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6 November 2024

SES Document No: 2024_2605-RP-01_Rev0

Andrew Ellis
Lonquist & Co. LLC
Houston, TX
E-mail: andy@lonquist.com

SUBJECT: Class VI Injection Well Metallurgy Review – Libra Project

Dear Mr. Ellis:

Stress Engineering Services, Inc. (SES) appreciates the opportunity to assist you and Lonquist & Co. LLC with metallurgy recommendations for Simoneaux CO_2 injection wells for the Lapis Energy Libra Project in St. Charles, Louisiana. Our analysis and recommendations are described in this report.

Please contact me if you have any questions.

Regards,

Adam C. Rowe, PE
Principal
Metallurgical Engineer
Phone: 281.955.2900
E-mail: adam.rowe@stress.com
Texas Registered Engineering Firm F-195

1. Background

Stress Engineering Services, Inc. (SES) was contacted by Lonquist & Co. LLC to provide metallurgy recommendations for Simoneaux CO_2 injection wells for the Lapis Energy Libra Project in St. Charles, Louisiana. Well diagrams for three injection wells are shown in Appendix A. The injection interval ranges from 3,504 feet to 9,854 feet, and the deepest well of the three provided had a total depth of 9,975 feet. The top perforation is reportedly at 9,187 feet.

Lonquist provided an injectate quality specification, flow assurance modeling results, and well information for consideration in this metallurgy review. The composition restrictions in the quality specification are shown in Table 1. Additional information provided by the client is presented in Table 2.

Table 1. Injectate Quality Specification

Constituent	Unit	Value
CO_2	vol%	>97
Methane (C1)	vol%	<3
Ethane plus (C2+)	vol%	<1
H_2S	ppmw	<10
Total sulfur	ppmw	<30
O_2	ppmw	<10
Inerts (N_2, Ar, etc.)	vol%	<0.5
Water vapor	lb/MMscf	<30
Glycol	gal/MMscf	<0.3
CO	ppmw	<4250
NO_X	ppmw	<1
SO_x	ppmw	<1
Particulates	ppmw	<1
Amines	ppmw	<1
H_2	vol%	<1
Hg	ng/l	<5
NH_3	ppmw	<50
Liquids	-	Nil allowed
Compressor lube oil	ppmw	<50

Table 2. Additional Well Parameters

Parameter	Value
Tubing size	4.5 inch
Design life	20 years
Storage formation salinity	125,000 ppm TDS
Wellhead temperature (WHT)	84.9 °F
Wellhead pressure (WHP)	2520.4 psia
Flowing bottomhole temperature (BHT)	124.3 °F
Shut-in BHT	203 °F
Bottomhole pressure (BHP)	4818 psia
Injection rate	1.5 MMTA/year

2. Factors Affecting Corrosion

It is important to note that corrosion will only occur when free water is in contact with the steels and corrosion resistant alloys (CRAs). If the water remains completely soluble in the supercritical CO_2 (SC-CO_2) and there is no risk of it breaking out, then corrosion will not occur. The specified limits of less than 30 lb/MMscf water and no liquids have been used successfully for years in CO_2 pipelines and should cause minimal corrosion concerns in the tubing during normal injection. However, if upset or shutdown conditions allow water to condense, it will be very low pH and corrosive to any carbon steel exposed to this free water phase. Once the SC-CO_2 contacts the reservoir fluids, the corrosion risk can be significant depending on numerous factors such as impurities in the CO_2, temperature at the injection zone, and the chloride content of the saline reservoir.

The presence of impurities such as H_2S, SO_x, NO_x, and O_2 and their concentrations have a significant influence on corrosion in the presence of free water as well as in the injection zone. Temperature is an important parameter for defining the corrosion risk, but its impact is dependent on corresponding factors such as partial pressure of H_2S (pH_2S), partial pressure of CO_2 (pCO_2), pH, O_2 concentration, etc.

2.1 pH

Considerable work has been done at Ohio University studying the response of fresh water pH to CO_2, as shown in Figure 1. Libra SC-CO_2 conditions are off the scale of this chart, but at 4818 psi (332 bar) and 124 °F (51 °C) and above, the pH of fresh water is predicted to be 3.0 to 3.1 [1]. Therefore, any steel components exposed to free water will be exposed to low pH with no buffering. Modeling conducted by SES on similar carbon capture and sequestration (CCS) projects has shown that the pH is even lower when the SC-CO_2 is in contact with saline formation water, typically below pH 3, so the packer, tubing below the packer, and injection zone casing will need to be corrosion resistant alloy (CRA) in order to resist wall loss in these conditions.

