SECTION 4 – ENGINEERING DESIGN AND OPERATING STRATEGY

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4.1 Introduction

The following section describes the engineering design details and operational strategies employed during the planning of the proposed Pecan Island Injection Well No. 001 and Pecan Island Injection Well No. 002. The engineering design details meet the requirements of Statewide Order (SWO) 29-N-6 **§3617.A** and Title 40, U.S. Code of Federal Regulations (40 CFR) **§146.86**.

The design, construction, and operation of injection wells fall under the jurisdiction of the EPA Underground Injection Control (UIC) program. Class VI injection wells are designed for the sole purpose of injection and storage of CO_2, safely targeted in injection zones, and contained within those zones—to ensure protection of all Underground Sources of Drinking Water (USDWs).

The Pecan Island Project is proposing wells centrally located to various surrounding industrial companies that produce CO_2 as a by-product at high levels at their facilities. The environment and these companies will benefit from capture of the CO_2 by-product and its safe and permanent injection into formations having the proper geology and rock qualities. ExxonMobil Low Carbon Solutions Onshore Storage LLC (ExxonMobil) proposes to inject CO_2 into upper and middle Miocene sands. The formation properties of this reservoir make it an excellent candidate for injection of CO_2. It is a highly porous, highly permeable, saline-filled sand zone that contains approximately 5,000 ft of gross vertical thickness of sands, interbedded with shale layers to help isolate each potential zone of injection.

The specific requirements for the design of a carbon capture and sequestration (CCS) Class VI well are described in the following sections.

4.2 Engineering Design

The primary concern for the design of a Class VI CO_2 sequestration well is to ensure the protection of the USDW from any CO_2 injectate contamination. The design parameters for such a well consider injection rates, injection volumes, fluid properties, and chemical properties of the injectate fluid.

The combination of CO_2 mixed with formation fluids and other injectate components, including H_2S, can be corrosive. As a result, a proposed CO_2 sequestration well is designed to withstand the corrosive environment to which the well components, including casing, tubing, wellhead equipment, and downhole tools, will be exposed. The engineering design also considers the cement used in the well. The cement design and products selected are designed to fill the annulus in order to create a good bond between the casing and formations and withstand the nature of the corrosive fluids. The production casing, cementing, tubing, packer, and other well components are designed to prevent the migration of CO_2 above the upper confining zone (UCZ).

The CO_2 injectate will be sequestered in the Miocene sands, bound by the upper and lower confining zones discussed in *Section 1 – Site Characterization*. Additionally, intermittent layers of shales are present throughout the injection interval and will act as additional vertical barriers. The sands in the project area are located below [redacted] thick. The sands are porous, permeable, and unconsolidated, which make them favorable for CO_2 injection and storage.

[redacted] Upon installation of the completion assembly, injection will start at the deepest sand interval per the current model plan. The CO_2 plume will be monitored during and after injection to ensure that the plume follows the model expectations. An extensive monitoring program is included in *Section 5 – Testing and Monitoring Plan*.

At the end of injection for a given zone, the injection interval will be plugged back to isolate that zone. The next injection interval will then be accessed through the screen assembly by perforating the inner string, establishing communication to the reservoir. The injectate will then be injected and sequestered into that new zone until the end of injection life for that interval. The above process will be repeated until the uppermost injection interval below the UCZ is reached, as shown in Table 4-1 and Table 4-2 for the Pecan Island Injection Wells No. 001 and 002, respectively.

Table 4-1 – Pecan Island Injection Well No. 001 Operational Strategy

Stage	Top Perf (ft)	Gross Thickness (ft)	Net Pay (ft)	Duration (yrs)
[redacted]				

Table 4-2 – Pecan Island Injection Well No. 002 Operational Strategy

Stage	Top Perf (ft)	Gross Thickness (ft)	Net Pay (ft)	Duration (yrs)
[redacted]				

[redacted]

[redacted]

This design also allows for continuous monitoring of the casing and tubing annulus to ensure wellbore and mechanical integrity are maintained.

Figures 4-1 and 4-2 show the proposed wellbore designs for the Pecan Island Project. Figures 4-3 and 4-4 show the certified well-location plats.

[redacted]

Figure 4-1 – Pecan Island Injection Well No. 001 Wellbore Schematic

[redacted]

Figure 4-2 – Pecan Island Injection Well No. 002 Wellbore Schematic

[redacted]

Figure 4-3 – Plat for Pecan Island Injection Well No. 001

[redacted]

Figure 4-4 – Plat for Pecan Island Injection Well No. 002

The drilling and completion design for the Pecan Island Injection Well No. 001 is as follows:

- Drive Pipe
  - [redacted]
- Surface Casing
  - To be set below the lowermost USDW
    - The USDW will be determined by means of open-hole logging during the drilling of the well. If necessary, the final setting depth will be adjusted.
    - The current estimated setting depth is [redacted] TVD.
  - [redacted] hole size
  - [redacted] outer diameter (OD) casing
  - Cemented to surface
- [redacted]roduction Casing
  - [redacted]
  - Cemented back to surface
    - Cement to be comprised of:
      - CO_2-compatible cement from TD through the UCZ, designed to be from [redacted]
- Injection Tubing
  - [redacted] tubing at [redacted].

