brine Pilot is a field experiment to evaluate the potential of brine aquifers to serve as a geologic repository for sequestered CO_2 [*Hovorka*, 2005]. The Frio experiment is part of the U.S. Department of Energy's broad program to explore feasibility and operational issues related to geologic sequestration of CO_2 in a brine-filled reservoir to mitigate the impacts of increasing CO_2 emissions on global climate. Many complex physical and chemical processes arise from the injection of CO_2 into a brine-filled reservoir. The CO_2 has greater mobility and lower density than the brine, resulting in a faster moving, distinct gaseous phase with potentially significant gravity drive. Chemically, the CO_2 is soluble in the brine, resulting in a lowered brine pH and a diverse range of chemical interactions, such as carbonate formation from CO_2 by minerals containing alkaline cations. (The reader is referred to *Pruess et al.* [2003], *Gunter et al.* [1993], and *Bachu et al.* [1994] for a discussion on some of these physical and chemical processes.) One of the prime objectives of the Frio Brine Pilot experiment is to observe formation fluid changes caused by the introduced CO_2. Acquiring frequent samples is necessary to both define the arrival time and track geochemical changes occurring at the front of the CO_2 plume. Testing can yield insight into the transport processes controlling CO_2 movement and lead to better understanding of the underlying mechanisms controlling geologic CO_2 sequestration.

[3] Obtaining a representative downhole fluid sample from great depths has never been a simple endeavor. During sampling, changes in pressure and temperature produce changes in fluid chemistry [*Kharaka and Hanor*, 2004]. Traditional sampling in boreholes has been performed either by a submersible pump or by lowering a sampling device within the well bore [*Lerner and Teutsch*, 1995]. In two-phase systems, submersible pumps fail to operate and gas separators are needed, drastically changing the composition of the downhole fluid. Sampling devices lowered into the well bore, such as the flow-through downhole Kuster sampler (Kuster Company, Long Beach, California), require wire lines and need to be run in and out of the borehole for each sample acquired. Because the sample obtained by the sampler is of limited volume, if the well bore is not purged prior to deploying the sampler, the representativeness of the collected fluid would be in question. There are other methods used for producing fluids from deep boreholes, such as conventional gas lift systems, but these alter the chemical and physical composition of the recovered fluids

[1] Lawrence Berkeley National Laboratory, Berkeley, California, USA.
[2] U. S. Geological Survey, Menlo Park, California, USA.
[3] Oak Ridge National Laboratory, Oak Ridge, Tennessee, USA.
[4] Bureau of Economic Geology, University of Texas at Austin, Austin, Texas, USA.
[5] Sandia Technologies LLC, Houston, Texas, USA.

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and are not usually considered acceptable for geochemical sampling.

[4] The U-tube sampling system (Figure 1) developed for the Frio Brine Pilot experiment utilizes a compressed gas to move the fluid to be sampled through a small diameter tube that goes down to the zone of interest and returns to the surface, forming a "U." A short stinger with a check valve runs through a pneumatic packer used to isolate the perforated section of the well bore and terminates at an inlet filter sitting in formation fluid. This system is fundamentally the same as the porous cup sampler developed for vadoze zone sampling by *Wood* [1973]. Others have since used this technique for shallow groundwater [*Einfeld and Koglin*, 2000]. To acquire a sample, the U-tube, as shown in Figure 1, is first purged with compressed nitrogen. The tube is then vented, allowing formation fluid to enter the U through the check valve and displace the venting nitrogen. Finally, compressed gas is applied to the drive leg tube, and fluid is collected from the sample leg of the U-tube. While the operation of the sampler is conceptually straightforward, the actual processing of the sample stream for the case of two-phase formation fluids (i.e., both a brine and supercritical CO_2 phase) requires care to maintain controlled conditions during sampling.

[5] This paper is primarily concerned with describing the U-tube sampling process. The ability of the system to process the multiphase brine/CO_2 fluid is demonstrated through the presentation of data collected during CO_2 injection. A simple radial model is used to estimate the CO_2 formation saturation using the measured CO_2 and tracer transport times, suggesting the fundamental capability of CO_2 to bypass the lower-mobility brine. While the Frio Brine Pilot experiment was limited in size and duration, the data collected are similar to the data required for long-term monitoring and verification of geologic CO_2 sequestration. While the U-tube sampling methodology is presented in the context of our particular field experiment, it is seen to have potential for use in much broader applications.

2. Frio Field Site and Experimental Conditions

[6] The Frio Brine Pilot experiment was conducted in a 24 m thick mineralogically complex Oligocene reworked fluvial sandstone located within the Frio formation. The Sun-Gulf-Humble Fee Tract 1 in Liberty County, Texas, well 4, a nonproducing oil well, was recompleted and perforated between 1,528.3 m and 1,534.4 m to serve as an observation borehole. With an apparent dip of 20 degrees, a new CO_2 injection well was drilled 30 m downdip, and perforated 12 m deeper, between 1,540.8 m and 1,546.3 m. The perforations were all within the upper 6.1 m of the 24 m thick sand, which logs indicate is isolated by a thin regionally continuous silty-shale layer. Location of the Frio site relative to Houston and a stratigraphic cross section is shown in Figure 2. The testing plan called for the injection of CO_2 at a rate of 3 kg/sec while monitoring downhole pressures, temperatures, fluid composition, and chemical changes at the observation borehole. Geophysical logging using electrical, seismic, and saturation logging tools was carried out both to perform baseline characterization and to understand changes occurring because of the CO_2 injection.

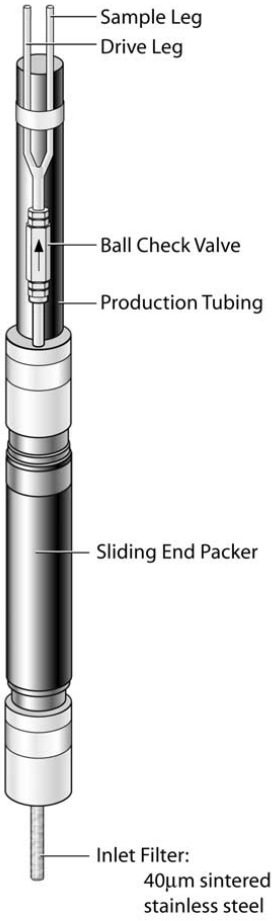

Figure 1. Details of the U-tube sampling system downhole assembly.