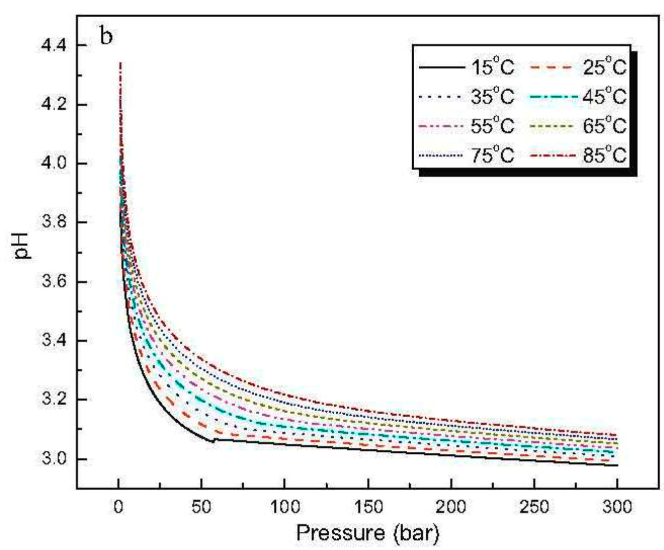


Figure 1. Variation of pH as a function of pressure and temperature.

The presence of impurities in the CO_2 such as SO_2 and NO_2 can reduce the pH further. Ayello et al. found that adding as little as 100 ppm SO_2 to SC-CO_2 at 1,099 psi and 104 °F reduced the pH another decade below that shown in Figure 1 to approximately 2.5 [2]. For the Libra Project, SO_2 and NO_2 are reportedly restricted to less than 1 ppm apiece. Such low values are not expected to significantly affect the pH in the subject wells.

2.2 Impurities

As noted above, H_2S, SO_x, NO_x, and O_2 in the SC-CO_2 stream can significantly affect the corrosivity of the water phase. SO_x and NO_x are not expected to be significant in these wells and will not be discussed further. Similarly, O_2 and H_2S are restricted to 10 ppm apiece, which are likewise not expected to have a substantial impact on corrosion. However, their potential effects warrant discussion.

Oxygen dissolves into the water phase, increasing corrosivity to carbon steels and possible pitting and crevice corrosion in CRAs. Some CRAs may be susceptible to stress corrosion cracking when oxygen is present, even if they are not otherwise susceptible in oxygen-free production environments. Only a very small amount of dissolved oxygen (10-20 ppb measured in the water phase) is needed to promote accelerated corrosion in martensitic stainless steels. Sophisticated modeling software is required in order to predict the dissolved oxygen resulting from 10 ppm O_2 in the SC-CO_2 at 4818 psia. Modeling conducted by SES for other CCS projects with similar conditions indicates that dissolved oxygen could be on the order of 200-300 ppb, so testing may be needed to qualify martensitic stainless steels for this environment.

H_2S can be a factor for steels from a cracking standpoint and possible pitting attack. NACE MR0175/ISO 15156 is at present the best guideline available to assess H_2S risk; however, it specifically only addresses cracking due to H_2S referred to as sulfide stress cracking (SSC). NACE MR0175/ISO 15156 sets a limit based on the partial pressure of H_2S at 0.05 psia, at and above which cracking may occur. For the Simoneaux wells with a BHP of 4818 psia, 10 ppm H_2S corresponds to approximately 0.05 psia pH_2S. While this would make the wells borderline sour, recent work has suggested that such low H_2S is not unusually damaging in SC-CO_2, particularly when the more accurate term fugacity (fH_2S) is used to describe the H_2S activity [3]. Furthermore, most CRA tubing and casing have historically exhibited good performance in 0.05 psia pH_2S. Therefore, H_2S is not expected to be a concern from a cracking standpoint for these wells.

The impact of hydrogen (H_2) on CRAs has not been investigated experimentally in CCS and CCUS systems, but H_2 is not expected to be of significant concern for CRA selection in most CCS and CCUS systems due to the low partial pressures (fugacities) of H_2 and low operating temperatures relative to where hydrogen degradation is normally observed. At less than 1% H_2 (<48 psia pH_2), hydrogen should not be a significant consideration for the Simoneaux wells.

2.3 Temperature and Chloride Content

In SC-CO_2 well environments, the effect of temperature on corrosion is strongly dependent on the injectate impurities and formation water chloride concentration. However, in general, the corrosivity of acidic water to well equipment increases with temperature. Based on the background information provided, the maximum flowing temperature at the bottom of the well will be 124 °F, but the shut-in BHT could be as high as 203 °F. 124 °F is a relatively low temperature that is not likely to substantially affect alloy selection, but the higher shut-in temperature of 203 °F may eliminate some candidate alloys for the injection casing.

