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RAILROAD COMMISSION OF TEXAS

OIL AND GAS DIVISION

PERMIT TO GEOLOGIC STORAGE AND ASSOCIATED INJECTION OF ANTHROPOGENIC CARBON DIOXIDE (CO2)

ExxonMobil Low C Sol On Stor LLC (P5 # 101256)
22777 Springwoods Village Pkwy
Spring, TX 77389

Class VI Permit Number: 58608
Project/Facility Name: Sunflower Carbon Capture and Storage
Counties: Jefferson & Liberty, District 03

Effective Date: XXXXXX, 2026
Expiration Date: Life of the project, if injection begins within five (5) years from the effective date; otherwise, a renewal application must be filed with a fee within 21 days before XXXXXX, 2031.

Authority is granted to inject **anthropogenic CO2** into the wells identified herein in accordance with pursuant to the Texas Water Code, Chapter 27, the Texas Natural Resources Chapter 91, and Underground Injection Control (UIC) regulations of the Railroad Commission of Texas, codified at Title 16, Part 1, Chapter 5 of the Texas Administrative Code (16 TAC) Subchapters A and B, §§5.101, 5.102, 5.201, 5.202, 5.203, 5.204, 5.205, 5.206, 5.207, and 5.208, and based on information contained in the application dated May 2026, subject to the following terms and conditions:

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TABLE 1: GENERAL INFORMATION

Source of CO2	Total CO2 Storage Mass (Million Metric Tons)	Duration of Injection (Years)	Topmost Confining Zone	Injection Zone Formation Name
ExxonMobil's USGC CO2 Pipeline	25.3	11	Intra-Fleming Shale	Fleming 2, Fleming 3 Frio 1, Frio 2 & Frio 3

TABLE 2: INJECTION WELL IDENTIFICATION AND PERMIT PARAMETERS

Well Name & No.	Latitude (NAD83)	Longitude (NAD83)	Injection. Interval (TVD)		Max. Injection Mass Rate (Metric Tons per day)	Max. Surface Injection Pressure (psi)	Max. Bottom Hole Injection Pressure (psi)
			Top (Feet)	Bottom (Feet)			
Sunflower INJ No.1	30.0204249	-94.4656525	3,572	7,720	6,850	2,000	4,500
Sunflower INJ No.2	30.0485414	-94.4219994	3,588	7,723			
Sunflower INJ No.3	30.0487361	-94.4054694	3,595	7,775			

TABLE 3: MONITOR WELLS IDENTIFICATION

Well Name & No.	API No./Well ID	Purpose	Total Depth, TVD (Feet)	Date Drilled
Sunflower AZM/IZM #01	245-32934	Located outside the AOR, monitoring only P/T (DAS/DTS) inj. zone, UCZ & ACZ	7,951	TBD
Sunflower AZM #01	291-32978	Located in AOR-West, sampling from first permeable sand, above UCZ	3,365	TBD
Sunflower AZM #02	245-32938	Located in AOR-East, sampling from first permeable sand, above UCZ	3,365	TBD
Sunflower USDW #01	NA	Located in AOR-West, sampling from Chicot aquifer	350-500	TBD
Sunflower USDW #02	NA	Located in AOR-East, sampling from Chicot aquifer	350-500	TBD
Sunflower USDW #03	NA	Located in AOR-East, sampling from Chicot aquifer	350-500	TBD

STANDARD CONDITIONS:

1. The operator must submit a proposed schedule at least **30 days** to District Office and notify at least **48 hours** prior to:

   a. beginning any well completion, workover or remedial operation
   b. conducting any required test, logging or surveys

   All information and test results must be filed with SIP unit using the email SIP@rrc.texas.gov. and a copy to the District Office, which shall be signed and certified.

2. Before surface casing is installed, the operator must run appropriate logs, such as resistivity, spontaneous potential, and caliper logs.

3. After each casing string is set and cemented, the operator must run logs, such as a cement bond log, variable density log, and a temperature log, to ensure proper cementing.

4. Before long string casing is installed, the operator must run logs appropriate to geology, such as resistivity, spontaneous potential, porosity, caliper, gamma ray, and fracture finder logs, to gather data necessary to verify the characterization of the geology and hydrology.

5. Injection must be through tubing set on a packer. The packer must be set no higher than 100 feet above the top of the permitted interval.

6. The well must be constructed using CO2 compatible materials.

7. The wellhead must be equipped with a pressure observation valve on the tubing and for annulus.

8. The well must use alarms and automatic shut-off systems designed to alert and shut-in the well when operating parameters such as annulus pressure, injection rate or other parameters diverge from permitted ranges.

9. The annulus between the tubing and the long string casing must be filled with a corrosion inhibiting fluid and must maintain on the annulus a pressure, that exceeds the operating injection pressure.

10. The total volume of CO_2 injected into the storage facility must be metered through a master meter. The volume and/or mass of CO_2 injected into each injection well must be metered through an individual well meter. If mass is determined using volume, the operator must provide calculations.

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11. Prior to injection, whole cores or sidewall cores of the injection and confining zones; and formation fluid samples from the injection zone must be taken. Thereafter, a detailed report prepared by a log analyst that includes well log analyses, core analyses and formation fluid sample information such as temperature, pH, conductivity must be submitted.

12. Must provide the chemical composition and temperature of the CO_2 stream.

13. An annulus pressure test must be performed prior to injection and at least once **every five years** thereafter, or subsequently after any work over. The test pressure must equal the maximum authorized injection pressure or 500 psig, whichever is less, but must be at least 200 psig. The test results must be submitted in accordance with the instructions of **Form H-5** within **30 days** after the testing.

14. Prior to injection, the operator must perform an **initial** pressure fall-off or other test and submit a written report of the results of the test, including details of the methods used to perform the test and to interpret the results, all necessary graphs, and the testing log, to verify permeability, injectivity, and initial pressure using water or CO_2.

15. Prior to commencing injection, the permittee must deploy and maintain a seismic monitoring system (minimum of one in-ground seismic monitoring station) meeting the equipment specifications to become part of the state (e.g. TexNet) seismic monitoring network.

16. The injection pressure, rate, temperature, volume and/or mass, and the pressure on the annulus and annulus fluid volume added must be monitored **daily** and reported **semi-annually** on a monthly basis on Form H-10.

17. At least **once per year** until the injection well is plugged, the external mechanical integrity of the casing must be performed using a method approved by the director (e.g., diagnostic surveys such as oxygen-activation logging or temperature or noise logs). The results of the test, including details of the methods used to perform the test and to interpret the results, all necessary graphs, and the testing log must be submitted.

18. Within **30 days** after completion, a new Form W-2 and Log must be filed to show the current completion status of the well. The date of the injection well permit, and the permit number must be included on the new Form W-2.

19. Every **five years** or more frequently the AoR will be reevaluated, and the resultant information must be submitted in an electronic format.

20. The operator must submit an **annual report** detailing the re-calculated AOR unless the operator submits a statement signed by an appropriate company official confirming that monitoring and operational data supports the current delineation of the AOR on file with the Commission.

21. Injection fee. The operator must pay the Commission **an annual fee** of $0.025 per metric ton of CO_2 injected into the geologic storage facility.

22. Post-injection care fee. The operator must pay the Commission **an annual fee** of $50,000 for each year that the operator does not inject into the geologic storage facility until the director has authorized storage facility closure.

23. The operator may transfer the facility permit to another operator and must submit written notice of an intended permit transfer to the director at least **45 days** prior to the date the transfer of operations is proposed to take place.

24. The operator must identify each location in which geologic storage activities take place, including each injection well, with a sign that meets the requirements specified in 16 TAC §3.3(1), (2), and (5) of this title (relating to Identification of Properties, Wells, and Tanks). In addition, each sign must include a telephone number where the operator or a representative of the operator can be reached **24 hours a day**, **seven days a week** in the event of an emergency.

25. The operator of a geologic storage facility must comply with the requirements of Chapter 5, subchapter B as well as with all other applicable Commission rules and orders, including the requirements of Chapter 8 of this title (relating to Pipeline Safety Regulations) for pipelines and associated facilities.

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26. Within **30 days** of receipt of this permit, the permittee shall certify to the Director in an electronic format, that the operator has read and is familiar with all terms and conditions of this permit. This certification shall be signed and made in accordance with requirements of Title 16 TAC §5.207(c) and (d).

27. The permittee may not commence injection until the Director has given a **written authorization** to commence injection.

SPECIAL CONDITIONS:

1. The following eleven (11) wells will require **corrective action:**

API Number	Lease Name & Well No.	Total Depth (ft)	Schedule (Year)	No. of Wells
245-30290	Carpenter #001	7,816	0	6
245-00004	P. H. Carpenter #001	7,753		
245-00005	Frank Carpenter, et al #001	8,515		
245-03214	Wilson et al #001	6,395		
245-00008	B. H. Willis #001	6,530		
245-03240	A. M. Carpenter Est. #001	5,928		
245-31931	Garth #001	5,830	21	2
291-32614	Broussard Farms #001	11,375		
245-00006	F. S. Wilson #1	7,012	31	2
291-32215	E. A. Henderson #001	14,030		
245-31491	Champion International Corp. et al Gas Unit #001	16,260	41	1
			Total No. of Wells =	**11**

Within **30 days** after plugging and/or recompletion, a complete well plugging record (Form W-3) and/or Form W-2 must be filed.

2. Injection cannot begin until a surety bond in an amount of **$31,488,275** has been filed. The bond must be renewed and continued in effect until the conditions of the bond or letter of credit have been met or its release is authorized. An **annual** update of the cost estimate to increase or decrease to account for any changes must be provided within **60 days** prior to the anniversary date of the establishment of the financial instruments used to comply. Whenever the current cost estimate increases or decreases, the face amount of the financial assurance instrument may be increased or reduced to the amount of the current cost estimate.

Provided further that, should it be determined that such injection fluid is not confined to the approved interval, then the permission given herein is suspended and the injection operation must be stopped until the fluid migration from such interval is eliminated. Failure to comply with all the conditions of this permit may result in the operator being referred to enforcement to consider assessment of administrative penalties and/or the cancellation of the permit.

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APPROVED AND ISSUED ON **XXXXXXX, 2026**

_____
Rob Castillo, Manager
Special Injection Permits Unit

Class VI Permit Condition & Details

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PERMIT CONDITIONS

A. EFFECT OF PERMIT

The permittee is allowed to engage in underground injection in accordance with the conditions of this permit. Notwithstanding any other provisions of this permit, the permittee authorized by this permit shall not construct, operate, maintain, convert, plug, abandon, or conduct any other injection activity in a manner that allows the movement of injection, annulus, or formation fluids into underground sources of drinking water (USDW) or any unauthorized geologic zones. The objective of this permit is to prevent the movement of fluids into or between USDW or into any unauthorized geologic zones consistent with the requirements of **16 TAC §§5.203(d)(1)(C)**, **5.203(e)(1)(A)(i)** and **5.203(j)(2)(H)**. Any underground injection activity not specifically authorized in this permit is prohibited. For purposes of enforcement, compliance with this permit during its term constitutes compliance with Texas Water Code, Chapter 27, and the Texas Natural Resources Code, Chapter 91. Issuance of this permit does not convey property rights of any sort or any exclusive privilege; nor does it authorize any injury to persons or property, any invasion of other private rights, or any infringement of State or local laws or regulations. Nothing in this permit shall be construed to relieve the permittee of any duties under applicable regulations.

B. PERMIT ACTIONS

1. **Modification, Revocation and Reissuance, and Termination –** The Director of the RRC Class VI UIC Program, hereinafter, the Director, may, for cause or upon request from any interested person, including the permittee, modify, revoke and reissue, or terminate this permit in accordance with **16 TAC §5.202(d)(2)(A)**. The filing of a request for a permit modification, revocation and reissuance, or termination, or notification of planned changes, or anticipated noncompliance on the part of the permittee does not stay the applicability or enforceability of any permit condition in accordance with **16 TAC §5.206(o)(2)(K)**.

2. **Minor Modifications –** Upon the consent of the permittee, the Director may modify a permit to make the corrections or allowances for minor changes in the permitted activity as listed in **16 TAC §5.202(d)(2)(A)(viii).** Any permit modification not processed as a minor modification under **16 TAC §5.202(d)(2)(A)(viii)** shall be made for cause, and with a draft permit and public notice as required in **16 TAC §5.204**.

3. **Transfer of Permit –** An operator may transfer its geologic storage facility permit to another operator if the requirements of **16 TAC §5.202(c)** are met. A new operator shall not assume operation of the geologic storage facility without a valid permit in accordance with **16 TAC §5.202(c)** and Section O(6)(b) of this permit.

C. SEVERABILITY

The provisions of this permit are severable under **16 TAC §5.208(b)**, and if any provision of this permit or the application of any provision of this permit to any circumstance is held invalid, the application of such provision to other circumstances and the remainder of this permit shall not be affected thereby.

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D. CONFIDENTIALITY

In accordance with the Texas Public Information Act, Texas Government Code, Chapter 552, any information submitted to the RRC pursuant to this permit may be claimed as confidential business information by the submitter. Any such claim shall be asserted at the time of submission by clearly identifying each page with the words "confidential business information" on every page containing such information. If no claim is made at the time of submission, the RRC may make the information available to the public without further notice. If a claim is asserted, the validity of the claim will be assessed in accordance with the procedures in the Texas Public Information Act, Texas Government Code, Chapter 552. Claims of confidentiality for the following information will be denied:

1. The name and address of the permittee; and
2. Information which deals with the existence, absence, or level of contaminants in drinking water.

E. DEFINITIONS

All terms used in this permit shall have the meaning set forth in the Texas Water Code, Chapter 27, or the Texas Natural Resources Code, Chapter 91, and the RRC's UIC regulations specified at **16 TAC §5.102**. Unless specifically stated otherwise, all references to "days" in this permit should be interpreted as calendar days.

F. DUTIES AND REQUIREMENTS

1. **Prohibition of Movement of Fluid into a USDW –** The permittee shall not construct, operate, maintain, convert, plug, abandon, or conduct any other injection activity in a manner that allows the movement of a fluid containing any contaminant into USDWs. If any water quality monitoring of a USDW indicates the movement of any contaminant into the USDW, the Director may take enforcement action or prescribe such additional requirements for construction, corrective action (including closure of the injection well), operation, monitoring, or reporting as are necessary to remediate and prevent such movement.

2. **Duty to Comply –** The permittee shall comply with all conditions of this permit. Any permit noncompliance constitutes a violation of **16 TAC §5.206(o)(2)(A)** and is grounds for enforcement action, permit termination, revocation and reissuance, modification, or for denial of a permit renewal application.

3. **Duty to Reapply –** If the permittee wishes to continue an activity regulated by this permit after its expiration, the permittee shall apply for and obtain a new permit.

4. **Penalties for Violations of Permit Conditions –** Any person who violates a permit requirement is subject to civil and/or criminal penalties and other enforcement action under the Texas Natural Resources Code, Title 3, Section 91.143 and Texas Water Code, Chapter 27. Any person who willfully violates permit conditions may be subject to criminal prosecution under the Texas Natural Resources Code, Title 3, Section 91.143 and Texas Water Code, Chapter 27.

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5. **Need to Halt or Reduce Activity Not a Defense –** It shall not be a defense for the permittee in an enforcement action to claim that it would have been necessary to halt or reduce the permitted activity to maintain compliance with the conditions of this permit in accordance with **16 TAC §5.206(o)(2)(B)**.

6. **Duty to Mitigate –** The permittee shall take all timely and reasonable steps necessary to minimize or correct any adverse impact on the environment resulting from noncompliance with this permit in accordance with **16 TAC §5.206(o)(2)(C)**.

7. **Proper Operation and Maintenance –** The permittee shall at all times properly operate and maintain all facilities and systems of treatment and control and related appurtenances which are installed or used by the permittee to achieve compliance with the conditions of this permit. Proper operation and maintenance include, among other things, effective performance, adequate funding, adequate operator staffing and training, and adequate laboratory and process controls, including appropriate quality assurance procedures. This provision requires the operation of back-up or auxiliary facilities or similar systems only when necessary to achieve compliance with the conditions of this permit in accordance with **16 TAC §5.206(o)(2)(D)**.

8. **Duty to Provide Information –** The permittee shall furnish to the Director in electronic format, within the time specified by the type of submittal or as defined by the Director, any information which the Director may request to determine whether cause exists for modifying, revoking and reissuing, or terminating this permit, or to determine compliance with this permit or the UIC regulations. The permittee shall also furnish to the Director, upon request, within a time specified, electronic copies of records required to be kept in accordance with this permit by **16 TAC §5.206(o)(2)(H)**.

9. **Inspection and Entry –** The operator shall allow any member or employee of the Commission, on proper identification, to by **16 TAC §5.206(o)(2)(I):**

    (a) Enter upon the permittee's premises where a regulated facility or activity is located or conducted, or where electronic or non-electronic records are kept under the conditions of this permit.

    (b) Have access to and copy, at reasonable times, any electronic or non-electronic records that are kept under the conditions of this permit.

    (c) Inspect, at reasonable times, any facilities, equipment (including monitoring and control equipment), practices, or operations regulated or required under this permit and

    (d) Sample or monitor, at reasonable times, for the purposes of assuring permit compliance or as otherwise authorized by the Texas Water Code, §27.071, or the Texas Natural Resources Code, §91.1012, any substances or parameters at any location, including facilities, equipment or operations regulated or required under this permit.

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10. **Signatory and Certification Requirements –** All reports, notifications, or any other information, required to be submitted by this permit or requested by the Director shall be signed and certified in accordance with **16 TAC §§5.206(o)(2)(L), 5.207(c)** and **5.207(d)**.

G. AREA OF REVIEW AND CORRECTIVE ACTION

1. The Area of Review (AoR) is the area surrounding the injection well where USDWs may be endangered by the injection activity. The area of review was 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 permittee shall maintain and comply with the approved AoR and Corrective Action Plan (CAP) included as Attachment A, which is an enforceable condition of this permit, and shall meet the requirements of **16 TAC §5.206(g)**.

2. As documented in Attachment A, eleven (11) wellbore penetrations within the AoR require plugging and recompletion because these wellbores penetrated the injection zone or confining layer within the Sunflower Carbon Capture and Storage Project. These are:

- Carpenter No. 1 (API 42-245-30290)
- P.H. Carpenter No. 1 (API 42-245-00004)
- Frank Carpenter, et al. No. 1 (API 42-245-00005)
- Wilson, et al. No. 1 (API 42-245-03214)
- B.H. Willis No.1 (API 42-245-00008)
- A.M. Carpenter Est. No. 1 (42-245-03240)
- Garth No. 1 (API 42-245-31931)
- Broussard Farms No. 1 (API 42-291-32614)
- F.S. Wilson No. 1 (API 42-245-00006)
- E.A. Henderson No. 1 (API 42-291-32215)
- Champion International Corp. et al. Gas Unit No. 1 (API 42-245-31491)

3. At least sixty (60) days prior to commencing corrective action, the permittee shall notify the Director. As corrective action activities are completed, the permittee shall provide periodic updates, including plugging reports, to the Director.

4. Every five (5) years as specified in the AoR and CAP, or more frequently when monitoring and operational conditions warrant, the permittee shall reevaluate the AoR and perform corrective action in the manner specified in **16 TAC §5.206(g)** and update the AoR and CAP or demonstrate to the Director that no update is needed. Reevaluation of the AoR and CAP shall meet the requirements of **16 TAC §5.203(d)(1)(A) - (C)** and shall include a new survey of wells within the existing or modified AoR.

5. Following each AoR reevaluation or a demonstration that no evaluation is needed, the permittee shall submit a report of the resultant information in an electronic format to the Director for review and approval. Once approved by the Director, the revised AoR and CAP will become an enforceable condition of this permit.

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H. FINANCIAL RESPONSIBILITY

The permittee shall maintain financial responsibility and resources to meet the requirements of **16 TAC §5.205** for the life of this permit and through all phases of the project. The permittee must maintain financial responsibility until site closure is authorized by the Director as described in Section P of this permit. The permittee shall use financial instruments as listed in **16 TAC §5.205(c)(2)(D)** to cover all costs associated with the requirements of this permit. The approved financial responsibility and estimated costs for this permit are found in Attachment J and in the administrative record of this permit.

1. **Costs to be Covered –** The financial instrument(s) shall be sufficient to cover the cost of:
   (a) Corrective action (that meets the requirements of **16 TAC §5.203(d)(2)**.

   (b) Injection well plugging (that meets the requirements of **16 TAC §5.203(k).**

   (c) Emergency and remedial response (that meets the requirements of **16 TAC §5.203(l).**

   (d) Post injection site care and site closure (that meets the requirements of **16 TAC §5.206(m)**.

2. **Cost Estimate Updates and Adjustments –** A detailed written estimate for each phase is included in Attachment J of this permit. The cost estimates must be performed for each phase separately and must be based on the costs to the Commission 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. and the dollar amount of the financial assurance shall be approved by the Director in accordance with **16 TAC §5.205(c)(2)(C)(i).**

   (a) A qualified professional engineer licensed by the State of Texas, as required under Occupations Code, Chapter 1001, relating to Texas Engineering Practice Act, must prepare or supervise the preparation of a written estimate of the highest likely amount necessary to close the geologic storage facility. The owner or operator must submit to the director the written estimate under seal of a qualified licensed professional engineer, as required under Occupations Code, Chapter 1001, relating to Texas Engineering Practice Act in accordance with **16 TAC §5.205(c)(2)(C)(ii).**

   (b) During the life of this permit, the permittee shall adjust the cost estimate for annual inflation and any amendments made to the Project Plans included as Attachments A-J of this permit, which address costs associated with items (a) through (d) in Section H(1) of this permit. The permittee shall adjust cost estimates annually at least 60 days prior to the anniversary date of the establishment of the financial instrument(s) and provide this adjustment to the Director in an electronic format in accordance with **16 TAC §5.205(c)(2)(E).** All cost and Project Plan adjustments are subject to the Director's approval.

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3. **Notification –**

(a) Whenever a cost estimate increases to an amount greater than the face amount of a controlling financial instrument, the permittee, at least 60 days after the increase, shall 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 a current cost estimate decreases to an amount less than the face amount of a controlling financial instrument, the face amount of the financial assurance instrument may be reduced to the amount of the current cost estimate only after the permittee has received written approval from the Director in accordance with **16 TAC §5.205(c)(2)(G)**.

(b) The permittee shall notify the Director by certified mail and in an electronic format of adverse financial conditions that may affect the ability to carry out injection well plugging, post-injection site care and site closure, and any applicable ongoing actions under Corrective Action and/or Emergency and Remedial Response. The notice of bankruptcy shall be filed in accordance with **16 TAC §§3.1(f)** (relating to Organization Report; Retention of Records; Notice Requirements) and **5.205(d)(1)**. Such notice shall be provided to the RRC's Office of General Counsel and to the Director.

(i) The owner or operator filing a bond must ensure that the bond provides a mechanism for the bond or surety company to give prompt notice to the Commission and the owner or operator of any action filed alleging insolvency or bankruptcy of the surety company or the bank or alleging any violation that would result in suspension or revocation of the surety or bank's charter or license to do business in accordance with **16 TAC §5.205(d)(2)**.

(ii) Upon the incapacity of a bank or surety company by reason of bankruptcy, insolvency or suspension, or revocation of its charter or license, the Commission must deem the owner or operator to be without bond coverage in accordance with **16 TAC §5.205(d)(3).** The Commission must issue a notice to any owner or operator who is without bond coverage and must specify a reasonable period to replace bond coverage, not to exceed 60 days.

I. WELL CONSTRUCTION

The design and specifications for the injection well, injection zone monitoring wells, confining zone monitoring wells, and the USDW monitoring wells are included in Attachment B of this permit.

1. **Injection Well Construction –** The wells shall be constructed in accordance with **16 TAC §§3.13** and **5.203(e)(1)**. The design and construction shall allow continuous monitoring of the annulus between the long string casing and the injection tubing and accommodate testing devices and workover tools. During construction, the permittee may make changes to the design of the injection well consistent with the conditions of this permit. If changes are made to the design of the well, notification shall be made to the Director, and the construction changes shall be provided for review and approval by the

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Director before installation. Once the construction of the well is completed, and prior to authorization to inject, the permittee shall submit the final, as-built construction specifications and diagrams within 30 days for review and approval by the Director. Any deviations from the proposed design and as-built construction of the well shall be noted. If the changes in well design are significant, the Director may require this permit to be modified.

2. **Siting –** The permittee has demonstrated to the satisfaction of the Director that the well is in an area with suitable geology in accordance with the requirements at **16 TAC §5.206(b)(6)**.

3. **Casing and Cementing –** The wells shall be cased and cemented in accordance with **16 TAC §§3.13 and 5.203(e)(1)(B)**. Casing, cement, or other materials used in the construction of the well shall have sufficient structural strength for the life of the geologic sequestration project. All well materials shall be compatible with all fluids with which the materials may be expected to come into contact and shall 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 shall prevent the movement of fluids into or between USDWs for the expected life of the well. The casing and cement used in the construction of this well are shown in Attachment B of this permit and in the administrative record for this permit. Any changes shall be submitted in an electronic format for approval by the Director before installation.

4. **Tubing and Packer Specifications –** The tubing and packer design shall meet the requirements of **16 TAC §§3.13** and **5.203(e)**. Tubing and packer materials used in the construction of the well shall be compatible with fluids with which the materials may be expected to come into contact and shall meet or exceed standards developed for such materials by the American Petroleum Institute, ASTM International, or comparable standards acceptable to the Director. Injection shall only take place through the tubing, with a packer set in the long string casing within or below the nearest cemented and impermeable confining system no more than 100 feet above the injection zone in accordance with **16 TAC §5.203(e)(1)(C)(i)**. The tubing and packer used in the well are represented in engineering drawings contained in Attachment B of this permit. Any change shall be submitted in an electronic format for review and approval by the Director before installation.

5. **Sampling and Monitoring Devices –** The permittee shall install and maintain in good condition all devices required to measure, monitor, and record the data required by Attachment F of this permit. The permittee shall ensure that the devices installed, and methods used are sufficient to represent the activity being measured, monitored, or recorded. Calculated flow data or periodic monitoring are not acceptable for required continuous monitoring except as a back-up system if the primary continuous monitoring devices become inoperable. The Director shall be notified of such occurrences, and continuous monitoring devices should be repaired or replaced as soon as practicable. If this period of time is extensive in the opinion of the Director, injection activities shall cease until such time that normal monitoring is restored. The permittee shall ensure the wells' construction and near-wellhead design is appropriate for the collecting of samples and

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fulfilling of all monitoring requirements of this permit. The permittee shall ensure all gauges used for monitoring and testing are properly calibrated.

6. **Construction of Monitoring Well – 16 TAC §§5.203(j)(2)(D)(i), 5.203(j)(2)(D)(ii), 5.203(j)(2)(E),** and **5.203(j)(2)(G)** require monitoring of the carbon dioxide plume and pressure front of the confining and injection zones and monitoring of USDW located above the injection zone. These sections are incorporated by reference into this permit. USDW, confining zone, and injection zone monitoring wells shall be constructed in the manner depicted in Attachment B of this permit using materials that are compatible with the injected fluids. All monitoring wells shall be constructed in a manner to provide representative samples that can be analyzed for the monitoring parameters required by this permit. Once the construction of the monitoring wells has been completed, the as-built construction diagrams shall be included in the Pre-injection Testing Report to be submitted to the Director in accordance with Section J of this permit.

J. PRE-INJECTION TESTING

Testing is required during the construction of the well in accordance with **16 TAC §5.203(f)**. This testing is required to verify the geology of the well site to ensure compliance with the well construction requirements in accordance with **16 TAC §5.203(e)** and to test viability of the wells to meet the stipulated operational requirements. The pre-injection testing plan is included as Attachment D of this permit.

1. Prior to the Director authorizing injection, the permittee shall perform all pre-injection logging, sampling, and testing specified at **16 TAC §5.203(f)**. This testing shall include:

    (a) Logs, surveys and tests to determine or verify the depth, thickness, porosity, permeability, lithology, and formation fluid salinity in all relevant geologic formations. These tests shall include:

        (i) Deviation checks that meet the requirements of **16 TAC §5.203(f)(1)(A).**

        (ii) Logs and tests before and upon installation of the surface casing that meet the requirements of **16 TAC §5.203(f)(1)(B).**

        (iii) Logs and tests before and upon installation of the long-string casing that meet the requirements of **16 TAC §5.203(f)(1)(D).**

        (iv) Tests to demonstrate internal and external mechanical integrity that meet the requirements of **16 TAC §5.203(h)** and

        (v) Any alternative methods (MIT), provided that the type of test has the written approval of the Administrator pursuant to requirements at **16 TAC §5.203(h)(2)(E).**

    (b) Documentation of the measured fluid temperature, pH, conductivity, reservoir pressure, and static fluid level of the injection zone that meet the requirements of **16 TAC §5.203(f)(3)(A)**.

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(c) Whole cores or sidewall cores of the injection zone and confining system and formation fluid samples from the injection zone that meet the requirements of **16 TAC §5.203(f)(3)(B)**.

(d) Tests to determine well-specific data regarding the injection and confining zones. These tests shall determine fracture pressure and the physical and chemical characteristics of the injection and confining zones and the formation fluids in the injection zone that meet the requirements of **16 TAC §§5.203(f)(2)(C)** and **5.203(f)(3)(B)**.

(e) Tests to verify hydrogeologic characteristics of the injection zone that meet the requirements of **16 TAC §5.203(f)(2),** including:

(i) A pressure fall-off test or

(ii) Other test and submit to the director a written report of the results of the test, including details of the methods used to perform the test and to interpret the results, all necessary graphs, and the testing log, to verify permeability, injectivity, and initial pressure using water or CO2.

2. The permittee shall submit to the Director for approval in an electronic format a schedule for pre-operational testing activities 30 days prior to conducting the first test and submit any changes to the schedule 30 days prior to the next scheduled test. The permittee shall provide the Director with the opportunity to witness all logging, sampling, and testing required under this permit and submit notice at least 48 hours in advance of any actual activity in accordance with **16 TAC §5.206(i)**.

K. INJECTION WELL OPERATING REQUIREMENTS

1. Outermost Casing Injection Prohibition – Injection between the outermost casing protecting USDWs and the well bore is prohibited.

2. Injection Fluids/Carbon Dioxide Sources – The carbon dioxide to be sequestered comes from high-concentration industrial sources including clean hydrogen, ammonia, direct reduced iron plants, and natural gas treatment facilities that feed into ExxonMobil's Gulf Coast CO2 pipeline network. The permittee may propose additional sources of carbon dioxide for injection, subject to review and approval by the Director.

3. Injection Pressure Limitation – Except during stimulation, the permittee shall ensure that injection pressure does not exceed 90 percent of the fracture pressure of the injection zone(s) to ensure that the injection does not initiate new fractures or propagate existing fractures in the injection zone(s). Under no circumstance shall injection pressure initiate fractures or propagate existing fractures in the confining zone or cause the movement of injection or formation fluids into a USDW. The maximum injection pressure limit is listed in Attachment E of this permit.

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4. **Stimulation Program –** All stimulation activities shall be approved by the Director prior to conducting the stimulation. The permittee shall carry out the Stimulation Program in accordance with Attachment C of this permit.

5. **Additional Injection Limitations –** No injection fluid other than that identified on Page 1 of this permit may be injected except fluids used for stimulation, rework, and well tests as approved by the Director. Injection shall occur within the injection tubing.

6. **Annulus Fluid –** The permittee shall fill the annulus between the tubing and the long string casing with a non-corrosive fluid approved by the Director.

7. **Annulus/Tubing Pressure Differential –** Except during workovers or times of annulus maintenance, the permittee shall maintain pressure on the annulus that exceeds the operating injection pressure as specified in Attachment E of this permit, unless the Director determines that such requirement might harm the integrity of the well or endanger USDW.

8. **Automatic Alarms and Automatic Shut-off System –**

   (a) The permittee shall:

      i. Install, continuously operate, and maintain an automatic alarm and automatic shut-off system or, at the discretion of the Director, down-hole shut-off systems, or other mechanical devices that provide equivalent protection; and

      ii. Successfully demonstrate the functionality of the alarm system and shut-off system prior to the Director authorizing injection, and at a minimum of once every twelfth month after the last approved demonstration.

      iii. Establish well-specific thresholds for activating the shut-off system and submit revised Attachments E & H.

   (b) Testing under this Section shall involve subjecting the system to simulated failure conditions and shall be witnessed by the Director or the Director's representative unless the Director authorizes an unwitnessed test in advance. The permittee shall provide notice in an electronic format at least 30 days prior to running the test and shall provide the Director or the Director's representative with the opportunity to witness the test. The test shall be documented using either a mechanical or digital device which records the value of the parameter of interest, or by a service company job record. A final report including any additional interpretation necessary for evaluation of the testing shall be submitted to the Director in an electronic format within the time period specified in Section O(4) of this permit.

9. **Precautions to Prevent Well Blowouts –** Except at specific times as approved by the Director, the permittee shall maintain on the well a pressure which will prevent the return of the injection fluid to the surface. The wellbore shall be filled with a fluid of sufficient specific gravity during workovers to maintain a positive (downward) pressure gradient and/or a plug shall be installed which can resist the pressure differential. A blowout

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preventer shall be installed and kept in proper operational condition whenever the wellhead is removed to work on the well. The permittee shall follow procedures such as those below to ensure that a backflow or blowout does not occur:

(a) Limit the temperature and/or corrosivity of the injectate; and

(b) Develop procedures necessary to ensure that pressure imbalances do not occur.

10. Circumstances Under Which Injection Shall Cease – Injection shall cease when any of the following circumstances arises:

(a) Failure of the well to pass a mechanical integrity test;

(b) A loss of mechanical integrity during operation;

(c) The automatic alarm or automatic shut-off system is triggered;

(d) A significant unexpected change in the annulus or injection pressure;

(e) The Director determines that the well lacks mechanical integrity;

(f) Movement of injection or formation fluids outside of the current, approved injection interval is detected;

(g) Conditions described in Section M(C)(3), Seismic Event Response, occur;

(h) The Director determines the site is no longer suitable for injection based on new information; and

(i) The Director determines that the permittee is unable to maintain compliance with any condition of this permit or regulatory requirement, and the Director determines that injection should cease.

11. Approaches for Ceasing Injection –

(a) In all instances where injection ceases, the permittee shall immediately cease injection and shut-in the well as outlined in the Emergency and Remedial Response Plan (Attachment H of this permit), and the Permittee must get approval from the Director to resume injection.

(b) If an automatic shutdown (i.e., down-hole or at the surface) is triggered, the Permittee must immediately investigate and identify the cause of the shutdown as expeditiously as possible. If, upon investigation, the well appears to lack mechanical integrity, or if the required monitoring of data from continuous recording devices or automatic shutoff systems indicates that the well may lack mechanical integrity, the Permittee must take the actions listed below in Section L of this Permit.

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L. MECHANICAL INTEGRITY

The injection wells shall maintain internal (casing, tubing and packer) and external (fluid movement into geologic units other than the injection zone) mechanical integrity for the entirety of its operational life. No significant leaks in the casing, tubing, or packer can occur without corrective actions. The determination of whether the injection well has mechanical integrity is at the discretion of the Director. Mechanical integrity is determined through testing and test procedures approved by the Director. Approved mechanical integrity testing procedures are in the Testing and Monitoring Plan in Attachment F of this permit. Other tests and/or procedures not listed in this plan will be considered by the Director for approval.

1. **Standards –** Other than during periods of well workover (repair or maintenance) approved by the Director in which the sealed tubing-casing annulus is disassembled for maintenance or corrective procedures, the injection well shall have and maintain mechanical integrity consistent with **16 TAC §5.203(h).** To meet these requirements, mechanical integrity tests/demonstrations shall be witnessed by the Director or an authorized representative of the Director unless prior approval has been granted by the Director to run an un-witnessed test. In order to conduct testing without a RRC representative, the following procedures shall be followed:

    (a) The permittee shall submit prior notification in an electronic format at least 30 days prior to testing, including the information that no RRC representative is available, and receive permission from the Director to proceed.

    (b) The test shall be performed in accordance with the Testing and Monitoring Plan (Attachment F of this permit) and documented using either a mechanical or digital device that records the value of the parameter of interest; and

    (c) A final report including any additional interpretation necessary for evaluation of the testing shall be submitted in an electronic format within the time period specified in Section O(4) of this permit.

2. **Mechanical Integrity Testing –** The permittee shall conduct a casing inspection log and mechanical integrity testing (MIT) as follows:

    (a) After construction, and prior to receiving authorization to inject from the Director, the permittee shall demonstrate internal mechanical integrity of the well. This demonstration is achieved by the performance of the following testing pursuant to **16 TAC §5.203(h)(2):**

        (i) A pressure test with liquid or gas.

        (ii) A casing inspection log; or

        (iii) An alternative approved by the Director that has been approved by the Administrator pursuant to requirements at **16 TAC §5.203(h)(2)(E)**.

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(b) Prior to receiving authorization to inject, the permittee shall perform one of the following testing to demonstrate external mechanical integrity pursuant to **16 TAC §5.203(h)(2)**:

(i) Tracer surveys such as an oxygen activation log.

(ii) Temperature or noise logs.

(iii) An alternative approved by the Director that has been approved by the Administrator pursuant to requirements at **16 TAC §5.203(h)(2)(E).**

(c) Other than during periods of well workover (repair or maintenance) approved by the Director, in which the sealed tubing-casing annulus is disassembled for maintenance or corrective procedures, the permittee shall continuously monitor injection pressure, injection rate, injection mass, pressure on the annulus between tubing and long string casing, and annulus fluid volume as specified in **16 TAC §§5.203(h)(1)(C)** and **5.206(e)(2)**.

(d) At least once per year, the permittee shall perform the testing to demonstrate external mechanical integrity pursuant to **16 TAC §5.203(h)(1)(D)** and as listed in Section L (2)(b) of this permit. All test data shall be sent to SIP@rrc.texas.gov and a copy to District Director.

(e) After any well repair or workover that may compromise the internal mechanical integrity of the well, the internal mechanical integrity of the well shall be demonstrated by conducting test(s) approved by the Director. In cases where a well has lost mechanical integrity, written approval by the Director is required before the injection can resume. All test data shall be sent to SIP@rrc.texas.gov and a copy to District Director.

(f) Prior to plugging the well, the permittee shall demonstrate external mechanical integrity as described in Attachment G and it meets the requirements of **16 TAC §5.203(k).** Written approval by the Director is required before plugging operations may commence. All test data shall be sent to SIP@rrc.texas.gov and a copy to District Director.

(g) The Director may require the use of other tests to demonstrate mechanical integrity other than those listed above, provided that the type of test has the written approval of the Administrator pursuant to requirements at **16 TAC §5.203(h)(2)(E).** All test data shall be sent to SIP@rrc.texas.gov and a copy to District Director.