[7] The Frio Brine Pilot experiment posed a series of challenges that seemed to eliminate all of the commonly used methods for downhole sampling. The Frio brines are high in total dissolved solids (TDS) (10% by weight) and near saturation with methane; thus they are easily altered by degassing or oxidation caused by contact with air. The competing sampling requirements, causing minimal disturbance to the flow field while ensuring that the sample represented formation fluid, meant that a delicate balance between purge quantity, sample frequency, and sample size needed to be maintained. The sample fluid was to be kept at pressure, so that there would be no gas loss and the sample would be isolated from external contaminants, particularly oxygen, which would lead to rapid changes in sample chemistry. One of the sampling goals was to determine the arrival time of the CO_2 front and capture the geochemical changes as the plume passed by the observation borehole. This would require a method that could operate

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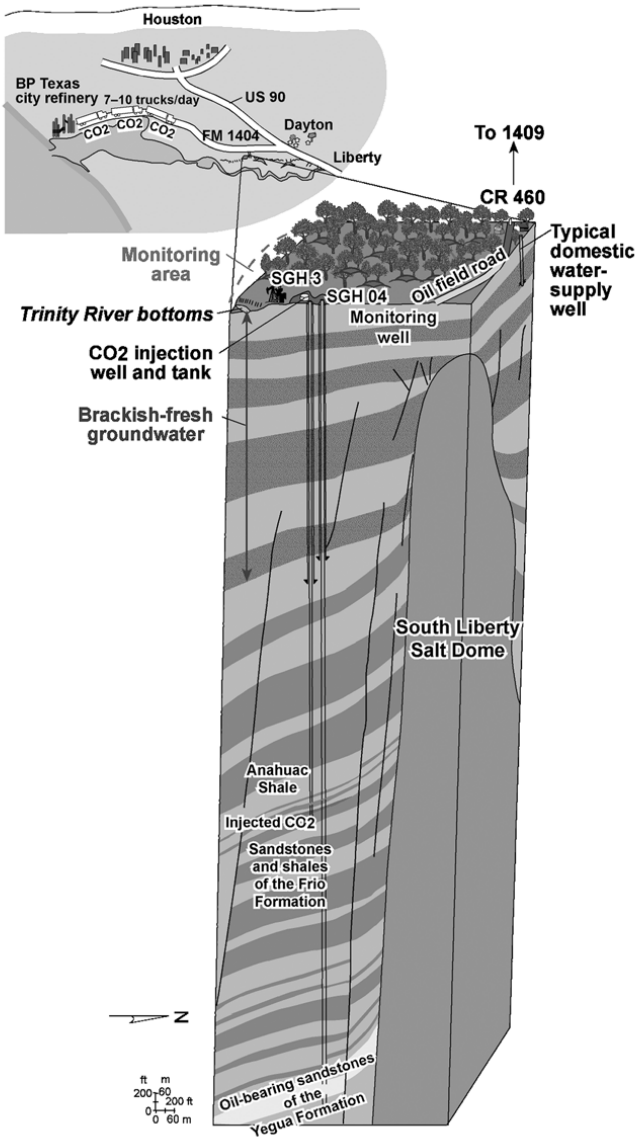

Figure 2. Location of the Frio Field Site, 60 km from Houston, Texas, and a schematic of the underlying stratigraphy. CO_2 was injected in the Frio Formation, capped by the low-permeability Anahuac Shale.

both frequently and reliably during a 24-hour a day, continuous operation.

[8] We theorized before the test that at some point during the CO_2 injection, the well bore fluids in the observation borehole would transition from single-phase brine to a supercritical CO_2/brine mixture that would lift itself, owing to the low density of the fluid. While it would have been possible to allow the well to produce itself at this point, the relatively large diameter of the production tubing would have resulted in either (1) perturbing the flow field through rapid production or (2) poor temporal resolution and large fractionation of brine and CO_2 phases if production in the tubing was throttled back. The U-tube optimized transport of mixed-phase fluids to the surface at a high velocity,

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providing samples with minimal phase separation and good temporal resolution.

3. The U-Tube Sampling System

[9] To meet the requirements of sampling at the Frio field site, we designed the U-tube sampling system in parallel with the observation well completion. A pneumatic packer was used to isolate the perforated interval. From a geochemical sampling standpoint, it would have been best to put the bottom of the packer just above the top perforation, minimizing the volume below the packer. However, to accommodate some of the planned logging operations, the packer was set 14.3 m above the top perforation. The inlet port to the U-tube, a 60 cm long piece of 40-μm sintered stainless steel (Mott Corporation, Farmington, Connecticut), was located 30 cm below the bottom of the packer. The volume of the cased interval between the bottom of the packer and the top of the perforations was 177.1 L, with the 6.1 m perforated interval having an additional 75.4 L volume.

[10] The decision to move the packer above the zone of interest to facilitate geophysical logging had implications for the composition of the sampled fluid. The supercritical CO_2, being buoyant, would preferentially displace brine and accumulate beneath the bottom of the packer. This behavior is beneficial for identifying the earliest time of arrival for the gaseous components. However, it may not reflect the true composition of the formation fluid. We can assume that the composition of the collected fluid, in a single-phase system, reflects a permeability-weighted average of the fluid immediately outside of the borehole perforations, but the situation in a multiphase system is more complicated. Because the mobility of the supercritical CO_2 is much greater than the native brine, the CO_2 will preferentially enter the well bore, to the possible exclusion of the lower-mobility brine within the formation.

[11] The inner diameter of the U-tube tubing is the most important design factor in determining the behavior of the sampler and the ability to obtain fresh formation fluid. As the tubing diameter increases, the sample size gets larger, but the amount of compressed gas required to drive the sample also increases. To prevent degassing and phase segregation in the sample tubing, the U-tube is back-pressured to bottom hole conditions at the top of the sample tube. The pressure required to drive the sample to the surface at formation pressure requires that the bottom of the U-tube be maintained at twice the formation pressure during sampling. Since the Frio observation well bottom hole pressure is 146 bars, the resulting pressure at the bottom of the closed U-tube is 292 bars. Since the hydrostatic pressure in the U-tube (because of the 1513.9 m column of nitrogen) adds ~44 bars to the downhole pressure, the surface compressor must therefore be capable of delivering nitrogen at 248 bars to retrieve a sample at formation pressure.