Similarly, the corrosivity of the water phase to CRAs increases with increasing chloride content. In certain conditions, high chloride concentrations can compromise the integrity of the protective passive oxide layer. For this well, the formation water salinity is reportedly 125,000 ppm total dissolved solids (TDS). If we conservatively assume that the salinity is entirely comprised of sodium chloride (125,000 g/l NaCl), then the chloride concentration would be about 75,000 ppm, which will be used for this analysis.

3. Relevant Research Data

There continues to be a lack of reliable data for CRAs in SC-CO_2 environments. In the absence of SC-CO_2 data, the closest analogy to selecting CRAs for SC-CO_2 is from the oil and gas industry where a wealth of data resides for the various CRAs. Figure 2 and Figure 3 show typical diagrams used to initially select stainless steel CRAs based on pCO_2, temperature, and chlorides for 13Cr and 22Cr stainless steels [3].

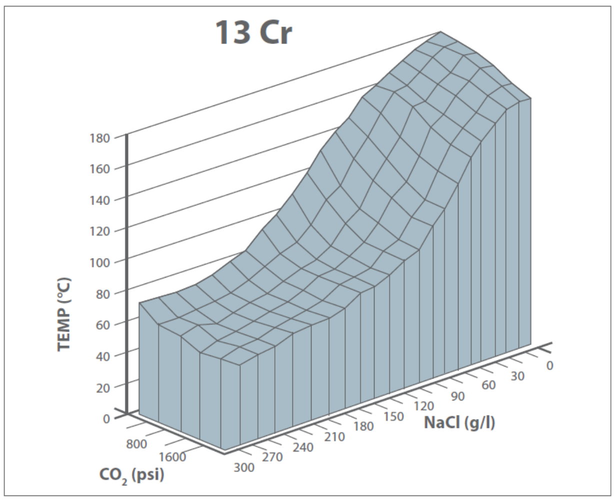


Figure 2. Envelope of acceptable conditions for L80 13Cr

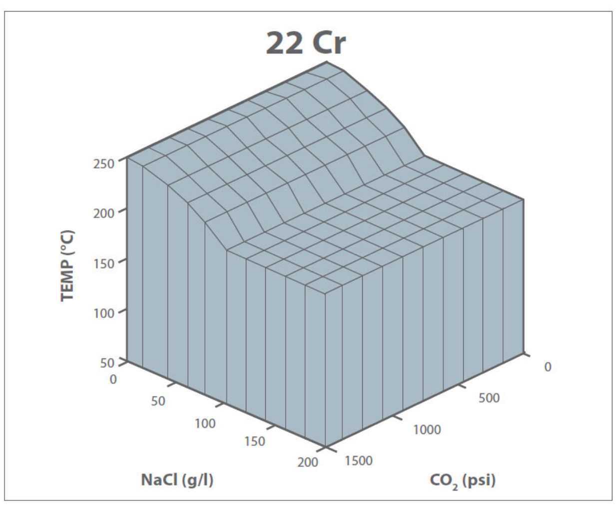


Figure 3. Limits for 22Cr stainless steel

These figures do not cover the high pCO_2 seen in SC-CO_2 systems and do not account for restrictions when H_2S and/or O_2 impurities are present. However, these guides are useful considerations for those SC-CO_2 conditions which do not include H_2S and have limited O_2 (≤ 10 ppm in the gas phase). Even in the absence of these impurities, it can be seen that 13Cr would be at risk of corrosion at the shut-in temperature of 203 °F (95 °C).

While the volume of work done on CRAs exposed to SC-CO_2 with various impurities is small compared to the significant research over the years for oil and gas, there are pertinent data that are useful to guide further selection of CRAs in SC-CO_2 in the presence of water. Most of the CRA research for SC-CO_2 has focused on the use of 13Cr stainless steel (e.g., AISI 420 martensitic stainless steel), which is generally available as API Specification 5CT Grade L80 Type 13Cr and API Specification 5CRA Group 1. The majority of this research has found plain 13Cr to be unsuitable in SC-CO_2 environments. For example, Hashizume et al. evaluated a 13Cr stainless steel in various SC-CO_2 environments with and without O_2 [5]. Immersion tests were performed at 212 °F in solutions containing 30,000 ppm chlorides at different pressures of CO_2, and 13Cr exhibited corrosion damage in all environments.

Less data is available for Super 13Cr (S13Cr), which contains nominally 5% Ni and 2% Mo, but the oil and gas industry has historically had good experience with S13Cr in various corrosive production environments. Matsuo tested S13Cr and 25Cr super duplex stainless steel (SDSS) in SC-CO_2 with impurities of SO_2 and O_2 [6]. In the absence of any impurities, the S13Cr alloy was corrosion resistant; however, for all amounts of O_2 and SO_2 tested, the S13Cr was not suitable, but the 25Cr SDSS was corrosion resistant. These tests provide helpful data, but they are limited by the low chlorides (30,000 ppm) and limited exposure durations (96 hours) used.