3. Prior Notice, MIT Procedures and Reporting –

(a) The permittee shall notify the Director in an electronic format of intent to demonstrate mechanical integrity at least 30 days prior to such a demonstration. At the discretion of the Director a shorter time period may be allowed.

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(b) The mechanical integrity tests and procedures are listed in Attachments D and F. Use of non-approved tests and procedures may result in disqualification of the tests.

(c) Reports of mechanical integrity demonstrations which include logs shall include an interpretation of results by a knowledgeable log analyst. The permittee shall report in an electronic format the results of a mechanical integrity demonstration within 30 days of the testing.

4. **Gauge and Meter Calibration –** Prior to testing, the permittee shall calibrate all gauges and meters used in monitoring and testing required by this permit. A copy of the calibration certificate shall be submitted to the Director in an electronic format with the report of the test per **16 TAC §5.206(e)(5)(B)(i)** and the operator and the director must apply methods and standards generally accepted in the industry in accordance with **16 TAC §5.207(a)(1)**.

5. **Loss of Mechanical Integrity –**

(a) If the permittee or the Director finds that a well fails to demonstrate mechanical integrity during a test, or fails to maintain mechanical integrity during operation, or that a loss of mechanical integrity as defined by **16 TAC §5.102(36)** is suspected during operation (such as a significant unexpected change in the annulus or injection pressure), the permittee shall:

(i) Cease injection in accordance with Section K(9), and Attachments E or H of this permit;

(ii) Take all steps that are reasonably necessary to determine whether there may have been a release of the injected carbon dioxide stream or formation fluids into any unauthorized zone. If there is evidence of potential USDW endangerment, the Emergency and Remedial Response Plan shall be implemented (Attachment H of this permit);

(iii) Follow the reporting requirements as directed in Section O of this permit;

(iv) Restore and demonstrate mechanical integrity to the satisfaction of the Director and receive written approval from the Director prior to resuming injection; and

(v) Notify the Director in an electronic format when injection can be expected to resume.

(b) If an automatic shutdown (i.e., downhole or at the surface) is triggered, the permittee shall immediately investigate and identify as expeditiously as possible the cause of the shutdown. If, upon investigation, the well appears to be lacking mechanical integrity, or if the required monitoring indicates that the well may be lacking mechanical integrity, the permittee shall take the actions listed above in Section L(5)(a)(i) through (v).

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(c) If the well loses mechanical integrity prior to the next scheduled test date, then the well shall either be plugged or repaired and retested within 30 days of losing mechanical integrity. The permittee shall not resume injection until mechanical integrity is demonstrated and the Director gives written approval to resume injection in cases where the well has lost mechanical integrity.

6. **Mechanical Integrity for Monitoring Wells –** All monitoring wells shall maintain internal and external mechanical integrity for the entirety of their operational life**.** No significant leaks in the casing can occur and require corrective actions**.** The determination of whether the monitoring well has mechanical integrity is at the discretion of the Director**.** Mechanical integrity tests and procedure for the confining zone, injection zone and USDW monitoring wells are outlined in Attachment F of this permit**.** Testing and demonstration of monitoring wells shall be conducted on the same schedule as the injection well. Other tests and/or procedures not listed in this plan will be considered by the Director for approval.

7. **Mechanical Integrity Testing on Request from Director –** The permittee shall demonstrate mechanical integrity at any time upon written notification from the Director.

M. SEISMIC EVENT RESPONSE

The operator shall develop and implement a seismic monitoring plan that provides for the contribution of data to an existing public seismic network (e.g., TexNet, see http://www.beg.utexas.edu/texnet-cisr/texnet). The purpose of seismic monitoring is to contribute to the body of knowledge available to better resolve earthquake locations, especially depth, and to provide local seismic data to better implement earthquake response plans after a disposal well permit is issued. The seismic monitoring plan should include the method of seismic monitoring, location and type of instrumentation, and an archive of the data in a public seismic database. Use the following webpage to obtain minimal station requirements: http://www.beg.utexas.edu/texnet-cisr/seismic-station-requirements.
Prior to injection, the operator must deploy and maintain a minimum of one in-ground seismic station meeting the equipment specifications to become part of the state seismic monitoring network (currently TexNet).

1. Seismic Monitoring –

(a) Prior to commencing injection, the permittee must deploy and maintain a seismic monitoring system (minimum of one in-ground seismic monitoring station) meeting the equipment specifications to become part of a public seismic monitoring network to allow long-term monitoring by seismologists, and allowing them to determine the presence or absence, magnitude, and hypocenter location, of any induced seismic activity of magnitude 1.8 M or above.

(b) The system should be designed with surface monitors and/or downhole monitors as required to meet minimum magnitude of completeness (Mc) of 1.8 M or an alternative site-appropriate minimum magnitude approved by the Director in consultation with the State Seismologist, and to appropriately calibrate event magnitudes and hypo central locations. The system shall be calibrated with check-shots, sonic logs, or other local velocity information, preferably in depth.

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(c) The permittee shall analyze seismic and other relevant data to determine whether the risk of triggering an earthquake of magnitude 3.5 M or greater is significantly increased by injection. If, after analysis of seismic and other relevant data, the permittee determines that there is such an increase in risk, the permittee shall notify the Director immediately and submit to the Director a mitigation plan for the Director's review within 15 days of that determination. The permittee shall implement the plan as approved by the Director. The appropriate response to seismic events depends on the Magnitude (M) of the seismic event according to the following protocols.

2. **Seismic events not recorded or M less than 2.0 –** Continue normal operations.

3. **Seismic events with M equal to or greater than 2.0 but less than 3.5 –** The permittee shall notify the Director (District Director or Technical Permitting Director) of any such event within 24 hours, providing information on the status of the injection site. If the annulus pressure of the well decreases below the set alarm, injection operations shall cease. In that situation, within 30 days the permittee shall evaluate the internal mechanical integrity of the well by performing tests in accordance with Section L(2)(a) of this permit. If the well fails the mechanical integrity test or the permittee identifies any problems with the injection system that might impact a USDW, the injection well shall remain shut-in and the permittee shall submit a report in electronic format as soon as possible but no later than five (5) days from the time the permittee becomes aware of the circumstances. The report shall contain a description of the circumstances and if the situation has not been corrected, the anticipated time it is expected to continue; and steps taken or planned to reduce, eliminate, and prevent recurrence of the circumstances. Upon completion of the steps to ensure mechanical integrity and the subsequent mechanical integrity demonstration, the permittee shall submit the results and any other required documentation to the Director in an electronic format. If after the testing the well demonstrates mechanical integrity and issues that might impact USDWs are not identified, the permittee shall provide a report of those findings to the Director for review and approval. Injection operations cannot resume until the Director grants approval to recommence injection.

4. **Seismic Events with M equal to or greater than 3.5 –** For seismic events equal to or greater than 3.5 M, injection operations shall immediately cease. The permittee shall notify the Director of any such event within 24 hours, providing information on the status of the injection well system. If the annulus pressure decreased below the well's set alarm before shutting in the well, then the permittee shall evaluate the internal mechanical integrity of the well by performing tests in accordance with Section L(2)(a) of this permit. The permittee shall also perform an evaluation of the external mechanical integrity of the well in accordance with Section L(2)(b) of this permit. If the well fails either the internal or external mechanical integrity test or the permittee identifies any problems with the system that might impact a USDW, the injection well shall remain shut-in and the permittee shall submit a report in electronic format as soon as possible but no later than 30 days from the time the permittee becomes aware of the circumstances. The report shall contain a description of the failure and if the failure has not been corrected, the anticipated time it is expected to continue, and steps taken or planned to reduce, eliminate, and prevent recurrence of the failure. Upon completion of the steps to ensure mechanical integrity and the subsequent mechanical integrity demonstration, the permittee shall submit the results

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and any other required documentation to the Director. Injection operations cannot resume until the Director grants approval to recommence injection.

N. TESTING AND MONITORING REQUIREMENTS

1. **Testing and Monitoring Plan –** The specific measurement and reporting frequencies are listed in Attachment F.

   (a) The permittee shall maintain and comply with the approved Testing and Monitoring Plan included as Attachment F of this permit and with the requirements at **16 TAC §§5.206(e)**, and **5.206(o)(2)(I)**, and any modifications required by the Director after the effective date of this permit. The Testing and Monitoring Plan is an enforceable condition of this permit. Samples and measurements taken for the purpose of monitoring shall be representative of the monitored activity. Procedures for all testing and monitoring under this permit shall be submitted to the Director in an electronic format for approval at least 30 days prior to the test if they plan to deviate from the procedures outlined in Attachment F of this permit. When the test report is submitted, a full explanation shall be provided as to why any approved procedures were not followed. If the approved procedures were not followed, the Director may take appropriate action, including but not limited to, requiring the permittee to re-run the test.

   (b) The permittee shall update the Testing and Monitoring Plan as required by **16 TAC §5.207(a)(2)(D)** to incorporate monitoring and operational data and in response to AoR reevaluations required under Section G (1) of this permit or demonstrate to the Director that no update is needed. The amended Testing and Monitoring Plan or demonstration shall be submitted to the Director in an electronic format within one year of an AoR reevaluation; following any significant changes to the facility such as the addition of monitoring wells or newly permitted injection wells within the AoR; or when required by the Director.

   (c) Following each update of the Testing and Monitoring Plan or a demonstration that no update is needed, the permittee shall submit the resultant information in an electronic format to the Director for review and approval of the results. Once approved by the Director, the revised Testing and Monitoring Plan will become an enforceable condition of this permit.

2. **Carbon Dioxide Stream Analysis –** The permittee shall analyze the carbon dioxide stream prior to injection and with sufficient frequency to yield data representative of its chemical and physical characteristics, as described in the Testing and Monitoring Plan and to meet the requirements of **16 TAC §5.203(j)(2)(A)**.

3. **Continuous Monitoring –** The permittee shall install and use continuous recording devices to monitor the injection pressure, injection flow rate, injection mass, pressure on the annulus between the tubing and the long string of casing, annulus fluid level, and temperature. This monitoring shall be performed as described in the Testing and Monitoring Plan to meet the requirements of **16 TAC §5.203(j)(2)**. The permittee shall maintain for inspection at the facility an appropriately scaled, continuous record of these monitoring

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results as well as original files of any digitally recorded information pertaining to these operations.

4. **Groundwater (USDW) Monitoring Above the Confining Zone –** The permittee shall monitor groundwater (USDW) quality and geochemical changes above the confining zone that may be a result of carbon dioxide movement through the confining zone and additional identified geologic units. All monitoring conducted shall be performed for the parameters identified in the approved Testing and Monitoring Plan at the locations and depths, and at frequencies described in the Testing and Monitoring Plan to meet the requirements of **16 TAC §5.203(j)(2)(D)**.

5. **Soil & Soil Gas Sampling –** Soil and soil gas sampling will be contingent upon and triggered by detection of any USDW contamination in the monitor wells. In such an instance, the permittee shall monitor near-surface unsaturated zone soil and soil gas to meet the requirements of **16 TAC §5.203(j)(2)(H).**

6. **Carbon Dioxide Plume and Pressure Front Tracking –** The permittee shall track the extent of the carbon dioxide plume and pressure front using direct and indirect monitoring methods as described in the approved Testing and Monitoring Plan and in accordance with **16 TAC §5.203(j)(2)(E).** The permittee will sample the formation fluid temperature, pH, conductivity, reservoir pressure and static fluid level of the injection zone prior to starting injection to satisfy TAC §5.203(f)(3)(A) and CFR §146.87(c). Continuous pressure and temperature measurements of the injection zone will be recorded for semiannual reporting using a downhole pressure gauge in the Sunflower AZM/IZM No. 01. The data collected will be used to monitor the location of the plume and pressure front, evaluate its movement through time, and compare to the plume and pressure front predictions of the AoR model. Tracking the extent of the CO_2 plume and the position of the pressure front by using indirect, geophysical techniques, which may include seismic, electrical, gravity, or electromagnetic surveys and/or down-hole CO_2 detection tools.

7. **Corrosion Monitoring –** The permittee shall perform corrosion monitoring of the well construction materials for loss of mass, thickness, cracking, pitting, and other signs of corrosion on a quarterly basis using the procedures described in the Testing and Monitoring Plan and in accordance with **16 TAC §5.203(j)(2)(C).** This ensures that the well components meet the minimum standards for material strength and performance set forth in **16 TAC §5.203(e)(1)(B)**.

8. **External Mechanical Integrity Testing –** The permittee shall demonstrate external mechanical integrity annually as described in the approved Testing and Monitoring Plan and shall comply with Section L of this permit in order to meet the requirements of **16 TAC §§5.203(h)(1)(D)** and **5.206(e)(1)**.

9. **Pressure Fall-Off Test –** The permittee shall conduct a pressure fall-off test at least once every five (5) years unless more frequent testing is required by the Director based on site-specific information. The test shall be performed as described in the Testing and Monitoring Plan to meet the requirements of **16 TAC §5.203(j)(2)(G)**.

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10. **Additional Monitoring –** If required by the Director as provided in **16 TAC §5.203(j)(2)(H)** the permittee shall perform any additional monitoring determined to be necessary to support, upgrade, and improve computational modeling of the AoR evaluation.). An update shall be made to the Testing and Monitoring Plan, and the subsequent monitoring shall be performed as described in the update.

O. REPORTING AND RECORDKEEPING

The permittee shall submit reports at frequencies described in the approved Testing and Monitoring Plan, and as required by this permit. Reports shall contain all the data and information required to be monitored, gathered, and reported by this permit and meet the requirements of **16 TAC §§5.206(c), 5.206(d), 5.206(e),** and **5.207**.

1. **Electronic Reporting –** All reports, submittals, notifications, correspondence to the Director, and records made and maintained by the permittee under this permit shall be in an electronic format. The permittee shall electronically submit all required reports to an address or location as determined by the Director.

2. **Semi-Annual Reports –** The permittee shall submit reports on a semi-annual basis in accordance with **16 TAC §5.207(a)(2)(C).** The reporting period for semi-annual reports will be from January 1 through June 30 and from July 1 through December 31. Reports shall be submitted within 30 days of the end of each reporting period. Semi-annual reports shall include all data collected on a continuous, daily, monthly, quarterly and semi-annual basis as described in the approved Testing and Monitoring Plan. The second semi-annual report for each year shall include all data collected on an annual basis as described in the approved Testing and Monitoring Plan. Reports shall contain the following information and data, as well as all other information and data collected not listed below, but as described in the approved Testing and Monitoring Plan:

    (a) Any changes to the physical, chemical, and other relevant characteristics of the carbon dioxide stream from the proposed operating data.

    (b) Monthly average, maximum, and minimum values for injection pressure, flow rate and daily volume, temperature, and annular pressure.

    (c) A description of any event that exceeds operating parameters for annulus pressure or injection pressure specified in this permit.

    (d) A description of any event which triggers the shut-off systems required in Section (K)(6) of this permit pursuant to **16 TAC §5.206(d)(2)(F)** and the response taken.

    (e) The monthly volume and mass of the carbon dioxide stream injected over the reporting period and the volume and mass injected cumulatively as of the end of the reporting period.

    (f) Monthly annulus fluid volume added or removed; and

    (g) Results of the continuous monitoring required in Section N(3) including:

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(i) A tabulation of: (1) daily maximum injection pressure, (2) daily minimum annulus pressure, (3) daily minimum value of the difference between simultaneous measurements of annulus and injection pressure, (4) daily volume and mass, (5) daily maximum flow rate, and (6) average annulus tank fluid level; and

(ii) Graph(s) of the continuous monitoring as required in Section N(3) of this permit, or of daily average values of these parameters. The injection pressure, injection volume and mass and flow rate, annulus fluid level, annulus pressure, and temperature shall be submitted on one or more graphs, using contrasting symbols or colors, or in another manner approved by the Director.

(h) Results of any additional monitoring identified in the Testing and Monitoring Plan and described in Section N of this permit.

3. Twenty-Four (24)-Hour Reporting –

(a) The permittee shall report to the Director any permit noncompliance which may endanger human health or the environment and any events that require implementation of actions in the Emergency and Remedial Response Plan (Attachment H of this permit). Any information shall be provided orally within 24 hours from the time the permittee becomes aware of the circumstances. Such oral reports should include, but need not be limited to the following information:

(i) Any evidence that the injected carbon dioxide stream or associated pressure front may cause endangerment to a USDW, or any monitoring or other information which indicates that any contaminant may cause endangerment to a USDW;

(ii) Any noncompliance with a permit condition, or malfunction of the injection system, which may cause fluid migration into or between USDWs;

(iii) Any triggering of the shut-off system required in Section (K)(7) of this permit (i.e., downhole or at the surface);

(iv) Any failure to maintain mechanical integrity;

(v) Pursuant to compliance with the requirement for surface air/soil gas monitoring or other monitoring technologies, if required by the Director in accordance with **16 TAC §5.203(j)(2)(H)** due to any release of carbon dioxide to the atmosphere or biosphere; and

(vi) Actions taken to implement appropriate protocols outlined in the Emergency and Remedial Response Plan (Attachment H of this permit).

(c) A written submission shall be provided to the Director in an electronic format within five (5) days of the time the permittee becomes aware of the circumstances

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described in Section O(3)(a) of this permit. The submission shall contain a description of the noncompliance or emergency, or remedial response and its cause; the period of noncompliance, emergency, or remedial response, including exact dates and times, and, if the noncompliance has not been corrected, the anticipated time it is expected to continue as well as actions taken to implement appropriate protocols outlined in the Emergency and Remedial Response Plan (Attachment H of this permit); and steps taken or planned to reduce, eliminate and prevent recurrence of the noncompliance or emergency or condition requiring remedial response.

4. Reports on Well Tests and Workovers – Report within 30 days, the results of:

(a) Periodic tests of mechanical integrity;

(b) Any well workover, including stimulation;

(c) Any other test of the injection well conducted by the permittee if required by the Director; and

(d) Any test of any monitoring well required by this permit

5. Advance Notice Reporting –

(a) **Well Tests –** The permittee shall give at least 30 days advance written notice to the Director in an electronic format of any planned workover, stimulation, or other well test and submit notice at least 48 hours in advance of any actual activity.

(b) **Planned Changes –** The permittee shall give written notice to the Director in an electronic format, as soon as possible, of any planned physical alterations or additions to the permitted facility. An analysis of any new injection fluid shall be submitted to the Director for review and written approval at least 30 days prior to injection; this approval may result in a permit modification.

(c) **Anticipated Noncompliance –** The permittee shall give at least 14 days advance written notice to the Director in an electronic format of any planned changes in the permitted facility or activity which may result in noncompliance with permit requirements.

6. Additional Reports –

(a) **Compliance Schedules –** Reports of compliance or noncompliance with, or any progress reports on, interim and final requirements contained in any compliance schedule of this permit shall be submitted in an electronic format by the permittee no later than 45 days following each schedule date.

(b) **Transfer of Permits –** This permit is not transferable to any person except after notice is sent to the Director in an electronic format at least 45 days prior to transfer and the requirements of **16 TAC §5.202(c)** have been met. Pursuant to requirements at **16 TAC §5.202(d)(2)(A)(v)(VIII),** the Director will require

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modification or revocation and reissuance of the permit to change the name of the permittee and incorporate such other requirements as may be necessary under the SDWA. All financial responsibility cost estimates, documentation, and instruments as required by **16 TAC §5.203(n)** and by Section H of this permit shall be updated and provided to the Director by any new owner or operator of the well.

(c) **Other Noncompliance –** The permittee shall report in an electronic format all other instances of noncompliance not otherwise reported with the next monitoring report. The reports shall contain the information listed in Section O(3)(a) of this permit.

(d) **Other Information –** When the permittee becomes aware of failure to submit any relevant facts in the permit application or that incorrect information was submitted in a permit application or in any report to the Director, the permittee shall submit such facts or corrected information in an electronic format within 10 days of discovery in accordance with **16 TAC §5.203(p)**.

7. Records and Record Retention –

(a) The permittee shall retain records and all monitoring information, including all calibration and maintenance records and all original chart recordings for continuous monitoring instrumentation and copies of all reports required by this permit (including records from pre-injection, active injection, and post-injection phases) for a period of at least 10 years from collection.

(b) The permittee shall maintain records of all data required to complete the permit application form for this permit and any supplemental information (e.g., modeling inputs for AoR delineations and reevaluations, plan modifications) submitted under **16 TAC §§5.206(l), 5.206(m),** and **5.207(e)** until at least 10 years after site closure.

(c) The permittee shall retain records concerning the nature and composition of all injected fluids until at least 10 years after site closure.

(d) The retention periods specified in Section O(7)(a) through (c) of this permit may be extended by the Director at any time. The permittee shall continue to retain records after the retention period specified in Section O(7)(a) through (c) of this permit or any extension thereof expires unless the permittee delivers the records to the Director or obtains written approval from the Director to discard the records.

(e) Records of monitoring information shall include:

(i) The date, exact place, and time of sampling or measurements.

(ii) The name(s) of the individual(s) who performed the sampling or measurements.

(iii) A precise description of both sampling methodology and the handling of samples.

(iv) The date(s) analyses were performed.

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(v) The name(s) of the individual(s) who performed the analyses.

(vi) The analytical techniques or methods used and

(vii) The results of such analyses.

P. WELL PLUGGING, POST-INJECTION SITE CARE, AND SITE CLOSURE

The permittee shall maintain and comply with the approved Well Plugging Plan (Attachment G) and the approved Post Injection Site Care and Site Closure Plan (Attachment I) and shall comply with the requirements of **16 TAC §§3.14, 5.203(k), 5.205(b), 5.205(c), 5.205(d), and 5.206(k)(6)(A).** The Well Plugging Plan and the Post-Injection Site Care and Site Closure Plan are enforceable conditions of this permit.

1. **Well Plugging Plan Revisions –** If data indicates and the permittee deems it necessary, or if the Director requires the approved plans in Attachments G and I of this permit to be modified, revised plan(s) shall be submitted in an electronic format to the Director for review and written approval. Any amendments to the Well Plugging Plan and/or the Post-Injection Site Care and Site Closure plan shall be approved by the Director and shall be incorporated into the permit and are subject to the permit modification requirements at **16 TAC §5.203(k)(3)(A)**.

2. **Required Activities Prior to Plugging –** The permittee shall flush the wells with an inert buffer fluid, determine the post-injection bottomhole pressure, and perform final internal and external mechanical integrity tests prior to injection well plugging. The internal and external mechanical integrity tests shall be performed as required by Section L of this permit.

3. **Notice of Plugging and Abandonment –** The permittee shall notify the Director in writing in an electronic format pursuant to **16 TAC §5.206(k)(6)(A)** least 60 days before plugging, conversion or abandonment of the well. A shorter notice period may be allowed at the discretion of the Director.

4. **Plugging and Abandonment Approval and Report –**

(a) The permittee shall receive written approval from the Director before plugging the well and shall plug and abandon the well as required by **16 TAC §§3.14** and **5.203(k),** as described in the approved Well Plugging Plan (Attachment G of this permit).

(b) Within 30 days after plugging, the permittee shall submit in an electronic format a plugging report to the Director. The report shall be signed and certified by the permittee in accordance with **16 TAC §5.203(k)(4),** and by the person who performed the plugging operation (if other than the permittee.) The permittee shall retain the well plugging report in an electronic format for ten (10) years following site closure. The report shall include:

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(i) A statement that the well was plugged in accordance with the approved Well Plugging Plan (Attachment G of this permit); or
(ii) If the actual plugging differed from the approved plan, a statement describing the actual plugging and an updated plan specifying the differences from the plan previously submitted and explaining why the Director should approve such deviation. If the Director determines that a deviation from the plan incorporated in this permit may endanger USDWs, the permittee shall replug the well as required by the Director.

5. **Temporary Abandonment –** If the permittee ceases injection for more than 24 consecutive months, the well is considered to be in a temporarily abandoned status, and the permittee shall plug and abandon the well in accordance with the approved Well Plugging Plan, **16 TAC §5.203(k)**, or make a demonstration of non-endangerment of this well that is satisfactory to the Director while it is in temporary abandonment status. During any periods of temporary abandonment or disuse, the well shall be tested to ensure that it maintains mechanical integrity, in compliance with the requirements and frequency specified in Section L(2) of this permit. The permittee shall continue to comply with the conditions of this permit, including all monitoring and reporting requirements in compliance with all requirements of this permit and all applicable regulations.

6. **Post-Injection Site Care and Site Closure Plan –** The permittee shall maintain and comply with the Post-Injection Site Care and Site Closure Plan in Attachment I of this permit and comply with the requirements of **16 TAC §§5.203(m)**, and **5.206(k).** The Post-Injection Site Care period is the length of time anticipated to demonstrate that the carbon dioxide injection poses no threat to USDWs and is an enforceable condition of this permit.

(a) Upon cessation of injection, the permittee shall either submit in electronic format for the Director's approval an amended Post-Injection Site Care and Site Closure Plan or demonstrate through monitoring data and modeling results that no amendment to the plan is needed.

(b) At any time during the life of the project, the permittee may modify and resubmit in an electronic format the Post-Injection Site Care and Site Closure Plan for the Director's approval in accordance with **16 TAC §5.206(k)(1)(B).** The permittee may, as part of such modifications to the Plan, request a modification to the post-injection site care timeframe that includes documentation of the information in **16 TAC §5.203(m)(7)**.

(c) The monitoring as outlined in the approved Post-Injection Site Care and Site Closure Plan shall define the position of the carbon dioxide plume and pressure front, provide a comparison of data collected to the predictions made by the AoR model, and demonstrate that USDWs are not being endangered in accordance with **16 TAC §§5.206(e)(3)** and **5.206(k)(3)(A)**.

(d) Prior to authorization for site closure, the permittee shall submit to the Director for review and approval, in an electronic format, a demonstration, based on information collected pursuant to Section P(6)(b) of this permit, that the carbon dioxide plume and the associated pressure front do not pose an endangerment to USDWs and that no additional monitoring is needed to ensure that the project does not pose an

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endangerment to USDWs, as required in **16 TAC §5.206(k)(3)**. The Director reserves the right to amend the post-injection site monitoring requirements (including an extension of the monitoring period) if there is a concern that USDWs are at risk of endangerment.

(e) The permittee shall notify the Director in an electronic format at least 120 days before site closure. At this time, if any changes to the approved Post-Injection Site Care and Site Closure Plan in Attachment I of this permit are proposed, the permittee shall submit a revised plan.

(f) After the Director has authorized site closure, the permittee shall plug all monitoring wells as specified in Attachments G and I of this permit in a manner which will not allow movement of injection or formation fluids that endangers a USDW. The permittee shall also restore the surface site to its pre-injection condition.

(g) The permittee shall submit a site closure report in an electronic format to the Director within 90 days of site closure. The report shall include the information specified at **16 TAC §5.206(k)(6)**.

(h) The permittee shall record a notation on the deed to the facility property or any other document that is normally examined during a title search that will in perpetuity provide any potential purchaser of the property the information listed at **16 TAC §5.206(l)**.

(i) The permittee shall retain for 10 years following site closure an electronic copy of the site closure report, records collected during the post-injection site care period, and any other records required under **16 TAC §§5.203(k), 5.206(j)** and **5.206(k)(6).** The permittee shall deliver the records in an electronic format to the Director at the conclusion of the retention period.

Q. EMERGENCY AND REMEDIAL RESPONSE

The Emergency and Remedial Response Plan describes actions the permittee shall take to address movement of the injection or formation fluids that may cause endangerment to a USDW during construction, operation, and post-injection site care periods. The permittee shall maintain and comply with the approved Emergency and Remedial Response Plan (Attachment H of this permit), which is an enforceable condition of this permit, and comply with the requirements of **16 TAC §5.203(l)**.

1. If the data collected indicates evidence that the carbon dioxide plume and or pressure front may cause endangerment to a USDW, the permittee shall:

(a) Cease injection in accordance with Sections K(9) and Attachments E or H of this permit;

(b) Take all reasonable steps necessary to identify and characterize any release from the underground injection system;

(c) Notify the Director within 24 hours.

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2. Annual update is required in accordance with **16 TAC §5.207(a)(2)(E).** Operators must submit an annual statement, signed by an appropriate company official, confirming that the operator has:

   (a) Reviewed the monitoring and operational data that are relevant to a decision on whether to reevaluate the AoR and the monitoring and operational data that are relevant to a decision on whether to update an approved plan required by **16 TAC §§5.203 or 5.206** of this title;

   (b) Determined whether any updates were warranted by material change in the monitoring and operational data or in the evaluation of the monitoring and operational data by the operator; and

   (c) Operators must submit either the updated plan or a summary of the modifications for each plan for which an update the operator determined to be warranted pursuant to subclause (I) of this clause. The director may require submission of copies of any updated plans and/or additional information regarding whether or not updates of any particular plans are warranted.

   At least every five years, or more frequently if the monitoring and operational data warrant, the permittee shall review and update the Emergency and Remedial Response Plan or demonstrate to the Director that no update is needed. The permittee shall also incorporate monitoring and operational data and in response to AoR reevaluations required under Section G(4) of this permit or demonstrate to the Director that no update is needed. The amended Emergency and Remedial Response Plan or demonstration shall be submitted to the Director in an electronic format within thirty (30) days of an AoR reevaluation in accordance with **16 TAC §5.207(a)(3),** following any significant changes to the facility such as the addition of injection wells, or when required by the Director. If the amendments to the Emergency and Remedial Response Plan cause the cost estimates to change, then a new Financial Responsibility Demonstration shall be submitted for review and approval by the Director in accordance with Section H of this permit.

3. Following each update of the Emergency and Remedial Response Plan or a demonstration that no update is needed, the permittee shall submit the resultant information in an electronic format to the Director for review and confirmation of the results. Once approved by the Director, the revised Emergency and Remedial Response Plan will become an enforceable condition of this permit.

R. COMMENCING INJECTION

The permittee may not commence injection until:

1. Results of the formation testing and logging program as specified in Section J of this permit and in **16 TAC §5.203(f)** are submitted to the Director in an electronic format and subsequently reviewed and approved by the Director;

2. Mechanical integrity of the wells has been demonstrated in accordance with **16 TAC §§5.102(36)**, **5.203(h)(1)(B)** and **5.203(h)(1)(D)**, and in accordance with Section L(1) through (3) of this permit;

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3. The completion of corrective action required by the Area of Review and Corrective Action Plan found in Attachment A of this permit in accordance with **16 TAC §5.203(d)(1)(C)**;

4. All requirements at **16 TAC §5.203** have been met, including but not limited to reviewing and updating of the Area of Review and Corrective Action, Testing and Monitoring, Well Plugging, Post-Injection Site Care and Site Closure, and Emergency and Remedial Response plans to incorporate final site characterization information, final delineation of the AoR, and the results of pre-injection testing, and information has been submitted in an electronic format, reviewed and approved by the Director;

5. Construction is complete and the permittee has submitted to the Director in an electronic format a notice that completed construction is in compliance with **16 TAC §5.203(e)(1)** and Section I of this permit;

6. The Director has inspected or otherwise reviewed the injection well and all submitted information and finds it is in compliance with the conditions of the permit;

7. The Director has approved demonstration of the alarm system and shut-off system under Section K (7) of this permit; and

8. The Director has given written authorization to commence injection.

S. PAYMENT OF FEES TO THE STATE OF TEXAS

In accordance with **16 TAC §5.205**, the permittee shall pay the following fees:

1. **Application Fee for Amendment –** The applicant must pay to the Commission an application fee of $25,000 for each application to amend a permit for a geologic storage facility in accordance with **16 TAC §5.205(a)(1)(B)**.

2. **Injection Fee –** The operator must pay to the Commission an annual fee of $0.025 per metric ton of CO_2 injected into the geologic storage facility in accordance with **16 TAC §5.205(a)(2)**.

3. **Post-Injection Care Fee –** The operator must pay to the Commission an annual fee of $50,000 each year the operator does not inject into the geologic storage facility until the director has authorized storage facility closure in accordance with **16 TAC §5.205(a)(3)**.

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ATTACHMENTS

These attachments include, but are not limited to, permit conditions and plans concerning operating procedures, monitoring and reporting, as required by **16 TAC §§5.203, 5.205, 5.206, and 5.207.** The permittee shall comply with these conditions and adhere to these plans as they are approved by the Director by their incorporation into this permit.

A. AREA OF REVIEW AND CORRECTIVE ACTION PLAN

B. WELL CONSTRUCTION PLAN

C. STIMULATION PLAN

D. PRE-INJECTION/PRE-OPERATIONAL TESTING PLAN

E. INJECTION WELL OPERATING CONDITIONS

F. TESTING AND MONITORING PLAN

G. WELL(S) PLUGGING PLAN

H. EMERGENCY AND REMEDIAL RESPONSE PLAN

I. POST-INJECTION SITE CARE AND SITE CLOSURE PLAN

J. FINANCIAL ASSURANCE DEMONSTRATION

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Railroad Commission of Texas

Attachment A – Area of Review and Corrective Action Plan

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Underground Injection Control – Class VI Permit Application for Sunflower Carbon Capture and Storage Project Injection Wells No. 01, No. 02, and No. 03

SECTION 3 – AREA OF REVIEW AND CORRECTIVE ACTION PLAN

Sunflower Carbon Storage Project
Jefferson and Liberty Counties, Texas
ExxonMobil Low Carbon Solutions Onshore Storage, LLC
Amendment 3: August 2026

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SECTION 3 – AREA OF REVIEW AND CORRECTIVE ACTION PLAN

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3.1 Area of Review and Corrective Action Plan

ExxonMobil Low Carbon Solutions Onshore Storage, LLC (ExxonMobil) is undertaking the Sunflower Carbon Capture and Storage (CCS) Project (Sunflower Project) in Jefferson and Liberty Counties, Texas, to sequester approximately 25.3 million metric tons (MMT) of CO_2 over 11 years. This Area of Review (AOR) and Corrective Action Plan was prepared to meet the requirements of Title 16, Texas Administrative Code (16 TAC), Part 1, Chapter 5.

ExxonMobil is pursuing individual Class VI permits for three injection wells consistent with 16 TAC **§5.203**. Given the proximity of the proposed injection wells for the Sunflower Project, ExxonMobil plans to obtain approval from the Underground Injection Control (UIC) Program director (UIC Director) to delineate the AOR and prepare the Corrective Action Plan to represent the collective effects of the three injection wells within the project AOR. Although the effects were evaluated in the collective, the required maps showing the delineated AOR and the Corrective Action Plan for artificial penetrations are submitted separately for each well so that they may be incorporated into each injection well's Class VI permit.

3.2 Objectives

A comprehensive modeling and evaluation effort was undertaken to accomplish the following objectives, consistent with the requirements of 16 TAC **§5.203(d)(1)**:

- Predict the extent of the CO_2 plume and pressure front, which form the basis for the AOR, using computational modeling, and identify all wells that require corrective action (16 TAC **§5.203(d)(1)(A)(i)**).
- Provide a plan to perform the required corrective action on artificial penetrations in the AOR (16 TAC **§5.203(d)(1)(C)**) that could threaten the underground source of drinking water (USDW).
- Support the development of effective monitoring strategies for the Testing and Monitoring Plan by identifying the locations where groundwater quality or pressure monitoring should be performed.
- Help direct emergency response planning by identifying potential vulnerable areas within or near the AOR that could require consideration when implementing an emergency response.
- Ensure that the Emergency and Remedial Response Plan and financial responsibility demonstration account for the most recently approved AOR (16 TAC **§5.205(b)(3)**).
- Provide a guide for periodic AOR reevaluations to inform site management and monitoring over the life cycle of the Sunflower Project (16 TAC **§5.206(g)**).
- Retain modeling inputs and data used to support AOR reevaluations for 10 years (16 TAC **§5.206(g)(5)**).

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3.3 AOR Delineation Based on Model Results

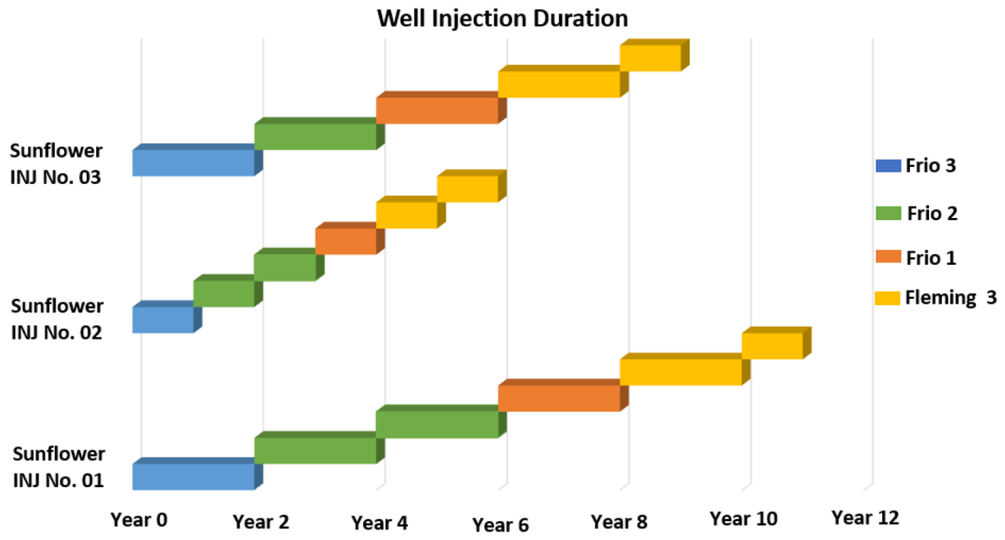
The following subsections summarize information discussed further in *Section 2.7* (on model results) to provide context for the Corrective Action Plan and the AOR reevaluation plan that follow. More detailed information regarding geologic and dynamic model inputs and workflows are presented in *Section 2 – Plume Model.*

3.3.1 Extent of CO_2 Plume

In accordance with 16 TAC **§5.203(d)**, areal grid block size in the model was selected to optimize model runtimes, limit grid distortion effects, and allow for sufficiently accurate contouring of the plume extent. The operational and geologic input parameters were used in the Intersect model to generate projections of plume and pressure migration vs. time. Each well was initially completed and then recompleted into incrementally shallower portions of the injection intervals per the schedule presented in Figure 3-1.

Figure 3-2 presents the time-dependent, maximum areal extent of the CO_2 plume projected to be present in any of the injection zone layers at 5 years from the start of injection, at the end of injection, and at the stabilization of the plume. The CO_2 saturation and the areal extent of the plumes generated by CO_2 injection expand with time. As the volume of injected CO_2 increases, the CO_2 plumes from each injection well commingle in some of the layers. Once injection stops, the CO_2 footprint migration slows considerably. The combined effects of relative permeability, capillary pressure, CO_2 dissolving in brine, and limited structural dip ultimately arrest the extent of the CO_2 plume migration drift updip to the north-northwest. Figure 3-3 illustrates the cross-sectional view of the time-dependent CO_2 plume.