[12] A 9.5 mm O.D. × 1.2 mm wall thickness stainless steel tube was used for the drive and sample legs of the U-tube. With this geometry and an installed depth of 1513.9 m, the total volume of the U-tube was 117.7 L. Since the hydrostatic fluid level at the Frio field site is ~100 m below ground surface, the sampling tubes filled with 102.1 L of fluid from the formation during the U-tube venting process. Four 200-bar-rated stainless steel sample collection pressure vessels, each with a volume of 13 L, were used to collect a portion of the sampled fluid at formation pressure.

[13] Lifting the water from the sampling interval to the ground surface via the U-tube, and purging the sampling equipment of residual water between samples, was an eight-step process. A description of the eight operating steps is provided below, along with the major components of the automated U-tube sampling equipment, including the flow manifolds, data acquisition system, and control software.

[14] Custom-built flow manifolds, a data acquisition system, and software were combined to form an integrated hardware and software system to lift the water and to automatically control the sample processes. The flow manifolds consisted of various combinations of manual, pressure release, check and/or pneumatic-actuated valves, filters, pressure regulators, tanks, pumps, compressors, pressure gauges and transducers, and piping (Figure 3). These hardware components stored, conveyed, and controlled the movement of fluids from the sample interval in the well to the surface, where the water and gases were sampled and analyzed.

[15] The individual flow manifolds, shown in Figure 3, comprise the U-tube sampler and were used to control specific processes that will be described shortly, along with the eight sample processes. The data acquisition system consisted of sensors (pressure transducers and strain gauges), programmable data logging devices that had both input (logging) and output (control) capabilities, and a personal computer. These hardware components measured, recorded, and stored test data, provided a feedback mechanism for the software to control processes, and provided the computer platform on which the control software operated. Custom software was written using LabVIEW graphical programming language (National Instruments, Austin, Texas) to log and archive the data, control the hardware, and automate the sampling processes.

[16] A 12,000 L capacity liquid nitrogen (LN) dewar was used as the source of high-purity nitrogen gas, to lift the water in the U-tube and to purge residual water from the system after sampling. LN was drawn from the dewar through a passive, short-tube vertical evaporator, where it boiled, producing nitrogen gas. The nitrogen gas was then compressed from the inlet pressure of 1.1 bars to 272 bars using a five-stage 30 horsepower compressor and stored in four 14,000 L (at standard pressure) capacity high-pressure gas cylinders. The LN dewar, compressor, and high-pressure gas cylinders are referred to as the high-pressure gas supply manifold (Figure 3).

[17] Filling of the high-pressure gas cylinders was accomplished by continuously measuring pressures in the high-pressure gas supply manifold, using a 0–680 bars pressure transducer (gauge P1, Figure 3). Feedback from the pressure transducer was monitored by the control software, which started and stopped the compressor by switching a control relay in the compressor's power supply. The software compared the measured pressures against lower and upper pressure set points, defined by the user, to determine when to start and stop the compressor, respectively. A poppet valve on the compressor served as a safety back-up in case of a problem with the control system.

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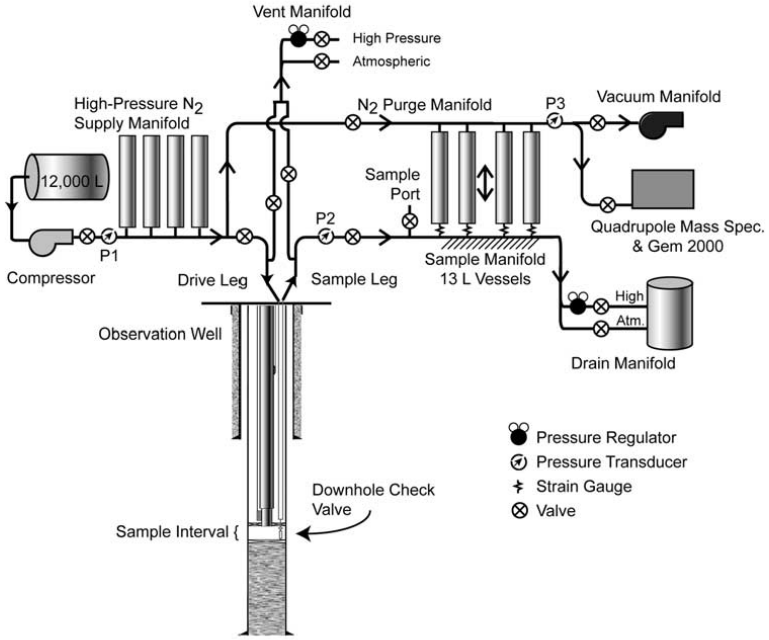

Figure 3. Simplified schematic of the U-tube sampling system. Computer-controlled valves allowed the U-tube sampling sequence to be automated. All monitored parameters, including valve positions and pressures, are continuously logged for posttest analysis.

[18] The first step in the sampling process, referred to as the U-tube fill cycle, consisted of filling the U-tube with water from the test interval. This was accomplished by venting the drive and sample legs of the U-tube to the atmosphere through the vent manifold (Figure 3). Venting the U-tube caused the check valve, located in the well at the bottom of the U-tube assembly, to open. Water then flowed from the packed off section of the well (i.e., sample interval) through the downhole check valve, into both limbs of the U-tube. Water entered and rose in the sample and drive legs of the U-tube, as long as the fluid pressure was below the bottom hole pressure. The maximum water level rise in the tube is achieved by venting the U-tube to the atmosphere. Water will then seek a maximum level equal to the hydraulic head in the reservoir. For the Frio Brine Pilot, the U-tube was allowed to fill with water for ~15 min, at which point, closing the vent manifold ended the cycle.