There are currently no independent data available publicly for 15Cr and 17Cr stainless steel in SC-CO_2 conditions at the shut-in temperature of 203 °F. The sole manufacturer of the alloy, JFE, has presented limited data, but it has not been independently verified. Kamo et al. tested 15Cr and 17Cr stainless steels in 302 °F SC-CO_2 and 121,200 ppm chlorides with 53 ppm O_2 impurities [7]. Results showed low corrosion rates and no pitting for both alloys. However, it should be noted that the test duration of 168 hours is not considered sufficient to predict long term performance. Modified 13Cr, equivalent to S13Cr, pitted in similar conditions at 212 °F but did not pit when tested without oxygen.

Very few oil and gas data exist for duplex stainless steels at a pH of 3, but work by Kharusi et al. [8] tested 22Cr in simulated condensed and formation water with 170,000 ppm chlorides at pH 3.2 and a temperature of 90 °C (194 °F) and found it to be resistant to pitting. Unpublished work by Nippon Steel has shown that 22Cr is corrosion resistant in SC-CO_2 up to 212 °F, but these tests only considered 5% NaCl (30,000 ppm chlorides) in the formation brine [9].

Although public data are limited, SES has access to some inhouse test data and substantial experience with these alloys that can be considered for guidance. SES experience indicates that 25Cr, as specified on the proposed well diagrams, should be suitable in Simoneaux conditions.

4. Discussion and Recommendations

The reported conditions for Simoneaux injection wells are relatively mild with respect to chemistry. The impurities associated with increased risk to well equipment – H_2S, SO_x, NO_x, H_2, and O_2 – are restricted to 10 ppm or lower in the CO_2 injectate. Likewise, the 75,000 ppm chlorides estimated to be in the formation brine is moderate compared to many of the storage formations used for CCS. The flowing BHT of 124 °F is also mild, but the shut-in BHT of 203 °F will be the limiting parameter for material selection.

Based on the available test data and SES experience, 25Cr super duplex stainless steel would be adequate for downhole tubulars in contact with injectate/storage fluids as well as packer and valve bodies if the strength is sufficient. 22Cr is likely acceptable for downhole tubulars, but there are no data supporting its use in contact with SC-CO_2 and 75,000 ppm chloride brine at 203 °F.

The data that have been published by JFE for 15Cr and 17Cr alloys are encouraging for this application. However, given that the tests were only for short exposure durations and results have not been independently verified, testing is recommended before selecting these alloys for injection wells.

Similarly, JFE data shows that two Modified 13Cr alloys (13Cr-4Ni-1Mo and 13Cr-5Ni-2Mo) are resistant to corrosion in SC-CO_2 and 121,200 ppm chloride brine 212 °F when no impurities are present, but both alloys experience pitting when 50 ppm O_2 is added to the SC-CO_2. This is consistent with Nippon Steel data that shows S13Cr to be corrosion resistant at 212 °F but susceptible to pitting when various impurities are present. This suggests that S13Cr may be a marginal selection at a shut-in BHT of 203 °F, so it cannot be recommended at this time without additional testing.

It is clear from the available test data and SES experience that plain 13Cr is not suitable for equipment expected to be in contact with the injectate and liquid water.

Table 3 provides metallurgy recommendations and comments for the Simoneaux injection wells. The 25Cr material called out in the proposed well design shown in Appendix A is suitable for the injection zone casing. The L80 casing called out above the upper confinement zone (UCZ) should also be suitable so long as the external cement is sound and internal annular fluids are well maintained. However, the L80 casing toward the bottom of the well where the perforations are planned will be susceptible to corrosion if in contact with the injectate and formation water. Assessing the risk of lower casing damage to well integrity and operability is outside the scope of this review and should be considered by the owner/operator. The L80 tubing above the packer is acceptable so long as there is no water condensation or formation water backflow. Otherwise, CRA would be required to resist corrosion.

Corrosion resistant alloy packers and safety valves are commonly made of S13Cr, 25Cr, and precipitation-hardened nickel-base alloys (i.e., 718, 925, and 725). The packer alloy is recommended to be similar to the casing across the injection zone (25Cr) unless greater strength is needed, in which case Alloy 925 or Alloy 718 is recommended.

The primary components of the tree/wellhead are the lower master valve, the tubing hanger, tubing head and tubing head adapter. Like with the tubing, the corrosion concern in the tree is the periodic formation of liquid water. If water dropout is infrequent, and since there is only 10 ppm or less H_2S in the CO_2 stream (this gives a partial pressure of H_2S less than the 0.05 psia threshold required for ISO 15156 compliance), this equipment can be made to API 6A Class BB except for the lower master valve which should be Class CC. For tubing hangers, it is common to use the same or comparable metallurgy as the tubing alloy.