- Tubing annulus will be filled with a non-corrosive fluid.
- Packer
  - [redacted]
- Wellhead
  - [redacted]

The drilling and completion design for the Pecan Island Injection Well No. 002 is as follows:

- Drive Pipe
  - [redacted]
- Surface Casing
  - To be set below the lowermost USDW
    - The USDW will be determined by means of open-hole logging during the drilling of the well. If necessary, the final setting depth will be adjusted.
    - The current estimated setting depth is [redacted]
  - [redacted]
  - [redacted]
  - Cemented to surface
- [redacted]

[redacted]

- Cemented back to surface
  - Cement to be comprised of:
    - CO_2-compatible cement blend from TD through the UCZ, designed to be from [redacted]

- Injection Tubing

[redacted]

  - Tubing annulus will be filled with a non-corrosive fluid.
- Packer

[redacted]

- Wellhead

[redacted]

A detailed drilling-and-completion prognosis is included in *Appendix D*.

4.2.1 Detailed Discussion of Injection Well Design

ExxonMobil plans to inject a maximum volume of captured carbon gas of [redacted] per year (MMTA) into each of the proposed wells. This translates to a rate of approximately [redacted]. The tubing design, including size, weight, and grade, is based on the properties of the injectate, rate of injection, and injection pressures determined during the detailed reservoir modeling. Table 4-3 shows the standard conditions of CO_2 used in the modeling and flow calculations.

Table 4-3 – CO_2 Inlet 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

*psia – pounds per square inch absolute

**lbm – pounds mass

A tubing design sensitivity was run that considered calculated pipe-friction losses, exit velocities, compression requirements, and economic evaluations. Bottomhole pressures (BHP) were calculated from detailed reservoir-engineering model runs as shown in Figures 4-5 and 4-6. The data identify when the maximum BHP occurs during the life of the project, and the resulting maximum flowing pressure at surface, allowing for proper design of the casing, tubing, and wellhead configurations.

[redacted]

Figure 4-5 – Injection Pressure Plot for Well No. 001

[redacted]

Figure 4-6 – Injection Pressure Plot for Well No. 002

For the reservoir model, a conservative value of 100% CO_2 was used for the injectate stream. The anticipated chemical composition of the pipeline CO_2 is outlined in Table 4-4.

Table 4-4 – Injectate Parameters

[redacted]

The input injection parameters from the model are shown in Table 4-5. The calculated injection parameters are shown in Table 4-6 for Well No. 001 and in Table 4-7 for Well No. 002.

Table 4-5 – Input Injection Parameters for Injection Well No. 001

Inputs	Well No. 001	Well No. 002
Max Injection Rate (MMTA)	[redacted]	[redacted]
Pressure Constraint Gradient (psi/ft)	[redacted]	[redacted]
Injection Duration (yrs)	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
Absolute Roughness Factor	[redacted]	[redacted]
Wellhead Temperature (°F)	[redacted]	[redacted]

Table 4-6 – Calculated Injection Parameters for Well No. 001

Stage	Date	Max Rate (MMT/yr)	Avg Rate (MMT/yr)	Max BHP (psi)	Avg BHP (psi)	Max WHP (psi)	Avg WHP (psi)
[redacted]							

Table 4-7 – Calculated Injection Parameters for Well No. 002

Stage	Date	Max Rate (MMT/yr)	Avg Rate (MMT/yr)	Max BHP (psi)	Avg BHP (psi)	Max WHP (psi)	Avg WHP (psi)
[redacted]							

Based on the inputs and the results from the model, [redacted] through the injection interval is the appropriate size necessary to move the desired volumes of supercritical CO_2 in each well. The model also verified that the CO_2 would remain in supercritical state in each wellbore.

Based on appropriate bit-size selection, pipe-clearance considerations, and recommended annular spacing for assurance of proper cementing, the following casing sizes are appropriate to accommodate the [redacted] completion design.

[redacted]

4.2.1.1 Drive Pipe

Because of the loose, unconsolidated nature of the sediments found immediately beneath the waterline, drive pipe will be needed to ensure that the hole integrity is maintained during the initial drilling of the Pecan Island Injection Wells No. 001 and No. 002. [redacted] drive pipe will be used to accommodate this need in both wells and driven to [redacted] blows per foot of advancement) by a hydraulic ram.

The drive pipe size was selected to facilitate the desired bit size for drilling of the surface casing borehole. A [redacted]. bit will be used to drill the next section of the well through the [redacted] of the drive pipe.