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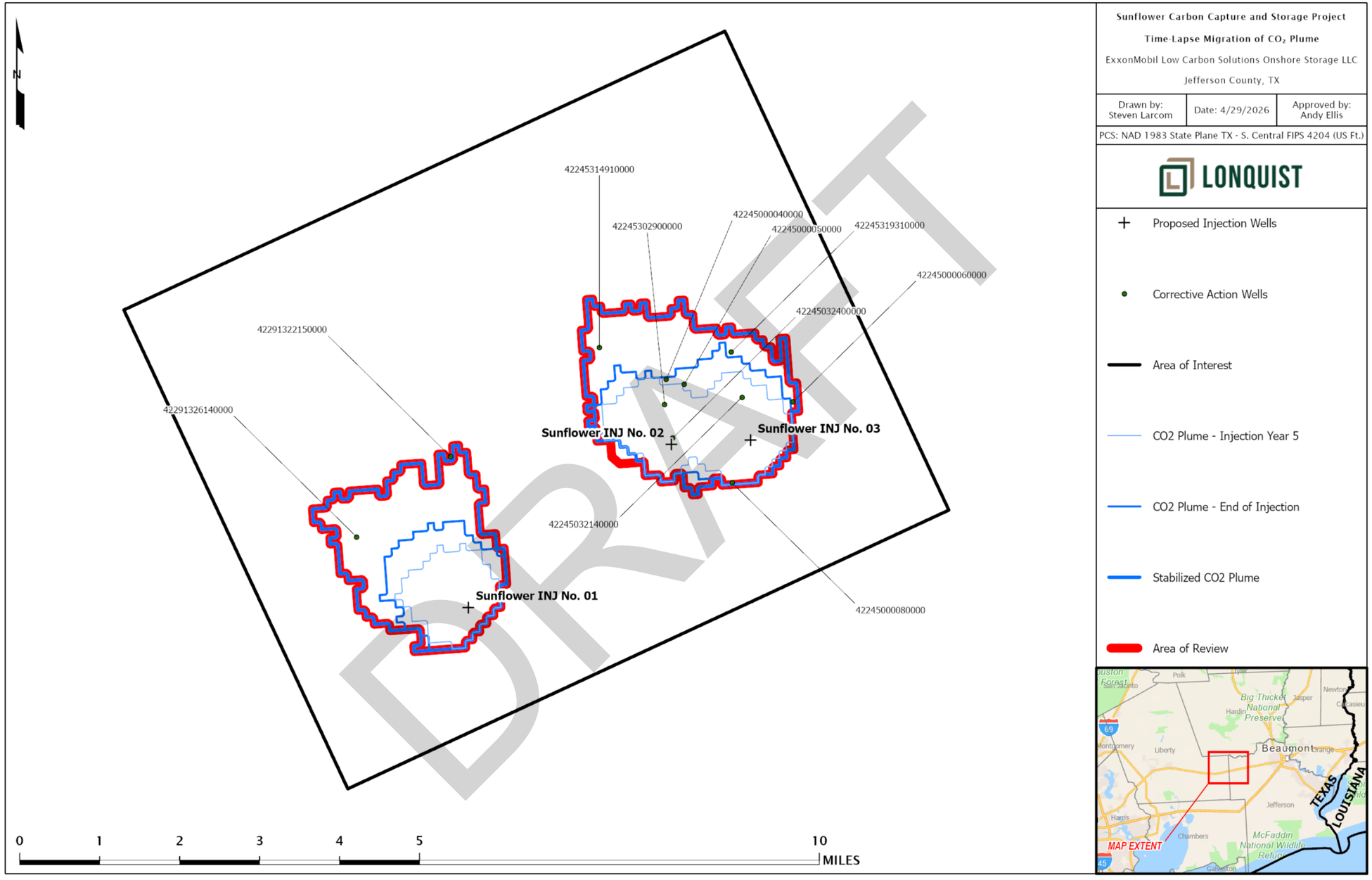


Stage	Injection Formation	Maximum Injection Rate Constraint (MMTPA)			Total Per Zone (MMT)
		Sunflower INJ No. 01	Sunflower INJ No. 02	Sunflower INJ No. 03	
1	Frio 3	1.2	1.0	0.8	5.0
2	Frio 2 Lower	1.0	1.2	1.2 *	7.8
3	Frio 2 Upper	0.5	1.2		
4	Frio 1	1.0	1.0	1.0	5.0
5	Fleming 3 Lower	1.0	1.0	1.0	7.5
6	Fleming 3 Upper	1.0	1.0	0.5	
Total Per Well (MMT)		10.4	6.4	8.5	**Site Total (25.3)**

* For Sunflower INJ No.3 stages 2 & 3 are combined.

Propietary Business Information

Figure 3-1 – Summary of Injection Intervals and Durations for Each Injection Well



Sunflower Carbon Capture and Storage Project

Time-Lapse Migration of CO_2 Plume

ExxonMobil Low Carbon Solutions Onshore Storage LLC

Jefferson County, TX

Drawn by: Steven Larcom	Date: 4/29/2026	Approved by: Andy Ellis

PCS: NAD 1983 State Plane TX - S. Central FIPS 4204 (US Ft.)

LONQUIST

- Proposed Injection Wells
- Corrective Action Wells
- Area of Interest
- CO2 Plume - Injection Year 5
- CO2 Plume - End of Injection
- Stabilized CO2 Plume
- Area of Review

Figure 3-2 – Time-Lapse Migration of CO_2 Plume

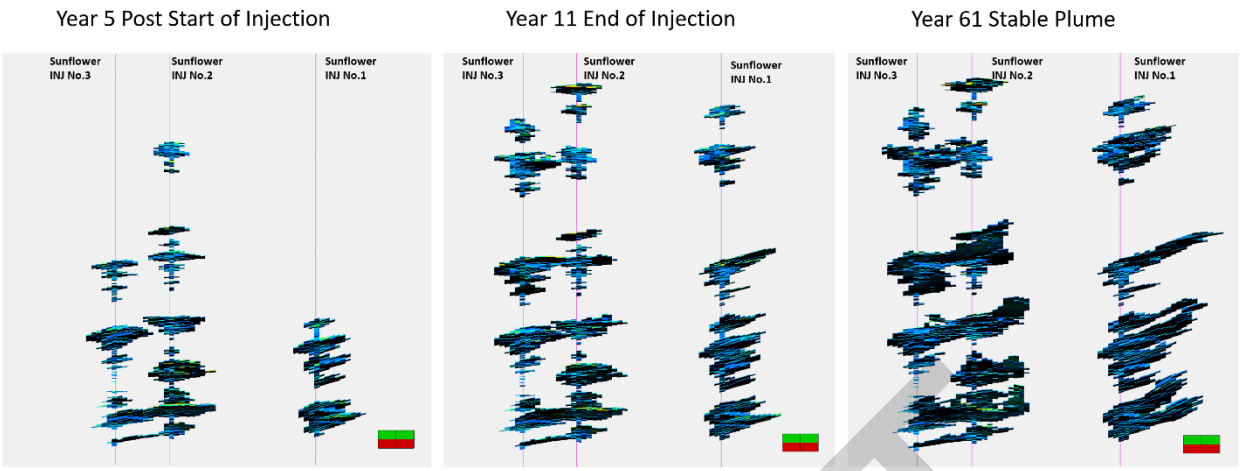


Figure 3-3 – Time-Lapse Migration of CO_2 Plume, Cross Section View Looking South

The rate of plume size growth is expected to diminish rapidly following the cessation of injection. The plume is expected to reach its maximum size approximately 50 years after injection ends—when the plume is considered stable.

3.3.2 Delineation of the Critical Pressure Front

In accordance with 16 TAC **§5.203(d)**, the pressure AOR was delineated by the critical pressure front created by the injection of CO_2 into the injection intervals. Critical pressure is the increase in reservoir pressure that has a potential to create a crossflow of brine from the injection zone into the lowermost USDW, assuming the presence of a hypothetical bridging conduit such as an unplugged borehole. The first step to predict the pressure front of interest is to calculate the critical pressure for each completion stage. Once critical pressure is estimated, a numerical simulation is used to predict the size and shape of the critical pressure front defined by this pressure contour as detailed in *Section 2.7.3 – Plume Model*. The critical pressure front is shown in in Figure 3-4.

3.3.3 Final AOR

The maximum areal extents of both the CO_2 plume and the critical pressure front were used to delineate the AOR at any time interval or depth. The larger extent of either CO_2 saturation or critical pressure rise was used to define the AOR boundary. Figure 3-2 illustrates the maximum extent of the stabilized CO_2 plume. The critical pressure front, illustrated in Figure 3-5, represents the maximum areal cone of influence and combines results from the six completion intervals for each of the three injection wells. Superimposing the maximum CO_2 plume and critical pressure boundaries, Figure 3-5 provides the AOR boundary for the project along with the 11 artificial penetrations through the upper confining zone (UCZ) that require corrective action.

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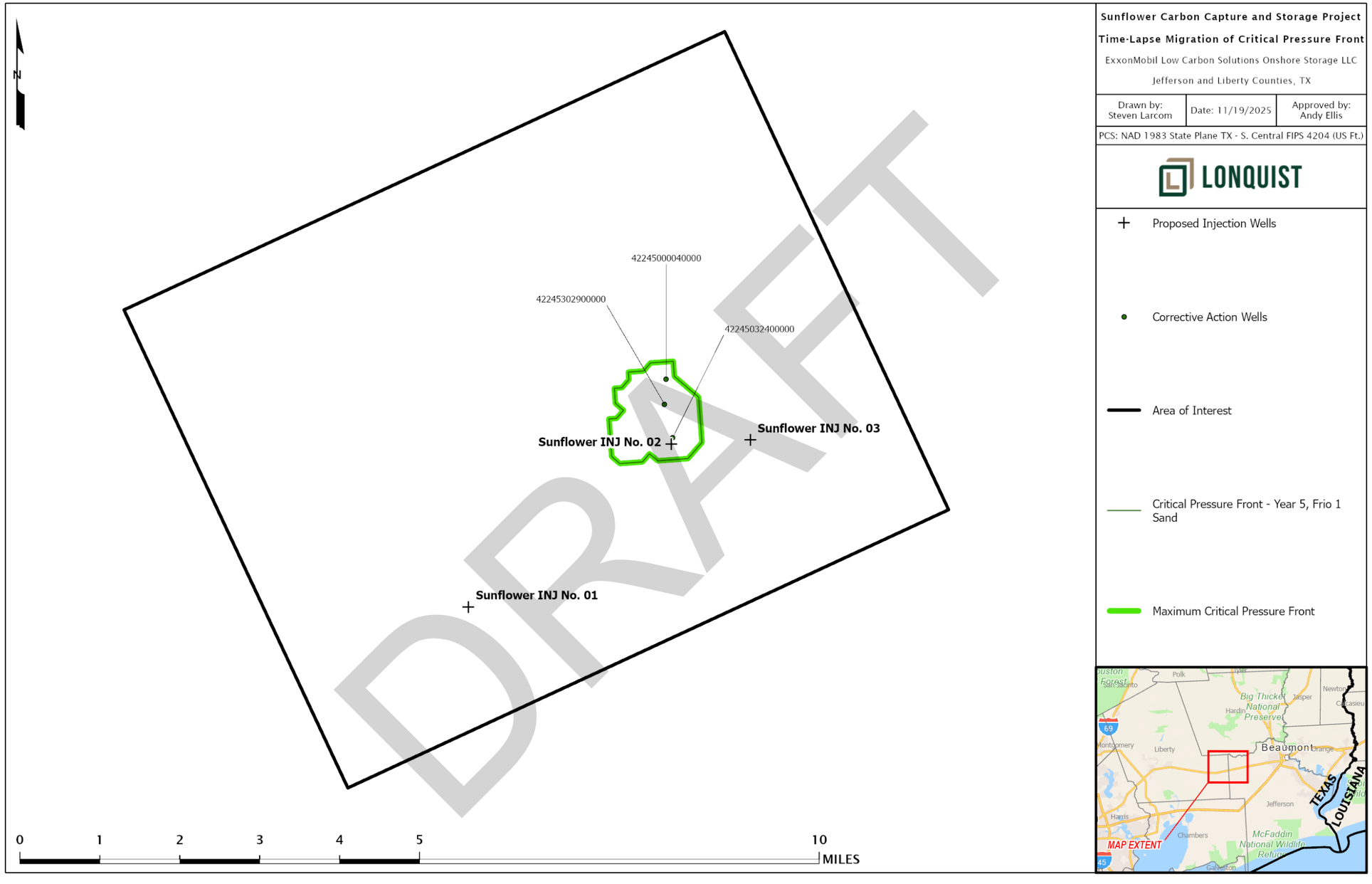


Figure 3-4 – Time-Lapse Migration of Critical Pressure Front

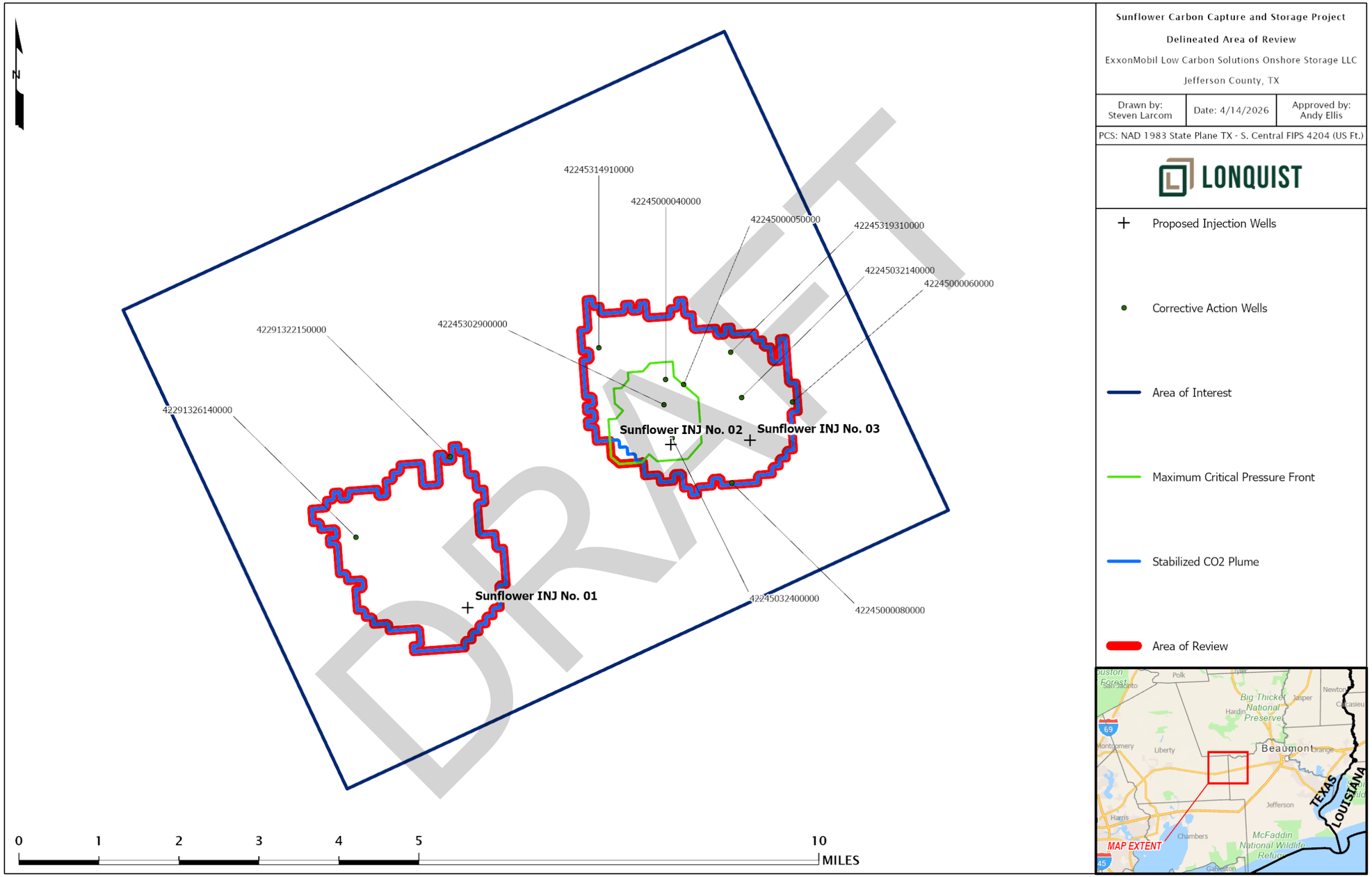


Figure 3-5 – Delineated Area of Review

3.4 Stages of Model Development

The stages of development for the CO_2 plume and pressure front model started with pre-operational phase data and industry standards to predict the AOR boundary. The geomodel and reservoir model rely on these data and on industry-standard correlations for the assignments of properties based on site-specific conditions derived from analysis of stratigraphic test well data. Physical rock-property distributions assigned to the model based on geostatistics have been analyzed and are consistent with all available data, including that of the stratigraphic test well.

Looking forward to the operational phase of the Sunflower Project, updates will be made to the model for calibration purposes. The model calibration procedures will likely focus on the parameters that have been identified during the pre-operational modeling effort as the most sensitive parameters during sensitivity analyses. The calibration process is intended to be an iterative process, with updates to the geomodel and input parameters, to achieve an acceptable agreement between model predictions and the collected testing and monitoring data.

3.5 Corrective Action Plan and Schedule

Consistent with 16 TAC **§5.203(d)**, the primary objective of this Corrective Action Plan is to identify the potential risk for loss of CO_2 or brine containment through artificial penetrations of the UCZ, and to specify corrective actions that would be taken to restore the integrity of the UCZ, if needed. ExxonMobil undertook a thorough investigation of artificial penetrations within and immediately adjacent to the AOR. Public and private databases were searched, and a total of 27 stratigraphic test wells, legacy oil and gas wells (legacy wells), and water wells were identified within the AOR. *Appendix C-2* shows the 16 water wells within the AOR.

Eleven artificial penetrations were found to penetrate the UCZ as shown in Figure 3-5, based on an analysis of the available data. All 11 of these artificial penetrations warrant corrective action planning and scheduling based on conservative assumptions regarding the potential for impact by injection. Following the requirements outlined in 16 TAC **§5.203(d)(1)(B)** and **§5.203(d)(1)(C)**), each artificial penetration within the AOR that may penetrate the UCZ was evaluated either for the quality of casing and cementing, in the case of existing wells—or for the quality of plugging and abandonment (P&A), in the case of abandoned wells.

This section provides for each well a rigorous corrective action process that begins with additional well-assessment activity and ends with establishing incremental barriers to remedy the potential for CO_2 or brine crossflow between the injection zones and the USDW. A USDW map within the AOI was used for setting the USDW cement plugs. The USDW map is featured and discussed in *Section 1 – Site Characterization*.

3.5.1 Data Acquisition and Evaluation of Artificial Penetration Information

In accordance with 16 TAC **§5.203(b)** and **§5.203(d)(1)(B**), a search was conducted to identify and assess the occurrence of artificial penetrations within the AOR. Additionally, a comprehensive

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search of publicly available data sets was also performed to search for state- or EPA-approved subsurface cleanup sites, including Superfund/Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA) sites, hazardous waste/Resource Conservation and Recovery Act (RCRA) sites, brownfields, and leaking underground storage tanks—as well as springs, mines, and quarries within the AOR. No such sites were found to exist within the Sunflower Project AOR. ExxonMobil also searched for other pertinent features including roads and structures intended for human occupancy which are shown in *Appendix C-5*. Pipelines that are located within the AOR are shown in Appendix G-2.

The following data sources were reviewed to identify the aforementioned sites within the AOR:

- Railroad Commission of Texas (TRRC) Geographical Information System (GIS) Database
- Texas Water Development Board
- Texas Commission on Environmental Quality UIC central file room database
- Third-party oil-and-gas record databases including Enverus Drilling Info, IHS Energy Portal, Tobin Data, EMSDB, HART, and Enerdeq
- EPA EnviroAtlas
- National Mine Map Repository

A tabulation of identified artificial penetrations within the AOR was created using a combination of the above data and is summarized in Table 3-1. Available records for the identified artificial penetrations are included in *Appendix C*.

Based on the artificial penetrations identified in the above databases, the following additional analysis was or will be conducted to assess the accuracy of well presence, location, and condition:

- A physical record request was made to the TRRC, and the available documents were reviewed.
- An aeromagnetic survey that fully includes the AOR was conducted in late 2025.
- In-person reconnaissance surveys will be conducted once surface access is secured.

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Table 3-1 – Summary of Artificial Penetrations Within the AOR

#	Well Name	State / Federal Well ID (API No.)[1]	Well Type	Well Status	Date Drilled	Depth (ft KB)	Latitude, Longitude (NAD 27)	Penetrates UCZ?	Plume (CO_2 or Pressure Front)
1	Carpenter #001	4224530290	Dry Hole	P & A	11/14/1974	7,816	30.05589, -94.42295	Yes	CO_2 Plume
2	P. H. Carpenter #001	4224500004	Dry Hole	P & A	3/16/1958	7,753	30.06002, -94.42207	Yes	CO_2 Plume
3	Frank Carpenter et al #001	4224500005	Oil	P & A	10/18/1957	8,515	30.05893, -94.41876	Yes	CO_2 Plume
4	Wilson et al #001	4224503214	Dry Hole	P & A	4/16/1966	6,395	30.05622, -94.40685	Yes	CO_2 Plume
5	F. S. WILSON #1	4224500006	Dry hole	P & A	11/8/1937	7,012	30.05514, -94.39594	Yes	CO_2 Plume
6	Garth #001	4224531931	Dry hole	P & A	3/8/1988	5,800	30.0646, -94.40914	Yes	CO_2 Plume
7	Broussard Farms #001	4229132614	Dry Hole	P & A	10/16/2005	11,375	30.033768, -94.4881094	Yes	CO_2 Plume
8	Champion International Corp. Etal Gas Unit #001	4224531491	Dry Hole	P & A	7/2/1981	16,260	30.06639, -94.436	Yes	CO_2 Plume
9	B. H. Willis #001	4224500008	Dry Hole	P & A	2/20/1938	6,500	30.04081, -94.40924	Yes	CO_2 Plume
10	A M CARPENTER EST #001	4224503240	Dry Hole	P & A	5/27/1966	5,928	30.04957, -94.42157	Yes	CO_2 Plume
11	E. A. Henderson #001	4229132215	Dry Hole	P & A	7/6/1994	14,002	30.0478163, -94.4678153	Yes	CO_2 Plume
12	Water Well 1	6161701	Water	Unknown	1/1/1956	538	30.029162, -94.481937	No	-
13	Water Well 2	6161807	Water	Unknown	1/1/1906	692	30.044717, -94.425271	No	-
14	Water Well 3	166225	Water	Unknown	5/4/2004	310	30.048606, -94.424993	No	-
15	Water Well 4	166230	Water	Unknown	5/4/2004	125	30.048606, -94.424993	No	-
16	Water Well 5	184051	Water	Unknown	12/7/2005	140	30.033329, -94.470548	No	-
17	Water Well 6	202618	Water	Unknown	2/28/2006	115	30.029439, -94.463327	No	-
18	Water Well 7	211286	Water	Unknown	6/11/2005	122	30.018328, -94.481104	No	-
19	Water Well 8	250951	Water	Unknown	10/7/2005	130	30.033606, -94.488604	No	-
20	Water Well 9	276258	Water	Unknown	11/18/2011	110	30.056940, -94.400549	No	-
21	Water Well 10	370003	Water	Unknown	5/28/2014	280	30.062773, -94.414716	No	-
22	Water Well 11	370064	Water	Unknown	6/4/2014	285	30.062773, -94.417493	No	-
23	Water Well 12	410300	Water	Unknown	9/19/2015	244	30.070212, -94.41831	No	-
24	Water Well 13	410622	Water	Unknown	10/30/2015	240	30.066106, -94.41666	No	-
25	Water Well 14	417832	Water	Unknown	1/5/2016	240	30.070662, -94.417426	No	-
26	Water Well 15	544238	Water	Unknown	3/29/2020	310	30.048200, -94.426718	No	-
27	Water Well 16	650111	Water	Unknown	9/15/2023	110	30.047509, -94.416539	No	-

*Water well datum is below ground level.
**Kelly bushing (KB) not available in historical records.
****NAD 27 – North American Datum of 1927

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[1] Readily available well identification numbers provided from public data sources up to November 20, 2025

3.5.1.1 Physical Records Review

The records of artificial penetrations with the AOR were reviewed through digital copies on the TRRC online databases, Enverus Drilling Info, and IHS Energy Portal. These records are included in *Appendix C*.

3.5.1.2 Aeromagnetic Survey

Due to the age of well development in the area, additional data collection is required to improve the accuracy of well locations and details. Magnetic survey methods have been used to fully scan the AOR for magnetic anomalies caused by subsurface features, which could include abandoned wellbores with iron or steel casing. The magnetic surveys were successfully conducted in December of 2025 and the data collected was of sufficient quality to determine that all anomalies within the AOR are accounted for through publicly available databases; no additional corrective action is necessary at this time.

3.5.1.3 Review of Abandoned Well Plugging Records

ExxonMobil conducted an evaluation of the information available for the artificial penetrations listed in Table 3-1. The list of topics reviewed included the following:

- Well depth and completion
- Well drilling date
- Well abandonment date
- Openhole or cased-hole identification
- Location of reported plugs
- Casing and cementing records
- Records of mechanical integrity tests or logs performed
- Well deviations

Wells listed on rows 1 through 11 were identified as penetrating the UCZ and subject to an assessment of plugging records and, potentially, to corrective action for deficiencies.

3.5.1.4 Summary of Artificial Penetrations Tabulation

Wells and boreholes that did not penetrate the UCZ were determined to pose no hypothetical risk to function as a vertical conduit from the injection zone. For those artificial penetrations that were completed below the UCZ, multiple sources of information were reviewed, and the relevant information was analyzed in detail (16 TAC **§5.203(d)(1)(B)**). Table 3-1 presented a summary of the artificial penetrations of interest for developing the Corrective Action Plan. Schematics detailing UCZ penetrating wells and their proposed corrective action plans are presented in *Appendix C*.

3.5.2 Corrective Action Plan for Artificial Penetrations

ExxonMobil developed a Corrective Action Plan for each artificial penetration that was identified to have the potential to act as a vertical conduit, because it was either not plugged or not plugged

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in a manner that, as required by 16 TAC **§5.203(d)(1)**, mitigates the movement of CO_2 or other fluids that could potentially endanger USDWs. For the wells identified with plugging deficiencies, the basis for the corrective action strategy is to reenter and install cement barriers to mitigate migration potential.

3.5.2.1 Corrective Action Phasing

Figures 3-2 and 3-4 show the location of the wells identified for corrective action in relation to the 5-year CO_2 plume and pressure front. Table 3-2 lists the expected arrival of the CO_2 plume and pressure front at each artificial penetration, and the schedule for when corrective action is planned. All required corrective action will be executed prior to the CO_2 plume or pressure front contacting the artificial penetration.

As described in *Section 5 – Testing and Monitoring Plan*, direct and indirect monitoring technologies will be used to track the CO_2 plume and pressure front. A planned reevaluation of the AOR will occur after 5 years of injection and at 5-year intervals, at a minimum, throughout the life cycle of the Sunflower Project. If, at any evaluation, the rate of the CO_2 plume or pressure front expansion is predicted to impact additional artificial penetrations that may be found, the Corrective Action Plan will be amended to include the necessary corrective action to address the potential for USDW endangerment, in accordance with 16 TAC **§5.203(d)(2)(B)** and **(C)**.

3.5.2.2 Analysis of Wells Identified for Corrective Action

Table 3-3 summarizes the available information concerning the borehole or well completion features and the P&A activities, as appropriate. ExxonMobil reviewed this information and determined the specific defects that require mitigation under 16 TAC **§5.203(d)(1)**.

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Table 3-2 – List of Artificial Penetrations and Schedule for Corrective Action

Well Name	API Number	Latitude, Longitude (NAD 27)	CO_2 Plume Arrival (Yr)	Pressure Front Arrival (Yr)	Schedule
Carpenter #001	4224530290	30.05589, -94.42295	5	5	Pre-Operation
P. H. Carpenter #001	4224500004	30.06002, -94.42207	11	5	Pre-Operation
Frank Carpenter et al #001	4224500005	30.05893, -94.41876	~5	-	Pre-Operation
Wilson et al #001	4224503214	30.05622, -94.40685	5	-	Pre-Operation
B. H. Willis #001	4224500008	30.04081, -94.40924	5	-	Pre-Operation
A M CARPENTER EST #001	4224503240	30.04957, -94.42157	5	5	Pre-Operation
Garth #001	4224531931	30.0646, -94.40914	21	-	Phased
Broussard Farms #001	4229132614	30.033768, -94.4881094	21	-	Phased
F. S. WILSON #1	4224500006	30.05514, -94.39594	31	-	Phased
E.A Henderson #001	4229132215	30.0478163, -94.4678153	31	-	Phased
Champion International Corp. Etal Gas Unit #001	4224531491	30.06639, -94.436	41	-	Phased

Table 3-3 – Summary of P&A Deficiency for Wells Penetrating the UCZ

Well Name	API No.	Apparent Deficiency or Uncertainty Based on Review of Available Information			Summary of Corrective Action
		Casing Records at UCZ	USDW plug(s) installed	UCZ plug(s) installed	
Carpenter #001	4224530290	Open Hole	No	No	Pump open hole with Corrosacem cement plug(s) and Portland cement plug(s)
P. H. Carpenter #001	4224500004	Cased Hole	No	No	Pump inside casing with Corrosacem cement plug(s) and Portland cement plug(s)
Frank Carpenter et al #001	4224500005	Cased Hole	No	No	Pump inside casing with Corrosacem cement plug(s) and Portland cement plug(s)
Wilson et al #001	4224503214	Open Hole	No	No	Pump open hole with Corrosacem cement plug(s) and Portland cement plug(s)
B. H. Willis #001	4224500008	Open Hole	No	No	Pump open hole with Corrosacem cement plug(s) and Portland cement plug(s)
A M CARPENTER EST #001	422450324	Cased Hole	No	No	Pump inside casing with Corrosacem cement plug(s) and Portland cement plug(s)
Garth #001	4224531931	Open Hole	No	No	Pump open hole with Corrosacem cement plug(s) and Portland cement plug(s)
Broussard Farms #001	4229132614	Cased Hole	No	No	Pump inside casing with Corrosacem cement plug(s) and Portland cement plug(s)
F. S. WILSON #1	4224500006	Open Hole	No	No	Pump open hole with Corrosacem cement plug(s) and Portland cement plug(s)
E. A. Henderson #001	4229132215	Cased Hole	Yes	No	Pump inside casing with Corrosacem cement plug(s) and Portland cement plug(s)
Champion International Corp. Etal Gas Unit #001	4224531491	Cased Hole	No	No	Pump inside casing with Corrosacem cement plug(s) and Portland cement plug(s)

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3.5.3 Corrective Action Sequence Plan

The planned actions are based on proposed plug deficiencies potentially present in the legacy wells based on the available records (displayed above, in Table 3-3). Each artificial penetration in the CO_2 plume will be reentered, and if sufficient barriers are not present, each well will have the appropriate barriers installed during the corrective action P&A field operations. The barriers will be established at the UCZ, the surface casing shoe (where applicable), the base of usable quality water (BUQW), the base of the lowermost USDW, the base of superior quality water (SQW), and the wellhead surface. While ExxonMobil deems OPC as the fit for purpose technical solution for the Sunflower CCS Project justified and supported by API 5100 and ExxonMobil's own 30-, 60-, and 180-day testing which has been provided to the Texas Railroad Commission, presented and published at industry conference, and both having been summarized in this permit, CorrosaCem – or suitable equivalent - is being proposed for the plug across the UCZ to address regulator feedback on any uncertainty of approval through the permitting process with OPC at the confining zone. *Section 4.4.3* in *Section 4 – Well Construction and Operating Conditions* presents additional discussion on OPC.

A detailed summary of the corrective action sequence for each well is presented further below, in Table 3-4—and in *Appendix C*, as specific well schematics for each well to be reentered.

3.5.3.1 Preparing the Surface Location

Prior to mobilizing at a well location, ExxonMobil will conduct an initial site visit to identify current site access and wellhead conditions. A subsurface survey may be completed utilizing ground-penetrating radar to identify the well location. If legacy equipment remains on the site, the equipment will be removed prior to mobilization. Surface piping and electrical components will be assessed and removed from the site locations. Additionally, access roads to the area surrounding the pad and wellhead-access improvements may be needed to facilitate safe entrance and egress along with rig operations.

If a sign or marker is present, the first step will be to confirm that the API number on the plat corresponds to the well where mobilization is taking place, to complete corrective action operations. After the P&A marker or exposed metal plate is removed, the necessary equipment will be rigged up on the well. The cement surface plug of the well will be drilled out and the hole reentered for corrective action.

ExxonMobil will follow required notification requirements prior to commencing remedial field activities that may take the form of workover or drilling operations. At least 5 days prior to commencement of well plugging operations, ExxonMobil will notify the TRRC via a request for approval of the proposed procedure for plugging the well, using Form W-3A. ExxonMobil will also notify the TRRC at least 48 hours prior to the start of plugging operations.

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3.5.3.2 Reentry Activities

The appropriate operational approach will be used during the reentry of each openhole legacy well for re-plugging operations, in an attempt to advance the drill pipe and bottomhole assembly from the well surface to the depth of the base of the UCZ. Based on ExxonMobil's experience with similar P&A efforts, sidetracking from the original borehole is a potential risk. Sidetracking can be caused by wellbore collapse or tagging fill/ledges in the borehole.

To mitigate the risk of sidetracking out of the original legacy wellbores, ExxonMobil will compare the log of parameters—the rate of penetration, torque, and observed cuttings at depth—to local recently drilled wells in the area, to measure the degree of tracking within the original wellbore, as the bottomhole assembly is advanced to target depth for the placement of the cement plugs. Specialized tools, steering, or other procedures will be utilized if reasonable and appropriate to reduce the potential for sidetracking to occur. If wellbore collapse, tagging fill/ledges, or other anomalies are apparent that are judged to prevent the reentry from staying within the original borehole of a legacy well, in consultation with the UIC Director, ExxonMobil will stop the openhole recovery operations at that depth, evaluate available data from the well collected to that point, complete the cement plug at the maximum depth that can be attained as specified for the well, and continue up-borehole with the remainder of the P&A plan for the well.

3.5.3.3 Setting a Plug for the UCZ

Each legacy well requiring corrective action will have a CorrosaCem cement plug set at the base of the UCZ. The cement will be designed to withstand the long-term exposure of temperature, pressure, and chemical environment. The barrier will be tested for estimated hardness and integrity after placement. While ExxonMobil deems OPC as the fit for purpose technical solution for the Sunflower CCS Project justified and supported by API 5100 and ExxonMobil's own 30-, 60-, and 180-day testing which has been provided to the Texas Railroad Commission, presented and published at industry conference, and both having been summarized in this permit, CorrosaCem – or suitable equivalent - is being proposed for the plug across the UCZ to address regulator feedback on any uncertainty of approval through the permitting process with OPC at the confining zone.

3.5.3.4 Setting Plugs at the Casing Shoe, Lowermost USDW, BUQW, SQW, and Surface

A cement plug will be set at the USDW, BUQW, SQW, and casing shoe (when present). The lowermost USDW will be plugged with a minimum 130-foot cement plug that will be set at the base of the lowermost USDW depth, starting from 50 feet beneath that depth and extending 80 feet above the target depth. All cement plugs set in this manner, and for any plug above the UCZ plug, will be OPC.

In accordance with 16 TAC **§3.14(e)**, the BUQW will be plugged with a minimum 130-foot cement plug set at the base of the BUQW, starting 50 feet beneath that depth and extending 80 feet above the target depth. The cement will be lab-tested prior to pumping, and pressure-tested or tagged at each relevant marker. A final 30-foot cement plug will be set at the surface before cutting the casings 5 feet beneath the surface.

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3.5.3.5 Corrective Action for Inadequate Cement Isolation or Casing-Cement Bond Deficiencies

Based on the wells identified for corrective action, cement bond logs (CBLs) will only be performed if there is insufficient evidence that cementing has been completed to the surface—and that the lack of primary cement poses a risk to the USDW or corrective action integrity. During reentry, the annulus/casing will be exposed by removing the soil. Visual inspection will be performed to verify cement evidence at the surface. If there is no cement evidence, and primary cement is critical for UCZ and USDW isolation, then a CBL will be considered. If cement is observed, no CBL will be required.

3.5.3.6 Surface Restoration

The wellhead will be cut off at 5 feet below ground level. A metal plate with the API number will be welded to the top of the casing. The area around the well will be backfilled above the casing stub to the surface. The site will then be restored to its previous conditions.

3.5.3.7 Reporting Completion of Corrective Action

After completing the corrective actions and re-plugging a well, a W-3 plugging report will be submitted to the TRRC within 30 days of plugging, including the W-15 cementing report. Records of the corrective actions will be submitted to the UIC Director.

3.5.4 Site-Specific Review of Corrective Actions

Table 3-4 provides the corrective action sequences for the 11 wells. For each legacy well that will be reentered for evaluation and re-plugging, *Appendix C-4* provides the well schematics that have been developed based on both the historical information and the completion of the associated proposed corrective actions. It should be noted that the legacy-well corrective action schematics carry notional plug depths.

ExxonMobil will consult TRRC's Groundwater Advisory Unit, obtain letters for the USDW, BUQW, and SQW, and adjust the plug depths accordingly to meet or exceed TRRC's standards.