Table 3. Metallurgy Recommendations for Simoneaux Injection Wells

Equipment		Recommended Alloys	Comments
Casing	Across the Injection and Upper Confining Zone (UCZ)	25Cr SDSS	22Cr is likely suitable but lacks data S13Cr, 15Cr, and 17Cr could be suitable if qualified by corrosion testing
	Above the UCZ	API 5CT Grade L80	
Tubing	Above the packer	API 5CT Grade L80	Carbon steel is acceptable as long as there is no water condensation or formation water backflow
	Below the packer	N/A	No tailpipe shown in the well diagrams
Packer and safety valve		25Cr SDSS Alloy 925 or Alloy 718 if greater strength is needed	S13Cr could be suitable if qualified by corrosion testing
Wellhead/Tree		API 6A Class BB or CC	Class CC if frequent water dropout is expected
Tubing hanger		API 6A Class BB or CC	
Lower master valve		API 6A Class CC	

5. References

1. Y.S. Choi and S. Nesic, “Determining the corrosive potential of CO_2 transport pipeline in high pCO_2–water environments”, Int. J. of Greenhouse Gas Control, vol. 5, p. 788, 2011.
2. F. Ayello et al., “Effects of Impurities on the Corrosion of Steel in Supercritical CO_2”, Corrosion 2010, Paper No. 10193, NACE, 2010.
3. B. Craig et al., “A Limited Evaluation of the Applicability of NACE MR0175/ISO 15156 H_2S Limits to Supercritical CO_2 Pipelines”, Corrosion J. vol. 80, p. 922, 2024.
4. B. Craig and L. Smith, “Corrosion Resistant Alloys (CRAs) in the oil and gas industry – selection guidelines update,” Nickel Inst. Pub 10073, 2011.
5. S. Hashizume et al., “Corrosion Performance of CRAs in Water Containing Chloride Ions under Supercritical CO_2”, Corrosion 2013, Paper No. 2264, NACE, 2013.
6. D. Matsuo et al., “Corrosion Resistance of Super Duplex Stainless Steel for CCS Usage under Supercritical CO_2 Conditions with Impurity Gas”, Corrosion 2022, No. 17602, NACE, 2022.
7. Y. Kamo et al., “Corrosion Behavior of Martensitic Based Stainless Steels in Chloride Solutions Saturated with CO_2 Containing Impurity Gases”, Corrosion 2023, Paper No. 18908, AMPP, 2023.
8. A.A. Kharusi et al., “New Material Application Limits of Duplex Stainless Steel in Sour Service,” NACE CORROSION 2019, Paper No. 12814.
9. Nippon Steel Corporation Internal Bulletin.