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

4.2.1.2 Surface Casing

The surface hole will be drilled below the USDW with a [redacted] bit, to casing set [redacted] for each of the injection wells. A string of [redacted] casing will be run and cemented with the casing centered in the open hole with centralizers. Being centralized, the size of the annulus chosen will provide a consistent thickness of cement between the casing and open hole. Cement will be circulated to surface. If the cement level falls after the cement is circulated to surface, a top-job will be performed if needed. This ensures a good cement bond from the surface casing shoe to surface and protects the critical USDW. After cementing, a cement bond log will be run to evaluate and verify good bonding throughout the surface hole.

Summaries of engineering calculations for the surface casing are displayed in Tables 4-8 to 4-10. The engineering calculations for both injection wells in this project were performed assuming the same wellbore conditions and setting depth for surface casing.

Table 4-8 – Surface Casing Engineering Calculations – Wells No. 001 and 002

Surface Casing – Kick Load (Burst)								
Description	**Casing Wt. (lb/ft)**	**Depth (ft)**	**Tensile (psi)**	**Collapse (psi)**	**Burst (psi)**	**Capacity (bbl**/ft)**	**ID (in.)**	**Drift ID (in.)**
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]			[redacted]	[redacted]	[redacted]			
[redacted]			[redacted]	[redacted]	[redacted]			

Surface Casing – Casing Pressure Test (Burst)								
Description	**Casing Wt. (lb/ft)**	**Depth (ft)**	**Tensile (psi)**	**Collapse (psi)**	**Burst (psi)**	**Capacity (bbl/ft)**	**ID (in.)**	**Drift ID (in.)**
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]			[redacted]	[redacted]	[redacted]			
[redacted]			[redacted]	[redacted]	[redacted]			

Surface Casing – Cementing Casing (Collapse)								
Description	**Casing Wt. (lb/ft)**	**Depth (ft)**	**Tensile (psi)**	**Collapse (psi)**	**Burst (psi)**	**Capacity (bbl/ft)**	**ID (in.)**	**Drift ID (in.)**
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]			[redacted]	[redacted]	[redacted]			
[redacted]			[redacted]	[redacted]	[redacted]			

*ppg – pounds per gallon
**bbl – barrels

Table 4-9 – Surface Casing Cement Summary

System	Top (ft)	Bottom (ft)	Cement Volume (ft³)
[redacted]			

Table 4-10 – Surface Casing Volume Calculations

Section	Footage (ft)	Capacity (ft³/ft)	Excess (%)	Cement Volume (ft³)
[redacted]				

To ensure that cement returns to surface are achieved, 100% excess of open-hole volumes were used to calculate cement volume.

4.2.1.3 Intermediate Liner

The intermediate hole will be drilled with a [redacted] above the UCZ for both wells. A string of [redacted] being centered in the open hole with centralizers. Being centralized, the size of the annulus chosen will provide a consistent thickness of cement between the casing and open hole to approximately [redacted]

Summaries of engineering calculations for the intermediate casing for the two injection wells are shown in Tables 4-11 to 4-14.

Table 4-11 – Intermediate Liner Engineering Calculations for Well No. 001

Intermediate Casing – Kick Load (Burst)								
Description	**Casing Wt. (lb/ft)**	**Depth (ft)**	**Tensile (psi)**	**Collapse (psi)**	**Burst (psi)**	**Capacity (bbl/ft)**	**ID (in.)**	**Drift ID (in.)**
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]			[redacted]	[redacted]	[redacted]			
[redacted]			[redacted]	[redacted]	[redacted]			

Intermediate Casing – Casing Pressure Test (Burst)								
Description	**Casing Wt. (lb/ft)**	**Depth (ft)**	**Tensile (psi)**	**Collapse (psi)**	**Burst (psi)**	**Capacity (bbl/ft)**	**ID (in.)**	**Drift ID (in.)**
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Pressure [redacted]			[redacted]	[redacted]	[redacted]			
[redacted]			[redacted]	[redacted]	[redacted]			

Intermediate Casing – Cementing Casing (Collapse)								
Description	**Casing Wt. (lb/ft)**	**Depth (ft)**	**Tensile (psi)**	**Collapse (psi)**	**Burst (psi)**	**Capacity (bbl/ft)**	**ID (in.)**	**Drift ID (in.)**
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]			[redacted]	[redacted]	[redacted]			
[redacted]			[redacted]	[redacted]	[redacted]			

*OBM – oil-based mud

**OH – Open Hole

Table 4-12 – Intermediate Liner Engineering Calculations for Well No. 002

Intermediate Casing – Kick Load (Burst)								
Description	**Casing Wt. (lb/ft)**	**Depth (ft)**	**Tensile (psi)**	**Collapse (psi)**	**Burst (psi)**	**Capacity (bbl/ft)**	**ID (in.)**	**Drift ID (in.)**
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]			[redacted]	[redacted]	[redacted]			
[redacted]			[redacted]	[redacted]	[redacted]			

Intermediate Casing – Casing Pressure Test (Burst)								
Description	**Casing Wt. (lb/ft)**	**Depth (ft)**	**Tensile (psi)**	**Collapse (psi)**	**Burst (psi)**	**Capacity (bbl/ft)**	**ID (in.)**	**Drift ID (in.)**
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]			[redacted]	[redacted]	[redacted]			
[redacted]			[redacted]	[redacted]	[redacted]			