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Table 3-4 – Summary of Corrective Actions for Wells Penetrating the UCZ

Well Name	Cased or Open Hole at UCZ	API No.	Proposed Corrective Actions
Carpenter #001	Open Hole	4224530290	• Excavate and visually inspect for cement outside surface casing. • Re-head and pressure test as needed. • Wash down open hole to UCZ. • At UCZ, set 130-ft balanced CorrosaCem cement plug. • Across USDW, set 130-ft balanced OPC cement plug. • Across BUQW and surface shoe, set 250-ft balanced OPC cement plug. • At SQW, set 130-ft balanced OPC cement plug. • Set surface cement plug.
P. H. Carpenter #001	Cased Hole	4224500004	• Excavate and visually inspect for cement outside surface casing. • Re-head and pressure test as needed. • Drill out existing plug(s) and wash down cased hole to UCZ. • At UCZ, set 130-ft balanced CorrosaCem cement plug. • Across USDW, set 130-ft balanced OPC cement plug. • Across BUQW, set 130-ft balanced OPC cement plug. • At SQW, set 130-ft balanced OPC cement plug. • At surface shoe, set 130-ft balanced OPC cement plug. • Set surface cement plug.
Frank Carpenter et al #001	Cased Hole	4224500005	• Excavate and visually inspect for cement outside surface casing. • Re-head and pressure-test as needed. • Drill out existing plug(s) and wash down cased hole to UCZ. • At UCZ, set 130-ft balanced CorrosaCem cement plug. • Across USDW, set 130-ft balanced OPC cement plug. • Across BUQW, set 130-ft balanced OPC cement plug. • At SQW, set 130-ft balanced OPC cement plug. • At surface shoe, set 130-ft balanced OPC cement plug. • Set surface cement plug.
Garth #001	Open Hole	4224531931	• Excavate and visually inspect for cement outside surface casing. • Re-head and pressure-test as needed. • Wash down open hole to UCZ. • At UCZ, set 130-ft balanced CorrosaCem cement plug. • Across USDW, set 130-ft balanced OPC cement plug. • Across BUQW, set 130-ft balanced OPC cement plug. • At surface shoe and across SQW, set 335-ft balanced OPC cement plug. • Set surface cement plug.
F.S. Wilson #1	Open Hole	42224500006	• Excavate and visually inspect for cement outside surface casing. • Re-head and pressure-test as needed. • Wash down open hole to UCZ. • At UCZ, set 130-ft balanced CorrosaCem cement plug. • Across USDW, set 130-ft balanced OPC cement plug. • Across BUQW, set 130-ft balanced OPC cement plug. • At surface shoe, set 130-ft balanced OPC cement plug. • Across SQW, set 130-ft balanced OPC cement plug. • Set surface cement plug.
Wilson et al #001	Open Hole	4224503214	• Excavate and visually inspect for cement outside surface casing. • Re-head and pressure-test as needed. • Wash down open hole to UCZ. • At UCZ, set 130-ft balanced CorrosaCem cement plug. • Across USDW, set 130-ft balanced OPC cement plug. • Across BUQW, set 130-ft balanced OPC cement plug. • Across SQW, set 130-ft balanced OPC cement plug. • At surface shoe, set 130-ft balanced OPC cement plug. • Set surface cement plug.
Broussard Farms #001	Cased Hole	4229132614	• Excavate and visually inspect for cement outside surface and visually confirm intermediate casing at surface. • Re-head and pressure-test as needed (mechanical integrity tests). • Drill out existing plug(s) and wash down cased hole to UCZ. • At UCZ, perforate, set retainer, and squeeze 76-ft CorrosaCem cement plug inside 4-1/2” casing and 296-ft CorrosaCem cement in 7-5/8”x10-3/4” annulus • Across USDW, perforate, set retainer, and squeeze 130-ft OPC cement plug. • Across BUQW, perforate, set retainer, and squeeze 130-ft OPC cement plug. • Across SQW, perforate, set retainer, and squeeze 130-ft OPC cement plug. • Set surface cement plug.
Champion International Corp. Etal Gas Unit #001	Cased Hole	4224531491	• Excavate and visually inspect for cement outside surface casing. • Re-head and pressure-test as needed. • Drill out existing plug(s) and wash down cased hole. • Across UCZ, set 130-ft balanced CorrosaCem cement plug. • Across surface shoe, set 130-ft balanced OPC cement plug. • Across USDW, set 130-ft balanced OPC cement plug. • Across BUQW, set 130-ft balanced OPC cement plug. • Across SQW, set 130-ft balanced OPC cement plug. • Set surface cement plug.

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Well Name	Cased or Open Hole at UCZ	API No.	Proposed Corrective Actions
A M CARPENTER EST #001	Cased Hole	4224503240	• Excavate and visually inspect for cement outside surface casing. • Re-head and pressure test as needed. • Drill out existing plug(s) and wash down cased hole to UCZ. • At UCZ, set 130-ft balanced CorrosaCem cement plug. • Across USDW, set 130-ft balanced OPC cement plug. • Across BUQW, set 130-ft balanced OPC cement plug. • Across SQW, set 130-ft balanced OPC cement plug. • At surface shoe, set 130-ft balanced OPC cement plug. • Set surface cement plug.
B.H. Willis #001	Open Hole	4224500008	• Excavate and visually inspect for cement outside surface casing. • Re-head and pressure-test as needed. • Wash down open hole to UCZ. • At UCZ, set 130-ft balanced CorrosaCem cement plug. • Across USDW, set 130-ft balanced OPC cement plug. • Across BUQW, set 130-ft balanced OPC cement plug. • At surface shoe and SQW, set 218-ft balanced OPC cement plug. • Set surface cement plug.
E. A. Henderson #001	Cased Hole	4229132215	• Excavate and visually inspect for cement outside surface casing. • Re-head and pressure-test as needed. • Drill out existing plug(s) and wash down cased hole to UCZ. • At UCZ, set 130-ft balanced CorrosaCem cement plug. • Across surface shoe, set 130-ft balanced OPC cement plug. • Across USDW, set 130-ft balanced OPC cement plug. • Across BUQW, set 130-ft balanced OPC cement plug. • Across SQW, set 130-ft balanced OPC cement plug. • Set surface cement plug.

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3.5.5 Plan for Site Access

In accordance with 16 TAC **§5.203(d)(1)(C)** and **§5.203(d)(2)(C)**, ExxonMobil is in the process of negotiating land access for each of the artificial penetrations identified for corrective action. Research to identify the well owners via regulatory databases has been completed. Land access has been secured for all but two wells as outlined in Table 3-5. The two wells which land access has not been secured are anticipated to see CO2 31 and 41 years after injection begins and land access will be secured far in advance with an anticipated access date of end of 2027.

Discussions are underway with the owner and operators of record to enter into an access agreement to perform corrective actions. If appropriate and necessary, ExxonMobil will seek plugging orders from the TRRC in accordance with Subchapter C of Chapter 89 of the Texas Natural Resource Code to obtain access for corrective actions.

If the AOR reevaluation conducted at the minimum schedule of once every 5 years (16 TAC **§5.203(d)(2)(B)(i)**) identifies the potential for corrective action requirements at additional wells, ExxonMobil will promptly begin review of the additional wells in accordance with the process described in this Corrective Action Plan. If site access issues are identified for wells identified for corrective action, ExxonMobil will notify the UIC Director.

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Table 3-5 – Summary of Access Milestones for Corrective Action

Well Name	API Number	Proposed Actions for Access Rights	Anticipated Date of Final Access Agreement
Carpenter #001	42245302900000	Obtain access agreement from the surface owner.	Completed
P. H. Carpenter #001	42245000040000	Obtain access agreement from the surface owner.	Completed
Frank Carpenter et al #001	42245000050000	Obtain access agreement from the surface owner.	Completed
Wilson et al #001	42245032140000	Obtain access agreement from the surface owner.	Completed
B. H. Willis #001	42245000080000	Obtain access agreement from the surface owner..	Completed
A M CARPENTER EST #001	42245032400000	Obtain access agreement from the surface owner.	Completed
Garth #001	42245319310000	Obtain access agreement from the surface owner.	Completed
Broussard Farms #001	42291326140000	Obtain access agreement from the surface owner.	Completed
F. S. WILSON #1	42245000060000	Obtain access agreement from the surface owner.	Completed
Champion International Corp. Etal Gas Unit #001	42245314910000	Obtain access agreement from the surface owner.	~12/2027
E. A. Henderson #001	42291322150000	Obtain access agreement from the surface owner.	~12/2027

3.6 AOR Reevaluation Plan and Schedule

3.6.1 Frequency of AOR Reevaluation

ExxonMobil adopts the minimum frequency of 5 years for the AOR and Corrective Action Plan reevaluation. Information gathered from implementation of the Testing and Monitoring Plan (*Section 5*) will be used to evaluate whether a more frequent review period is warranted, based on the observed conditions of CO_2 plume and pressure front migration.

If an alteration of the AOR reevaluation frequency of a minimum of every 5 years is recommended, the change in frequency will be aligned with the data evaluation and findings relative to the degree of protectiveness of the USDW. ExxonMobil acknowledges that any amendments to the AOR and Corrective Action Plan must be approved by the UIC Director, must be incorporated into the permit, and are subject to the permit modification requirements at 16

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TAC **§5.202(d)(2)**, as appropriate. ExxonMobil also acknowledges the requirement in 16 TAC **§5.203(d)(2)(B)(i)** of the "minimum fixed frequency, not to exceed five years, at which the owner or operator proposes to reevaluate the area of review."

3.6.2 Content of the AOR Reevaluation

The requirements for AOR reevaluation are specified in 16 TAC **§5.206(g)** and include the following considerations:

- Reevaluate the AOR in the same manner specified in 16 TAC **§5.203(d)(1)(A)(i)-(ii)**.
- Identify all wells in the reevaluated AOR that require corrective action in the same manner specified in 16 TAC **§5.203(d)(1)**.
- Perform corrective action on wells requiring it in the reevaluated AOR, in the same manner specified in 16 TAC **§5.203(d)(1)(C)**.
- Submit an amended AOR and Corrective Action Plan or demonstrate to the UIC Director through monitoring data and modeling results that no amendment to the plan is needed. Any amendments to the AOR and Corrective Action Plan must be approved by the UIC Director, must be incorporated into the permit, and are subject to the permit modification requirements at 16 TAC **§5.202(d)(2)**, as appropriate.

3.6.3 Conditions Warranting AOR Reevaluation

The monitoring and operational conditions that would warrant a reevaluation of the AOR prior to the next scheduled reevaluation (i.e., the minimum fixed frequency established in 16 TAC **§5.203(d)(2)(B)(i)**) are outlined in Table 3-6—which provides a list of the potential triggers for an AOR reevaluation consistent with the requirements of 16 TAC **§5.203(d)(2)(B)(iii)**. These triggering events are based on a review of the hydrogeological site characteristics, the AOR and plume model results, and the pre-operational and operational plans for the Sunflower Project.

For each potential triggering event, Table 3-6 provides a summary of how the monitoring and operational data will be used to inform an AOR reevaluation, and how corrective action will be conducted to reduce the potential for threats to the USDW, if any arise. If an AOR reevaluation were to occur, corrective actions will be reevaluated.

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Table 3-6 – Potential Triggers for AOR Reevaluation

Monitoring and Operational Conditions that May Warrant AOR Reevaluation	How Monitoring and Testing Data Will Inform the AOR Reevaluation	How Corrective Action Will Be Conducted to Reduce the Potential for Threats to USDW
Significant changes in operations that mandate AOR reevaluation under 16 TAC **§5.203(d)(2)** as outlined below	The AOR reevaluation will be informed by both planned changes to operations and by testing and obtaining monitoring data that signal potential unexpected CO_2 plume migration impacting the extent of the AOR. Examples may include identification of a new offset well installation by third parties. Certain short-term operational changes, such as temporary well shut-ins, are not expected to warrant AOR reevaluation.	ExxonMobil will notify and coordinate with the UIC director to determine appropriate next steps
New offset operations are established that could affect the injection intervals.	Rerun the reservoir plume model with new data. If the plume increases in shape or extents to an unexpected level beyond the AOR, reevaluate the AOR.	ExxonMobil will notify and coordinate with the UIC director to determine appropriate next steps
An injection well exhibits a significant anomalous change in surface pressure for a sustained period of time.	Incorporate new pressure information and rerun the reservoir plume model with new data. Investigate if the monitoring wells' pressure gauges show a similar anomalous change at any depth and incorporate the monitoring well pressure information in the reservoir plume model. If the plume increases in shape or extents to an unexpected level beyond the AOR, reevaluate the AOR.	ExxonMobil will notify and coordinate with the UIC director to determine appropriate next steps
A casing or tubing leak is detected by casing integrity logging.	Investigate possible tubing leak and trigger contingency monitoring to reevaluate the AOR.	ExxonMobil will notify and coordinate with the UIC director to determine appropriate next steps.
Results from site monitoring differ from model predictions (16 TAC **§5.203(d)(2)(B)(iii)**) as outlined below.	An evaluation of monitoring data (required under 16 TAC **§5.203(j)**) indicates that CO_2 and/or pressure front migration is significantly different than that predicted by the current AOR delineation model and, therefore, warrants an AOR reevaluation. The following examples provide specific criteria for differences in monitoring data and model predictions that may trigger an AOR reevaluation (16 TAC **§5.203(d)(2)(B)(iii)**).	ExxonMobil will notify and coordinate with the UIC director to determine appropriate next steps
Seismic event greater than a 3.0 magnitude occurs within a 5.6-mile radius of an injection well.	Evaluate pressure and temperature data relative to operating limits and pressures in the in-zone monitoring wells. Evaluate the need to enhance the monitoring program to confirm the extent of the CO_2 plume.	ExxonMobil will notify and coordinate with the UIC director to determine appropriate next steps
Indication of concentrations above the baseline for USDW samples of TDS, major cations and anions, CO_2 concentration, isotopic values, or pH increase in a statistically significant way.	Resample the fluid that contained the elevated concentrations and compare the resample results with numerical criteria for trends and/or exceedances of target concentrations.	ExxonMobil will notify and coordinate with the UIC director to determine appropriate next steps
The presence of separate-phase CO_2 is detected in the sampled fluids above the confining zone, but below the lowermost USDW, resulting from CO_2/fluid migration out of the injection zone.	Investigate possible migration pathways and trigger contingency monitoring to reevaluate the AOR.	ExxonMobil will notify and coordinate with the UIC director to determine appropriate next steps

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Appendix C – AOR Maps and Corrective Action Well Schematics:

Appendix C-1: Overview Map
Appendix C-2: Freshwater Well Map
Appendix C-3: Freshwater Well List
Appendix C-4: Corrective Action Schematics for the 11 Corrective Action Wells
Appendix C-5: Site Review Map

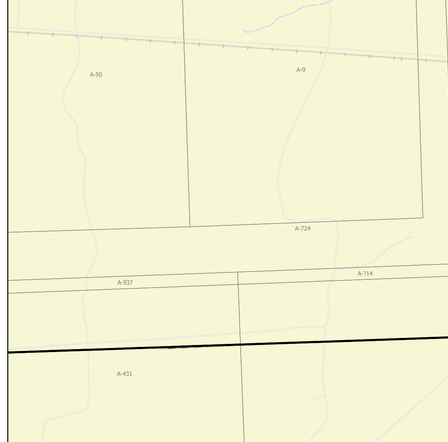
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Appendix C – Area of Review and Corrective Actions

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Appendix C1 – Oil & Gas Wells Map

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Sunflower Carbon Capture and Storage Project

Area of Review

Oil & Gas Wells

ExxonMobil Low Carbon Solutions Onshore Storage LLC

Jefferson and Liberty Counties, Texas

Appendix C-1

Drawn by:	Date:	Approved by:
Steven Larcom	4/14/2026	Andy Ellis

PCS: NAD 1983 State Plane TX - S. Central FIPS 4204 (US Ft.)

LONQUIST

Texas Registration No. F-8952

- Proposed Injection Wells

Oil & Gas Wells within AOI

- ACTIVE
- COMPLETED
- DRILLED
- INACTIVE
- PERMITTED
- P & A
- UNKNOWN
- EXPIRED PERMIT
- CANCELLED

- Area of Interest
- Maximum Critical Pressure Front
- Stabilized CO2 Plume
- Area of Review
- Abstracts
- Counties

1:22,000

0 ½ 1 1½ 2 4 Miles

0 1,000 2,000 3,000 4,000 5,000 10,000 Feet

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Appendix C2 - Freshwater □ ells Map

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Sunflower Carbon Capture and Storage Project

Area of Review

Freshwater Wells

ExxonMobil Low Carbon Solutions Onshore Storage LLC

Jefferson and Liberty Counties, Texas

Appendix C-2

Drawn by: Steven Larcom	Date: 5/29/2026	Approved by: Andy Ellis

PCS: NAD 1983 State Plane TX - S. Central FIPS 4204 (US Ft.)

LONQUIST

Texas Registration No. F-8952

- Proposed Injection Wells
- Maximum Critical Pressure Front
- Stabilized CO2 Plume
- Area of Review

TWDB Groundwater Wells
- Domestic
- Industrial
- Irrigation
- Stock
- Unused
- Plugged or Destroyed

SDRDB Groundwater Wells
- Domestic
- Public Supply
- Industrial
- Irrigation
- Monitor
- Rig Supply
- Stock

- Distance Call (Closest Freshwater and Drinking Water Wells to Project Sunflower Injection Well)
- Counties

1:15,000

0 ½ 1 1½ 2 4 Miles

0 1,000 2,000 3,000 4,000 5,000 10,000 Feet

Appendix C3 - Freshwater Wells List

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Appendix C-3

Area of Review: Freshwater Wells List

WELL REPORT NO.	OWNER'S NAME	OWNER ADDRESS	CITY/STATE/ZIP	LAT. NAD 83	LONG. NAD83	WELL USE	WATER LEVEL (FT.)	TOTAL DEPTH (FT.)	DATE DRILLED
6161701	A. L. Banke	Box 155	Nome, TX 77629	30.029162	-94.481937	Irrigation	18.9	538	1958
6161807	Southern Pacific Co.	*Illegible*	Nome, TX 77629	30.044717	-94.425271	Plugged or Destroyed	2.0	692	1906
166225	Kevin Robbins	1783 Old Grayburg	Nome, TX 77629	30.048606	-94.424993	Domestic	25.0	310	5/4/2004
166230	Robbins	4783 Old Grayburg	Nome, TX 77629	30.048606	-94.424993	Domestic	25.0	125	5/4/2004
184051	Ballard Exploration, Inc.	1021 Main St. Ste 2310	Houston, TX 77002	30.033329	-94.470548	Rig Supply	15.0	140	12/7/2005
202618	Transit Mix Concrete	850 Pine	Beaumont, TX 77701	30.029439	-94.463327	Industrial	15.0	115	2/28/2006
211286	Westport O&G/KerrMcGee O&G	16666 North Chase BM 2114	Houston, TX 77070	30.018328	-94.481104	Rig Supply	12.0	122	6/11/2005
250951	Cimarex Energy Co.	707 17th Street Ste 3300	Denver, CO 80202	30.033606	-94.488604	Rig Supply	15.0	130	10/7/2005
276258	Mike Doguet	2400 Hwy 326	Nome, TX 77629	30.056940	-94.400549	Stock	20.0	110	11/18/2011
370003	Matt Willey	PO Box J	Nome, TX 77629	30.062773	-94.414716	Domestic	18.0	280	5/28/2014
370064	Greg Devillier	PO Box 694	Nome, TX 77629	30.062773	-94.417493	Domestic	23.0	285	6/4/2014
410300	Charles Daniels	PO Box 46	Nome, TX 77629	30.070212	-94.418310	Domestic	24.0	244	9/19/2015
410622	Katie Spencer	2225 N Major	Beaumont, TX 77701	30.066106	-94.416660	Domestic	38.0	240	10/30/2015
417832	Billy G Daniels	2764 Nome	Nome, TX 77629	30.070662	-94.417426	Domestic	24.0	240	1/5/2016

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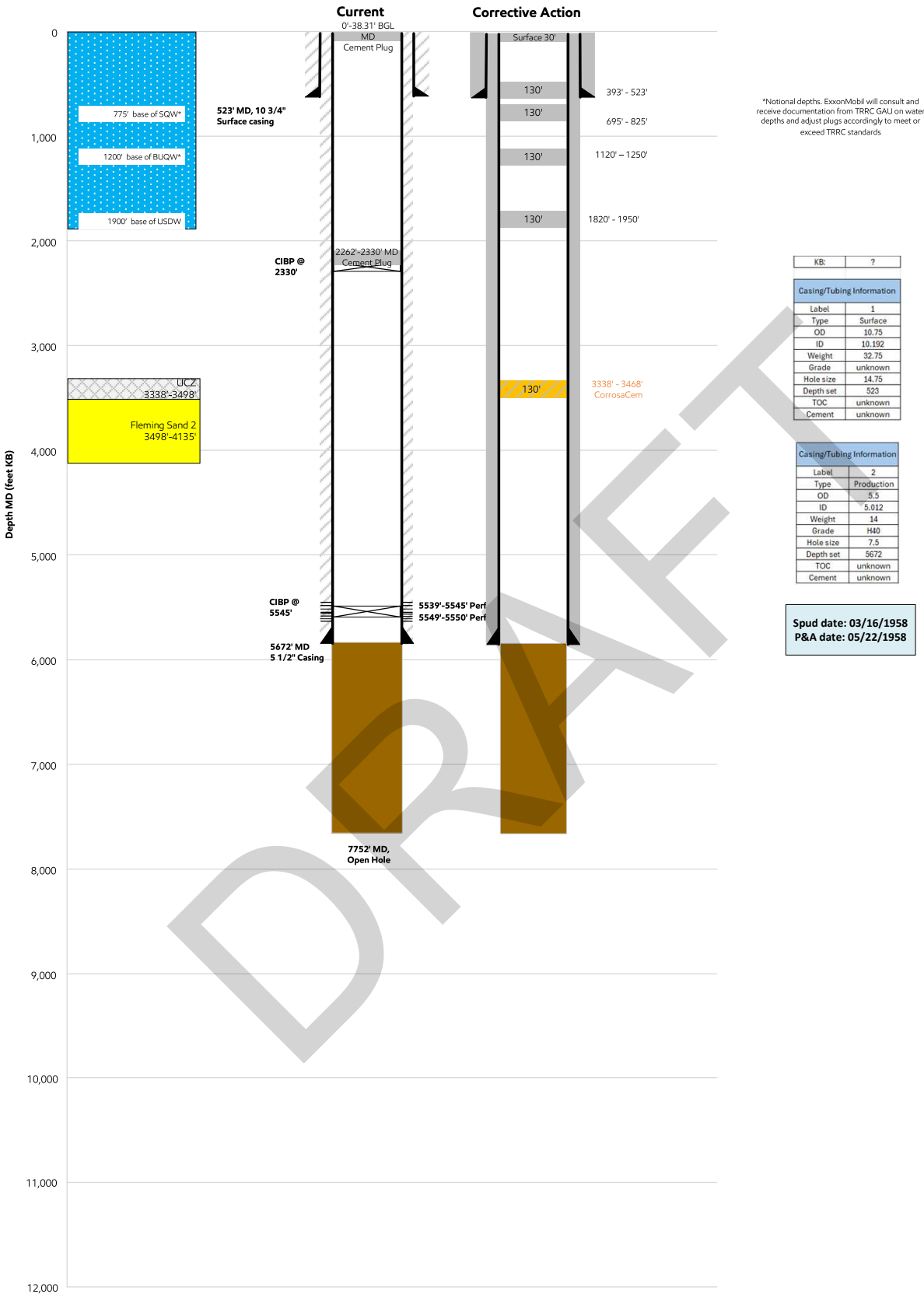
544238	Kevin Robins	4628 Old Grayburg Rd	Nome, TX 77629	30.048200	-94.426718	Domestic	20.0	310	3/29/2020
650111	Mike Doguet	2400 Hwy 326	Nome, TX 77629	30.047509	-94.416539	Irrigation	15.0	110	9/15/2023

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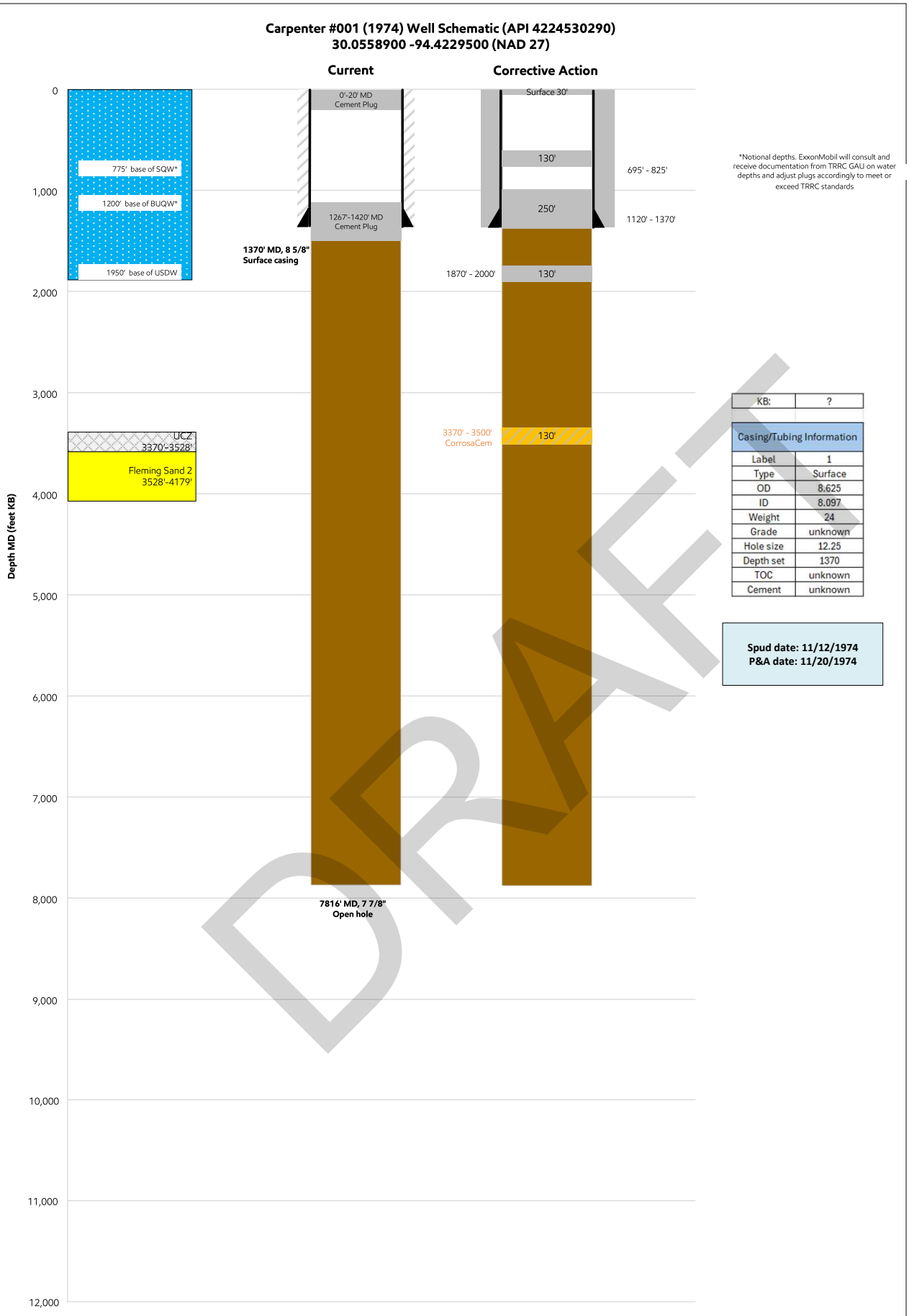
Appendix C4 - Correcti e Action ell ore Schematics

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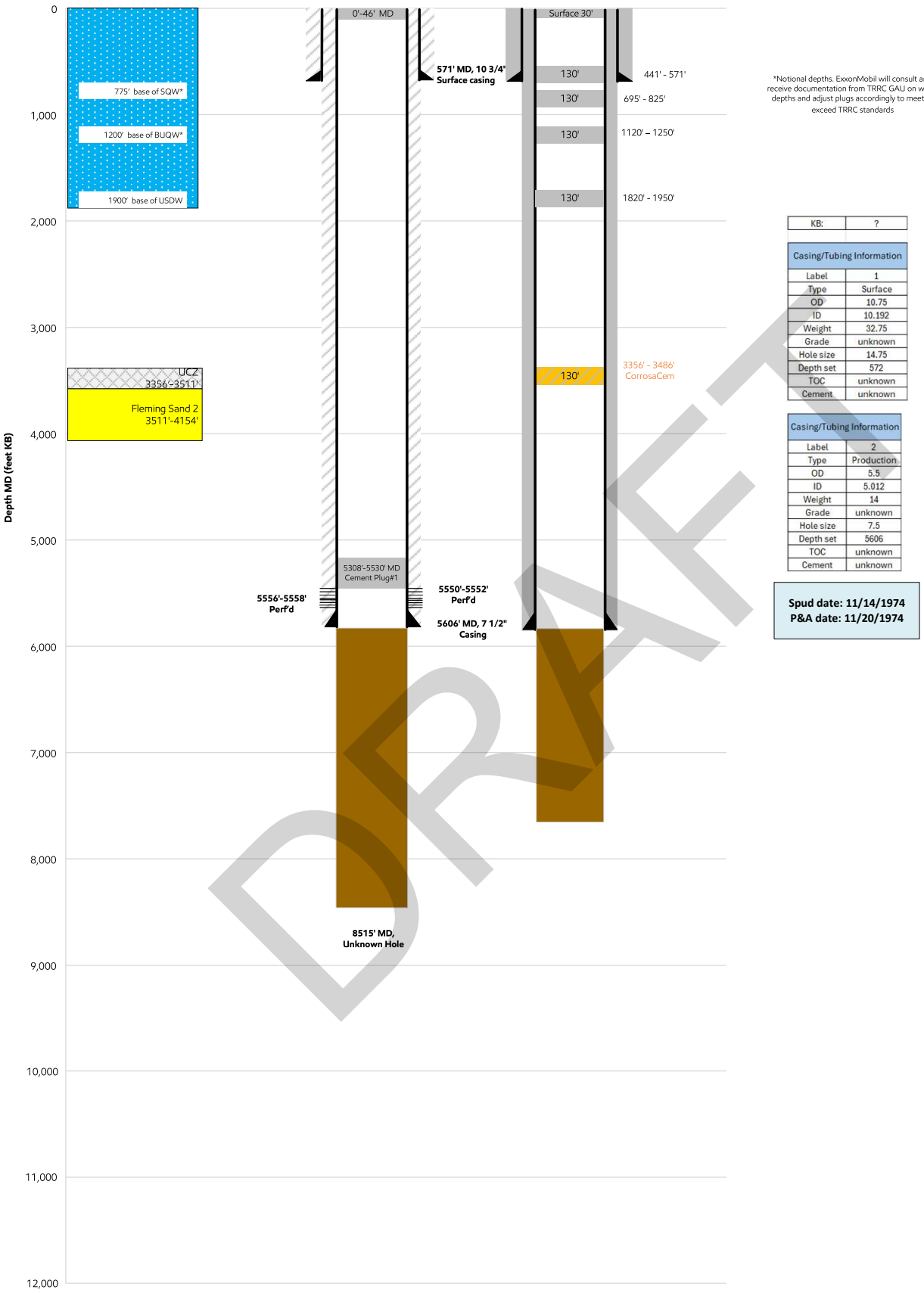
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Appendix C-4
P. H. Carpenter #001 (1958) Well Corrective Action Schematic
API 4224500004
Sunflower Carbon Storage Project
ExxonMobil Low Carbon Solutions Onshore Storage LLC
Newton, Texas



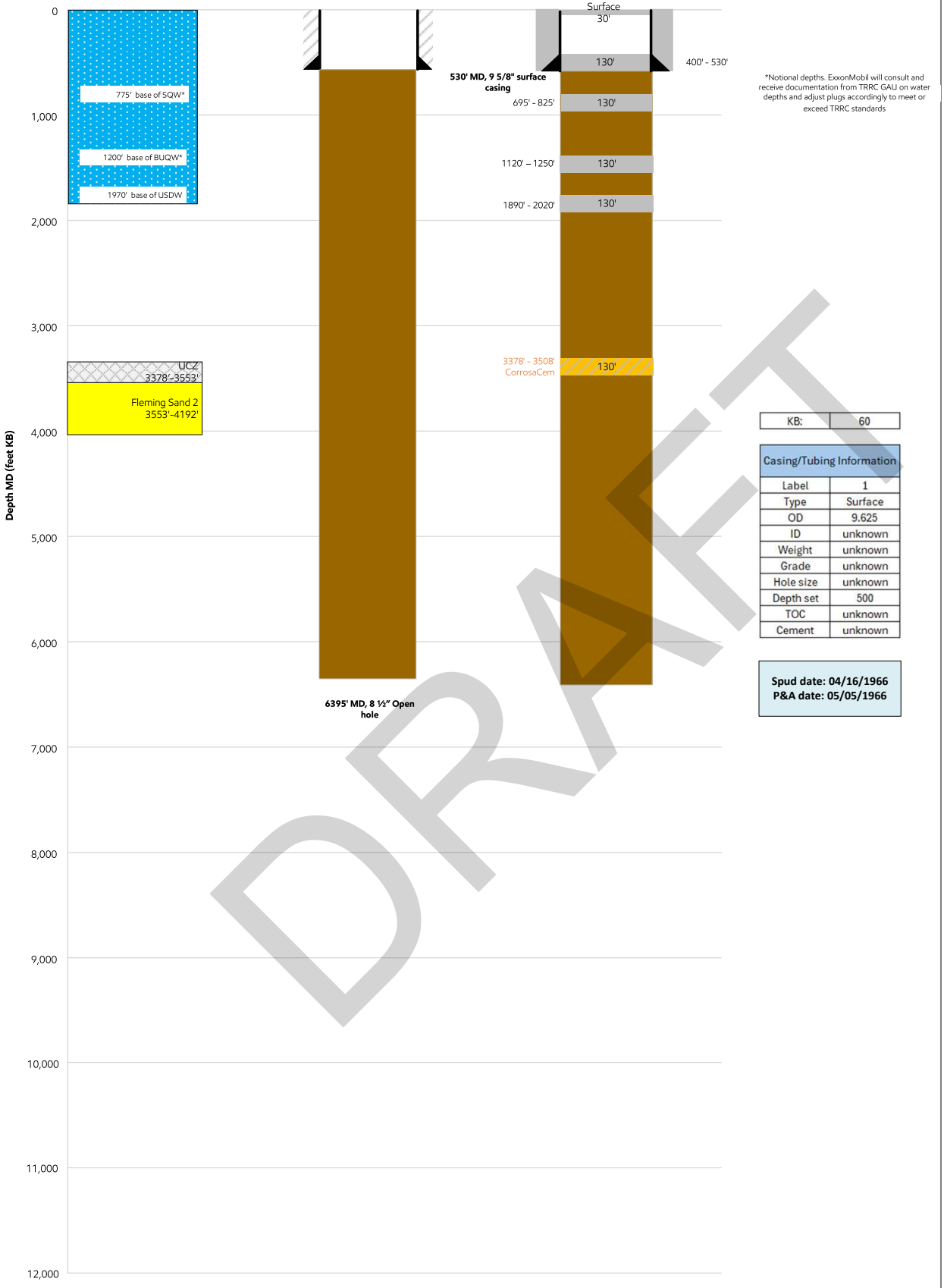
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Appendix C-4
Carpenter #001 (1974) Well Corrective Action Schematic
API 4224530290
Sunflower Carbon Storage Project
ExxonMobil Low Carbon Solutions Onshore Storage LLC
Newton, Texas



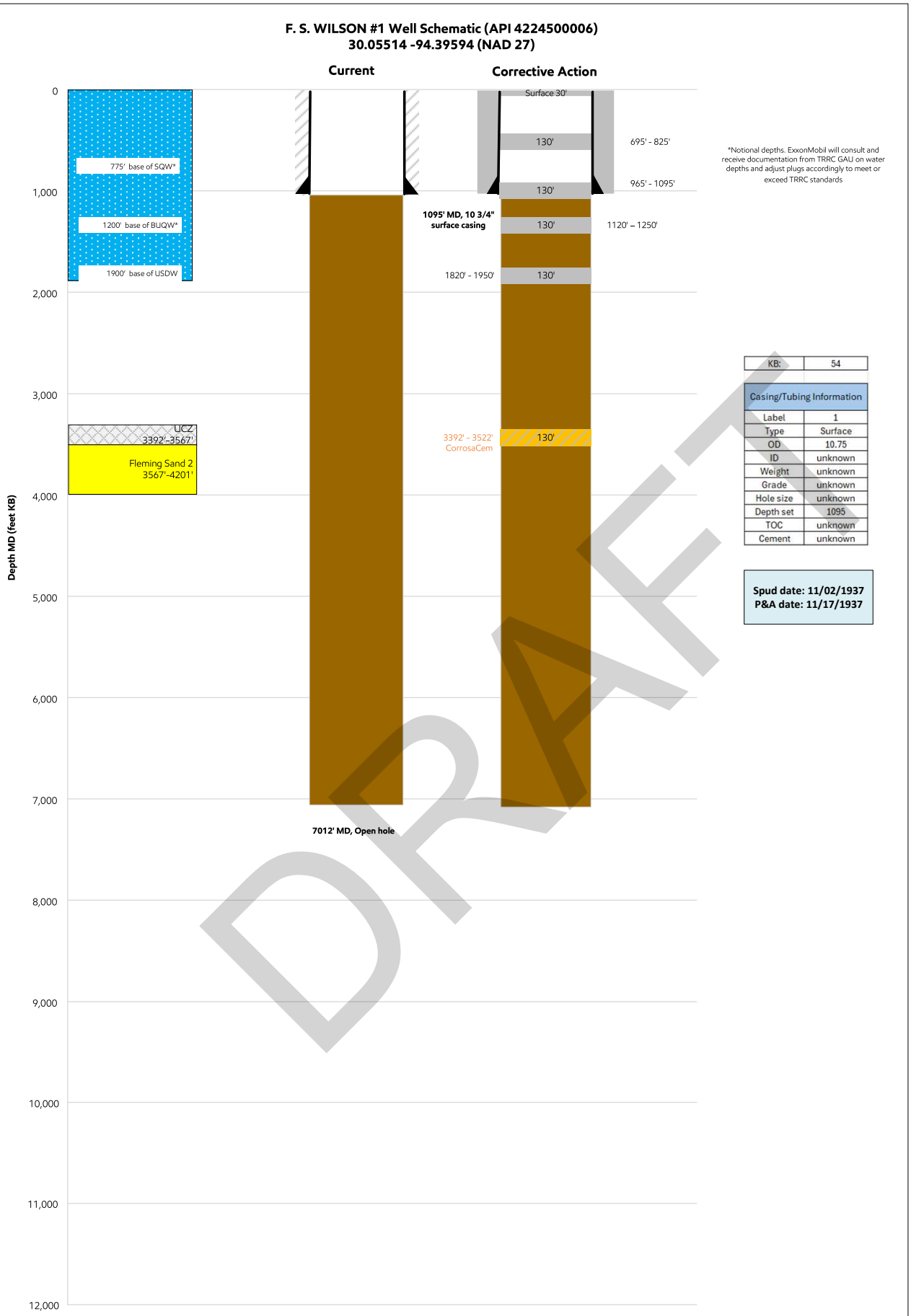
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Appendix C-4
Frank Carpenter et al #001 (1957) Well Corrective Action Schematic
API 4224500005
Sunflower Carbon Storage Project
ExxonMobil Low Carbon Solutions Onshore Storage LLC
Newton, Texas