[19] The second, third, and fourth steps, referred to as the sampler purge, bleed-down and evacuation cycles, respectively, were performed in parallel with the U-tube fill cycle to save time. The second step consisted of purging the gas sample manifold, sample vessels, and liquid sample manifold (Figure 3) with nitrogen gas to remove any residual fluid from these components prior to sampling. This process helped minimize cross contamination from previous samples and took about 6 min to complete. Gas from the high-pressure supply manifold was allowed to flow through the N_2 purge manifold (Figure 3), sweeping residual water from the sample manifolds and vessels, out through the drain manifold and into a large tank. Once the purge cycle was completed, the nitrogen gas was turned off at the start of the third step, and the gas pressure in the various manifolds was allowed to bleed down through the drain manifold to the atmosphere. All manifolds were shut in at the completion of the bleed-down cycle, which lasted ~4 min.

[20] The fourth step, or evacuation cycle, involved using a vacuum pump to remove residual nitrogen gas from the sample manifolds and vessels before collecting the next sample. Any residual nitrogen would serve to dilute the gases collected during sampling and therefore reduce the sensitivity of the measurements. The vacuum manifold (Figure 3) was opened, and a rotary vane vacuum pump was turned on to evacuate the gas from the sampling manifolds and vessels. A maximum vacuum of 660 mm Hg could be obtained with this pump. The manifold was closed and the pump was turned off at the end of the evacuation cycle, which took ~2 min to complete.

[21] The fifth step involved charging the U-tube drive leg with nitrogen gas to produce water under high pressure from the sample interval. Sample recovery was initiated by pressurizing the drive leg of the U-tube, using the nitrogen gas (at 272 bars) stored in the high-pressure gas supply manifold. Pressurizing the fluid in the U-tube caused the downhole check valve to close, preventing water (and nitrogen) from flowing back into the sample interval. It also created the driving force to push the water in the U-tube "uphill" to the surface, via the sample leg of the tube. At the same time that the drive leg of the tube was charged with

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gas, water (and any residual gas located at the top of the water column) flowed up the sample leg of the U-tube to the surface, where it discharged through the high-pressure vent (Figure 3). A backpressure regulator, located before the high-pressure vent and set at 136 bars, maintained the sample fluid within the U-tube near the downhole reservoir pressure.

[22] It was important to maintain the samples at reservoir conditions, both to prevent dissolved gases from coming out of solution and to minimize changes in brine chemistry during the sampling process. It was common practice during step 5 to "dump" the first 10 min of sample (about 20 to 25 L) out the vent, because it was felt that this water was less representative of formation conditions than the fluid located near the bottom of the U-tube. This is because brine initially enters the U-tube under reservoir conditions and then depressurizes as it moves up the tube during the U-tube fill cycle (step 1). Therefore the initial 20 to 25 L of water came from the top of the water column in the downstream limb of the U-tube, where depressurization is greatest and changes in dissolved gas and water chemistry would be most pronounced. At the end of the dump cycle (i.e., step 5), we collected grab samples for aqueous geochemistry and offsite perfluorocarbon tracers (PFT) analysis.

[23] After dumping the prescribed amount of water, the high-pressure vent was closed and the sixth step, or sampling cycle, began. Water flowing up the U-tube during the dump cycle was immediately diverted from the high-pressure vent to the liquid sample manifold, consisting of four sample vessels (Figure 3). It typically took 10 to 12 min to lift 52 L of water to the surface and to fill the four sample vessels to capacity at ~150 bars. The combined weight of the vessel, water, and gas were continuously measured throughout the sampling cycle, using electronic strain gauges located at the base of each sample vessel.

[24] Pressure measurements from a 0–680 bar pressure transducer, located at the top of the sample vessels in the gas sample manifold (gauge P3, Figure 3), were used as the criteria for ending the sampling cycle. The control software automatically stopped the sampling cycle when the measured pressures in the manifold exceeded the bottom hole formation pressure (i.e., >150 bars). The sample manifold closed automatically at the end of the cycle, where the sample remained until analyzed.

[25] The seventh and eighth steps in the sampling process were performed concurrently and are referred to here as the analysis and U-tube purge cycles, respectively. The analysis cycle consisted of opening the analysis manifold, allowing water and dissolved gas to flow from the top of the sample vessels into a gas separator kept at atmospheric pressure. Free gas in the sample, and exsolved gases coming out of solution, were pumped from the top of the gas separator through a quadrupole mass spectrometer (Pfeiffer Vacuum Technology Inc., Nashua, New Hampshire) analyzer and a Gem 2000 Landfill Gas analyzer (CES-Landtec, Coltron, California). Both instruments were used to analyze gas compositions, with the Gem 2000 device intended to provide immediate estimates of the methane, oxygen, and CO_2 compositions. The analysis cycle was the only sampling step that was not fully automated, since the quantity of exsolved gas was expected to be highly variable throughout the test. The analyst was required to manually open the analysis manifold to prevent the accidental loss of sample during the analysis process, a critical step, deemed important enough to warrant the undivided attention of the analyst to prevent the accidental loss of data. A 500 cm^3 five-layer aluminized sampling bag (Calibrated Instruments, Hawthorne, New York) was filled, so that if replicates of analysis on the mass spectrometer were needed, they could be performed at a later time.

[26] The eighth and final step in the sampling process was to purge the remaining water from the U-tube prior to repeating the entire sampling process (steps 1–8) again. This process was performed in parallel with the gas analyses. Immediately following the closure of the sample manifold (step 6), water traveling up the U-tube was diverted back to the vent manifold and out the atmospheric vent to the drain. Periodically, the purged fluid was diverted to collection tanks. In several instances the 20 to 25 L of fluid were filtered through 0.1-μm filters, and the filters were analyzed for any CO_2 induced changes in microbial biomass. Nitrogen gas was swept through the U-tube for ~15 min to remove residual water. Both the vent manifold and high-pressure gas supply manifolds were closed at the end of the U-tube purge cycle.

[27] Automated control of the U-tube sampler worked flawlessly using solenoid actuated valves until the CO_2 began to enter the observation well in large quantities. As the quantity of CO_2 increased, Joule-Thomson cooling of the CO_2 as it travel through restrictive valves would cause the brine to freeze in the vent manifold, thus blocking the outlet. The sampler had to be shut down and allowed to thaw before sampling resumed in the manual operating mode. The CO_2 eventually completely displaced the brine in the well, changing the composition of the U-tube samples from a mixture of brine and gas to all CO_2 gas. Freezing problems became less severe when the system became self-lifting, meaning that the pressure of the CO_2 gas was sufficient to push or lift it from the test interval via the U-tube to the surface. Thus nitrogen gas was no longer needed to lift the sample.