Intermediate Casing – Cementing Casing (Collapse)								
Description	**Casing Wt. (lb/ft)**	**Depth (ft)**	**Tensile (psi)**	**Collapse (psi)**	**Burst (psi)**	**Capacity (bbl/ft)**	**ID (in.)**	**Drift ID (in.)**
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]			[redacted]	[redacted]	[redacted]			
[redacted]			[redacted]	[redacted]	[redacted]			

Table 4-13 – Intermediate Liner Cement Summary for Well No. 001

Section	Top (ft)	Bottom (ft)	Footage (ft)	Capacity (ft^3/ft)	Excess (%)	Cement Volume (ft^3)
[redacted]						

Table 4-14 – Intermediate Liner Cement Calculations for Well No. 002

Section	Top (ft)	Bottom (ft)	Footage (ft)	Capacity (ft^3/ft)	Excess (%)	Cement Volume (ft^3)
[redacted]						

An excess of 15% of the open-hole volumes was used to calculate cement volume.

4.2.1.4 Production Casing

The production casing, or long-string casing, is the final, permanently-cemented string of casing installed in the well. The production casing will be run from the surface to TD and cemented back to the surface. The key design criteria for the long string includes the use of:

- [redacted] from above the UCZ through the injection interval to TD;
- fiber optic cable along the exterior of the casing terminating above UCZ; and
- CO_2-compatible cement systems from [redacted] above the UCZ through the injection interval to TD.

A detailed metallurgical analysis was performed that considered the chemical composition of the injectate and downhole conditions as shown in Table 4-3 and included in *Appendix E*. The injectate stream is made up of [redacted]. Based on the analysis of the injectate stream and downhole conditions, the production casing will be [redacted] material to prevent corrosion and downhole failures, should any fluids enter the wellbore from the reservoir.

To prevent CO_2 migration out of the injection interval, CO_2-compatible cement will be run from TD to 400 ft above the UCZ, to provide a good barrier across the UCZ. By using CO_2-compatible material, the cement is protected from carbonic acid, maintaining integrity throughout the life of the project. Figures 4-1 and 4-2 (*Section 4.2*) illustrate the production casing design for both wells.

The Miocene sand for the Pecan Island Injection Wells No. 001 and Well No. 002 is approximately [redacted] thick. The sand is interbedded with layers of shale above each sand layer that will act as barriers to confine the CO_2 injectate below the UCZ. Given the unconsolidated nature of the reservoir, [redacted] The completion strategy for the wells is designed to start injection at the lowest sand interval selected. The CO_2 injectate will be injected for the predetermined amount of time or volume derived from the reservoir-injection plume modeling. When that interval has reached the predetermined time or volume, a plug will be set above that injection interval. Injection into the upper zones will be achieved [redacted] This strategy allows for an efficient and economic method for performing the work, since a workover rig is not necessary to perform the work. This process will repeat throughout the life of each well until the uppermost sand interval is completed.

Throughout the life of each well, the project will have a continual monitoring system in place. The system is designed to measure and record downhole temperatures from above the UCZ to surface, as well as to perform vertical seismic profile (VSP) surveys of the CO_2 plume, as discussed in *Section 5 – Testing and Monitoring Plan*. Monitoring systems will include a fiber optic cable with distributed temperature sensing (DTS) and distributed acoustic sensing (DAS) outside of the [redacted] The fiber optic cable will be installed above the UCZ, ending at the [redacted], and cemented into place when the casing-cementing job is performed.

The engineering and design parameters for the production casing are summarized in Tables 4-15 through 4-22.

Table 4-15 – Production Casing Engineering Calculations – Well No. 001

Production Casing – Casing Test (Burst)								
Description	**Casing Wt. (lb/ft)**	**Depth (ft)**	**Tensile (psi)**	**Collapse (psi)**	**Burst (psi)**	**Capacity (bbl/ft)**	**ID (in.)**	**Drift ID (in.)**
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]			[redacted]	[redacted]	[redacted]			
[redacted]			[redacted]	[redacted]	[redacted]			
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]			[redacted]	[redacted]	[redacted]			
[redacted]			[redacted]	[redacted]	[redacted]			
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]			[redacted]	[redacted]	[redacted]			
[redacted]			[redacted]	[redacted]	[redacted]			

Production Casing – Fully Evacuated Casing (Collapse)								
Description	**Casing Wt. (lb/ft)**	**Depth (ft)**	**Tensile (psi)**	**Collapse (psi)**	**Burst (psi)**	**Capacity (bbl/ft)**	**ID (in.)**	**Drift ID (in.)**
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]			[redacted]	[redacted]	[redacted]			

[redacted]								
[redacted]			[redacted]	[redacted]	[redacted]			
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]			[redacted]	[redacted]	[redacted]			
[redacted]			[redacted]	[redacted]	[redacted]			
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]			[redacted]	[redacted]	[redacted]			
[redacted]			[redacted]	[redacted]	[redacted]			