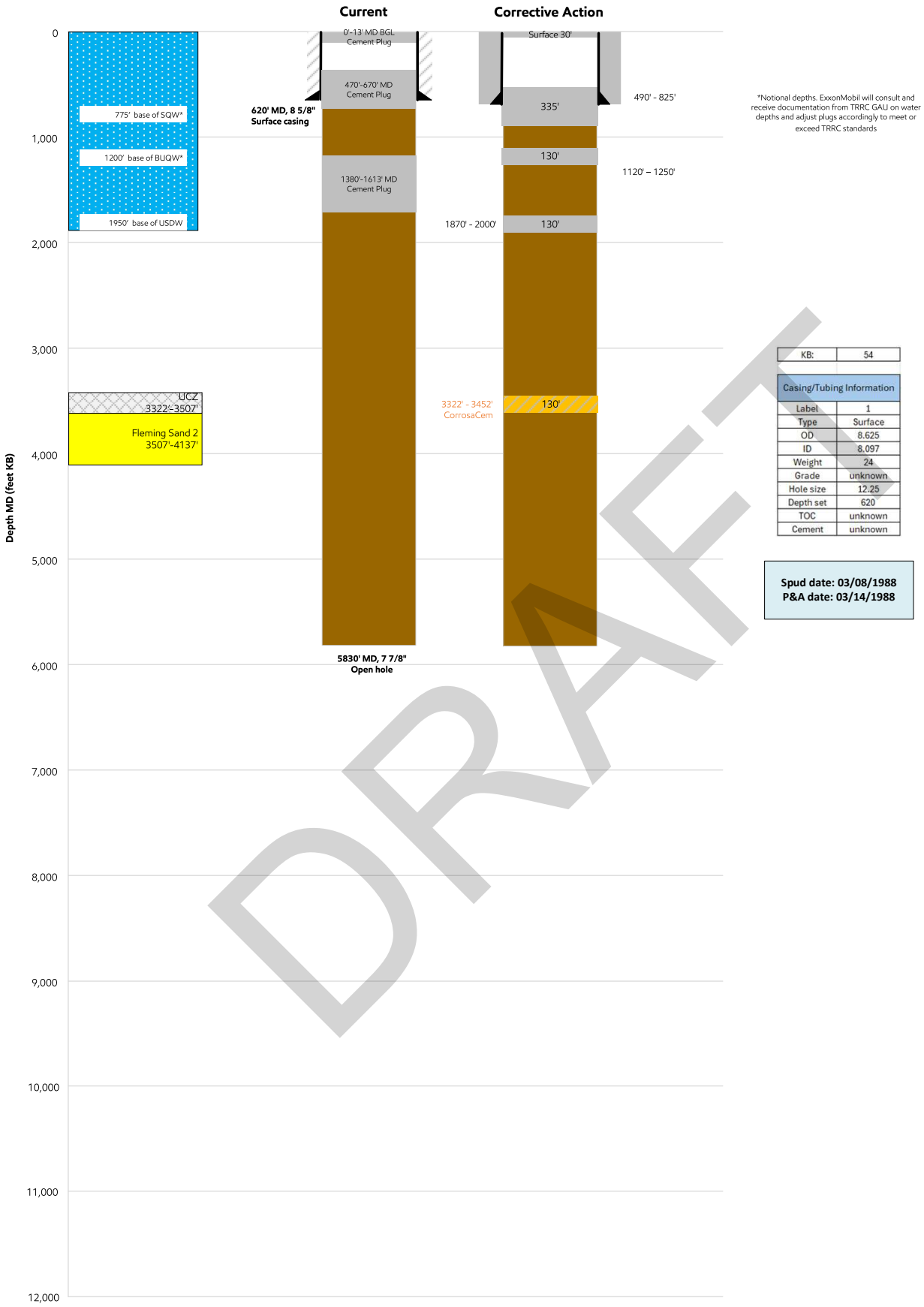
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Appendix C-4
Wilson et al #001 Well Corrective Action Schematic
API 4224503214
Sunflower Carbon Storage Project
ExxonMobil Low Carbon Solutions Onshore Storage LLC
Newton, Texas



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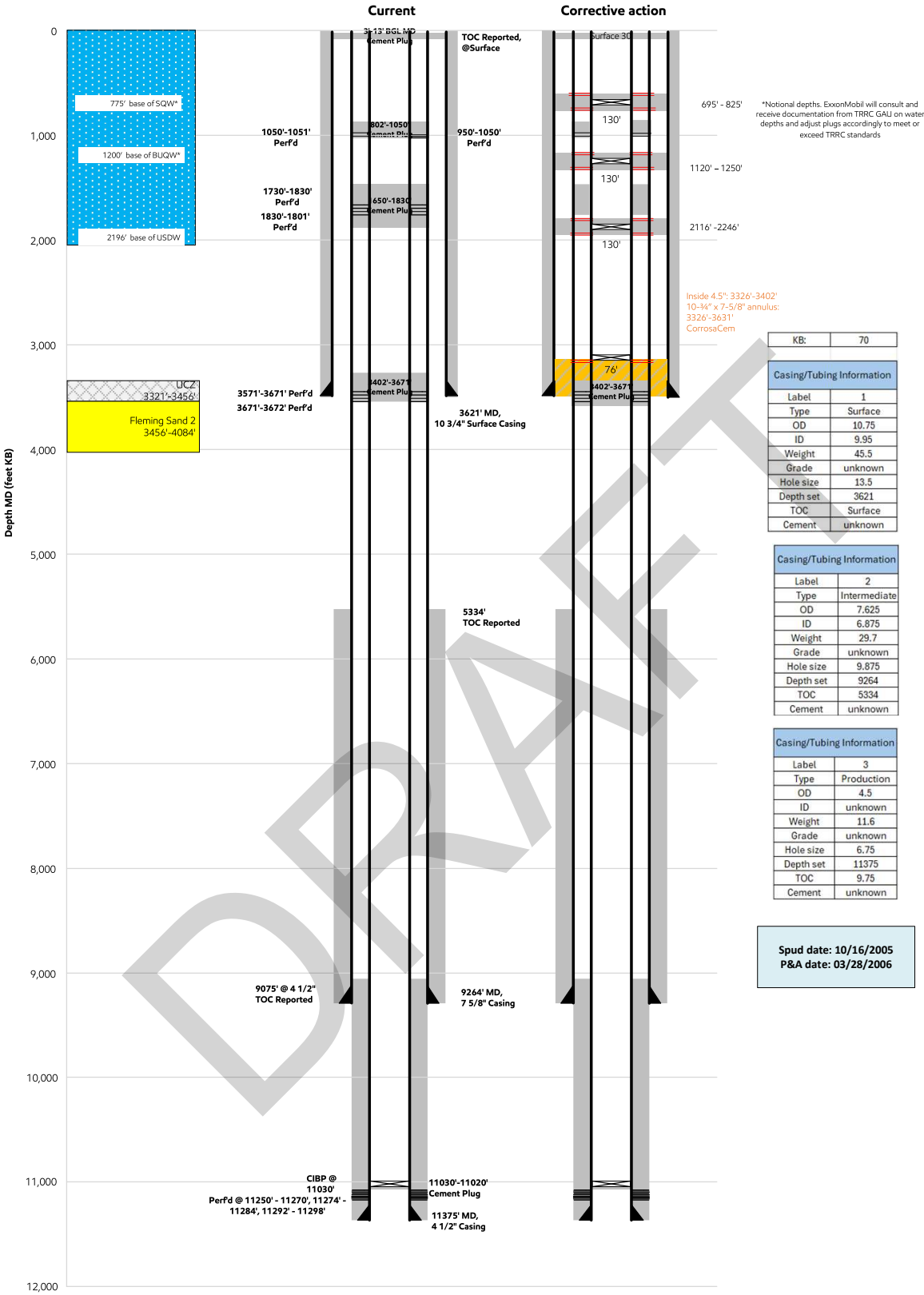
Appendix C-4
F. S. WILSON #1 Well Corrective Action Schematic
API 4224500006
Sunflower Carbon Storage Project
ExxonMobil Low Carbon Solutions Onshore Storage LLC
Newton, Texas



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Appendix C-4
Garth #001 (1988) Well Schematic Well Corrective Action Schematic
API 4224531931
Sunflower Carbon Storage Project
ExxonMobil Low Carbon Solutions Onshore Storage LLC
Newton, Texas

Broussard Farms #001 (2005) Well Schematic (API 4229132614)
30.033768, -94.4881094 (NAD 27)



*Notional depths. ExxonMobil will consult and receive documentation from TRRC GAU on water depths and adjust plugs accordingly to meet or exceed TRRC standards

KB:	70

Casing/Tubing Information	
Label	1
Type	Surface
OD	10.75
ID	9.95
Weight	45.5
Grade	unknown
Hole size	13.5
Depth set	3621
TOC	Surface
Cement	unknown

Casing/Tubing Information	
Label	2
Type	Intermediate
OD	7.625
ID	6.875
Weight	29.7
Grade	unknown
Hole size	9.875
Depth set	9264
TOC	5334
Cement	unknown

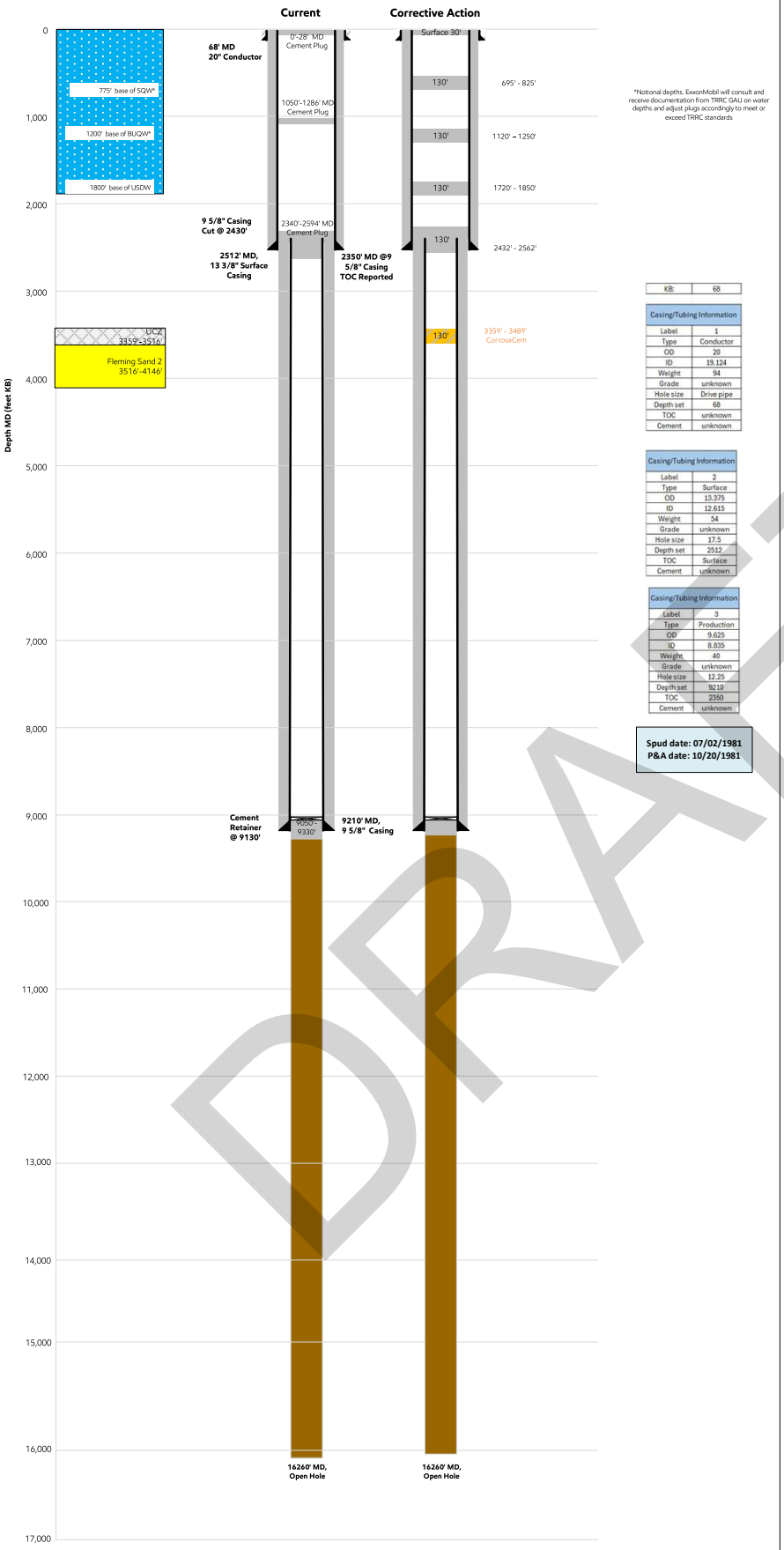
Casing/Tubing Information	
Label	3
Type	Production
OD	4.5
ID	unknown
Weight	11.6
Grade	unknown
Hole size	6.75
Depth set	11375
TOC	9.75
Cement	unknown

Spud date: 10/16/2005
P&A date: 03/28/2006

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Appendix C-4
Broussard Farms #001 (2005) Well Corrective Action Schematic
API 4229132614
Sunflower Carbon Storage Project
ExxonMobil Low Carbon Solutions Onshore Storage LLC
Newton, Texas

Champion International Corp. Etal Gas Unit #001 (1981) Well Schematic (API 4224531491)
30.0663900 -94.4360000 (NAD 27)



*Notional depths. ExxonMobil will consult and receive documentation from TRRC GAU on water depths and adjust plugs accordingly to meet or exceed TRRC standards

KB:	68

Casing/Tubing Information	
Label	1
Type	Conductor
OD	20
ID	19.124
Weight	94
Grade	unknown
Hole size	Drive pipe
Depth set	68
TOC	unknown
Cement	unknown

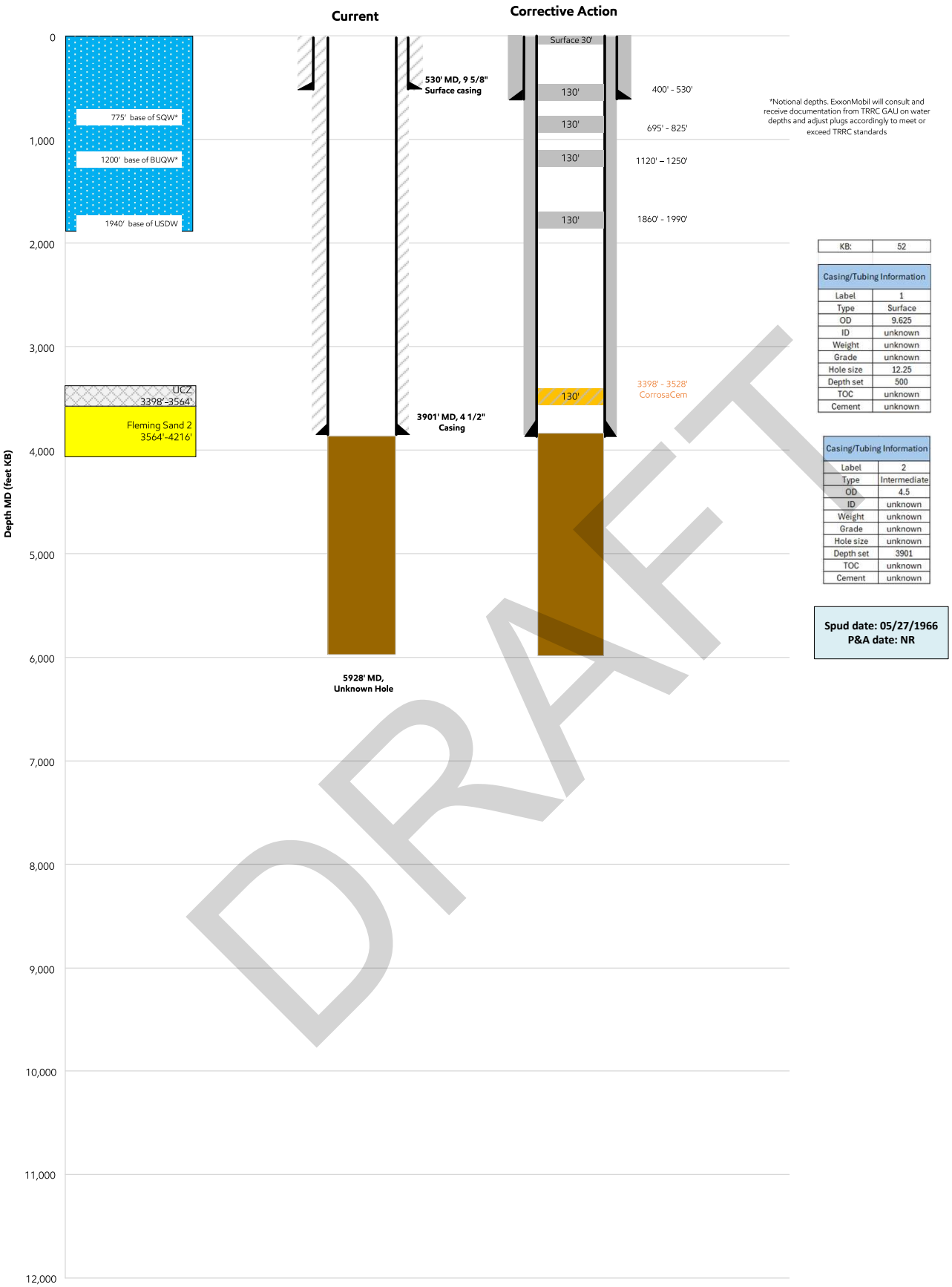
Casing/Tubing Information	
Label	2
Type	Surface
OD	13.375
ID	12.615
Weight	54
Grade	unknown
Hole size	17.5
Depth set	2512
TOC	Surface
Cement	unknown

Casing/Tubing Information	
Label	3
Type	Production
OD	9.625
ID	8.835
Weight	40
Grade	unknown
Hole size	12.25
Depth set	9210
TOC	2350
Cement	unknown

Spud date: 07/02/1981
P&A date: 10/20/1981

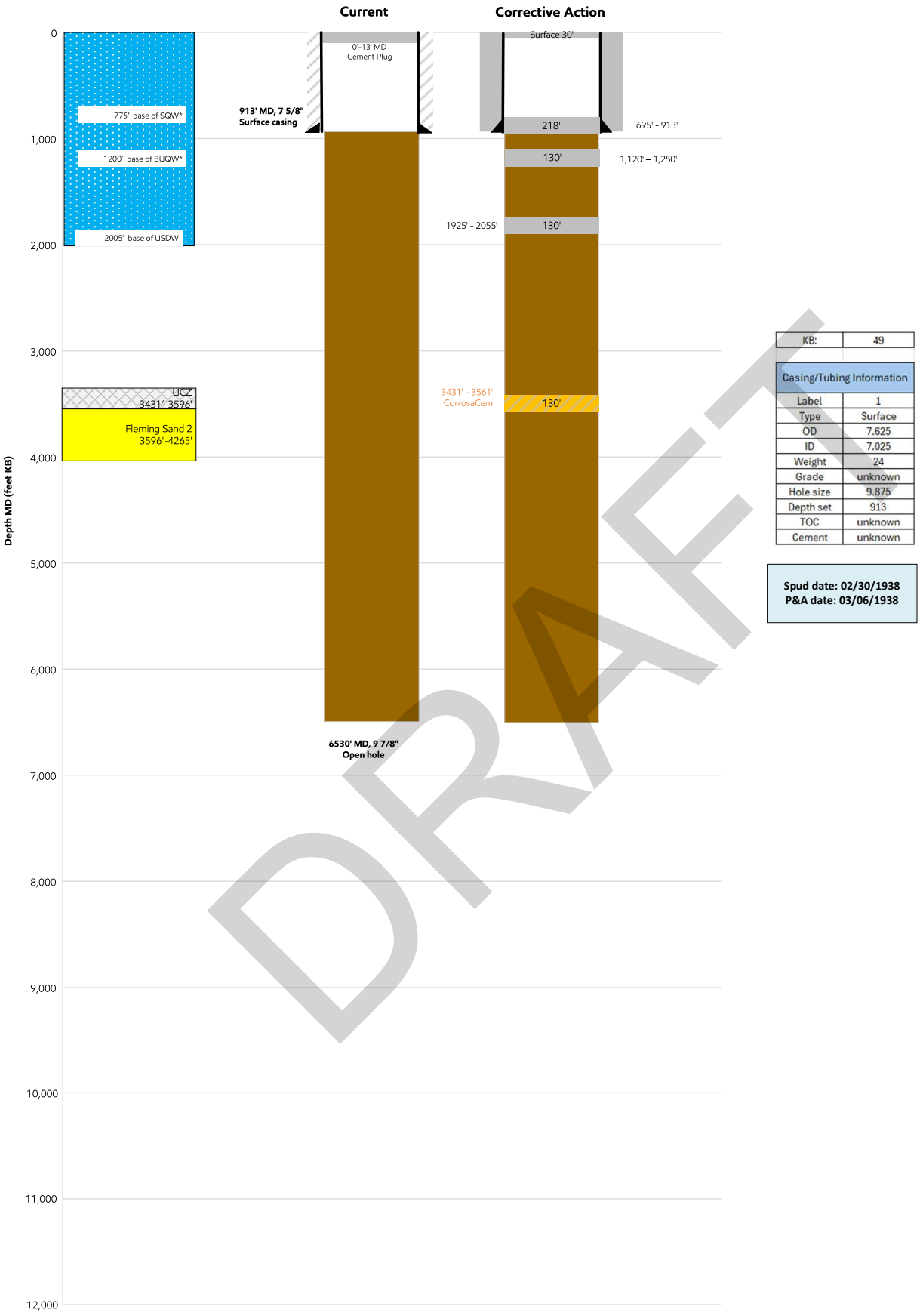
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Appendix C-4
Champion International Corp. Etal Gas Unit #001 (1981) Well Corrective Action Schematic
API 4224531491
Sunflower Carbon Storage Project
ExxonMobil Low Carbon Solutions Onshore Storage LLC
Newton, Texas



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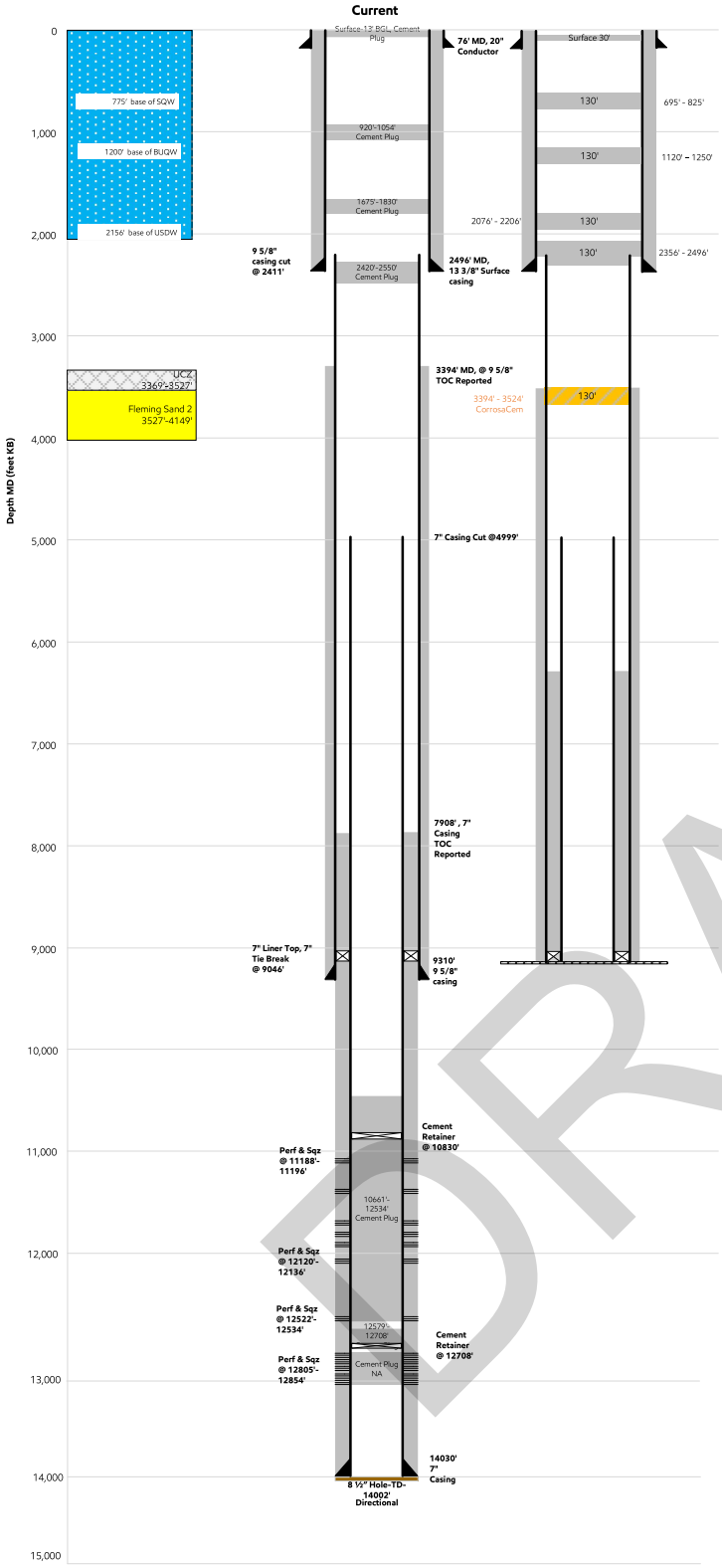
Appendix C-4
A M CARPENTER EST #001 (1967) Well Corrective Action Schematic
API 4224503240
Sunflower Carbon Storage Project
ExxonMobil Low Carbon Solutions Onshore Storage LLC
Newton, Texas



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Appendix C-4
B.H. Willis #001 (1938) Well Schematic Well Corrective Action Schematic
API 4224500008
Sunflower Carbon Storage Project
ExxonMobil Low Carbon Solutions Onshore Storage LLC
Newton, Texas

E. A. Henderson #001 (1994) Well Schematic (API 4229132215)
30.0478163 -94.4678153 (NAD 27)



KB:	65

Casing/Tubing Information	
Label	1
Type	Conductor
OD	20
ID	unknown
Weight	unknown
Grade	unknown
Hole size	Drive Pipe
Depth set	76
TOC	unknown
Cement	unknown

Casing/Tubing Information	
Label	2
Type	Surface
OD	13.375
ID	12.515
Weight	61
Grade	J-55
Hole size	17.5
Depth set	2496
TOC	Surface
Cement	unknown

Casing/Tubing Information	
Label	3
Type	Intermediate
OD	9.625
ID	8.535
Weight	53.5
Grade	L-80
Hole size	12.25
Depth set	9310
TOC	3394
Cement	unknown

Casing/Tubing Information	
Label	3
Type	Production
OD	7
ID	6.094
Weight	32
Grade	P-110
Hole size	8.5
Depth set	14000
TOC	7908
Cement	unknown

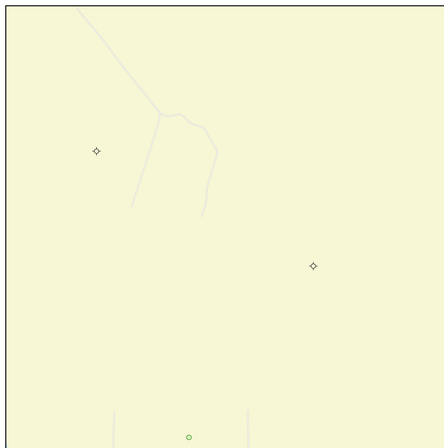
Spud date: 07/06/1994
P&A date: 03/14/1996

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Appendix C-4
E. A. Henderson #001 (1994) Well Corrective Action Schematic
API 4229132215
Sunflower Carbon Storage Project
ExxonMobil Low Carbon Solutions Onshore Storage LLC
Newton, Texas

Appendix C5 – Site Review Map

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Sunflower Carbon Capture and Storage Project

Area of Review

Site Review

ExxonMobil Low Carbon Solutions Onshore Storage LLC

Jefferson and Liberty Counties, Texas

Appendix C-4

Drawn by: Steven Larcom	Date: 5/29/2026	Approved by: Andy Ellis

PCS: NAD 1983 State Plane TX - S. Central FIPS 4204 (US Ft.)

LONQUIST

Texas Registration No. F-8952

- Proposed Injection Wells
- Proposed Monitoring Wells

Oil & Gas Well SHLs

- <Null>
- DISPOSAL
- DRY HOLE
- GAS
- OIL
- OIL & GAS
- OTHER
- <all other values>

Permanent Structures

- Residential
- Commercial
- Government
- Education
- Other
- RCRA Hazardous Waste Site (Active)
- Cleanups in my Community
- Area of Review
- Sunflower Geologic Storage Facility
- Counties

*Note: Extensive research was performed to check the project area for the presence of artificial penetrators, cleanup sites, mines and quarries, and any other infrastructure of note. The absence of any of these features on this map means that data sources indicate that they are not present within the project area. Data sources used for research include the United States Environmental Protection Agency (Superfund Sites, Active and Inactive RCRA Hazardous Waste Sites, Cleanups-in-my-Community); United States Geological Survey (mines and quarries); United States Fish & Wildlife Service (endangered species critical habitats); Texas Parks and Wildlife Department (wildlife management areas); Texas Water Development Board (springs); Enverus, TGS, RRC (artificial penetrators).

Sunflower USDW No. 01
Sunflower INJ No. 01
Sunflower AZM No. 01
Sunflower USDW No. 02
Sunflower INJ No. 02
Sunflower AZM/IZM No. 01
Sunflower AZM No. 02
Sunflower USDW No. 03
Sunflower INJ No. 03
110006131408
BRIGGS MOTOR CO
Nome
HARDIN
JEFFERSON
LIBERTY
Highway 326 S
Highway 90
Old Nome Rd
Old Graytown Rd
Nome Spur
Cotton Creek
Fancia Creek
Long Marsh
Mermentau Slough
Clay Gully
Private 103
Private Road 107
Nolte Canal
Lnva Canal
Pignut Gully
Willis Ln
Elmer Rd
Nolte Rd
Bonner Rd
Rodeo Dr
Paggi Rd
Blair Rd
Mason Rd
Tindall Rd
Florida St
Louisiana St
Gulf St
Market Dr
Kotz Rd
Avenue E
Avenue D
Avenue C
Avenue B
Avenue A
FM 1009
FM 365 Rd
1:15,000
0 ½ 1 1½ 2 4 Miles
0 1,000 2,000 3,000 4,000 5,000 10,000 Feet
N

Railroad Commission of Texas

Attachment B – Well Construction Plan

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Underground Injection Control – Class VI Permit Application for Sunflower Carbon Capture and Storage Project Injection Wells No. 01, No. 02, and No. 03

SECTION 4 – WELL CONSTRUCTION PLAN AND OPERATING CONDITIONS

Sunflower Carbon Capture and Storage Project
Jefferson and Liberty Counties, Texas
ExxonMobil Low Carbon Solutions Onshore Storage, LLC
Amendment 3: August 2026

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SECTION 4 – WELL CONSTRUCTION PLAN AND OPERATING CONDITIONS

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4.1 Well Construction Plan and Operating Conditions

ExxonMobil Low Carbon Solutions Onshore Storage, LLC (ExxonMobil) is undertaking the Sunflower Carbon Capture and Storage (CCS) Project (Sunflower Project) in Jefferson and Liberty Counties, Texas, to sequester CO_2 using three injection wells, Sunflower CCS Project Injection Wells No. 01, No. 02, and No. 03. This section contains information on the well construction and operating conditions in compliance with the requirements of Title 16, Texas Administrative Code (16 TAC), Part 1, Chapter 5A.

This section provides a narrative document with associated schematics and data summary tables that describe how ExxonMobil will construct the injection wells to meet the goals of 16 TAC **§5.203**—specifically, to do the following:

1. Prevent the movement of fluids into or between underground sources of drinking water (USDWs) or into unauthorized zones (16 TAC **§5.203(e)(1)(A)(i)**).
2. Permit the use of appropriate testing devices and workover tools (16 TAC **§5.203(e)(1)(A)(ii)**).
3. Permit continuous monitoring of the annulus space between the injection tubing and long string casing (16 TAC **§5.203(e)(1)(A)(iii)**).

The engineering design is based on the collection of as much site-specific data as possible. This level of effort was undertaken to facilitate the permit writing process, between conducting the pre-construction activities required at 16 TAC **§5.203(a)(2)** and the pre-operation phase activities required at 16 TAC **§5.203(g)**. ExxonMobil will install well signs pursuant to 16 TAC **§5.206(n)**.

In the event that ExxonMobil utilizes contractors for work at the storage facility, ExxonMobil will hold a pre-job safety meeting and explain emergency measures specific to such work prior to the work beginning (16 TAC **§5.206(h)(2)(B)**.

4.2 Objectives

ExxonMobil developed the engineering design, pre-operational testing plan, and operating strategy for the proposed injection wells to meet the following objectives:

- The injection well construction design, material specifications, and construction will be compatible with the composition of the CO_2 stream over the duration of the Sunflower Project to protect USDWs (16 TAC **§5.203(A)(i)**).

- The injection wells will undergo logging and testing prior to operation, to assess injection well and formation performance and update the operating strategy as necessary before the injection of CO_2 (16 TAC **§5.203(c)(2)(F**) and **§5.206**).

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- The injection well operating strategy provides continuous injection and annulus monitoring systems for each injection well, to control injection pressure and trigger automatic shutoff devices, consistent with safe operating procedures (16 TAC **§5.203(i)(1)**, **§5.203(e)(4)**, and **§5.203(i)(1)**; also **§5.206(d)(2)(F)**). ExxonMobil intends to always maintain mechanical integrity of the injection wells other than during periods of well workovers as outlined by 16 TAC **§5.203(h)(1)(A)** and will not injection between the outermost casing and wellbore as outlined by 16 TAC **§5.206(d)(2)(A).**

4.3 CO_2 Stream

The CO_2 stream injected into the reservoir will be 100% sourced from ExxonMobil's USGC CO2 pipeline. The stream is considered to be dehydrated. The majority of the full CO_2 stream constituents for the Sunflower Project are outlined in Table 4-1. Constituents with de minimis amounts are not reflected.

Table 4-1 – Major CO_2 Stream Constituents

Major Constituents	Mole Percent
Carbon dioxide (CO_2)	>97%
Hydrogen (H_2)	<1.5%
Methane (CH_4)	<3%
Ethane to Pentane (C_2 to C_5)	< 1.0%
Combined Nitrogen and Argon (N_2 and Ar)	<0.5%

The above stream components are in mole percentage, which is equal to volume percentage of the stream.

4.4 Material Selection

ExxonMobil assessed the corrosion-resistance properties of various metal alloys under the operating conditions expected on the proposed injection wells. The corrosion-resistance test results were used to select a reasonable and appropriate metal alloy for production casing and tubing compliant with the requirements of 16 TAC **§5.203(e)(1)(B)(ii)**.

4.4.1 Corrosion-Resistance Testing

ExxonMobil conducted a series of rigorous corrosion tests that simulated the worst-case potential well operations and downhole conditions of CO_2 within reservoir saline water. Specimens of metal alloys were placed in an autoclave test cell representing the corrosive environment that tubing and lower completion components will be subject to during the shut-in conditions, when CO_2 and reservoir connate water are present. Corrosion of the production tree and injection tubing is not expected during normal CO_2 injection operations, as the CO_2 stream is

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dehydrated. Table 4-2 reflects the testing conditions to simulate the corrosive environment, to demonstrate the corrosion-resistant capabilities of the selected material.

Table 4-2 – Simulation of Corrosive Environment

Test Objective	Test Conditions	Sunflower Project Expected Site Conditions	Material
Simulate corrosive United States Gulf Coast (USGC) environment	Propietary [redacted]	[redacted]	13Cr

[redacted]

The specimen was subjected to the anticipated downhole conditions for 30 days at reservoir temperature, pressure, and expected fluid interfaces. Post-test specimens were evaluated for general and localized corrosion. The specimen demonstrated corrosion-resistance capabilities.

The testing protocol is in line with the American Society for Testing and Materials (ASTM) guidelines.

The results for the USGC corrosion tests are summarized in Table 4-3. Reservoir temperature, pressure, and gas mixture were maintained per the specific test conditions, and the chloride content of the brine was varied. The corrosion rates from the 30-day test results are linearly extrapolated (worst-case scenario) to predict a maximum corrosion rate in mil/year (or 0.001 inch/year). As we inject CO_2 downhole, CO_2 saturation will increase in the near wellbore region and the reservoir temperature will decrease, both of which will continue to inhibit rate of corrosion.

Table 4-3 – Corrosion Testing Results at USGC Reservoir Conditions with 100,000 mg/L Chlorides

Chlorides (mg/L)	100,000
USGC Conditions – Averaged weight-loss corrosion rate (mil/year)	P [redacted]
USGC Conditions – Maximum localized corrosion rate (mil/year)	Pr [redacted]

4.4.2 Production Casing and Tubing Material Selection

Based on the extensive USGC corrosion-resistance testing, ExxonMobil deems 13Cr production casing and tubing sufficient in providing well integrity at the downhole conditions anticipated for both operating and later abandonment of the injection wells.

The metallurgy selection for the Sunflower Project is intended to be fit for purpose. Injection wells will be initially perforated in the planned injection stage, and injection will commence into this stage for approximately Propietar depending on the injection stage duration outlined in *Section 4.9.1*. After that period, the deepest injection interval will be plugged back, and the well will be recompleted uphole at the next injection interval, where a similar period of injection will occur. This interval will also be subsequently plugged back and uphole recompleted after the injection duration is reached. This process will continue until all the injection stages have been filled with CO_2 and the well can be permanently abandoned. During the anticipated maximum injection interval of about two years, it is expected that there may be approximately Propie of shut-in for routine well maintenance. During these periods, the casing below the injection packer, the injection packer, and the tubing could be exposed to CO_2 gas, associated gas impurities, and saline water. The casing above the packer will be isolated from formation fluids and constantly monitored during this period. During active CO_2 injection, the tubing, injection packer, and casing below the injection packer will be exposed to dense phase CO_2—but will not see potential corrosion like the carbon steel pipeline that is delivering CO_2 to the injection wells (i.e., absence of free water or formation fluids).

In the worst-case scenario, USGC conditions with formation fluids of Propietary chlorides, the maximum localized corrosion rate is expected to be Propietary This would require approximately Propietar of continuous shut-in exposure to CO_2 and formation fluids, to potentially lead to enough pitting to result in a through-wall leak in 13Cr casing.