[28] Changes were made to the sampling process and a new automated program was written to optimize CO_2 gas production when the well became self-lifting. Only the bleed-down (step 3), sampling (step 6), and analysis (step 7) cycles were retained; the remaining sample processes were no longer needed. The new sampling process essentially consisted of repeatedly filling and emptying the sample vessels of well bore fluid, predominantly CO_2. The automation program was modified so that the sampling (i.e., fill) cycle ended, and the bleed-down cycle began, when the gas pressure in the sample vessel exceeded 48 bars. Likewise, the bleed-down cycle ended, and the fill cycle began, when the pressure dropped below 7 bars. Lowering the pressure of the gas from 150 bars downhole (where it is in the supercritical state) to 48 bars in the sample vessels helped prevent freezing at the outlet, allowing much smoother operation of the system. Eliminating the sampler (step 2) and U-tube (step 8) purge steps using nitrogen gas, coupled with the pressure-controlled cycling noted above, meant that the sample vessels were always filled with fluid from the well. The sampling process took ~11 min and served to continuously "pump" the well. Gas composition was continuously monitored by

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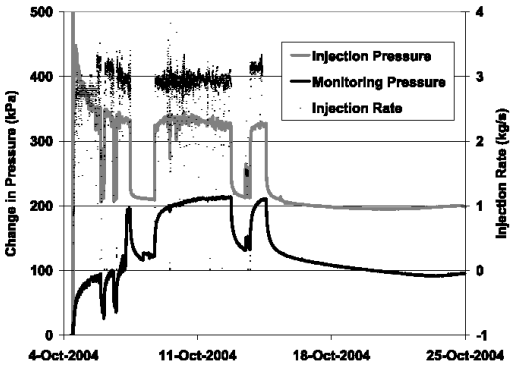

Figure 4. Changes in bottom hole pressures and injection flow rate measured during the Frio CO_2 sequestration experiment. The sharp midinjection pressure declines correspond to pauses in the injection.

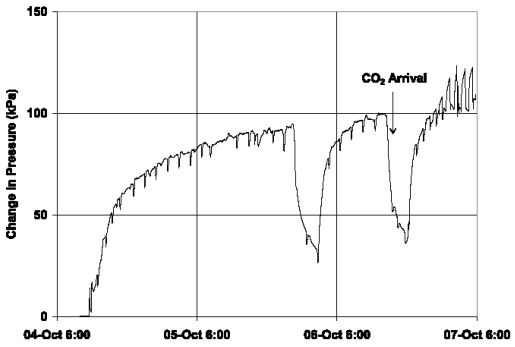

Figure 5. Short transitory pressure fluctuations associated with U-tube sampling events are apparent in the observation borehole bottom hole pressure. After CO_2 arrival the pressure transients became longer in duration and greater in amplitude.

feeding gas into the mass spectrometer in parallel with the fill and bleed-down cycles.

4. Results

[29] The Frio Brine Pilot experiment resulted in the injection of ~1600 t of food-grade CO_2 over a period of 10 days. CO_2 injection started on 4 October 2004 at 1134 UT, at a rate of ~3 kg/s. Figure 4 shows changes in the bottom hole pressure for the Frio injection well and observation well, along with the CO_2 injection rate. The two pressure declines that occurred on 5 October at 2230 UT and on 6 October at 1430 UT were pauses in CO_2 injection caused by problems in an injection booster pump. The two longer pauses in injection that occurred on 7 October at 1143 UT until 8 October at 1814 UT and 12 October at 1803 UT until 13 October at 1756 UT were performed to observe pressure transients and perform geophysical logging. Injection was halted on 14 October at 1413 UT, and the final pressure fall off was monitored until 29 October at 1230 UT.

[30] The U-tube collected 41 brine or brine/supercritical CO_2 samples between the start of the initial injection and 7 October at 1124 UT. Short-duration pressure transients in the observation zone corresponding to the U-tube sample times are shown in Figure 5. After the CO_2 arrival, the pressure transients became greater in duration and amplitude as a result of the increased fluid compressibility from two-phase conditions. As noted previously, increasing concentrations of CO_2 made sampling problematic, because Joule-Thomson expansion would cool valves and the brine would freeze. The U-tube sampling protocol was subsequently modified to accommodate the self-lifting borehole fluid as described in section 3. The U-tube was operated in self-lifting mode until 11 October at 1513 UT, when the automated analysis equipment on the surface was shut down and demobilized. During this later period of gas sampling, the mass spectrometer analyzed 327 samples. The U-tube was subsequently closed at the surface and available for periodic monitoring. Geophysical logging, performed after CO_2 injection, required the removal of all downhole equipment and the U-tube was permanently withdrawn from the well bore.

[31] The mass spectrometer analysis of the gas evolved from the pressurized samples is shown in Figure 6. The gas compositions were corrected for nitrogen in the sample tubes, which was assumed to be residual from the system purge procedure. Calibration inaccuracies and the nitrogen correction procedure resulted in a total gas composition of the primary constituents that does not always sum to 100%, and in a few cases varied significantly. While a more detailed gas chemistry analysis was performed on several samples to verify the accuracy of the field measurements and quantify the higher hydrocarbons, performing laboratory analysis on all samples collected would be cost prohibitive and would not have resulted in significant changes to the overall data set.

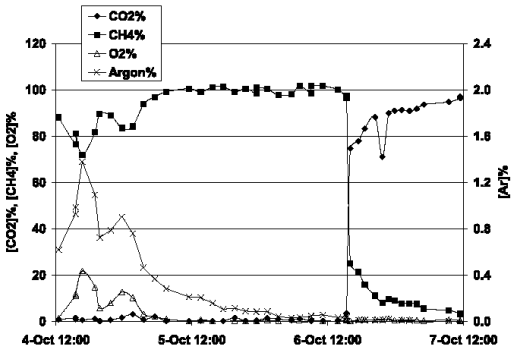

Figure 6. Analysis of gas composition in U-tube samples measured using a quadrupole mass spectrometer. The gas composition changes drastically after the CO_2 arrived in the observation well, with methane being displaced as the predominant component. The oxygen and argon reveal contamination of the formation that occurred during the sampling string installation.