Table 4-16 – Production Casing Engineering Calculations – Well No. 002

Production Casing – Casing Test (Burst)								
Description	**Casing Wt. (lb/ft)**	**Depth (ft)**	**Tensile (psi)**	**Collapse (psi)**	**Burst (psi)**	**Capacity (bbl/ft)**	**ID (in.)**	**Drift ID (in.)**
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]			[redacted]	[redacted]	[redacted]			
[redacted]			[redacted]	[redacted]	[redacted]			
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]			[redacted]	[redacted]	[redacted]			

[redacted]								
[redacted]			[redacted]	[redacted]	[redacted]			
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]			[redacted]	[redacted]	[redacted]			
[redacted]			[redacted]	[redacted]	[redacted]			

Production Casing – Fully Evacuated Casing (Collapse)								
Description	**Casing Wt. (lb/ft)**	**Depth (ft)**	**Tensile (psi)**	**Collapse (psi)**	**Burst (psi)**	**Capacity (bbl/ft)**	**ID (in.)**	**Drift ID (in.)**
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]			[redacted]	[redacted]	[redacted]			
[redacted]			[redacted]	[redacted]	[redacted]			
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]			[redacted]	[redacted]	[redacted]			
[redacted]			[redacted]	[redacted]	[redacted]			
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]			[redacted]	[redacted]	[redacted]			
[redacted]			[redacted]	[redacted]	[redacted]			

Table 4-17 – Production Casing Annular Geometry

			Well No. 001			Well No. 002	
Section	ID (in.)		Top (ft)	Bottom (ft)		Top (ft)	Bottom (ft)
[redacted]							

Table 4-18 – Production Casing Specifications

						Well No. 001			Well No. 002	
Section	OD (in.)	ID (in.)	Drift (in.)	Weight (lb/ft)		Top (ft)	Bottom (ft)		Top (ft)	Bottom (ft)
[redacted]										

Table 4-19 – Production Casing Cement Summary – Well No. 001

System	Top (ft)	Bottom (ft)	Cement Volume (ft^3)
[redacted]			

Table 4-20 – Production Casing Cement Summary – Well No. 002

System	Top (ft)	Bottom (ft)	Cement Volume (ft^3)
[redacted]			

Table 4-21 – Production Casing Detail Cement Calculations – Well No. 001

Hole Section (Casing / Hole Section)	Top (ft)	Bottom (ft)	Footage	Capacity (ft^3/ft)	% Excess	Cement Volume Stage 1	Cement Volume Stage 2
[redacted]							

Table 4-22 – Production Casing Detail Cement Calculations – Well No. 002

Hole Section (Casing / Hole Section)	Top (ft)	Bottom (ft)	Footage	Capacity (ft^3/ft)	% Excess	Cement Volume Stage 1	Cement Volume Stage 2
[redacted]							

An excess of 15% of open-hole volumes was used to calculate cement volume.

4.2.1.5 Centralizers

Centralizer selection and installation for the Pecan Island Injection Wells No. 001 and 002 serve two functions. [redacted] The recommended centralizer placement for both wells is shown in Table 4-23.

Table 4-23 – Surface Casing Centralizer Program

Centralizer Type	Centralizer Frequency	Well No. 001		Well No. 002	
		Depth (ft)	Qty	Depth (ft)	Qty
[redacted]					

Centralizer placement for the [redacted] The recommended centralizer placement is shown in Table 4-24.

Table 4-24 – Intermediate Casing Centralizer Program

Centralizer Type	Centralizer Frequency	Well No. 001		Well No. 002	
		Depth (ft)	Qty	Depth (ft)	Qty
[redacted]					

Centralizer placement for the [redacted] is designed to accommodate the installation of the fiber optic cable. Clamp centralizers and eccentric centralizers, of the same alloy as the production casing, will be used to ensure that the fiber optic cable is not damaged. The recommended placement of centralizers through the production casing is shown in Table 4-25.

Table 4-25 – Production Casing Centralizer Program

Centralizer Type	Centralizer Frequency	Well No. 001		Well No. 002	
		Depth (ft)	Qty	Depth (ft)	Qty
[redacted]					

4.2.1.6 Injection Tubing

The [redacted] injection tubing size and material were selected for use in both wells based on injection volumes, rates, and injectate composition. Like the casing string, the injectate and the potential for a corrosive environment are important considerations when selecting the metallurgy of the tubing. The planned design offers protection from the potential corrosive environment of the injectate stream and potential for influx of reservoir brine. A complete summary of the metallurgical analysis is included in *Appendix E*.

Taking into consideration the possibility of a water-and-CO_2 mixture resulting in the presence of carbonic acid, [redacted] material or better is recommended for the tubing string and will be utilized. Additionally, fiber optic cable and a pressure gauge array will be run during the completion and installed across each injection interval in both wells. A single pressure and temperature gauge will be installed above the packer to monitor CO_2 injection through the tubing. Throughout the life of each well, this system will monitor all the data from all zones that will be plugged, and from each new injection zone that is completed.