Note that the average weight-loss corrosion rate assumes that all the weight loss is due to reduction in sample wall thickness for reporting purposes. No wall loss was seen in the samples, so it is just an indication of test-sample weight loss due to pitting. The maximum localized corrosion rate indicates the maximum pitting depth discovered in a batch of test specimens under the same conditions. It gives an indication on how long it could take for the wall of well tubulars to be penetrated, assuming the injection well was in a shut-in condition and exposed to both brine and CO_2 at the same time.

Although no significant corrosion or pitting leading to leaks is anticipated based on the operating conditions of these wells, any such occurrence would be addressed as discussed in Table 4-4—an injection well tubular-failure analysis table, showing potential failures and the remedial actions required. The failure analysis table utilizes a Propietary corrosion rate, which is the worst-case maximum localized corrosion rate (pitting) from all the testing data (detailed in Table 4-3).

Table 4-4 – Potential Injection-Well Tubular Failures Due to Corrosion and Associated Details

Type of Failure	Result of Failure	(Brine + Gas) Minimum Exposure Time Required for Failure	Probability of Failure (e.g., Leak Through Tubular)	Remedial Action if Leak Occurs
Leak in casing below injection packer	Inconsequential—the casing is already perforated below injection packer.	• Propiet	Unanticipated down to lowest perforation taking CO_2	None required
Leak in wall casing above injection packer	Leak would be immediately identified due to pressure monitoring and remedial action initiated.	• Propiet	Unanticipated as casing would be protected by cement and packer and packer fluid in annulus	Pull tubing and patch casing or plug back above leak depth. No impact to USDW.
Leak in tubing	Leak would be immediately identified, and remedial action initiated.	• Propiet	Unanticipated — exposure to brine + gas is expected to be approximately 18 days	Pull tubing and replace as needed.

4.4.3 Ordinary Portland Cement

The compilation of published research, experimental data, and industry experience highlighted in American Petroleum Institute (API) Bulletin 5100 provides technical clarity on the suitability of ordinary Portland cement (OPC) as a well construction material for CCS applications and other environments where it may be exposed to CO_2. While chemical and physical alterations do occur in the presence of carbonic acid—a product of the reaction between CO_2 and water—the rate and depth of alteration are negligible for long-term storage objectives. The preponderance of literature referenced in the bulletin concludes that, when sound well construction and cement placement techniques are followed and operationally induced wellbore stresses are considered, the alteration of OPC by CO_2 does not compromise well integrity—making OPC a barrier material that is sound in environments with highly saturated CO_2. Additionally, the literature referenced in the bulletin states that where minor defects of mechanical damage are present, the reaction products of CO_2 and OPC can exhibit self-healing properties.

Beyond this overall conclusion, API Bulletin 5100 (2025) also states that, "*While current literature and experimental data support the use of OPC in CO_2-exposed applications, this conclusion does not eliminate the need to account for site-specific well conditions when designing and optimizing OPC barrier systems. Factors that can affect performance include temperature exposure; post-set well stresses; formation lithologies; formation fluid compositions; and CO_2 stream composition*" (Wu, Stiles and Gupta 2025). These factors are addressed below.

Regarding temperature exposure, the maximum anticipated bottom hole temperature expected for the Sunflower wells is ~170˚ F API Bulletin 5100 Table 1 – Summary of Experimental Results

of Alteration Rates of OPC Under Influence of CO2, shows a test case at ~170˚ F run on Class H cement. Based on the experiment, a penetration depth of 0.79m after 10,000 years (0.079 mm/yr.) was predicted.

Furthermore, ExxonMobil conducted internal testing of the impact of CO_2 on cement at 30- and 90- day durations and presented results supporting the conclusions of API Bulletin 5100 (2025) at a March 2025 CCUS SPE conference. ExxonMobil's experiment-based prediction of the carbonation rate results in less penetration than the noted API 5100 example.

To further evaluate long term effects, ExxonMobil repeated internal testing on cement samples at 180 days. The 180-day testing reaffirmed the findings of the 30- and 90-day tests and further supported the conclustions presented in API Bulletin 5100. In fact, the longer term 180-day testing indicates that carbonization occurs more slowly than predicted by extrapolation of short term data, as there was no significant increase in carbonization depth between test intervals. Additionally, all tested speciemens maintained sufficient compressive strength to qualify as a barrier under API cement barrier requirements.

Importantly, alteration (penetration) should not be interpreted as degradation. Rather, it indicates the depth to which the cement and carbonic acid have reacted, or the depth to which carbonation of the cement has occurred. The reaction forms $CaCO_3$ (limestone) which is harder and less permeable than the original cement. Internal cement testing performed at 200^0F showed that the gas permeability of a Class H cement dropped from 0.016mD to 0.0015mD after 30 days of brine and CO_2 exposure. As per API Bulletin 5100 (2025), "*In practical terms, when OPC is used for zonal isolation in the annulus, the cement column is long enough that the extrapolated time required for CO_2 to migrate through the entire length of the cement sheath exceeds long-term storage objectives*."

Regarding stress, the primary stress will be from the original pressure test of the casing up to a maximum of 5000psi. Subsequent tests will be done to 200psi above injection pressure. The cement will be fully set at the time of pressure test with a minimum of eight hours waiting time. Note that while damage to the cement is not expected, cement bond logs will be run to verify cement quality and yearly mechanical integrity tests will be run to identify any potential behind pipe fluid migration.

Formation lithology across the injection interval consists of sand and shale intervals that will not impact the cement. Formation fluid is high salinity brine (100mg/L chlorides). The cement will not be exposed to the formation fluid during setting due to overbalance, mud filter cake, and cement fluid loss additive which aids in development of a filter cake for the cement. Once the well is perforated and cement is exposed to the brine, the chlorides in the brine will not react with the cement after it has been set.

Finally, the worst-case injection gas composition is CO_2: >97.0%, O_2: <50ppm, H_2S: <50ppm, SO_x: <15ppm | NO_x: <15ppm. API Bulletin 5100 (2025) addresses the interaction between the CO_2 and cement where a protective carbonated layer will develop which has lower permeability than the

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original cement. Cement is fully oxidized and O_2 will not react with it. To address H_2S and SO_x content in the injection gas, a high sulfate resistant Class H cement will be used to prevent post-set degradation due to sulfate alteration. Both H_2S and SO_x can react with the cement to form calcium sulfate (gypsum). Calcium sulfate then reacts with tricalcium aluminate in the cement to form a crystal that has potential to expand and impact cement quality. High sulfate resistant Class H cement limits the amount of allowable tricalcium aluminate in the cement to prevent significant sulfate damage. SO_x and NO_x mixed with water can lower the pH; however, the small amount available (<15ppm each) does not have a meaningful effect on the pH already altered by the CO_2.

Overall, both API Bulletin 5100 (2025) and ExxonMobil's internal testing support the conclusion that OPC-based cement systems remain suitable barrier materials for CO_2 service. The anticipated temperature, stress conditions, formation lithology, formation fluid composition, and injection gas composition for the Sunflower Facility fall within conditions for which OPC performance has been demonstrated to maintain long-term well integrity.

ExxonMobil proposes single stage cementing for both the surface casing and production casing for all three injection wells.

A list of common cement additives is provided below for the blended Portland cement. The additives are used to improve setting time, reduce porosity, and improve overall strength if needed. Not all additives listed will be utilized. ExxonMobil will provide specifics in required regulatory reports based on final cement slurry blends which will be determined by laboratory testing using the mix water available at the rig site.

Fluid-loss additives such as:

- Cellulosic polymer, polyamines, sulfonated aromatic polymers, polyvinyl pyrrolidone, polyvinyl alcohol, acrylamide methyl propane sulfonate copolymers and terpolymers, bentonite, latexes, and crosslinked polyvinyl pyrrolidone

Dispersants such as:

- Polynapthalene sulfonate and polymelamine sulfonate

Retardants such as:

- Lignosulfonates, hydroxycarboxylic acids, cellulose derivatives, organophosphonates, and certain inorganic compounds

Accelerators such as:

- Calcium chloride, sodium chloride, and sodium silicates

Antifoam agents such as:

- Polyglycol ethers and silicones

While ExxonMobil deems OPC as the fit for purpose technical solution for the Sunflower CCS Project justified and supported by API 5100 and ExxonMobil's own 30-, 60-, and 180-day testing which has been provided to the Texas Railroad Commission, presented and published at industry

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conference, and both having been summarized in this permit, CorrosaCem – or suitable equivalent - is being proposed for the tail cement from total depth to the UCZ to address regulator feedback on any uncertainty of approval through the permitting process with OPC .

4.5 Well Design and Construction

The engineering design parameters for the three proposed injection wells are based on the planned injection rates, injection volumes, fluid properties, and chemical properties of the injectate fluid. Injection well design is a two-string design. The casing and cement were designed to have sufficient strength and material properties to withstand the pressure, temperature, and corrosive forces to which they will be exposed (16 TAC **§5.203(e)(1)(B)(ii**)). Well design schematics are included in *Appendix D* (16 TAC **§5.203(e)(2)(K**)).

4.5.1 Surface Conductor Pipe Design

The unconsolidated nature of the sediments in the upper subsurface soil requires the installation of a conductor pipe to establish and maintain borehole integrity. A cellar will be installed, a 26-inch hole will be drilled with an auger-style rig to depth, and a 20-inch casing will then be run and cemented conventionally. A 17 1/2-inch bit will be used to drill the next section of the well through the conductor pipe.

4.5.2 Surface Casing Design

The surface hole will be drilled to below the USDW (16 TAC **§5.203(e)(1)(B)(iii)**) with a 17 1/2-inch bit, with surface casing set below the USDW by approximately 200 feet for each of the injection wells. A string of 13 3/8-inch casing will be run and cemented to the surface, with the casing centered in the open hole with centralizers. Please note, ExxonMobil will log each injection well and consult with TRRC's GAU for a USDW determination prior to setting the surface casing. As such, the well design may be slightly amended based on as-drilled conditions. In any case, the surface casing will extend below the lowermost USDW for proper isolation of all protected water strata.

A summary of the surface casing design parameters is presented in Tables 4-5 through 4-8.

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Table 4-5 – Summary of Design for Surface Casing Specifications for the Sunflower Project Injection Wells

Section	OD (in.)	ID (in.)	Drift (in.)	Weight (lb/ft)	Burst (psi)	Collapse (psi)	Tensile (kips)	Intervals (ft)		
								INJ No. 01	INJ No. 02	INJ No. 03
13 3/8-in. J-55	13.375	12.415	12.259	68.0	3,450	1,950	1,069	0–~2,900	0–~2,220	0–~2,150

*OD – outer diameter
ID – inner diameter
lb/ft – pounds per foot
kips – thousand pounds

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Table 4-6 – Surface Casing Design Calculations for the Injection Wells*

13 3/8-in. Casing: 68 ppf J-55 BTC, 0–2,900 ft					
	Load Type – Working Stress Design	**Load (lb)**	**Depth (ft)**	**Min SF**	**Depth (ft)**
Burst	Kick	1,218(psi)	0	2.6	0
	Pressure Test – 2,500 psi with 10 ppg OBM	2,685 (psi)	2,900	1.14	2,900
Tension	Green Cement – 2,500 psi with 10 ppg OBM	408 (kips)	0	2.61	0
	Running with Overpull – 100 kips	269 (kips)	0	3.97	0
	Buckling Check – cement to surface, maximum MW 11.0 ppg	105 (kips)	0	10.1	0
Collapse	Cementing Collapse	441 (psi)	2,900	4.36	2,900
	Future Drilling – minimum MW 8.5 ppg	667 (psi)	2,900	2.88	2,900
BTC = buttress-thread and coupled; MW = mud weight; OBM = oil-based mud; ppf = pounds per foot; ppg = pounds per gallon; SF = safety factor *Note: Based on Injection Well No. 01					

Table 4-7 – Surface Casing Cement-Volume Calculations for the Injection Wells

Section	**Footage (ft)**	**Type**	**Weight (ppg)**	**Total Sacks**	**Excess (%)**	**Cement Height (ft)**	**Cement Volume (ft^3)**
INJ No. 01	~2,900	ASTM Type I-II equivalent to API Class A or B	12 (lead); 15 (tail)	914 (lead); 405 (tail)	20	To Surface	2,523
INJ No. 02	~2,220	ASTM Type I-II equivalent to API Class A or B	12 (lead); 15 (tail)	622 (lead); 404 (tail)	20	To Surface	1,872
INJ No. 03	~2,150	ASTM Type I-II equivalent to API Class A or B	12 (lead); 15 (tail)	622 (lead); 404 (tail)	20	To Surface	1,872
ft^3 = cubic feet *Note: possible additives listed in section 4.4.3 Depths and volumes to be updated based on post-drill conditions.							

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Table 4-8 – Summary of Design for Surface Casing Centralizers

Centralizer Type	Centralizer Frequency	Depth (ft)	Quantity
Bow Spring	One every joint	2,820 – 2,900	2
Bow Spring	One every third joint	0 – 2,039	23
		Total:	25
*Note: Based on Injection Well No. 01, frequency is consistent across all injector wells.			

4.5.3 Production Casing Design

The production hole will be drilled to below the surface casing with a 12 1/4-inch bit. A long string of 9 5/8-inch casing will be run and cemented to the surface, with the casing centered in the open hole with centralizers (16 TAC **§5.203(e)(1)(B)(v)**). The key design criteria for the long string includes use of the following:

- L80 carbon steel material used from the surface to the top of the permitted upper confining zone (UCZ)
- 13Cr material used from the top of the permitted UCZ to the bottom of the permitted injection zone
    - Tail cement: 13.5 ppg CorrosaCem – or suitable equivalent - cement from TD to above the UCZ (16 TAC **§5.203(e)(1)(B)(vi)**)
    - Lead cement: 12.5 ppg OPC cement above the UCZ to the surface

- Fiber optic line to TD (INJ No. 03) or to 50’ below the Top Anahuac (INJ No. 01)

Through the life of the proposed injection wells, the project will have a continuous temperature monitoring system in place—designed to record downhole temperature as discussed in *Section 5 – Testing and Monitoring Plan*. The monitoring system will include a fiber optic cable with distributed temperature sensing outside the 9 5/8-inch production casing on Injectors 1 and 3. The fiber optic cable will be installed from TD to 50’ below the Top Anahuac in Injector 01 and from TD to surface in Injector 03 and cemented in place when the cementing job for the 9 5/8-inch casing is performed. The Sunflower AZM/IZM No. 01 will also have fiber to TD.

The engineering and design parameters for the production casing are summarized in Tables 4-9 and 4-10. These depths will be updated based on the final logging of the injection wells.

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Table 4-9 – Production Casing Specifications

Section	OD (in.)	ID (in.)	Drift (in.)	Weight (lb/ft)	Burst (psi)	Collapse (psi)	Tensile (kips)	Intervals (ft TVD KB)		
								INJ No. 01	INJ No. 02	INJ No. 03
9 5/8-in. L80	9.625	8.681	8.525	47	6,870	4,760	1,086	0–3,400 7,865–7,945 (shoe track)	0–3,350 7,831-7,911 (shoe track)	0–3,350 7,912–7,992 (shoe track)
9 5/8-in. 13Cr-80	9.625	8.681	8.525	47	6,870	4,760	1,086	3,400–7,865	3,350–7,831	3,350–7,912

TVD = true vertical depth; KB = kelly bushing
13Cr-80 = 13 chrome with 80,000 psi yield strength
Note: Depths based on pre-drill model; actual depths will be subject to as-drilled conditions.

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Table 4-10 – Production Casing Design Calculations*

9 5/8-in. Production Casing: 47 ppf 80 ksi Yield Strength with Premium Connections					
	Load Type – Working Stress Design	**Load (lb)**	**Depth (ft)**	**Min SF**	**Depth (ft)**
Burst	Injection – 2,750 psi injection pressure, 7.0 ppg packer fluid	2,946 (psi)	0	2.3	0
	Pressure Test – 5,000 psi with 8.33 ppg displacement fluid	5,000 (psi)	0	1.4	0
Tension	Green Cement – 5,000 psi with 8.33 ppg displacement fluid	480 (kips)	0	2.26	0
	Running with Overpull – 100 kips	418 (kips)	0	2.6	0
	Buckling Check – cement to surface, injection temperature	185 (kips)	0	5.7	0
Collapse	Evacuated Collapse – full evacuation	4,148 (psi)	7,992	1.13	7,992
NADF = non-aqueous drilling fluid *Note: Based on Injection Well No. 03.					

Tables 4-11 to 4-14 provide the production casing cement-volume calculations for each injection well.

Table 4-11 – Production Casing Cement-Volume Calculations for Injection Well No. 01

Section	**Footage (ft)**	**Type**	**Weight (ppg)**	**Total Sacks**	**Excess (%)**	**Cement Height (ft)**	**Cement Volume (ft^3)**
Lead Cement	3,405	API Class H	12.5	742	20	0 – 3,405	1,357
Tail Cement	4,540	CorrosaCem	13.5	1,105	20	3,405 – 7,945	1,706
						Total Volume: ft^3 (bbl)	3,063 (546)
bbl = barrel Note: Depths and excess cement to be adjusted on as-drilled conditions.							

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Table 4-12 – Production Casing Cement-Volume Calculations for Injection Well No. 02

Section	Footage (ft)	Type	Weight (ppg)	Total Sacks	Excess (%)	Cement Height (ft)	Cement Volume (ft^3)
Lead Cement	3,396	API Class H	12.5	730	20	0 – 3,396	1,334
Tail Cement	4,515	CorrosaCem	13.5	1,099	20	3,396 – 7,911	1,670
						Total Volume: ft^3 (bbl)	3,031 (540)
bbl = barrel Note: Depths and excess cement to be adjusted on as-drilled conditions.							

Table 4-13 – Production Casing Cement-Volume Calculations for Injection Well No. 03

Section	Footage (ft)	Type	Weight (ppg)	Total Sacks	Excess (%)	Cement Height (ft)	Cement Volume (ft^3)
Lead Cement	3,425	API Class H	12.5	735	20	0 – 3,350	1,345
Tail Cement	4,567	CorrosaCem	13.5	1,112	20	3,350 – 7,911	1,716
						Total Volume: ft^3 (bbl)	3,061 (545)
bbl = barrel Note: Depths and excess cement to be adjusted on as-drilled conditions.							

Centralizer placement for the 9 5/8-in. production casing is designed to accommodate the installation of fiber optic cable and to promote a continuous, uniform column of cement throughout the production casing (16 TAC **§5.203(e)(1)(B)(v)**). The proposed placement of centralizers through the production casing is shown in Table 4-14.

Table 4-14 – Production Casing Centralizer Program

Centralizer Type	Centralizer Frequency	Injection Well No. 01		Injection Well No. 02		Injection Well No. 03	
		Depth (ft)	Qty	Depth (ft)	Qty	Depth (ft)	Qty
Centralizers	One every other joint	0–7,945	99	0–7,911	99	0–7,992	100

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4.6 Completion Design and Equipment

The engineering design parameters for the three proposed injection wells are based on the planned injection rates, injection volumes, fluid properties, and chemical properties of the injectate fluid. Injection well design is a cased and perforated natural completion. The tubing, packer, instrumentation, and wellhead equipment were selected to have sufficient strength and material properties to withstand the pressure, temperature, and corrosive forces to which they will be exposed (16 TAC **§5.203(e)(1)(B)(ii)**).

Completion schematics are included in *Appendix D*.

4.6.1 Injection Tubing Design

The production tubing will be 7-inch 13Cr-80 with premium connections, installed with an injection packer. This design uses 13Cr material or its equivalent in all sections where the CO_2 will contact the tubulars. A tubing design analysis was conducted that considered calculated pipe-friction losses, exit velocities, and compression requirements. Tables 4-15 (16 TAC **§5.203(e)(2)(C)**) and 4-16 provide the tubing design parameters and evaluation (16 TAC **§5.203(e)(1)(B)(ii)**).

Table 4-15 – Tubing Specifications

Section	OD (in.)	ID (in.)	Drift (in.)	Weight (lb/ft)	Burst (psi)	Collapse (psi)	Tensile (kips)	Intervals (ft MD)		
								Injection Well No. 01	Injection Well No. 02	Injection Well No. 03
7-in. 13Cr-80	7.000	6.276	6.151	26.0	7,240	5,410	604	0–7,338	0–7,147	0–7,167

MD = measured depth
Note: Depths listed represent each well's maximum setting depth for all completions stages. Depths to be adjusted based on injection well logs.

Table 4-16 – Engineering Design Calculations for Tubing

7-in. Production Tubing: 26 ppf 13Cr 80 ksi Yield Strength with Premium Connections				
Load Type	**Triaxial SF**	**Axial SF**	**Burst SF**	**Collapse**
Buoyed Weight with Overpull – 100 kips	2.24	2.24	100+	2.24
CO2 Injection – 2,000 psi injection pressure and 2,750 A-annulus pressure	2.91	3.98	100+	2.99
Shut-in	2.91	3.98	100+	2.99
Tubing Evacuation – 2,750 psi A-annulus pressure	1.80	4.11	100+	1.67
Tubing Leak	4.33	4.73	100+	4.33
Injection Test – 30 bpm fresh water	2.45	3.34	2.54	100+
Annulus Pressure Test – 2,750 psi	2.08	5.47	100+	1.80

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bpm = barrels per minute *Note: Based off Injection Well No. 03

4.6.2 Safety and Continuous Monitoring Device Design

The following safety and continuous monitoring devices were designed for installation in the injection wells (16 TAC **§5.203(j)(2)(B)**).

4.6.2.1 Downhole Pressure and Temperature Gauge Design

A single pressure and temperature gauge will be run above the injection packer in each injection well to provide real-time bottomhole monitoring data. Pressure and temperature measurements will be fed to the surface using the installed tubing encapsulated conductor (TEC) line.

4.6.2.2 Fiber Optic Design and Completion

Fiber optic cable will be run on wells to monitor temperature.

4.6.3 Injection Packer Design

An injection packer will be installed with the 7-inch injection tubing. The planned type of packer is the Halliburton Perma Series or suitable equivalent packer with hydrogenated nitrile butadiene rubber (HNBR) element and flow-wetted material components will be 13Cr or a suitable equivalent. Differential pressure ratings of the packer will be selected to withstand all expected injection and shut-in load cases. Prior to setting the packer, the tubing annulus will be filled with diesel. Diesel is non-corrosive because it is a nonpolar hydrocarbon that contains no water, ions, or acidity needed to support electrochemical corrosion.

4.6.4 Wellhead and Tree Equipment Design

The wellhead and tree are designed to manage working pressures and provide mechanical and pressure integrity for each injection well. The equipment will be manufactured to the requirements of API 6A. The wellhead and tree equipment in contact with injection fluids will be manufactured with stainless-steel or corrosion-resistant alloy (CRA) components. The following is a detailed list of the wellhead components:

- Landing base: transfers casing loads from casing head to the 20-inch conductor
- Casing head assembly: 13 3/8-inch bottom connection x 13 5/8-inch 5,000 psi flange top, with one 2 1/16-inch 5,000 psi outlet valve on one side
- Mandrel casing hanger: 9 5/8-inch 47# premium thread box bottom, with dual elastomer premium annulus seals
- Double-studded adapter (DSA): 13 5/8-inch 5,000 psi x 13 5/8-inch 5,000 psi, optional
- Tubing head spool assembly: 13 5/8-inch 5,000 psi x 13 5/8-inch 5,000 psi, with two 2 1/16-inch 5,000 psi outlets and two outlet valves on one side, and premium elastomer casing pack-off

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- Tubing hanger: 7-inch 26# premium thread box bottom, with control line ports and metal-to-metal hanger neck seal, API material class FF
- Production tree: 7 1/16-inch 5,000 psi API material class FF or EE with API monograms; configuration as follows:
    - Lower master valve – manual
    - Upper master valve – manual
    - Flow tee
    - Crown valve – manual
    - Tree cap
    - Inner wing valve manual
    - Instrumentation flange
    - Outer wing valve – actuated fail closed

The wellhead will be configured as illustrated in Figure 4-1. Suitable equivalents for the specific manufacturers or equipment models indicated in the figure may be substituted as appropriate, based on vendors used and equipment availability.

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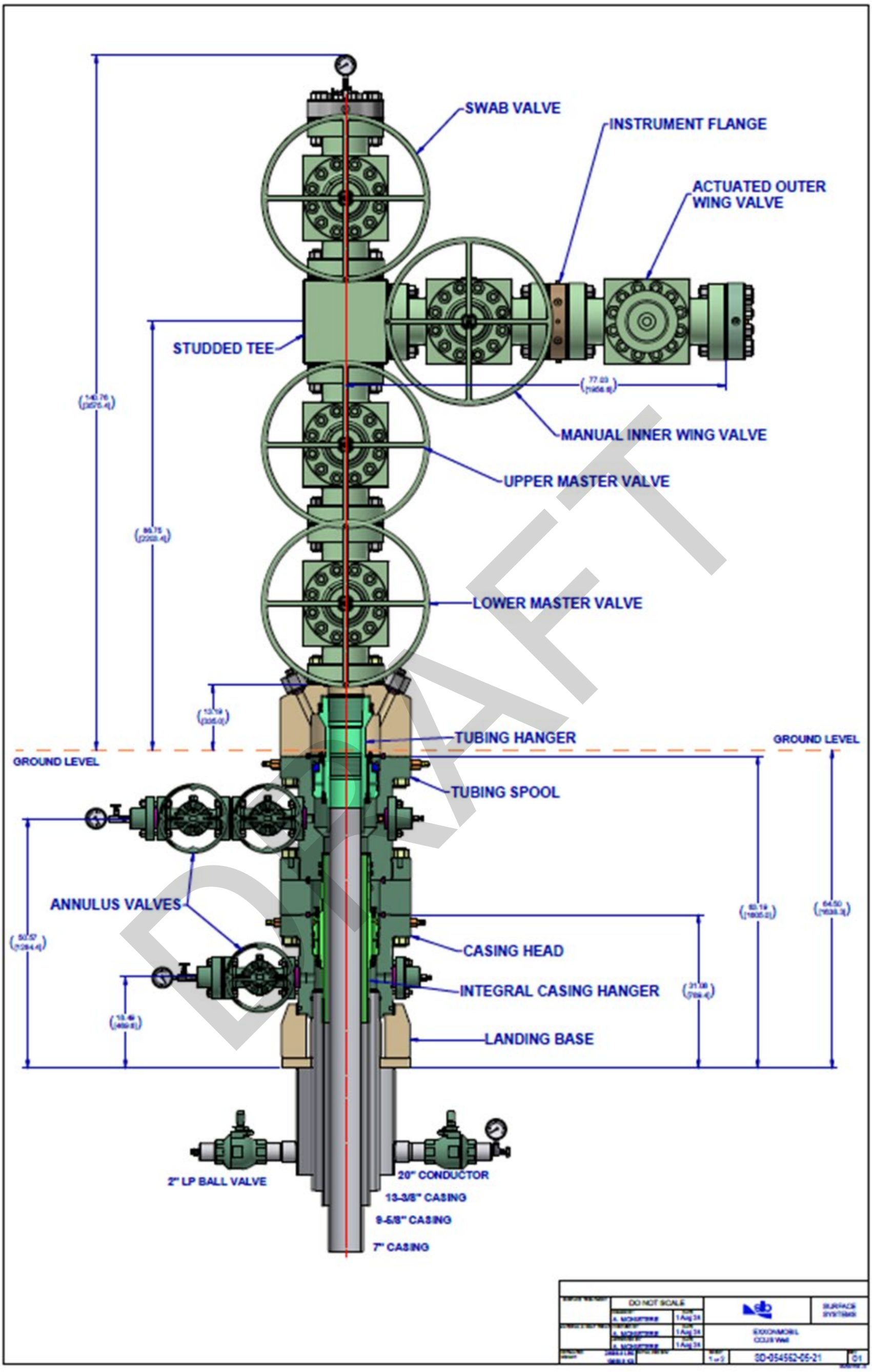


Figure 4-1 – Typical Wellhead Configuration for the Injection Wells

4.7 Well Drilling and Completion Design

4.7.1 Drilling and Completion Procedure for the Injection Wells

The proposed design summary and procedure for the proposed injection wells are described below. The tables presented here and in *Appendix D* provide the well design and completion details for each injection well. The final completion depths and specifications listed in those tables and the *Appendix D* schematics may be modified based on actual formation depths and/or conditions encountered during drilling.

- Preset the conductor.
  - 20 inches to 120 feet
- Drill 17 1/2-inch surface hole to TD and log.
  - Casing to be set below the base of the lowermost USDW.
    - The USDW will be confirmed by means of logging during the drilling of the well.
    - The planned surface TD is approximately 2,215 feet TVD KB + rathole.
- Run and cement the 13 3/8-inch surface casing.
  - Cemented to surface using blended OPC.
- Drill 12 1/4-inch production hole to TD and conduct pre-operation formation evaluation.
  - Planned production hole TD is specified by schematics in *Appendix D*.
- Run and cement the 9 5/8-inch production casing.
  - 9 5/8-inch casing is composed of L80 and 13Cr material.
    - L80 casing will cover shallow formations from the surface to the top of the upper confining zone (UCZ).
    - 13Cr-80 casing will cover the sealing and injection zones.
    - L80 casing will make up the shoe track.
    - The planned shoe depth for each well is specified by the schematics in *Appendix D*.
  - Cemented back to surface
    - Cement to be comprised of:
      - Tail cement: 13.5 ppg CorrosaCem – or suitable equivalent - cement from TD to above the UCZ
      - Lead cement: 12.5 ppg OPC cement above the UCZ to the surface
- Perforate and install the injection tubing and completion equipment.
  - 7-inch tubing set above top perforation.
    - Downhole pressure and temperature gauge set above the packer.
    - Landing nipple is set below the packer.
  - 13Cr tubulars will be used.
  - Tubing annulus will be filled with a noncorrosive fluid.

Within 30 days after completing each well, ExxonMobil will file with the division a complete record of the well on the appropriate form showing the current completion (16 TAC **§5.206(c)(2)**). A detailed drilling and completion prognosis for each injection well is included in *Appendix D*.

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4.8 Pre-Operational Testing Plan

A variety of geophysical well logs, core, and injection tests were collected during the construction of a nearby stratigraphic test well to verify and evaluate the depth, thickness, porosity, permeability, lithology, and formation fluid salinity in the relevant geologic formations. *Appendix D.3* details the actual core and injection test data taken in the nearby stratigraphic test well. Additional core, well log, and injection test data will be taken in the construction of the proposed injection wells as outlined below to satisfy 16 TAC **§5.203(f)**.

4.8.1 Injection and Confining Zone Core Sampling

The following preliminary coring operations are planned during the construction of the injection wells. Table 4-17 details the potential core intervals and operations per formation interval.

Table 4-17 – Summary of Preliminary Coring Operations

Interval	Injector No. 01	AZM/IZM No. 01
UCZ	CC in Frio	RSWC
Injection Zones		RSWC
LCZ		RSWC

RSWC = rotary sidewall core, taken via wireline during drilling operations; LCZ = lower confining zone; CC = conventional core
Note: Preliminary coring plans subject to change based on as-drilled conditions.

4.8.2 Pre-Operation Logging Program

The following geophysical logs are planned to characterize the site. The openhole logging plan is detailed in Table 4-18. The cased-hole logging plan is detailed in Table 4-19.

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Table 4-18 – Open hole Logging Plan for the Project

Section	Open hole Logs
17 1/2-in. hole	• Gamma Ray and Resistivity logs will be collected while drilling via logging while drilling (LWD) tools
12 1/4-in. hole	• Gamma Ray – All Injectors – LWD on Injector No. 02 • Resistivity – All Injectors – LWD on Injector No. 02 • Density – All Injectors – LWD on Injector No. 02 • Neutron – All Injectors – LWD on Injector No. 02 • Magnetic Resonance – Injectors No. 01 & 03 • Sonic – All Injectors – LWD on Injector No. 02 • Caliper – Injectors No. 01 & 03 • Borehole Imaging – AZM/IZM No. 01 only • Formation Pressure – AZM/IZM No. 01 only • Fluid Samples – AZM/IZM No. 01 only • RSWC – AZM/IZM No. 01 only

Table 4-19 – Cased-Hole Logging Plan for the Injection Wells

Section	Cased-Hole Logs
13 3/8-in. surface casing	• CBL, VDL, Temperature
9 5/8-in. production casing	• CBL, VDL, Temperature
7-in. production tubing and 9 5/8-in. casing	• Temperature • Through-Tubing Casing Inspection • Oxygen Activation or Pulsed Neutron

*CBL – cement bond log
VDL – variable density log

4.8.3 Injection Zone Characterization

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ExxonMobil will collect characterization data for the permitted injection zone of the injection wells, including formation fluid temperature, pH, specific conductivity, and formation pressure (16 TAC **§5.203(f)(3)(A)**).

4.8.4 Fluid Characteristics and Downhole Conditions

During the construction of the injection wells, ExxonMobil will collect formation fluid samples in the injection zone and the formation above the UCZ. Injection zone samples will be evaluated for the compatibility of the injectate with the formation fluids (16 TAC **§5.203(f)(2)**). Samples collected above the UCZ during the pre-operation phase will form the baseline data for comparison with water quality data representing the operating and post-operating phases of the Sunflower Project. The analysis plan for water samples collected in the injection zones and above the UCZ formation is specified in Table 4-20.

Table 4-20 – Sampling and Analysis Plan for the above UCZ Water Samples

Parameter/Analyte	Analytical Method
Total dissolved solids, alkalinity, electrical conductivity, temperature, pH	Standard lab analyses
Gas composition (CO_2, CH_4, O_2, N_2)	Gas chromatography
Dissolved cations (i.e., As, Ba, Ca, Fe, Mg, Mn, Na, K, Pb, Zn)	Ion chromatography
Dissolved anions (i.e., HCO_3, Br, Cl, NO_3 SO_4)	Ion chromatography
As = arsenic; Ba = barium; Br = bromine; Ca = calcium; CH_4 = methane; Cl = chlorine; Fe = iron; HCO_3 = bicarbonate; K = potassium; Mg = magnesium; Mn = manganese; N_2 = nitrogen; NO_3 = Nitrate; O_2 = oxygen; Pb = lead; SO_4 = sulfate; Zn = Zinc	

4.8.5 Injection and Confining Zone Formation Testing

Pressure transient well testing (e.g., a pressure falloff test) will be conducted on one injection well as a part of completion activities (16 TAC **§5.203(f)(2)(B)**). These tests are intended to confirm reservoir and operational parameters used in the permitting process and provide needed data on the geologic and hydrogeologic properties of subsurface formations. The following pressure falloff test procedures are proposed:

- A nonhazardous test fluid will be used during the injection test.
- The purpose of this test is to evaluate the injectivity index, skin, and permeability-thickness of the injection zone.
- For the permitted injection zone, an injectivity test will be performed prior to injection.
- The well will be shut in and the pressure falloff recorded with downhole gauges over sufficient time for proper analysis.

4.9 Injection Well Operating Strategy

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4.9.1 Overview of Injection Well Perforation and Completion Strategy

Upon permit approval, injection will start based on the stages and injection schedules referenced in Tables 4-21 through 4-23. Please note that the following perforation depths are notional and may be revised based on as-drilled conditions of the wells themselves.

Table 4-21 – Injection Sequencing Strategy for Injection Well No. 01

Stage	Sand Interval	Top Perf (ft MD)	Bottom Perf (ft MD)	Gross Thickness (ft)	Net Reservoir (ft)	Duration (years)	Completion Years after Startup
1	Frio Sand 3	7,378	7,638	415	205	2	0
2	Frio Sand 2 Lower	6,768	7,272	546	276	2	2
3	Frio Sand 2 Upper	6,590	6,710	236	180	2	4
4	Frio Sand 1	5,962	6,409	857	469	2	6
5	Fleming Sand 3 Lower	4,841	5,271	484	299	2	8
6	Fleming Sand 3 Upper	4,398	4,759	549	251	1	9

*MD – Measured Depth

Table 4-22 – Injection Sequencing Strategy for Injection Well No. 02

Stage	Sand Interval	Top Perf (ft MD)	Bottom Perf (ft MD)	Gross Thickness (ft)	Net Reservoir (ft)	Duration (years)	Completion Years after Startup
1	Frio Sand 3	7,187	7,707	538	222	1	0
2	Frio Sand 2 Lower	6,974	7,143	237	103	1	1
3	Frio Sand 2 Upper	6,506	6,900	430	237	1	2
4	Frio Sand 1	5,651	6,420	859	378	1	3
5	Fleming Sand 3 Lower	4,816	5,267	491	349	1	4
6	Fleming Sand 3 Upper	4,254	4,768	541	255	1	5

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Table 4-23 – Injection Sequencing Strategy for Injection Well No. 03

Stage	Sand Interval	Top Perf (ft MD)	Bottom Perf (ft MD)	Gross Thickness (ft)	Net Reservoir (ft)	Duration (years)	Completion Years after Startup
1	Frio Sand 3	7,207	7,756	603	242	2	0
2&3	Frio Sand 2	6,650	7,146	606	283	2	2
4	Frio Sand 1	5,989	6,448	836	296	2	4
5	Fleming Sand 3 Lower	4,868	5,309	451	262	2	6
6	Fleming Sand 3 Upper	4,587	4,851	618	270	1	7

ExxonMobil plans to use a staged approach injection strategy as shown in Figure 4-2. Once ExxonMobil ceases injection into a stage, that stage will be plugged back before perforating and injecting into a subsequent stage. The perforation depths that were provided in Tables 4-21 to 4-23 are based on the current geologic model described in *Section 1 – Site Characterization* and subject to change based on as-drilled conditions.