6. Limitations of This Report

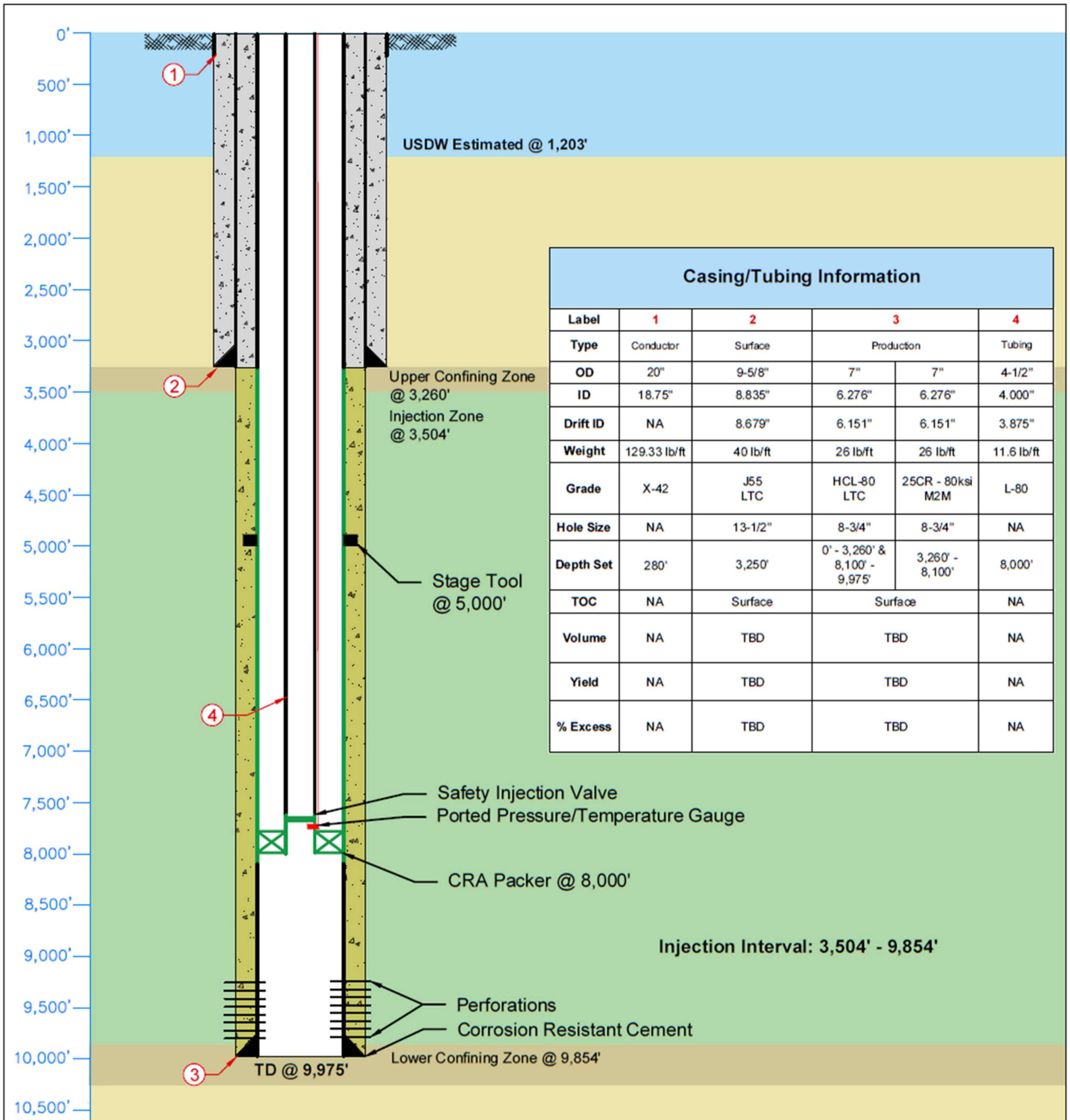
This report is prepared for the sole benefit of the Client, and the scope is limited to matters expressly covered within the text. In preparing this report, SES has relied on information provided by the Client and, if requested by the Client, third parties. SES may not have made an independent investigation as to the accuracy or completeness of such information unless specifically requested by the Client or otherwise required. Any inaccuracy, omission, or change in the information or circumstances on which this report is based may affect the recommendations, findings, and conclusions expressed in this report. SES has prepared this report in accordance with the standard of care appropriate for competent professionals in the relevant discipline and the generally applicable industry standards. However, SES is not able to direct or control operation or maintenance of the Client's equipment or processes.

7. Revision History

Document Control					
Rev	**Date**	**Description**	**Originator**	**Checker**	**Reviewer**
0	6-Nov-2024	Issued for use	Adam Rowe	--	M Miglin

Appendix A

Simoneaux Injection Well Diagrams



Casing/Tubing Information

Label	1	2	3		4
Type	Conductor	Surface	Production		Tubing
OD	20"	9-5/8"	7"	7"	4-1/2"
ID	18.75"	8.835"	6.276"	6.276"	4.000"
Drift ID	NA	8.679"	6.151"	6.151"	3.875"
Weight	129.33 lb/ft	40 lb/ft	26 lb/ft	26 lb/ft	11.6 lb/ft
Grade	X-42	J55 LTC	HCL-80 LTC	25CR - 80ksi M2M	L-80
Hole Size	NA	13-1/2"	8-3/4"	8-3/4"	NA
Depth Set	280'	3,250'	0' - 3,260' & 8,100' - 9,975'	3,260' - 8,100'	8,000'
TOC	NA	Surface	Surface		NA
Volume	NA	TBD	TBD		NA
Yield	NA	TBD	TBD		NA
% Excess	NA	TBD	TBD		NA