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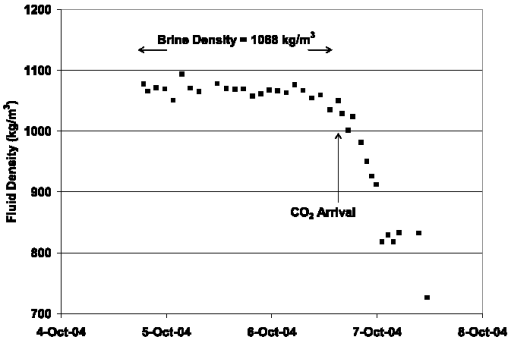

Figure 7. Fluid density measured in the U-tube samplers using strain gauges mounted below each high-pressure sampling cylinder. The arrival of CO_2 is marked by a decrease in sample fluid density, which declines until the fluid is almost all supercritical CO_2.

[32] Figure 6 shows the first sample confirming the arrival of the CO_2 was collected 50.9 hours after the start of injection, on 6 October at 1428 UT. While previous samples contain less than 1% CO_2, this sample contains 3.6% CO_2. The CO_2 concentration steadily increased throughout the next day of sampling, as CO_2 replaces CH_4 as the primary gaseous constituent in the sample stream. The oxygen and argon content in the early samples suggests contamination of the formation fluid caused by the introduction of surface water during the well bore completion, prior to injection of CO_2. Despite the well being produced using nitrogen lift in an attempt to remove this fluid, the continuing presence of oxygen and argon serves as a geochemical tracer, indicating the persistence of nonnative fluid in the formation.

[33] Figure 7 shows the density of the fluid collected in the high-pressure cylinders. The weight measurement was recorded when the sample cylinders reached the formation pressure of 146.3 bars. Note that supercritical CO_2 at 33°C and 146.3 bars has a density of 830 kg/m^3, which closely matches the values measured for four of the last five samples acquired. This agrees with the gas composition analysis, which indicated that the sample was almost entirely composed of CO_2. However, as noted earlier, the placement of the U-tube sampling inlet above the perforations in the well bore may have preferentially weighted the fluid samples toward the lighter CO_2.

[34] Three chemical parameters, electrical conductance, pH, and alkalinity, measured at the site immediately after sample collection from the observation well using the U-tube are shown in Figure 8. Results revealed that the electrical conductance was constant throughout the experiment at ~120 mS/cm (at T = 21–23°C), but there were major changes in the composition of recovered brine as the CO_2 reached the observation well, including a sharp drop in pH (from 6.7 to 5.7) and sharp increases in alkalinity (from 100 to 3000 mg/L as bicarbonate), as shown in Figure 8, and (not shown in Figure 8) dissolved Fe (from 30 to 1100 mg/L). The chemical data measured at the site at the start of the CO_2 injection were so close to the values obtained for brine samples collected using a downhole Kuster sampler from both the injection and the observation wells before CO_2 injection that we decided it was redundant to deploy the Kuster sampler downhole at the same time that the U-tube was operating.

[35] Water collected using the U-tube, the Kuster sampler, and other tools were subjected to detailed chemical analysis in the laboratory, using the methodologies described by *Kharaka and Hanor* [2004]. Results showed that the unmodified Frio brine was a Na-Ca-Cl-type water, with a salinity of 93,000 mg/L TDS, and with low Br/Cl ratios (indicating dissolution of halite from the nearby salt dome). The unmodified brine is close to saturation with methane, comprising ~95% of total dissolved gas at subsurface conditions (63°C and 143 bars). Results of geochemical modeling indicated that brine pH would have dropped lower than the measured value of 5.7, but for the fact that carbonate and iron oxyhydroxide minerals in the Frio were dissolving rapidly, causing the major increases in alkalinity and dissolved Fe [*Kharaka et al.*, 2005].

[36] Tracers were injected into the CO_2 injection stream at three different times (Table 1). The purpose of the tracer injections was twofold: first, arrival times are indicative of the formation CO_2 saturation and, second, differences in the travel times of tracers with different brine/CO_2 partitioning coefficients provide an estimate of the residual brine saturation. The first tracer injection consisted of a 5-hour-long injection pulse of PFTs, consisting of 1.55 kg perfluoromethylcyclohexane (PMCH) and 1.55 kg perfluorotrimethylcyclohexane (PTCH), on 4 October at 1326 UT, 2 hours after the initial CO_2 injection. A second tracer injection, consisting of 150 g perfluoromethylcyclobutane (PMCB) and 150 g perfluorodimethylcyclohexane (PDCH), was injected on 8 October at 1819 UT. The last tracers, injected beginning October 9 at 1137 UT, consisted of a suite of 83.80 g krypton, an undetermined (caused by pumping problems) quantity of sulfur hexafluoride (<200 g), 150 g PMCH, and 150 g PTCH tracer. Figure 9 shows the initial PFT breakthrough plotted along with the CO_2 concentration as a percent of gas recovered in the sample, and Figure 10 shows

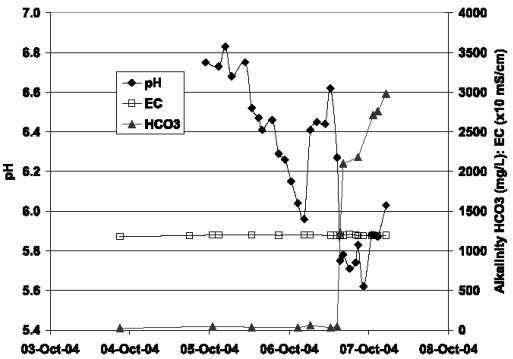

Figure 8. Electrical conductance, pH, and alkalinity of water samples collected with U-tube. Note the essentially constant conductance of ~120 mS/cm but the major drop in pH and increase of alkalinity as the CO_2 reached the observation well.