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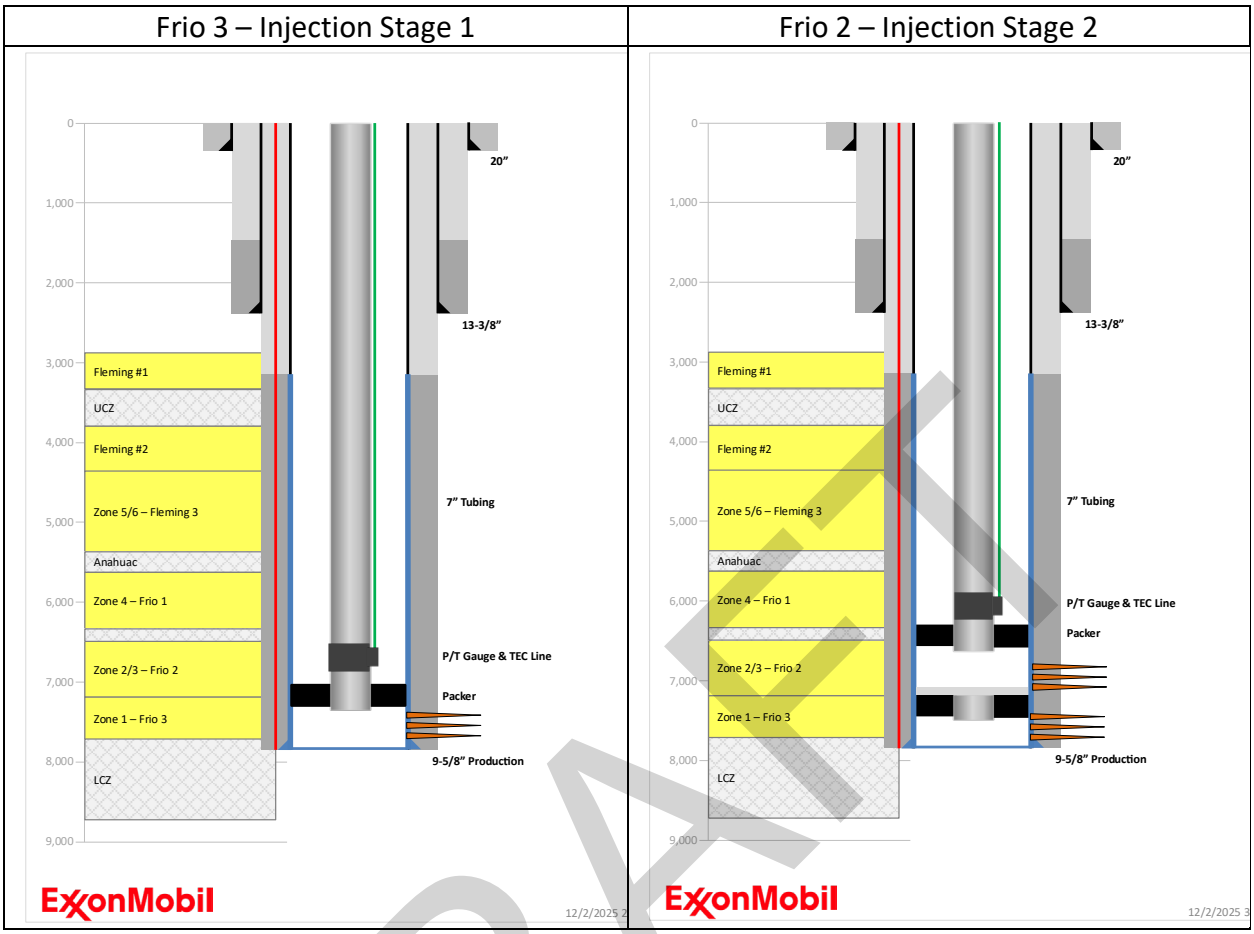


Figure 4-2 – Operational Completion Strategy for the Injection Wells

4.9.2 Injection Rate and Pressure

Table 4-24 provides the proposed operations for the injection wells, including injection rate and pressure by well. Average injection rates for each well's injection stages range from 0.5 to 1.2 MMTPA, with a maximum injection zone rate of 2.5 MMTPA. While each well will remain within its total annual injectivity allowance, temporary increases up to 2.5 MMTPA may occur. Both the maximum and average injection rates are predicted to result in reservoir pressure rises that are below 90% of the critical fracture pressure, shown in Table 4-24. Both the injection rates and pressures are within the operating window of the injection wells. In developing the injection strategy, ExxonMobil incorporated geomechanical studies of site-specific data.

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Table 4-24 – Summary of Injection Parameters for the Injection Wells

Stage	Sand Interval	Parameter	Injection Well No. 01	Injection Well No. 02	Injection Well No. 03
1	Frio 3	Maximum Injection Zone Rate (MMTPA)	2.5	2.5	2.5
		Average Injection Zone Rate (MMTPA)	1.2	1.0	0.8
		Maximum Allowed Surface Pressure (psi)	2,000	2,000	2,000
		Average Modeled Surface Injection Pressure (psi)	1088	1066	1067
		Maximum Modeled Surface Injection Pressure (psi)	1112	1070	1073
		Fracture Pressure (psi)	5,175	5,175	5,175
		Maximum Allowed BHP (psi)	4,500	4,500	4,500
		Maximum Modeled BHP (psi)	3,537	3,490	3,503
2	Frio 2 Lower	Maximum Injection Zone Rate (MMTPA)	2.5	2.5	2.5
		Average Injection Zone Rate (MMTPA)	1.0	1.2	1.2
		Maximum Injection Zone Surface Pressure (psi)	2,000	2,000	2,000
		Average Modeled Surface Injection Pressure (psi)	1029	1048	1034
		Maximum Modeled Surface Injection Pressure (psi)	1083	1069	1066
		Fracture Pressure (psi)	4,830	4,830	4,830
		Maximum Allowed BHP (psi)	4,200	4,200	4,200
		Maximum Modeled BHP (psi)	3,489	3,488	3,491
3	Frio 2 Upper	Maximum Injection Zone Rate (MMTPA)	2.5	2.5	**
		Average Injection Zone Rate (MMTPA)	0.5	1.2	
		Maximum Injection Zone Surface Pressure (psi)	2,000	2,000	
		Average Modeled Surface Injection Pressure (psi)	960	1016	
		Maximum Modeled Surface Injection Pressure (psi)	1022	1043	
		Fracture Pressure (psi)	4,554	4,554	

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Stage	Sand Interval	Parameter	Injection Well No. 01	Injection Well No. 02	Injection Well No. 03
		Maximum Allowed BHP (psi)	3,960	3,960	
		Maximum Modeled BHP (psi)	3,164	3,197	
4	Frio 1	Maximum Injection Zone Rate (MMTPA)	2.5	2.5	2.5
		Average Injection Zone Rate (MMTPA)	1.0	1.0	1.0
		Maximum Injection Zone Surface Pressure (psi)	2,000	2,000	2,000
		Average Modeled Surface Injection Pressure (psi)	941	935	939
		Maximum Modeled Surface Injection Pressure (psi)	955	1013	1026
		Fracture Pressure (psi)	4,313	4,313	4,313
		Maximum Allowed BHP (psi)	3,750	3,750	3,750
		Maximum Modeled BHP (psi)	3,085	3,128	3,148
5	Fleming 3 Lower	Maximum Injection Zone Rate (MMTPA)	2.5	2.5	2.5
		Average Injection Zone Rate (MMTPA)	1.0	1.0	1.0
		Maximum Injection Zone Surface Pressure (psi)	2,000	2,000	2,000
		Average Modeled Surface Injection Pressure (psi)	836	830	842
		Maximum Modeled Surface Injection Pressure (psi)	940	929	936
		Fracture Pressure (psi)	3,450	3,450	3,450
		Maximum Allowed BHP (psi)	3,000	3,000	3,000
		Maximum Modeled BHP (psi)	2,855	2,840	2,849
6	Fleming 3 Upper	Maximum Injection Zone Rate (MMTPA)	2.5	2.5	2.5
		Average Injection Zone Rate (MMTPA)	1.0	1.0	0.5
		Maximum Injection Zone Surface Pressure (psi)	2,000	2,000	2,000
		Average Modeled Surface Injection Pressure (psi)	776	762	769
		Maximum Modeled Surface Injection Pressure (psi)	830	823	835
		Fracture Pressure (psi)	3,174	3,174	3,174

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Stage	Sand Interval	Parameter	Injection Well No. 01	Injection Well No. 02	Injection Well No. 03
		Maximum Allowed BHP (psi)	2,760	2,760	2,760
		Maximum Modeled BHP (psi)	2,280	2,270	2,288

*BHP – bottomhole pressure

** For Sunflower INJ No.3 stages 2 & 3 (Frio 2 Lower & Upper) are combined

Table 4-255 – Injection Zone Depths

Injection Well	Top of Injection Zone (TVD, ft)	Bottom of Injection Zone (TVD, ft)
Sunflower INJ No. 01	3,572	7,720
Sunflower INJ No. 2	3,588	7,723
Sunflower INJ No. 03	3,595	7,775

The proposed injection zone depths are provided in Table 4-25 based on the work outlined in *Section 1 – Site Characterization*. ExxonMobil proposes an injection zone of 3,572 ft TVD - 7,775 ft TVD. ExxonMobil may slightly revise these depths based on the as-drilled conditions of the wells.

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4.9.3 Well Stimulation Procedures

ExxonMobil may stimulate the injection zone for the Sunflower CCS Project in the event it is necessary, to achieve desired injectivity (*Appendix D.4*). Stimulation may be conducted if injection impairment is observed during the life of the wells. Additional details on the stimulation plan can be found in *Appendix D.4*. Some of the potential causes for injection reduction are as follows:

- Formation damage (e.g., fines migration, scaling, debris in injection stream)
- Geochemical reactions due to fluid/reservoir incompatibility
- Salt precipitation due to in situ brine vaporization
- Reservoir compartmentalization or facies variation
- Shale swelling

ExxonMobil will provide advance notice of the proposed stimulation to the UIC Program director (UIC Director) in writing at least 30 days prior to injection and provide at least a 48-hour advanced notice in accordance with 16 TAC **§5.206(j)**. The detailed stimulation plan is provided in *Appendix D.4* and incorporates the following:

- Stimulation design to ensure the treatment will not interfere with containment
- Stimulation fluids detail (e.g., volumes, concentrations, additives)
- Stimulation fluid/ well material compatibility analysis

- Well integrity analysis (e.g., casing/tubing stress analysis)
- Stimulation procedure

The stimulation fluids will be an acid, most likely hydrochloric acid (HCl), or a water-based fluid treated as needed with the necessary chemicals and/or additives to achieve the desired results. Any stimulation would not interfere with the containment of the project. A high-level procedure is as follows and, as mentioned above, a case-specific stimulation plan procedure along with a detailed description of fluids to be used will be provided to the UIC Director should stimulation become necessary:

1. Determine the compatibility of stimulation chemicals with well materials, reservoir rock, and fluids.
2. Develop the stimulation plan based on the injection impairment cause.
3. Provide the work procedure and stimulation program to the UIC Director in writing at least 30 days prior to the planned date for start of the work (16 TAC **§5.206(j)**).
4. Prepare the wellsite and mobilize equipment.
5. Shut in and isolate the well from the CO_2 injection system. Allow the pressures to stabilize.
6. Rig up the stimulation equipment.
7. Prepare the well for stimulation.
8. Perform the stimulation treatment per approved plan.
9. Flush the wellbore with treated water and prepare the well to return to normal operation.
10. Rig down and return the well back to injection.

4.10 Operational Reporting Plan

During the operational phase of the Sunflower Project, ExxonMobil will, within 24 hours, report to the UIC Director a confirmed noncompliance, pursuant to the requirements in 16 TAC **§5.206(d)(2)(F)(ii)(III)**, **§5.207(a)(2)(A**), and **§5.206(h)(3)**—including the following:

- Evidence that the CO_2 plume or pressure front may endanger one or more USDWs
- The noncompliance situation as it relates to a permit condition
- Apparent malfunction of the injection system
- Triggering of a shutoff system
- Loss of mechanical integrity
- A release of CO_2 to the atmosphere or biosphere

ExxonMobil will cease injection and take all steps reasonably necessary to determine whether there may have been a release of CO_2 to an unauthorized zone, in the event that there is a loss of mechanical integrity (16 TAC **§5.206(d)(2)(F)(ii)(II)**).

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Appendix D – Well Construction Schematics and Procedures:

- Appendix D-1: Well Design and Completion Schematics for Injection Wells
- Appendix D-2: Drilling and Completion Prognosis for Injection Wells
- Appendix D-3: Nearby Stratigraphic Test Well Core and Injection Test Data
- Appendix D-4: Sunflower Stimulation Program

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Appendix D: ell Construction Schematics and rocedures

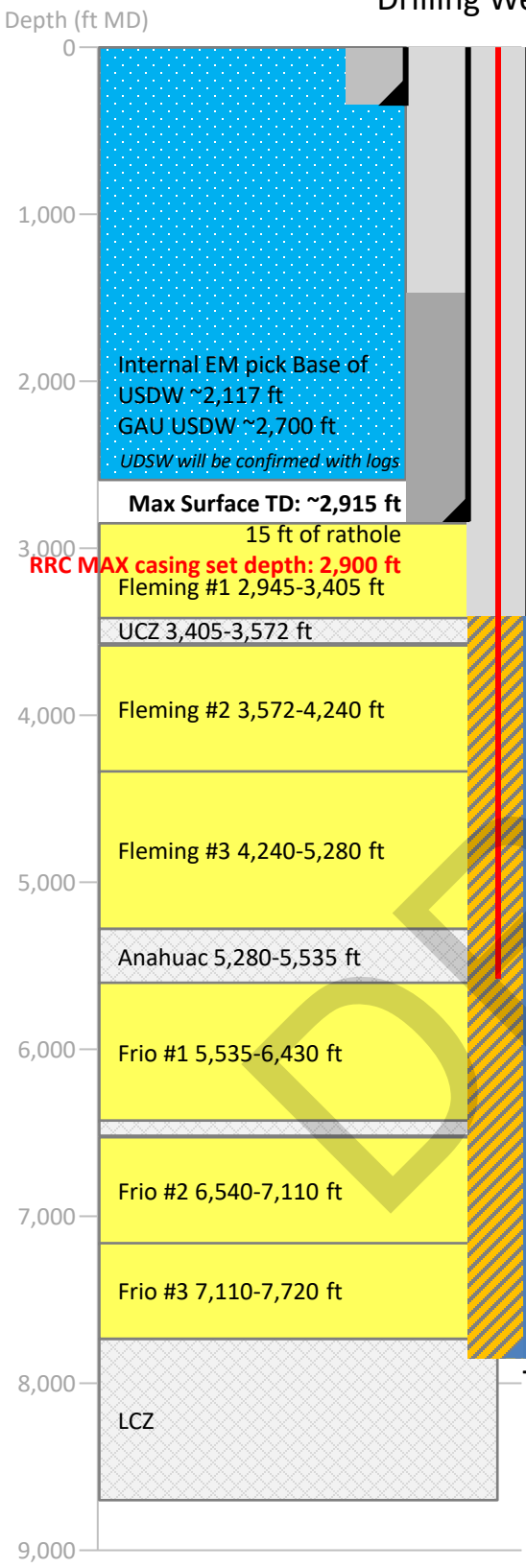
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Appendix D1: Well Design – Completion Schematics for Injection Wells

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Sunflower CCS Project Injection Well No. 01

Drilling Wellbore Schematic (Pre-Drill)



20" Conductor:
78.6 ppf, line pipe, Welded
0.375" WT, 19.25" ID

17.5" Hole Section:
Water based mud
Planned MW ~9.5 ppg

13-3/8" Surface Casing:
0 – 2,900 ft 13-3/8" 68 ppf, J55, BTC
0.480" WT, 12.259" drift ID
Burst 3450, Collapse 1950, Tensile 1069

12.25" Hole Section:
Oil based mud
Planned MW ~10.0 ppg

Production Cement:
0 – 3,405 ft Lead (12.5 ppg)
3,405 – 7,930 ft Tail (13.5 ppg)
CorrosaCem

9-5/8" Production Casing:
0 – 3,400 ft 9-5/8" 47ppf L80 TSH Blue/A
0.472" WT, 8.525" drift ID
Burst 6870, Collapse 4750, Tensile 1086
3,400 – 7,930 ft 47ppf 13Cr80 JFE Lion
0.472" WT, 8.525" drift ID
Burst 6870, Collapse 4750, Tensile 1086

Casing mounted fiber optic (DAS/DTS)
0 – 5330 ft MD
2x CDC (one above & below) each coupling

TD: ~7,945 ft MD / TVDdf
15 ft of rathole
Vertical Well; 0° Inc

Depths are notional and subject to change based on as-drilled conditions

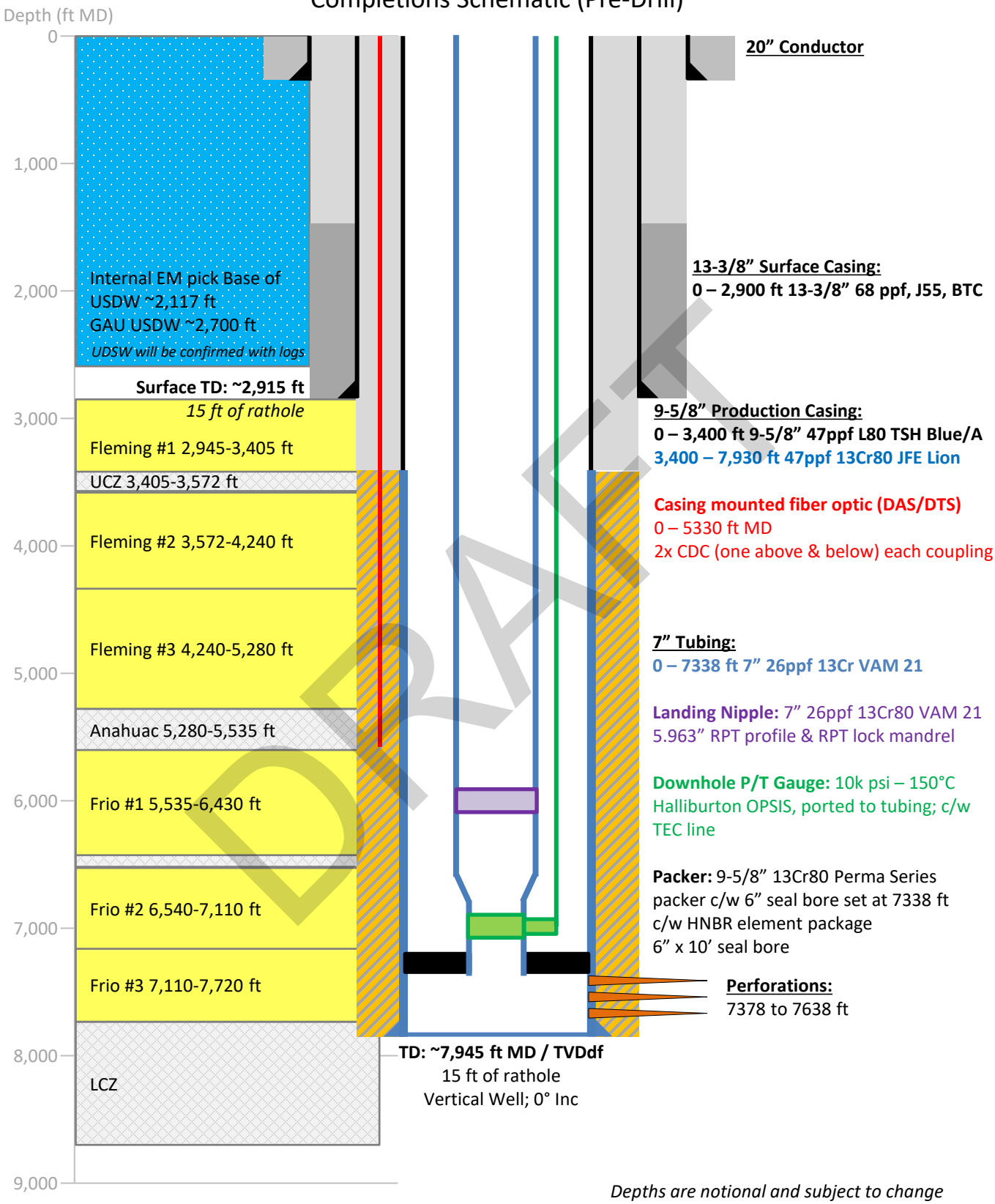
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Sunflower CCS Project Injection Well No. 01

Completions Schematic (Pre-Drill)



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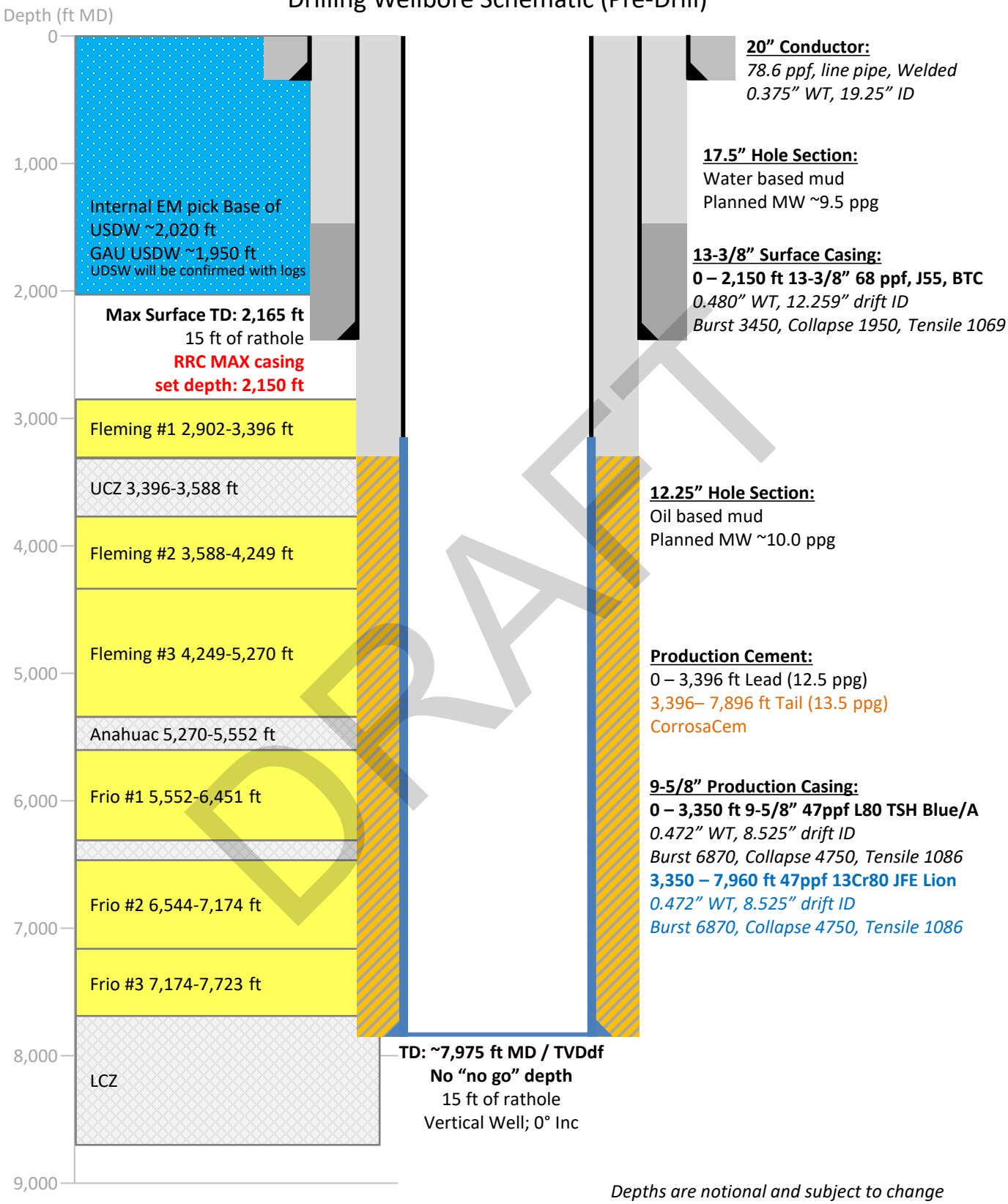
Depths are notional and subject to change based on as-drilled conditions

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Sunflower CCS Project Injection Well No. 02

Drilling Wellbore Schematic (Pre-Drill)



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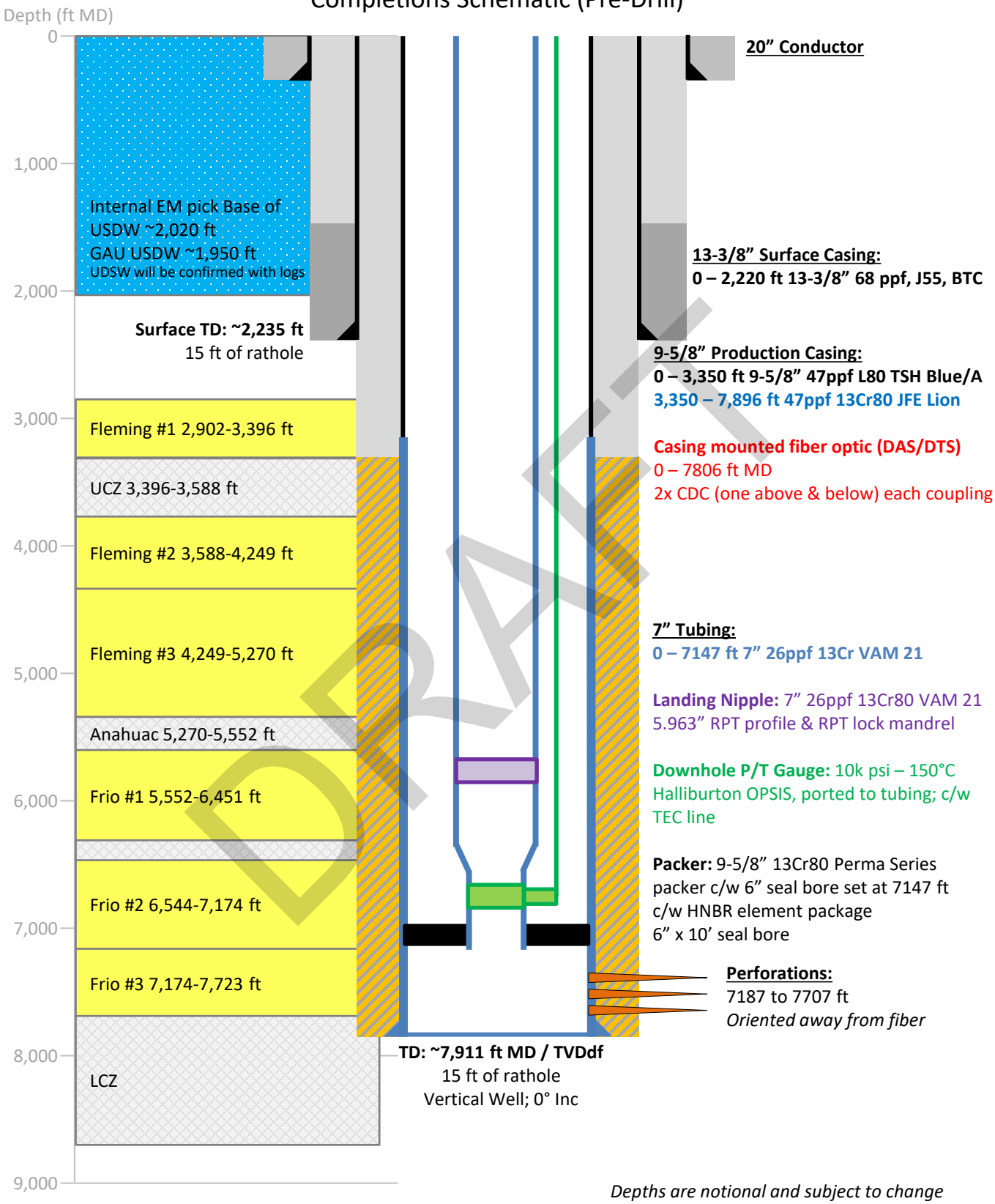
Depths are notional and subject to change based on as-drilled conditions

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Sunflower CCS Project Injection Well No. 02

Completions Schematic (Pre-Drill)



Depths are notional and subject to change based on as-drilled conditions

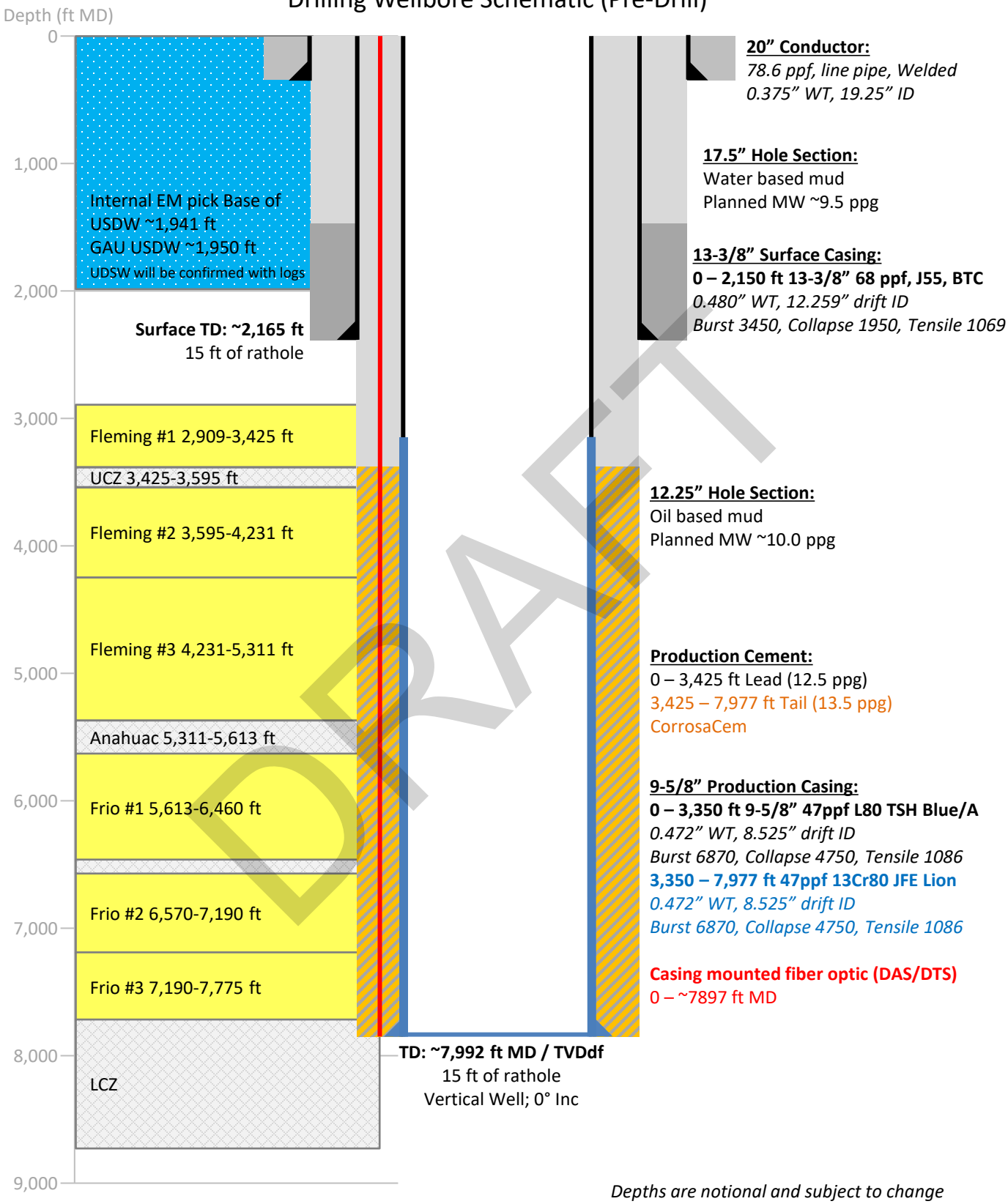
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Sunflower CCS Project Injection Well No. 03

Drilling Wellbore Schematic (Pre-Drill)



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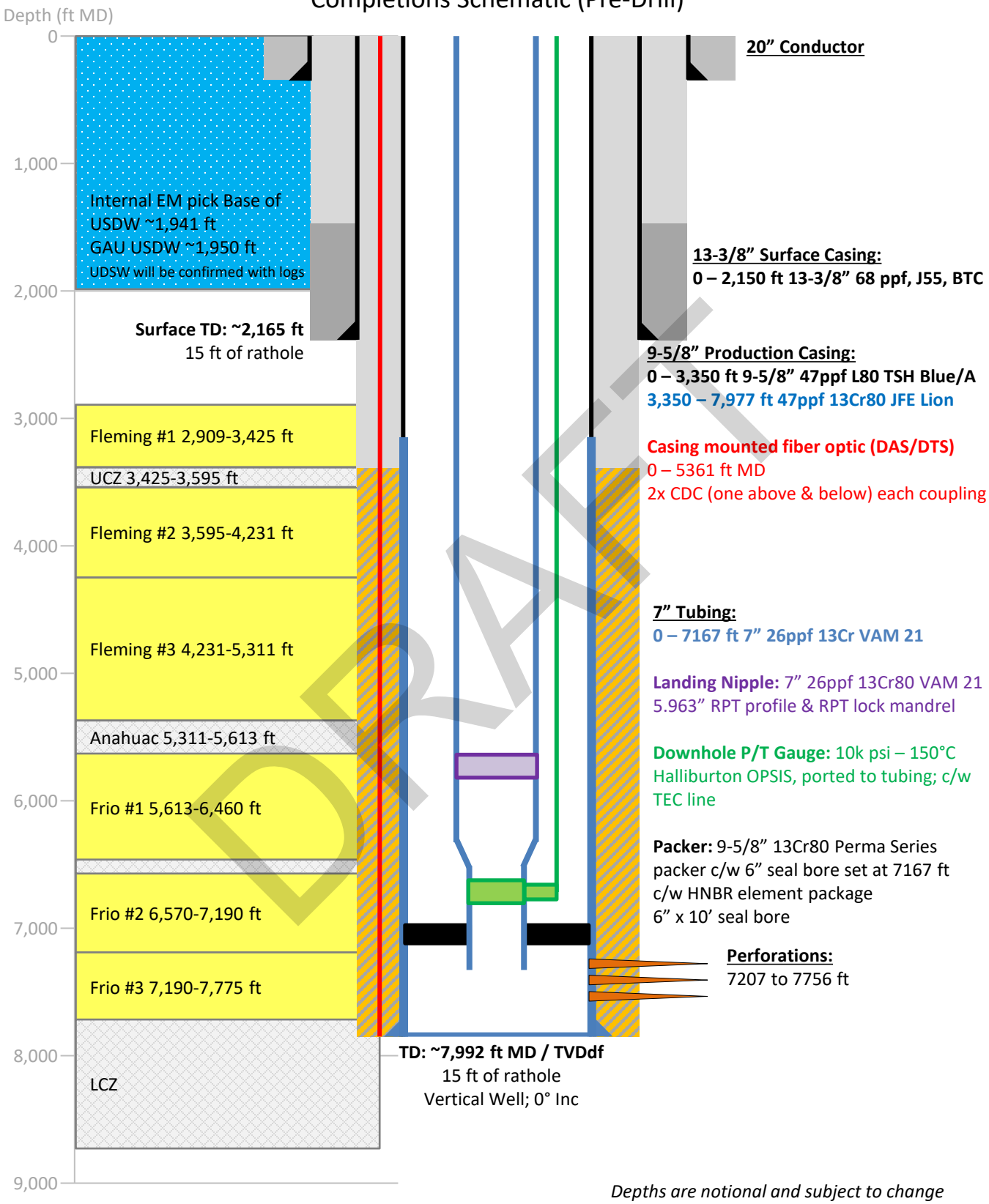
Depths are notional and subject to change based on as-drilled conditions

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Sunflower CCS Project Injection Well No. 03

Completions Schematic (Pre-Drill)



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Depths are notional and subject to change based on as-drilled conditions

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Appendix D2 - Drilling and Completion Prognosis for Injection Wells

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Appendix D.2: Drilling and Completion Prognosis for Injection Wells

Drilling Operations:

20-in. Conductor

1. Mobilize spud rig and equipment to drilling pad
2. Position rig on marked well center
3. Rig up spudder rig
4. Drill 26-in. hole with auger to ~150 ft MD
5. Run and cement 20-in. casing to surface
6. Demobilize spud rig as needed

13-3/8-in. Surface Casing

1. Mobilize drilling rig and equipment to drilling pad
2. Rig up drilling rig and auxiliary equipment
3. Pick up 17-1/2-in. bit/bottom hole assembly (BHA)
4. Clean-out conductor as needed
5. Drill 17-1/2-in. hole to total depth (TD) at ~2,215ft with water-based mud (WBM)
6. Run 13-3/8-in. surface casing with centralizers to TD
7. Cement surface casing to surface displacing with oil-based mud (OBM)
8. Check for cementer returns to surface and pump top-off cement job as required
9. Wait on cement

9-5/8-in. Production Casing

1. Install blowout preventer (BOP) and pressure test to required test pressure
2. Pick up 12-1/4-in. BHA and tag cement
3. Circulate bottoms up with OBM
4. Pressure test 13-3/8-in. casing to 2,750 psi over OBM
5. Drill out shoe track
6. Perform formation integrity test (FIT)
7. Drill 12-1/4-in. hole to TD with OBM.
8. Perform pre-operational testing required well logs
9. Run 9-5/8-in. production casing with centralizers and fiber optic cable to TD
10. Cement 9-5/8-in. production casing to surface
11. Wait on cement
12. Pressure test 9-5/8-in. casing

Completion Operations:

Install Completion

1. Mobilize / rig up workover rig
2. Install and pressure test BOP
3. Perforate injection stage 1
4. Set packer assembly

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5. Rig up tubing running equipment including cable management system
6. Pick up completion equipment
    1. Gauge mandrel and TEC line – pressure and temperature gauge
    2. Landing nipple
7. Run completion equipment on 7-in. tubing
8. Displace packer fluid
9. String in tubing in the injection packer and land tubing hanger
10. Terminate TEC
11. Test tubing and packer to required pressure
12. Rig up surface flowlines
13. Set back-pressure valve in tubing hanger
14. Install tree
15. Remove back-pressure valve from tubing hanger
16. Perform pre-operational wireline logs
17. Rig down and demobilize the rig and equipment

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Appendix D3 - Near-by Stratigraphic Well Core and Injection Test Data

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Appendix D4 - Stimulation Plan

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Appendix D.4: Stimulation Plan

Stimulation to enhance the injectivity potential of the injection zone may be necessary. Stimulation may involve but is not limited to flowing fluids into or out of the well, increasing or connecting pore spaces in the injection formation, or other activities that are intended to allow the injectate to move more readily into the injection formation. Advance notice of all proposed stimulation activities must be provided to the Director, as detailed below, prior to conducting the stimulation. In no circumstance will the stimulation interfere with containment. ExxonMobil will submit proposed schedule and procedures for all stimulation activities to the Director at least 30 days in advance, and submit notice at least 48 hours in advance, to provide the Commission opportunity to witness per 16 TAC **§5.206(h)(4)(i)**.

1. Introduction and Purpose

ExxonMobil may stimulate the injection zones for the Sunflower CCS Project to enhance the injectivity potential of CO2 injection wells. Stimulation may involve, but is not limited to, flowing fluids into or out of the well, increasing or connecting pore spaces in the injection formation, or other activities that are intended to allow CO2 to move more readily into the injection zone.