Tables 4-26 and 4-27 provide the design calculations for Wells No. 001 and 002.

Table 4-26 – Tubing Engineering Design Calculations – Well No. 001

Description	Casing Wt. (lb/ft)	Depth (ft)	Tensile (psi)	Collapse (psi)	Burst (psi)	Capacity (bbl/ft)	ID (in.)	Drift ID
[redacted]								

Table 4-27 – Tubing Engineering Design Calculations – Well No. 002

Description	Casing Wt. (lb/ft)	Depth (ft)	Tensile (psi)	Collapse (psi)	Burst (psi)	Capacity (bbl/ft)	ID (in.)	Drift ID
[redacted]								

The tubing will be installed using premium connections.

4.2.1.7 Packer Discussion

The proposed packer for both wells is a [redacted] Figure 4-7 provides a schematic of the planned packer.

[redacted]

Figure 4-7 – [redacted] Packer Schematic

The packer will be run with the [redacted] injection tubing. Prior to setting the packer, the tubing annulus will be filled with a non-corrosive fluid. The packer will be set by applying surface pressure against a plug set below the packer, previously installed via slickline.

4.2.1.8 Safety Injection Valve

A safety injection valve will be installed in the [redacted] tubing. The injection valve will prevent fluid backflow into the upper completion tubing and will keep the reservoir pressurized until equilibrium is achieved. Additionally, the safety injection valve will maintain the CO_2 below the valve in a supercritical state when closed. This design will minimize cross-flow events and reduce sand influx into the wellbore. The safety injection valve will be manufactured out of a 25SCr material or equivalent, to sustain the corrosive environment.

The safety injection valve will be run on wireline [redacted] The valve is designed to the American Petroleum Institute (API) 14A standard. The operation of the valve consists of a variable orifice that actively adjusts the instantaneous injection flow to maintain a consistent low-back pressure without a flapper or flow tube.

The valve will be retrieved each time an intervention is required to isolate an injection zone or perforate the [redacted]. inner string. Figure 4-8 provides a schematic and specifications for the safety injection valve.

[redacted]

Figure 4-8 – [redacted]

[redacted]

[redacted]

[redacted]

Figure 4-9 – [redacted]

[redacted]

[redacted]

Figure 4-10 – [redacted]

Downhole Pressure and Temperature Gauge

A single pressure and temperature gauge will be run above the injection packer in both wells, to provide real-time bottomhole injection information. The gauge will be ported to the tubing only, and data will be fed to the surface using the installed TEC line.

[redacted]

Fiber Optic

In addition to the fiber optic line run on the production casing, there will be one run on the exterior of the production tubing and through the lower completion for both wells. This fiber optic line will provide a secondary DAS for plume monitoring purposes and DTS for injection conformance. In the upper completion, the DTS functionality will be used to monitor mechanical integrity of the tubing and casing.

Pressure Gauge Array

A pressure gauge will be installed across each reservoir interval to provide continuous data in real time for reservoir monitoring purposes. A TEC line will be installed on the exterior of the tubing completion to power the gauges and provide communication to surface for both wells.

4.2.1.9 Wellhead Discussion

The wellhead is designed to combat working pressures and corrosion complications. The wellhead equipment will be manufactured with a combination of stainless-steel components across the hanger and casing spool. Inconel lining will be placed across trims, stems, gates, vales, etc. The wellhead will be configured as illustrated in Figure 4-11.

[redacted]

Figure 4-11 – ExxonMobil Pecan Island Injection Wells No. 001 and No. 002 Preliminary Wellhead Design

4.3 Testing and Logging During Drilling and Completion Operations

4.3.1 Coring Plan

The drilling procedure in *Appendix D-1* discusses the coring procedures for the Pecan Island Injection Wells No. 001 and No. 002. [redacted]

Coring depths, formations, and footages for full core samples are shown in Table 4-28.

Table 4-28 – Full Core Sample Depths

Formation	Well #1 Depth (ft)	Well #2 Depth (ft)	Footage
[redacted]			

[redacted]

4.3.2 Logging Plan

An extensive suite of electric logs will be run in the open-hole sections and in each string of casing. The open-hole logging plan is detailed in Table 4-29. The cased-hole logging plan is detailed in Table 4-30.