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Table 1. Tracer Injection Times and Arrival Times for the Frio Brine Pilot Experiment

Component[a]	Mass Injected	Injection Time: Date/Time, LT	Injection Time: Relative Time,[b] hours	Injection Duration, hours	Arrival Time: Date/Time, LT	Arrival Time: Relative Time,[b] hours	Peak Time: Date/Time, LT	Peak Time: Relative Time,[b] hours	Travel Time,[c] hours
CO_2	3 kg/s[d]	4 Oct/1134	(0.00)	N/A	6 Oct/1428	(50.90 + 0.0/−2.0)	N/A		50.9 + 0.0/−2.0
PMCH, PTCH	3.1 kg	4 Oct/1326	(1.87)	3.9	6 Oct/1428	(50.90 + 0.0/−2.0)	6 Oct/1520	(51.8 ± 0.9)	48.0 ± 0.9
PMCP, PDCH	0.3 kg	8 Oct/1819	(102.75)	1.0	10 Oct/1532	(147.97 ± 0.5)	10 Oct/2252	(155.3 ± 0.5)	50.22 ± 0.5
PMCH, PTCH	0.3 kg	9 Oct/1137	(120.05)	1.0	11 Oct/1142	(168.13 ± 0.5)	11 Oct/1836	(175.03 ± 0.5)	52.67 ± 0.5
SF_6	<200 g[e]	9 Oct/1137	(120.05)	0.58	11 Oct/1026	(166.87 ± 0.5)	11 Oct/1822	(174.80 ± 0.5)	52.63 ± 0.5
Kr	83.8 g	9 Oct/1239	(121.08)	0.13	11 Oct/1037	(167.05 ± 0.5)	11 Oct/2001	(176.45 ± 0.5)	53.47 ± 0.5

[a]PMCH, perfluoromethylcyclohexane; PTCH, perfluorotrimethylcyclohexane; PMCP, perfluoromethylcyclopentane; PDCH, perfluorodimethylcyclohexane.
[b]Values in parentheses are relative time to the start of the test, in hours.
[c]CO_2 travel time measured from first injection to first arrival, all other travel times measured as mean injection time subtracted from peak arrival time. Travel time for 8 October and 9 October injection have 110 min subtracted to account for travel time up the U-tube.
[d]The CO_2 injection was continuous, so the mass injected is given as a rate. All other tracers were injected over a short time period.
[e]Problems with the injection pump prevented an accurate determination of the quantity of SF_6 injected.

the tracer gas breakthrough for the second PFT injection and third suite of tracers as determined by quadrupole mass spectrometer analysis.

5. Discussion

[37] The U-tube downhole installation, depending upon a single check ball for operation, proved to be extremely reliable. The large surface area of the sintered metal filter and small pore size protected the check valve from particulates that could cause the ball from seating properly. Furthermore, cyclical testing of the check valve in both the check and flow directions at operational pressures was performed prior to installation, to minimize potential mechanical failures.

[38] In contrast to the reliable performance of the downhole system, the surface installation required oversight and maintenance. The inlet pressure of the nitrogen compressor needed to be maintained within a narrow band to prevent either starving the compressor or creating an overpressure condition. Tuning the LN storage tank, vaporizer, and pressure regulators, to maintain stable operating conditions with minimal user oversight, was necessary during the first two days of operation. The compressor created some difficulties because of the vibration it transmitted throughout the sampling system. In retrospect, vibration-isolating components would have reduced valve maintenance issues. Finally, the high concentration of supercritical CO_2 required heat to be applied to critical venting valves to prevent them from icing. Heat was applied using halogen lamps and heat guns; however, as the amount of supercritical CO_2 rose to almost 100% of the sampled fluid, adding enough heat to keep fluids moving slowed the sampling operation.

[39] A compilation of the travel times for the CO_2 and gaseous tracers is shown in Table 1. Table 1 includes the initial arrival time and peak arrival time, calculated based on the estimated time of entry into the U-tube sampler, and not when the sample was collected at the surface. To obtain the travel time for the CO_2 plume, the time at the start of injection is subtracted from the initial arrival. The travel time for the tracers has been calculated as the mean injection time subtracted from the peak arrival time.

[40] A simple radial flow model can be used to estimate CO_2 saturation using the tracer travel time. If we neglect buoyancy and assume the CO_2 flow field can be represented by a uniform radial disk with a formation thickness of 6.1 m

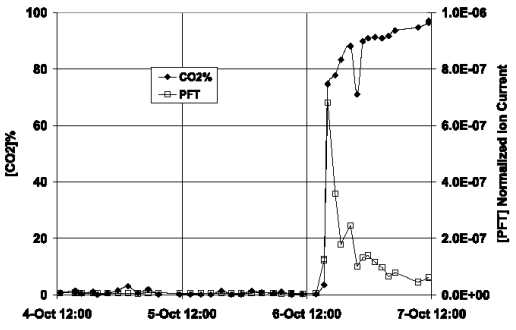

Figure 9. Initial breakthrough of the CO_2 plume and the PFT tracer breakthrough. CO_2 is measured as a percent of total gas recovered, and the PFT tracer concentration is mass spectrometer ion current normalized to total mass current.

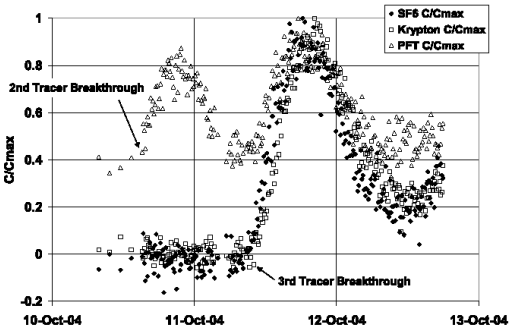

Figure 10. Tracer breakthrough curves for the second and third tracer injections. Note that PFT starting concentration is nonzero because of prior use of PFT tracers.

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and a porosity of 0.35, we can estimate the CO_2 saturation as

$$S_{CO_2} = \frac{Qt}{\pi r^2 l \phi_f}$$

where Q is the volumetric injection rate, t is the mean arrival time, r is the distance from injection borehole to observation borehole, l is the formation thickness, and ϕ_f is the formation porosity. CO_2 saturation in the formation pore space when the CO_2 front initially reached the observation well was 15.6%, based on the initial PFT tracer arrival. The formation saturation increased to 16.3% and 17.1% for the second and third tracer tests, respectively.

[41] It should be noted that while CO_2 occupied roughly 15% to 20% of the formation pore space, the sampled fluid contained nearly 100% CO_2. This occurs for two reasons: (1) the mobility of the low-viscosity supercritical CO_2 is much greater than the brine, and (2) the sampling system inlet location above the borehole perforations preferentially samples the less dense supercritical CO_2 phase within the borehole. As noted earlier, the location of the sampling system above the perforations was a compromise to facilitate application of downhole logging tools and was not viewed as optimal for geochemical analysis. However, the slow changes in CO_2 saturations, as estimated from the tracer arrival times, indicate that the CO_2 had established relatively stable preferred transport pathways and is primarily bypassing the relatively stagnant brine.