LONQUIST SEQUESTRATION LLC	Lapis Energy (LA Development), LP	Simoneaux CCS Injector No. 001	
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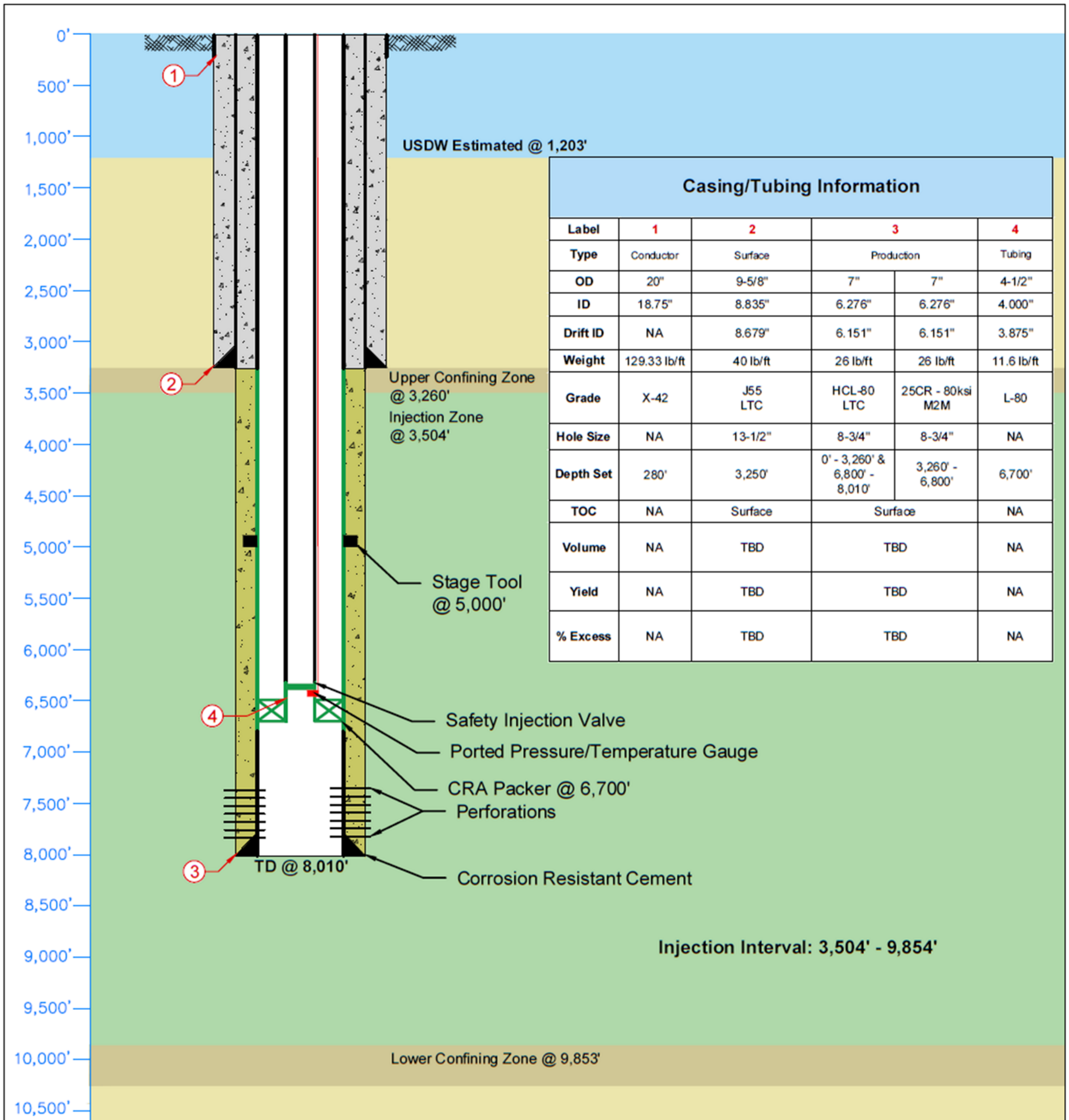
	Location: 90º 22' 17.226 W, 29º 48' 35.315" N (NAD 27)	**District:**	**Survey:**
	API No:	**Field:**	**Well Type/Status:**
Louisiana License EF-7423	**Serial No:** TBD	**Project No:** LS169	**Date:** 09/23/2024
12912 Hill Country Blvd. Ste F-200 Austin, Texas 78738 Tel: 512.732.9812 Fax: 512.732.9816	**Drawn:** Connor Lofton	**Reviewed:** Andrew Ellis	**Approved:** William H. George
	Rev No: 1	**Notes:**	



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Hole Size	NA	13-1/2"	8-3/4"	8-3/4"	NA
Depth Set	280'	3,250'	0' - 3,260' & 6,800' - 8,010'	3,260' - 6,800'	6,700'
TOC	NA	Surface	Surface		NA
Volume	NA	TBD	TBD		NA
Yield	NA	TBD	TBD		NA
% Excess	NA	TBD	TBD		NA