Table 4-29 – Open-Hole Logging Plan

Section	Open Hole Logs	Well No. 001	Well No. 002
[redacted]	Gyro Survey Gamma Ray Resistivity Spontaneous Potential Caliper	[redacted]	[redacted]
[redacted]	Gyro Survey Gamma Ray	[redacted]	[redacted]

	Resistivity Sonic Caliper		
[redacted]	Gyro Survey – from measurement while drilling (MWD) Gamma Ray Resistivity Density Neutron Magnetic Resonance Elemental Capture Spectroscopy Dipole Sonic Resistivity Imaging Ultrasonic Imaging Caliper RSWC Pressure and Fluid Sampling	[redacted]	[redacted]

Table 4-30 – Cased Hole Logging Plan

Section	Cased Hole Logs	Well No. 001 (ft)	Well No. 002 (ft)
[redacted]			

*CBL – cement bond log
**GR – gamma ray
***CCL – casing collar locator
^PBTD – plugged back total depth

4.3.3 Formation Fluid Testing

Prior to setting the production casing string, samples of the formation fluid will be obtained with an open-hole fluid recovery tool. Recovery sections will be determined based on open-hole evaluations.

4.3.4 Injection Falloff / Step-Rate Test

- A non-hazardous fluid, approved by the Louisiana Department of Natural Resources (LDNR) Injection and Mining Division (IMD) will be used during the injection test.
- Injection falloff test
  - The purpose of this test is to evaluate the injectivity index, skin, and permeability (kH) of the injection interval.
  - Inject at a rate of 20,000 bbls per day (13.9 bbls per minute) for three hours. The total volume to be injected is estimated to be 2,500 bbls.
  - Shut in well and record pressure falloff for at least three hours with downhole gauges. The injection falloff test parameters are detailed in Table 4-31.

Table 4-31 – Injection Falloff Test

Injection Falloff Test (per zone)				
Duration (hr)	Rate (kbd)	Rate (bph)	Rate (bpm)	Volume (bbl)
3	20	833.3	13.9	2,500

- Step-rate injection test
  - The purpose of this test is to evaluate the fracture pressure of the injection interval.
  - Step duration
    - Minimum step duration is 5 minutes.
    - Maximum step duration is 30 minutes.
    - Actual step duration will be established based on the time required for pressure stabilization during the initial step, and this step duration will be held for all additional steps.
  - Maximum planned injection rate is 50% above the operating injection rate.
  - Attempt to record three steps below and above the fracture.
  - The proposed steps are listed in Table 4-32.

Table 4-32 – Proposed Step-Rate Injection Test

Step	Duration (min)	Rate (kbd*)	Rate (bph**)	Rate (bpm***)	Volume (bbl)
1	5	10	416.7	6.9	35
2	5	20	833.3	13.9	69
3	5	30	1,250	20.8	104
4	5	40	1,667	27.8	139
5	5	50	2,083	34.7	174
6	5	60	2,500	41.7	208
Total	30				729

*kbd – thousand barrels per day
**bph – barrels per hour
***bpm – barrels per minute

4.4 Injection Well Operating Strategy

ExxonMobil plans to inject [redacted] of CO_2 into each of the Pecan Island Project injection wells. The CO_2 will be injected and remain in a supercritical state through the life of the project. The reservoir properties of the Miocene sands with high porosity and high permeability allow for a pseudo-infinite-acting reservoir, with the ability to absorb the injected CO_2 and relieve pressure quickly. The operator parameters for the injection wells are provided in Table 4-33.

Table 4-33 – Injection Parameters

Parameter	Well No. 001	Well No. 002
Gross Injection Interval	[redacted]	
Maximum Injection Volume		
Average Injection Volume		
Maximum Increase in BHP		
Maximum Allowed Surface Pressure (90% of Estimated Fracture Gradient)		
Modeled Maximum Surface Pressure Injection		
Maximum Annular Pressure		

Surface injection pressures will be limited so that the BHP does not exceed 90% of the fracture pressure of the injection reservoir. The anticipated surface and bottomhole injection pressures and injection rates over time for the wells are shown in Tables 4-34 and 4-35.

Table 4-34 – Injection Pressures and Volumes by Stage – Well No. 001

Completion Stage	Completion Date	Top Depth (ft)	Fracture Pressure (psi)	Maximum Allowable Bottomhole Pressure (psi)
[redacted]				

Table 4-35 – Injection Pressures and Volumes by Stage – Well No. 002

Completion Stage	Completion Date	Top Depth (TVD ft)	Fracture Pressure (psi)	Maximum Allowable Bottomhole Pressure (psi)
[redacted]				

To maximize the use of the available pore space, multiple injection intervals will be used. Each discrete injection interval was selected to maximize the utilization of the pore space and collectively maximize the usage of the acreage position for CO_2 sequestration. A summary of the planned injection strategy is listed in Table 4-36 for Well No. 001 and in Table 4-37 for Well No. 002.

Table 4-36 – Injection Intervals – Well No. 001

Completion Stage	Completion Date	Injection Duration (years)	Top Depth (ft)	Bottom Depth (ft)	Net Pay (ft)
[redacted]					

Table 4-37 – Injection Intervals – Well No. 002

Completion Stage	Completion Date	Injection Duration (years)	Top Depth (ft)	Bottom Depth (ft)	Net Pay (ft)
[redacted]					

Typical densities for the injectate range from 43.8 lb/ft^3 in the shallowest injection interval to 45.7 lb/ft^3 in the deepest injection interval. This is compared to approximately 68 lb/ft^3 for the connate brine in the same formations. This density difference and the high vertical permeability in the Miocene sands allow the CO_2 to migrate vertically to the top of each discrete injection interval and laterally under the confining layer of that injection interval.