6. Conclusion

[42] The demands of the Frio Brine Pilot experiment for multiphase geochemical samples, specifically the need for (at most) minimal disturbance of the flow field, placed very stringent requirements on the sampling system. The U-tube was able to provide frequent high-quality 52 L samples from the 1.5 km deep observation borehole at formation pressure. The sampling and tracer test data collection could not have been accomplished through more commonly deployed systems such as submersible pumps or downhole samplers. The samples obtained during the Frio Brine Pilot experiment are anticipated to provide a wealth of information, shedding light on the geochemical and physical processes affecting sequestration of CO_2 in deep brine-filled formations.

[43] The U-tube sampling system could see use in other applications requiring representative geochemical samples. Monitoring and verification programs for both CO_2 sequestration and geologic storage of radioactive wastes are anticipated to span many decades. The U-tube is an attractive solution for long-term sampling requirements, because of its simplicity and high reliability. Since the U-tube system provides high-quality samples under two phase conditions, it is a potentially valuable tool for fluid sampling needed for understanding the state of geothermal systems. In geothermal systems, corrosive downhole conditions and high temperatures make a U-tube constructed of corrosion resistant alloys an attractive alternative to specialized downhole samplers. The deployment of sampling systems, utilizing either multiple sample points within a single boring or multiple points throughout a dispersed well field, is practical because of the low cost of the U-tube downhole equipment.

[44] **Acknowledgments.** This work was supported by the Assistant Secretary of the Office of Fossil Energy, U.S. Department of Energy, National Energy Technology Laboratory under contract DE-AC03-76SF00098. The authors are grateful to Curtis Oldenburg and anonymous reviewers for providing careful reviews of this manuscript.

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U-tube Sampling

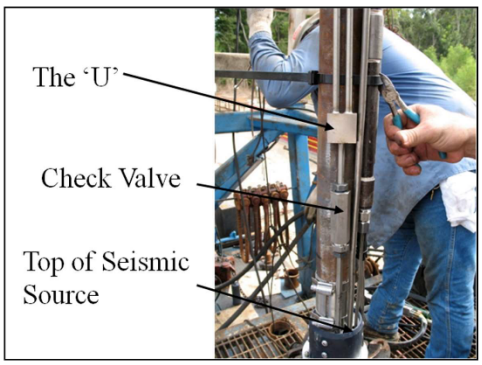
The U-tube provides representative aliquots of downhole fluids using a positive gas displacement pump driven with N_2. The benefits of U-tube sampling as compared to conventional wireline sampling approaches is that the U-tube is permanently deployed in the well and can be repeatedly operated over long periods of time without mobilizing equipment to the field or interfering with well operations.

Outline

- U-tube Sampling system overview
- Track record
- Contingencies
- Operational considerations

U-Tube Sampling – provides minimally disturbs aliquots of downhole fluid. Ideal for multiphase sampling such as CO_2 and brine

- Down-hole check valve permits fluid entry into a loop of stainless steel tube
- Fluid driven to surface with compressed ultra-pure N_2
- Large volume sample (~10-100 liters) at formation pressure
  - No degassing
  - Isolated from O_2 & contaminants
- When system becomes self-lifting, N_2 drive is no longer needed
- The U-tube can be deployed on tubing or behind casing



How the U-tube Operates

Step 1 – Vent drive and sample leg to atmosphere
Step 2 – Sample and drive leg will fill to hydrostatic
Step 3 – Apply N_2 to drive leg and force fluid up. Check valve closes
Step 4 – Collect fluid from sample leg
Step 5 – Continue to purge U-tube loop until it is free of fluid and ready to refill –

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B. Freifeld, Class VI Solutions, Inc.

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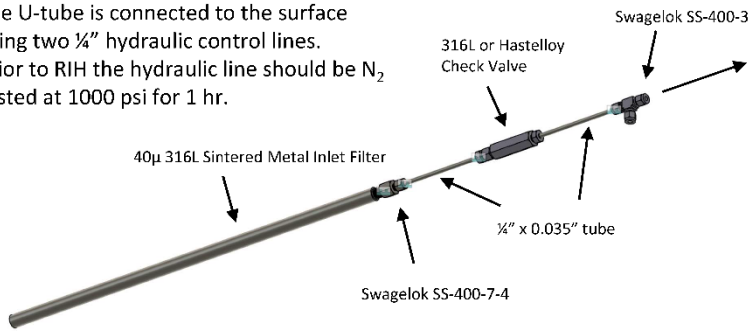
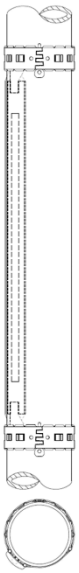
U-tube BHA

- The U-tube is connected to the surface using two ¼" hydraulic control lines.
- Prior to RIH the hydraulic line should be N_2 tested at 1000 psi for 1 hr.



- A Cannon Services or equivalent clamp protects the U-tube BHA during RIH.
- The U-tube can be tested anytime >24 hours after cementing is completed using a cylinder of compressed N_2. The wait time is to ensure that small particulates have had time to settle prior to pulling fluid into the U-tube.



CLASS VI SOLUTIONS

Dedicated monitoring well for meeting EPA Class VI requirements

- No perforations to eliminate potential leakage pathway
- Ability to perform periodic corrosion and cement evaluation logging of injection interval
- Pulsed neutron logging for CO_2 saturation in injection interval
- Microseismic monitoring of entire vertical section
- Potential indirect 4D Seismic VSP acquisition
- Pressure monitoring at bottom of the confining zone
- Pressure monitoring at top of injection zone, above perforations to evaluate vertical migration
- Pressure monitoring at middle of injection zone, for improved history-matching
- Pressure monitoring below injection zone for lower dissipation zone monitoring
- Quarterly Fluid sampling of the USDW
- Quarterly Fluid sampling of upper confining formation for early warning of potential leakage
- Pressure monitoring of upper confining formation for early warning of potential leakage