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Louisiana License EF-7423	**Serial No:** TBD	**Project No:** LS169	**Date:** 09/23/2024
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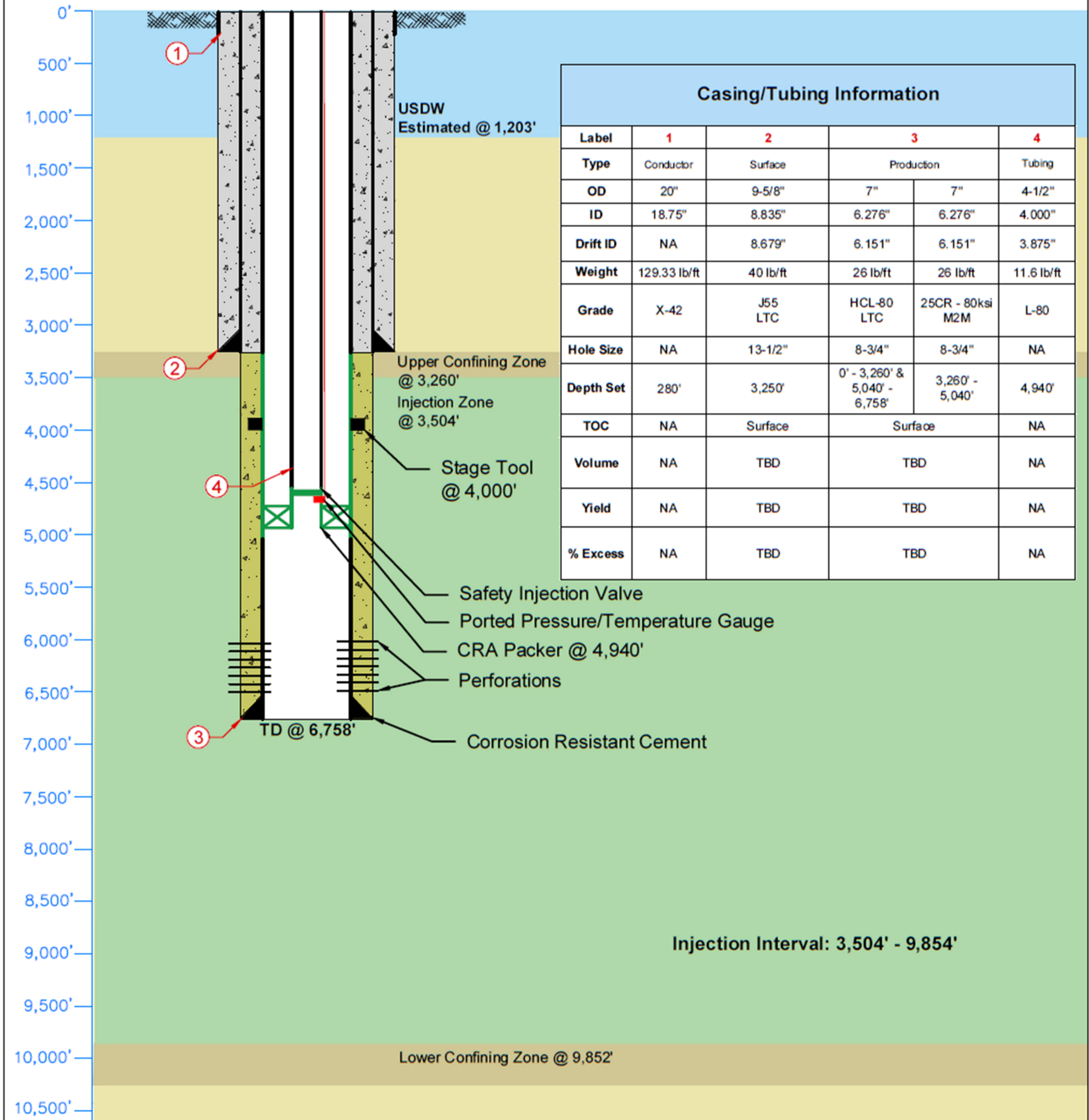

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Grade	X-42	J55 LTC	HCL-80 LTC	25CR - 80ksi M2M	L-80
Hole Size	NA	13-1/2"	8-3/4"	8-3/4"	NA
Depth Set	280'	3,250'	0' - 3,260' & 5,040' - 6,758'	3,260' - 5,040'	4,940'
TOC	NA	Surface	Surface		NA
Volume	NA	TBD	TBD		NA
Yield	NA	TBD	TBD		NA
% Excess	NA	TBD	TBD		NA

LONQUIST SEQUESTRATION LLC	Lapis Energy (LA Development), LP	Simoneaux CCS Injector No. 003	
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Louisiana License EF-7423	**Serial No:** TBD	**Project No:** LS169	**Date:** 09/23/2024
12912 Hill Country Blvd. Ste F-200 Austin, Texas 78738 Tel: 512.732.9812 Fax: 512.732.9816	**Drawn:** Connor Lofton	**Reviewed:** Andrew Ellis	**Approved:** William H. George
	Rev No: 1	**Notes:**	