The result is a significant "mushroom cap" effect, with the top of the mushroom expanding outwardly from the injection well (Figure 4-12).

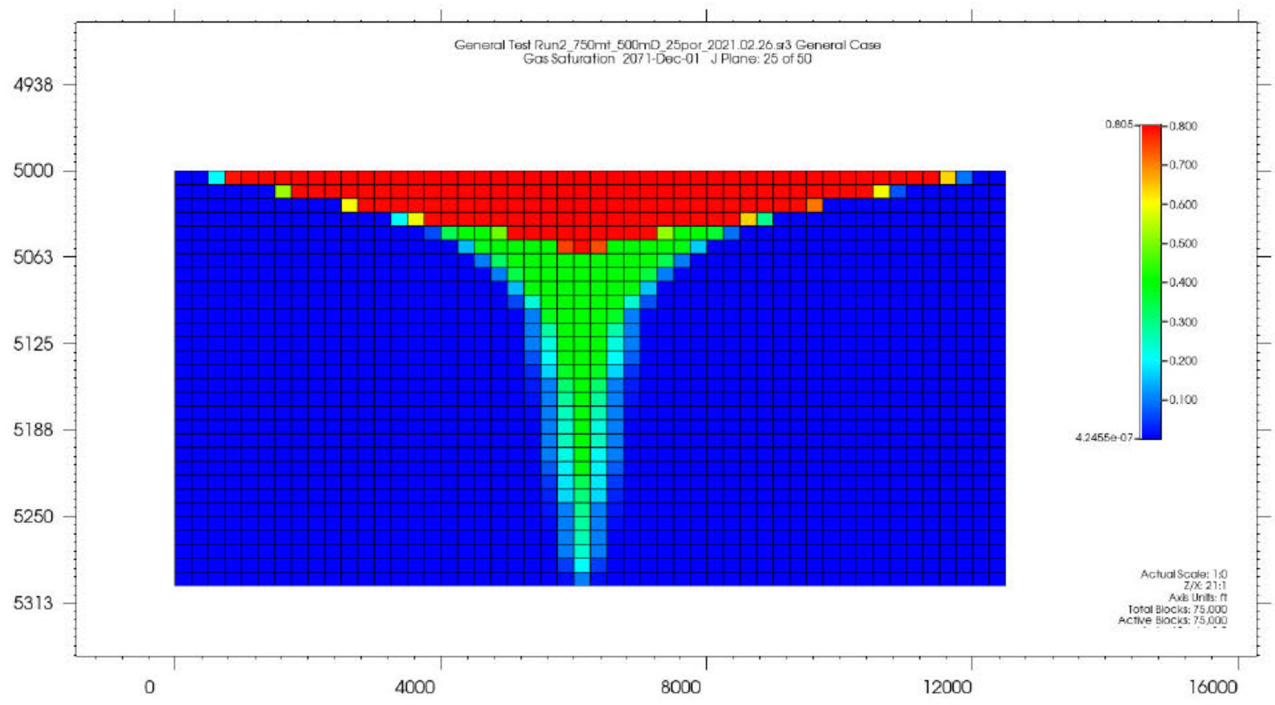

Figure 4-12 – Typical Plume Profile in High Permeability Formations

Reservoir management is important for sequestration wells in thick, high permeability, unconsolidated sand formations. At the end of each injection interval, wireline operations will be executed to recomplete into a new interval. A plug will be set to isolate the previous interval, and the [redacted] will be perforated to access the next interval for injection.

Figure 4-13 depicts this process in a general form.

[redacted]

Figure 4-13 – Operational Completion Strategy

The actual injection intervals, injection time frame, injection rate, and injection volume were displayed in Table 4-33 for both wells.

4.5 Injection Well Construction and Operation Summary

The proposed well design is engineered to address the potential hazards and risks associated with Class VI wells, including protection of the USDW. Casing setting points, materials, and cement meet and exceed the requirements for this classification of injection well. All requirements and regulations are satisfied by the well design. Additionally, efforts have been made to efficiently maximize use of the available pore space with the completion strategy and to mitigate issues with sand control while still allowing pressure monitoring throughout the injection interval.

The location for this project is ideally situated for carbon sequestration. 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 safely serve the State of Louisiana for years to come.

Appendix D – Well Construction Schematics and Procedures

- Appendix D-1 Drilling and Completion Prognoses
- Appendix D-2 Drilling Phase Wellbore Schematics
- Appendix D-3 Completion Phase Wellbore Schematics
- Appendix D-4 Injection Phase Wellbore Schematics
- Appendix D-5 Plug and Abandonment Phase Wellbore Schematics
- Appendix D-6 Pecan Island Injection Well No. 001 Cement Program
- Appendix D-7 Pecan Island Injection Well No. 002 Cement Program