ExxonMobil will adhere to all applicable regulatory requirements for any stimulation treatment that may be required. Specifically, and without limitation, ExxonMobil will comply with the following:

- 16 TAC **§5.203(e)(4)**: ExxonMobil will submit the proposed stimulation program, a description of stimulation fluids to be used and a determination that stimulation will not interfere with containment.
- 16 TAC **§5.206(h)(4)(i)**: ExxonMobil will notify the Director 30 days in advance of any planned stimulation activities and provide notice at least 48 hours before operations.
- 16 TAC **§5.207** ExxonMobil shall submit all required reports, submittals, and notifications to the Director. Additionally, per both 16 TAC **§5.207(b)(2)** and 40 CFR **146.91(e)**, ExxonMobil will also submit these reports, submittals, and notifications to EPA in an electronic format approved by EPA.

The information provided in this section specifically addresses the stimulation fluids, additives, and proposed stimulation procedures ExxonMobil may implement. This plan includes multiple stimulation methodologies that may be selected based on site-specific technical and operational conditions that may impact future well performance. The methods provided below may also be used to remediate scaling or perforation occlusion in the well.

1.1 Purpose of the Stimulation

Perforated intervals in the proposed injection zones may require stimulation periodically throughout the project life to enhance performance with the aim of restoring it to initial or optimum conditions. For example, stimulation may be needed to remediate injectivity loss resulting from mineral scales, clay fragments, metallic sulfide, or oxide particulates. Stimulation may also be necessary to remove any near-wellbore damage resulting from drilling and completion operations. Following well construction, remedial stimulation may be conducted before the commencement of CO2 injection..

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2. Stimulation Fluids

ExxonMobil will use acid blends for matrix stimulation that are typical for the industry. These include, but are limited to, mixture of acetic, hydrochloric, hydrofluoric, and/or other organic acids. These blends have been historically proven to remove near-wellbore damage caused by mineral scales, drilling muds, completion fluids, and clay fines while minimizing negative impacts to permeability. There is also potential for near-wellbore halite precipitation in the CO2 injectors, which may require remediation by periodic flushes with less saline water.

All chemical treatments will be evaluated and selected for compatibility with the treatment method. For example, mineral acids will be treated with chemical inhibitors to prevent corrosion damage to the tubing string. In addition, chemical will be evaluated and selected to avoid damage to the downhole packer sealing elements, casing, and other seals within the injection system that might be exposed to chemicals.

2.1 Additives

Additives may be utilized with the stimulation fluids to aid matrix stimulation while mitigating corrosion of tubulars and potential damage to the sequestration zone. These additives include, but are not limited to, corrosion or acid inhibitors, scale inhibitors, clay stabilizers, biocides, emulsifiers, chelating agents, mutual solvents, iron sequestrants, retarders, and/or surfactants. Compatibility of these additives with the stimulation fluids, tubulars and the reservoir will be confirmed prior to their use in any stimulation activities.

2.2 Diverters

Nitrogen, crosslink polymers, viscoelastic surfactants, solid particulates and/or fiber diverters may be added to stimulation fluids to achieve improved diversion and effective treatment for the target zone by diverting the stimulation fluids to the most impaired (i.e, low injectivity) perforations. Depending on the well-specific requirements and stimulation design, organic or polymeric diverting agents may also be selected. These diverters provide temporary restrictions during stimulation operations and degrade or break-down with time due to water solubility and temperature. The most suitable diverting agent will be selected based on one or more factors, including, anticipated pump rates, the length of the perforated interval, perforation density, and the selected technique for conveying acid to the injection zone (e.g., pumping through regular tubing or pumping down coiled tubing)

3. Mechanical Stimulation

In addition to chemical stimulation, mechanical stimulation of the well may be required independently, or in conjunction with chemical stimulation. Mechanical stimulation may be required if there is deposition that cannot be easily remediated with chemicals, or if mechanical means may be more effective. These mechanical options include, but are not limited to, backflow, adding perforations, or re-perforating. Perforating operations may be further enhanced with the use of propellants. Propellant stimulations will be designed for nominal height growth, and to remain within the injection zone and avoid fracture growth into the confining layer.

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4. Ensuring Containment

Except during stimulation, injection pressure will not exceed 90% of the established fracture pressure for the injection zone. Injection pressure at the downhole tubing pressure gauge and tubing/annulus surface gauges will be continuously monitored during the stimulation operation. Stimulation of the injection interval will be conducted to avoid affecting the confining layers.

5. Stimulation Procedures

A standard stimulation procedure is outlined below. This procedure may be modified depending on site-specific operational and technical conditions and the specific treatment requirements. The conveyance methods may include coil tubing, tubing-conveyed retrievable straddle packer assembly, snubbing unit, tubing flush, or bullheading.

1. Determine compatibility of stimulation chemicals with well materials, reservoir rock, and fluids.
2. Develop stimulation plan based on the injection impairment cause
3. Provide work procedure and stimulation program to the UIC Program Director at least 30-days prior to the planned date for start of the work and provide notice at least 48 hours in advance (16 TAC **§5.206(h)(4)(i)**).
4. Prepare wellsite and mobilize equipment
5. Shut-in and isolate the well from the CO2 injection system. Allow the pressures to stabilize
6. Rig up the stimulation equipment
7. Prepare the well for stimulation
8. Perform the stimulation treatments as per approved plan
9. Flush the wellbore with treated water and prepare the well to return to normal operations
10. Rig down and return the well back to injection

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Attachment D – Pre-Injection/Pre-Operational Testing plan

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4.8 Pre-Operational Testing Plan

A variety of geophysical well logs, core, and injection tests were collected during the construction of a nearby stratigraphic test well to verify and evaluate the depth, thickness, porosity, permeability, lithology, and formation fluid salinity in the relevant geologic formations. *Appendix D.3* details the actual core and injection test data taken in the nearby stratigraphic test well. Additional core, well log, and injection test data will be taken in the construction of the proposed injection wells as outlined below to satisfy 16 TAC **§5.203(f)**.

4.8.1 Injection and Confining Zone Core Sampling

The following preliminary coring operations are planned during the construction of the injection wells. Table 4-17 details the potential core intervals and operations per formation interval.

Table 4-17 – Summary of Preliminary Coring Operations

Interval	Injector No. 01	Injector No. 02
UCZ	CC in Frio	RSWC
Injection Zones		RSWC
LCZ		RSWC

RSWC = rotary sidewall core, taken via wireline during drilling operations; LCZ = lower confining zone; CC = conventional core
Note: Preliminary coring plans subject to change based on as-drilled conditions.

4.8.2 Pre-Operation Logging Program

The following geophysical logs are planned for each proposed injection well. The openhole logging plan is detailed in Table 4-18. The cased-hole logging plan is detailed in Table 4-19.

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Table 4-18 – Open hole Logging Plan for the Injection Wells

Section	Open hole Logs
17 1/2-in. hole	• None. • Gamma Ray and Resistivity logs will be collected while drilling via logging while drilling (LWD) tools
12 1/4-in. hole	• Gamma Ray – All Injectors • Resistivity – All Injectors • Density – All Injectors • Neutron – All Injectors • Magnetic Resonance – All Injectors • Sonic – All Injectors • Caliper – All Injectors • Borehole Imaging – Injector No. 02 only • Formation Pressure – Injector No. 02 only • Fluid Samples – Injector No. 02 only • RSWC – Injector No. 02 only

Table 4-19 – Cased-Hole Logging Plan for the Injection Wells

Section	Cased-Hole Logs
13 3/8-in. surface casing	• CBL, VDL, Temperature
9 5/8-in. production casing	• CBL, VDL, Temperature
7-in. production tubing and 9 5/8-in. casing	• Temperature • Through-Tubing Casing Inspection • Oxygen Activation or Pulsed Neutron

*CBL – cement bond log
VDL – variable density log

4.8.3 Injection Zone Characterization

ExxonMobil will collect characterization data for the permitted injection zone of the injection wells, including formation fluid temperature, pH, specific conductivity, and formation pressure (16 TAC **§5.203(f)(3)(A)**).

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4.8.4 Fluid Characteristics and Downhole Conditions

During the construction of the injection wells, ExxonMobil will collect formation fluid samples in the injection zone and the formation above the UCZ. Injection zone samples will be evaluated for the compatibility of the injectate with the formation fluids (16 TAC **§5.203(f)(2)**). Samples collected above the UCZ during the pre-operation phase will form the baseline data for comparison with water quality data representing the operating and post-operating phases of the Sunflower Project. The analysis plan for water samples collected in the injection zones and above the UCZ formation is specified in Table 4-20.

Table 4-20 – Sampling and Analysis Plan for the above UCZ Water Samples

Parameter/Analyte	Analytical Method
Total dissolved solids, alkalinity, electrical conductivity, temperature, pH	Standard lab analyses
Gas composition (CO_2, CH_4, O_2, N_2)	Gas chromatography
Dissolved cations (i.e., As, Ba, Ca, Fe, Mg, Mn, Na, K, Pb, Zn)	Ion chromatography
Dissolved anions (i.e., HCO_3, Br, Cl, NO_3 SO_4)	Ion chromatography
As = arsenic; Ba = barium; Br = bromine; Ca = calcium; CH_4 = methane; Cl = chlorine; Fe = iron; HCO_3 = bicarbonate; K = potassium; Mg = magnesium; Mn = manganese; N_2 = nitrogen; NO_3 = Nitrate; O_2 = oxygen; Pb = lead; SO_4 = sulfate; Zn = Zinc	

4.8.5 Injection and Confining Zone Formation Testing

Pressure transient well testing (e.g., a pressure falloff test) will be conducted on one injection well as a part of completion activities (16 TAC **§5.203(f)(2)(B)**). These tests are intended to confirm reservoir and operational parameters used in the permitting process and provide needed data on the geologic and hydrogeologic properties of subsurface formations. The following pressure falloff test procedures are proposed:

- A nonhazardous test fluid will be used during the injection test.
- The purpose of this test is to evaluate the injectivity index, skin, and permeability-thickness of the injection zone.
- For the permitted injection zone, an injectivity test will be performed prior to injection.
- The well will be shut in and the pressure falloff recorded with downhole gauges over sufficient time for proper analysis.

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Attachment E – Injection Well Operating Conditions

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4.9 Injection Well Operating Strategy

4.9.1 Overview of Injection Well Perforation and Completion Strategy

Upon permit approval, injection will start based on the stages and injection schedules referenced in Tables 4-21 through 4-23. Please note that the following perforation depths are notional and may be revised based on as-drilled conditions of the wells themselves.

Table 4-21 – Injection Sequencing Strategy for Injection Well No. 01

Stage	Sand Interval	Top Perf (ft MD)	Perf	Thickness	Reservoir	Duration (years)	Years after
2	Lower	6,768	7,272	546	276	2	2
3		6,590	6,710	236	180	2	4
5	Lower	4,841	5,271	484	299	2	8
6	Upper	4,398	4,759	549	251	1	9

*MD – Measured Depth

Table 4-22 – Injection Sequencing Strategy for Injection Well No. 02

Stage	Sand Interval	Top Perf (ft MD)	Perf	Thickness	Reservoir	Duration (years)	Years after
		6,974	7,143	237	103	1	1
3	Upper	6,506	6,900	430	237	1	2
5	Lower	4,816	5,267	491	349	1	4
		4,254	4,768	541	255	1	5

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Table 4-23 – Injection Sequencing Strategy for Injection Well No. 03

Stage	Sand Interval	Top Perf (ft MD)	Bottom Perf (ft MD)	Gross Thickness (ft)	Net Reservoir (ft)	Duration (years)	Completion Years after Startup
1	Frio Sand 3	7,207	7,756	603	242	2	0
2&3	Frio Sand 2	6,650	7,146	606	283	2	2
4	Frio Sand 1	5,989	6,448	836	296	2	4
5	Fleming Sand 3 Lower	4,868	5,309	451	262	2	6
6	Fleming Sand 3 Upper	4,587	4,851	618	270	1	7

ExxonMobil plans to use a staged approach injection strategy as shown in Figure 4-2. Once ExxonMobil ceases injection into a stage, that stage will be plugged back before perforating and injecting into a subsequent stage. The perforation depths that were provided in Tables 4-21 to 4-23 are based on the current geologic model described in *Section 1 – Site Characterization* and subject to change based on as-drilled conditions.

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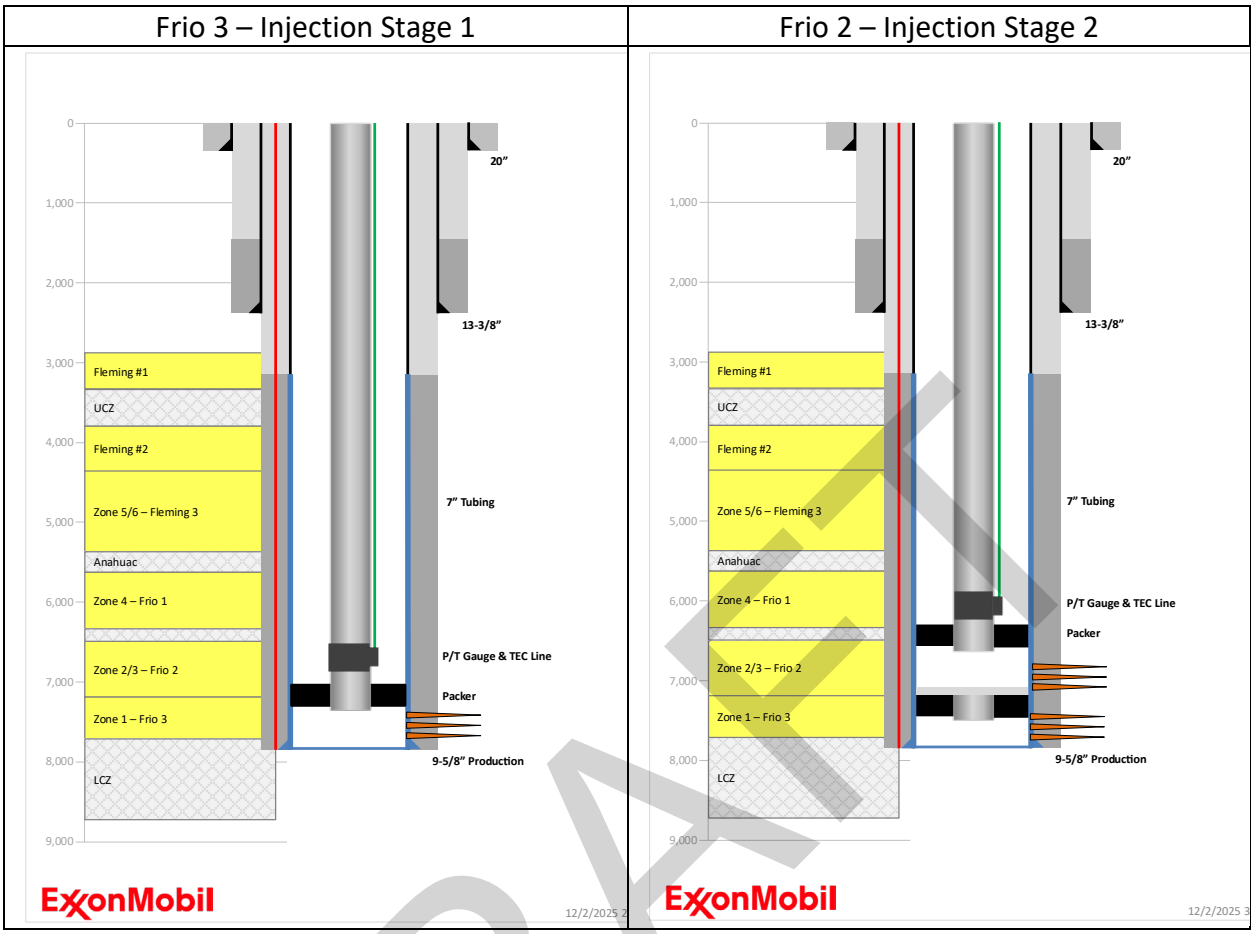


Figure 4-2 – Operational Completion Strategy for the Injection Wells

4.9.2 Injection Rate and Pressure

Table 4-24 provides the proposed operations for the injection wells, including injection rate and pressure by well. Average injection rates for each well's injection stages range from 0.5 to 1.2 MMTPA, with a maximum injection zone rate of 2.5 MMTPA. While each well will remain within its total annual injectivity allowance, temporary increases up to 2.5 MMTPA may occur. Both the maximum and average injection rates are predicted to result in reservoir pressure rises that are below 90% of the critical fracture pressure, shown in Table 4-24. Both the injection rates and pressures are within the operating window of the injection wells. In developing the injection strategy, ExxonMobil incorporated geomechanical studies of site-specific data.

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Table 4-24 – Summary of Injection Parameters for the Injection Wells

Stage	Sand Interval	Parameter	Injection Well No. 01	Injection Well No. 02	Injection Well No. 03
1	Frio 3	Maximum Injection Zone Rate (MMTPA)	2.5	2.5	2.5
		Average Injection Zone Rate (MMTPA)	1.2	1.0	0.8
		Maximum Allowed Surface Pressure (psi)	2,000	2,000	2,000
		Average Modeled Surface Injection Pressure (psi)	1088	1066	1067
		Maximum Modeled Surface Injection Pressure (psi)	1112	1070	1073
		Fracture Pressure (psi)	5,175	5,175	5,175
		Maximum Allowed BHP (psi)	4,500	4,500	4,500
		Maximum Modeled BHP (psi)	3,537	3,490	3,503
2	Frio 2 Lower	Maximum Injection Zone Rate (MMTPA)	2.5	2.5	2.5
		Average Injection Zone Rate (MMTPA)	1.0	1.2	1.2
		Maximum Injection Zone Surface Pressure (psi)	2,000	2,000	2,000
		Average Modeled Surface Injection Pressure (psi)	1029	1048	1034
		Maximum Modeled Surface Injection Pressure (psi)	1083	1069	1066
		Fracture Pressure (psi)	4,830	4,830	4,830
		Maximum Allowed BHP (psi)	4,200	4,200	4,200
		Maximum Modeled BHP (psi)	3,489	3,488	3,491
3	Frio 2 Upper	Maximum Injection Zone Rate (MMTPA)	2.5	2.5	**
		Average Injection Zone Rate (MMTPA)	0.5	1.2	
		Maximum Injection Zone Surface Pressure (psi)	2,000	2,000	
		Average Modeled Surface Injection Pressure (psi)	960	1016	
		Maximum Modeled Surface Injection Pressure (psi)	1022	1043	
		Fracture Pressure (psi)	4,554	4,554	

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Stage	Sand Interval	Parameter	Injection Well No. 01	Injection Well No. 02	Injection Well No. 03
		Maximum Allowed BHP (psi)	3,960	3,960	
		Maximum Modeled BHP (psi)	3,164	3,197	
4	Frio 1	Maximum Injection Zone Rate (MMTPA)	2.5	2.5	2.5
		Average Injection Zone Rate (MMTPA)	1.0	1.0	1.0
		Maximum Injection Zone Surface Pressure (psi)	2,000	2,000	2,000
		Average Modeled Surface Injection Pressure (psi)	941	935	939
		Maximum Modeled Surface Injection Pressure (psi)	955	1013	1026
		Fracture Pressure (psi)	4,313	4,313	4,313
		Maximum Allowed BHP (psi)	3,750	3,750	3,750
		Maximum Modeled BHP (psi)	3,085	3,128	3,148
5	Fleming 3 Lower	Maximum Injection Zone Rate (MMTPA)	2.5	2.5	2.5
		Average Injection Zone Rate (MMTPA)	1.0	1.0	1.0
		Maximum Injection Zone Surface Pressure (psi)	2,000	2,000	2,000
		Average Modeled Surface Injection Pressure (psi)	836	830	842
		Maximum Modeled Surface Injection Pressure (psi)	940	929	936
		Fracture Pressure (psi)	3,450	3,450	3,450
		Maximum Allowed BHP (psi)	3,000	3,000	3,000
		Maximum Modeled BHP (psi)	2,855	2,840	2,849
6	Fleming 3 Upper	Maximum Injection Zone Rate (MMTPA)	2.5	2.5	2.5
		Average Injection Zone Rate (MMTPA)	1.0	1.0	0.5
		Maximum Injection Zone Surface Pressure (psi)	2,000	2,000	2,000
		Average Modeled Surface Injection Pressure (psi)	776	762	769
		Maximum Modeled Surface Injection Pressure (psi)	830	823	835
		Fracture Pressure (psi)	3,174	3,174	3,174

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Stage	Sand Interval	Parameter	Injection Well No. 01	Injection Well No. 02	Injection Well No. 03
		Maximum Allowed BHP (psi)	2,760	2,760	2,760
		Maximum Modeled BHP (psi)	2,280	2,270	2,288

*BHP – bottomhole pressure

** For Sunflower INJ No.3 stages 2 & 3 (Frio 2 Lower & Upper) are combined

Table 4-255 – Injection Zone Depths

Injection Well	Top of Injection Zone (TVD, ft)	Bottom of Injection Zone (TVD, ft)
Sunflower INJ No. 1	3,572	7,720
Sunflower INJ No. 2	3,588	7,723
Sunflower INJ No. 3	3,595	7,775

The proposed injection zone depths are provided in Table 4-25 based on the work outlined in *Section 1 – Site Characterization*. ExxonMobil proposes an injection zone of 3,572 ft TVD - 7,775 ft TVD. ExxonMobil may slightly revise these depths based on the as-drilled conditions of the wells.

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4.9.3 Well Stimulation Procedures

ExxonMobil may stimulate the injection zone for the Sunflower CCS Project in the event it is necessary, to achieve desired injectivity (*Appendix D.4*). Stimulation may be conducted if injection impairment is observed during the life of the wells. Additional details on the stimulation plan can be found in *Appendix D.4*. Some of the potential causes for injection reduction are as follows:

- Formation damage (e.g., fines migration, scaling, debris in injection stream)
- Geochemical reactions due to fluid/reservoir incompatibility
- Salt precipitation due to in situ brine vaporization
- Reservoir compartmentalization or facies variation
- Shale swelling

ExxonMobil will provide advance notice of the proposed stimulation to the UIC Program director (UIC Director) in writing at least 30 days prior to injection and provide at least a 48-hour advanced notice in accordance with 16 TAC **§5.206(j)**. The detailed stimulation plan is provided in *Appendix D.4* and incorporates the following:

- Stimulation design to ensure the treatment will not interfere with containment
- Stimulation fluids detail (e.g., volumes, concentrations, additives)
- Stimulation fluid/ well material compatibility analysis

- Well integrity analysis (e.g., casing/tubing stress analysis)
- Stimulation procedure

The stimulation fluids will be an acid, most likely hydrochloric acid (HCl), or a water-based fluid treated as needed with the necessary chemicals and/or additives to achieve the desired results. Any stimulation would not interfere with the containment of the project. A high-level procedure is as follows and, as mentioned above, a case-specific stimulation plan procedure along with a detailed description of fluids to be used will be provided to the UIC Director should stimulation become necessary:

1. Determine the compatibility of stimulation chemicals with well materials, reservoir rock, and fluids.
2. Develop the stimulation plan based on the injection impairment cause.
3. Provide the work procedure and stimulation program to the UIC Director in writing at least 30 days prior to the planned date for start of the work (16 TAC **§5.206(j)**).
4. Prepare the wellsite and mobilize equipment.
5. Shut in and isolate the well from the CO_2 injection system. Allow the pressures to stabilize.
6. Rig up the stimulation equipment.
7. Prepare the well for stimulation.
8. Perform the stimulation treatment per approved plan.
9. Flush the wellbore with treated water and prepare the well to return to normal operation.
10. Rig down and return the well back to injection.

4.10 Operational Reporting Plan

During the operational phase of the Sunflower Project, ExxonMobil will, within 24 hours, report to the UIC Director a confirmed noncompliance, pursuant to the requirements in 16 TAC **§5.206(d)(2)(F)(ii)(III)**, **§5.207(a)(2)(A**), and **§5.206(h)(3)**—including the following:

- Evidence that the CO_2 plume or pressure front may endanger one or more USDWs
- The noncompliance situation as it relates to a permit condition
- Apparent malfunction of the injection system
- Triggering of a shutoff system
- Loss of mechanical integrity
- A release of CO_2 to the atmosphere or biosphere

ExxonMobil will cease injection and take all steps reasonably necessary to determine whether there may have been a release of CO_2 to an unauthorized zone, in the event that there is a loss of mechanical integrity (16 TAC **§5.206(d)(2)(F)(ii)(II)**).

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Railroad Commission of Texas

Attachment F – Testing and Monitoring Plan

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Underground Injection Control – Class VI Permit Application for Sunflower Carbon Capture and Storage Project Injection Wells No. 01, No. 02, and No. 03

SECTION 5 – TESTING AND MONITORING PLAN

Sunflower Carbon Capture and Storage Project
Jefferson and Liberty Counties, Texas
ExxonMobil Low Carbon Solutions Onshore Storage, LLC
Amendment 3: August 2026

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SECTION 5 – TESTING AND MONITORING PLAN

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5.1 Introduction

Consistent with the requirements of Title 16, Texas Administrative Code (16 TAC), Part 1, Chapter 5, ExxonMobil Low Carbon Solutions Onshore Storage, LLC (ExxonMobil) developed a comprehensive Testing and Monitoring Plan for the Sunflower Carbon Capture and Storage (CCS) Project (Sunflower Project) using a risk-based approach. The data collection included injectate monitoring; corrosion monitoring of the well tubulars, mechanical, and cement components; pressure falloff testing; obtaining seismic surveys; well logging; continuous monitoring of injection rate, pressure, and temperature; groundwater quality monitoring; and CO_2 plume and pressure front tracking. The data generated from implementation of the plan provides the basis to verify the confinement of the injectate in the permitted injection zones during the active injection phase of the project.

The post-injection phase of monitoring is provided in *Section 7 – Post-Injection Site Care (PISC) and Site Closure*, consistent with the structure of the Underground Injection Control (UIC) Class VI permit application for this project. In conjunction with careful site selection and area of review (AOR) delineation, this plan will be a critical component of the successful operation, PISC, and eventual closure of the Sunflower Project.

A key feature of the Testing and Monitoring Plan is that the location and frequency of monitoring and surveillance data acquisition and analysis are designed to align with the injection operation plan and the identified site-risk elements that impact and determine CO_2 plume and pressure front migration. This plan presents a data collection program to confirm that the injection is consistent with the permit requirements. The plan also includes a phased/triggered approach for the incremental implementation of testing and monitoring technology, consistent with the EPA's presentation of phased/triggered monitoring in their 2013 *UIC Program Class VI Well Testing and Monitoring Guidance*.[1] Overall, the risk of underground source of drinking water (USDW) endangerment is mitigated (1) by balancing the increase in CO_2 plume and pressure front size and location with the collection and analysis of data to track migration in the subsurface; and (2) by implementing robust risk management processes to assess the potential for leaks through the upper confining zone (UCZ) throughout the life of the project.

ExxonMobil intends for the Testing and Monitoring Plan and subsequent iterations to continue throughout the life of the Sunflower Project. An adaptive approach will be employed with respect to the monitoring frequency of select parameters, whereby the application of selected monitoring technologies may be decreased based on improved subsurface understanding and subsequent reduction of reservoir uncertainties. Monitoring results will be presented in semi-annual reports, wherein data will be evaluated and any proposed monitoring frequency modification within the Testing and Monitoring plan justified. Baseline data will be collected prior to injection start-up, and time-lapse comparisons to the baseline data will be made during the operational period of the project. The adaptive approach will be applied if the data collected

[1] UIC Program Class VI Well Testing and Monitoring Guidance, EPA 816-R-13-001 (March 2013). https://www.epa.gov/sites/default/files/2015-07/documents/epa816r13001.pdf)

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during the injection period shows results within the expected CO_2 behavior range. Should ExxonMobil anticipate any noncompliance of a permit condition or planned physical additions to the permit facility, the UIC Program Director (UIC Director) will be notified.

An ongoing dialogue between ExxonMobil and the UIC Program director is envisioned, marked by tying the monitoring plan reviews and proposed modifications to the AOR reevaluation frequency. Consistent with the discussion of AOR reevaluation in *Section 3 – Area of Review and Corrective Action Plan*, a minimum frequency of 5 years is planned to reevaluate the AOR and Corrective Action Plan. More frequent evaluations of the AOR and updates to the Corrective Action Plan may also be triggered if other unexpected changes in testing and monitoring data are detected as discussed in *Section 3*, Table 3-8. Key to this is the efficient review process that is proposed, particularly where the AOR reevaluation confirms that the plan is appropriate as written. If ExxonMobil determines that monitoring data suggests that potential corrective actions are needed and mitigation measures should be employed, then the Emergency and Remedial Response Plan (*Section 8*) will be implemented as appropriate.

The following objectives were developed for the Testing and Monitoring Plan in alignment with 16 TAC **§5.203(j)**:

- Use site characterization data, the site geologic conceptual model, and the results of computational modeling to identify areas or risk elements of potential concern for the project.
- Consider how possible migration pathways and subsurface uncertainties in confining zone and injection zone properties could affect the AOR boundaries and include this uncertainty in the testing and monitoring strategy.
- Select testing and monitoring strategies and a cadence of technologies' implementation that are tailored to the site-specific risk profile in conformance with the requirements.
- Identify project-specific factors to consider or incorporate in evaluating the data collected from the Testing and Monitoring Plan, which may indicate the potential risk to or endangerment of the USDW, as well as deviations from permitted conditions.

5.2 Reporting Requirements

The Testing and Monitoring Plan was developed to achieve two reporting objectives:

- Provide the necessary data to verify predictions of CO_2 plume and pressure front movement (16 TAC **§5.203(j)(2)(E)**).
- Provide the basis for evaluating the model inputs, making necessary changes, and reevaluating the AOR (16 TAC **§5.203(d)(2)(B)(ii)**).

In compliance with 16 TAC **§5.206** and **§5.207**, ExxonMobil will provide reports to the UIC Director at a semiannual frequency that document both the performance of the system and the CO_2 plume and pressure front tracking data. Relevant records pertaining to the Class VI testing and

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monitoring program will be submitted to the TRRC. Pursuant to 16 TAC **§5.206(b)(1),** ExxonMobil will report the results of the injection pressure and injection rate monitoring for each injection well on Form H-10 and the results of the internal mechanical integrity tests on Form H-5. In addition, ExxonMobil will follow the prescribed notification requirements for deviation from permit conditions, in the event of an operational malfunction that may allow CO_2 or brine to migrate into or between USDWs, or for other evidence of USDW endangerment.

The semiannual reports will include the data collected during each reporting period and a list of notifications triggered during a semiannual period, if any. Pursuant to 16 TAC **§5.203(a)(4)**, reports will be prepared by a qualified and knowledgeable person and logs, surveys, sampling, and tests required under Chapter 5 will include an interpretation. The following information is proposed for the routine performance reporting:

- Monthly average, maximum, and minimum values of injection pressure, flow rate and volume, and annular pressure
- 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 Sunflower Project
- Monthly annulus fluid volume added
- Results of CO_2 plume and pressure front tracking data analysis as described herein
- Any significant changes to the physical, chemical, and other relevant characteristics of the CO_2 stream from the proposed operating data that could impact plume migration or protection of USDWs
- A description of any event that triggered a shutoff device required according to 16 TAC **§5.206(d)(2)(F)**, and the response taken
- A description of any event that exceeded operating parameters for annulus pressure or injection pressure specified in the permit

The semiannual reports will be submitted 30 days after the completion of the quality control and quality review of the data for each reporting period. Table 5-1 describes the non-routine reporting triggers, contents, and schedule.

Additionally, pursuant to 16 TAC **§5.207(A)(2)(D)),** ExxonMobil will submit an annual report detailing any corrective action performed, new wells installed, re-calculated AOR or a statement that the current delineation is appropriate, and the updated area for which ExxonMobil has a good faith claim.

ExxonMobil will apply methods and standards generally accepted in industry and submit a description of tests and methods used for reports pertaining to mechanical integrity (16 TAC **§5.207 (a)(1)**).

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Table 5-1 – Summary of Triggering Events for Notification and Reporting Schedule

Triggering Event	Reporting Schedule
Planned well workover, stimulation activities, or other planned test of an injection well	Notification and proposed schedule to the UIC Director, in writing, 30 days in advance of planned activity for opportunity to witness. 48-hour notification in advance of such activity, other than stimulation for formation testing, to the TRRC.
Completion of well workover	30 days after completion of well workover
Any test of the injection well(s) conducted, if required by the UIC Director	30 days after completion of any testing required by the UIC Director filed in duplicate
Evidence of potential non-compliance with a permit condition, or potential malfunction of the injection system that may cause fluid migration into or between USDWs	Verbal notification – reported within 24 hours of verification of non-compliance or malfunction
Primary evidence that the injected CO_2 stream or associated pressure front may cause an endangerment to a USDW	Verbal notification – reported within 24 hours of verification of endangerment
A failure to maintain mechanical integrity	Verbal notification – reported within 24 hours of verification of mechanical integrity failure
A statistically significant change to the physical, chemical, or other relevant characteristics of the CO_2 stream from the composition described in the proposed operating plan (e.g., if the CO_2 stream becomes <90% of CO_2, where %=mol%=volume %)	Written notification – reported within 72 hours of verification of composition change
An operational condition that exceeds operating parameters for annulus pressure or injection pressure as specified in the permit	• Verbal notification – reported within 24 hours of verification of non-compliance with permit conditions • Written notification – reported within 72 hours of verification of non-compliance with permit conditions
A shutoff device that is activated anywhere in the injection well system	• Verbal notification – reported within 24 hours of event • Written notification – reported within 72 hours of event
Recorded seismic event with magnitude greater than 2.0	• Table 8-2 in *Section 8 – Emergency and Remedial Response Plan* details the response actions

ExxonMobil will adhere to the monitoring and record retention requirements outlined in 16 TAC **§5.206(e)(5)**. Additionally, ExxonMobil will provide all reports, submittals, and notifications to both the EPA and the Railroad Commission of Texas (TRRC) and retain records in accordance with 16 TAC **§5.207(e)** for a 10-year period after site closure. Injected-fluid data, including nature and composition, will be retained for the 10-year period following site closure. Monitoring data will be retained for a minimum of 10 years post-collection, while well plugging reports, PISC data, and the site closure report will be retained for 10 years after site closure.

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5.3 Testing Plan Review and Updates

In accordance with 16 TAC **§5.203(j)**, the Testing and Monitoring Plan will be reviewed and revised at least every 5 years to:

- Identify Sunflower Project-specific factors that may warrant revision to the plan.
- Incorporate information and changes necessary to monitor an increase in risk to endangerment of USDWs.
- Account for any deviations from permitted conditions that require plan modifications.

ExxonMobil will incorporate the collected monitoring data that characterize the project-specific factors and the changes needed, if any, to monitor both increased potential risk to the USDW and overall plan compliance with the UIC Director's requirements. Plan amendments will be submitted within 1 year of an AOR reevaluation, following significant facility changes (such as the development of offset monitoring wells or newly permitted injection wells within the AOR), or as the UIC Director requires.

Table 5-2 summarizes the various measurements discussed in the Testing and Monitoring Plan and the frequency of measurements for data collection and reporting purposes.

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Table 5-2 – Testing and Monitoring Plan Measurements and Frequency

Equipment / Measurement	16 TAC Regulation	Objective	Frequency
Coriolis flow meter	**§5.203(j)(2)(B)**	Measure mass flow rate	Continuously
Corrosion coupon	**§5.203(j)(2)(C)**	Measure corrosion levels on the types of metal used in the project	Quarterly
Injection stream sampling	**§5.203(j)(2)(A)**	Provide a more detailed analysis via periodic lab analysis of injection stream	Quarterly for first 2 years then semiannually
Central pad temperature gauge	**§5.203(j)(2)(A)**	Measure the temperature of the total injection stream at the pad before partitioning to injections	Continuously
Injection wellhead tubing pressure gauge	**§5.203(j)(2)(B)**	Measure downstream of choke	Continuously
Injection wellhead annulus pressure gauge	**§5.203(j)(2)(B)**	Verify that the annulus pressure is maintained	Continuously
Injection well downhole pressure and temperature gauge for active/open injection interval	**§5.203(j)(2)(B)**	Measure downhole pressure and temperature (injection mass-to-volume conversion, verifying that it is not exceeding maximum pressure)	Continuously
	§5.203(j)(2)(G)	Measure falloff pressure	At least once every 5 years
	Not required	Direct measurement of downhole pressure open to active injection zone	Continuously
Time-lapse seismic survey	**§5.203(j)(2)(E)**	Monitoring of CO_2 plume growth in the subsurface over time	Frequency from the start of operations: • Baseline survey: completed • Monitor Survey No. 01: 1–3 years • Monitor Survey No. 02: 6–8 years • Monitor Survey No. 03: 11 years
Injection well external mechanical integrity	**§5.203(j)(2)(F)**	To assess changes in the temperature profile due to migration of injected fluids	Annually
Injection annulus pressure test	**§5.203(h)(1)(C)**	Verify the absence of a leak in the annulus	Once every 5 years
Injection well casing inspection	**§5.203(j)(2)(F)**	Use through-tubing log to detect loss of metal mass in casing due to corrosion	Baseline only; repeat survey is triggered if risk of leakage is apparent
Sunflower AZM/IZM No. 01 downhole pressure / temperature gauge	**§5.203(j)(2)(D)(i) and §5.203(j)(2)(D)(ii)**	Detect pressure anomaly above the UCZ in case of unexpected vertical migration; will require careful analysis due to false-positive potential from sensor drift, geomechanical effects, and preexisting pressure trends due to potential far-field activities	Continuously
Sunflower AZM No. 01, No. 02	**§5.203(j)(2)(D)(i) and §5.203(j)(2)(D)(ii)**	Collect above-UCZ fluid as recommended by guidelines.	Quarterly for 2 years followed by annually
Sunflower AZM No. 01, No. 02 pressure gauge	**§5.203(j)(2)(D)(i) and §5.203(j)(2)(D)(ii)**	Detect pressure anomaly above the UCZ in case of unexpected vertical migration;	Continuously
USDW fluid sampling	**§5.203(j)(2)(D)(ii)**	Sample fluids from the Chicot aquifer, which is the most prolific USDW aquifer within the AOR, as recommended by guidelines, and analyze the composition.	Quarterly for pre-injection and first 2 years after start of injection, then annually

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5.4 Overall Strategy and Approach for the Testing and Monitoring Plan

The Class VI Permit regulations (16 TAC **§5.203** and **§5.206**) require various testing and monitoring activities to identify potential risks to, and the potential for endangerment of, USDWs during the injection phase of the Sunflower Project. ExxonMobil consulted with TRRC staff in pre-application discussions to identify the testing and monitoring activities that were best suited for the project. The site features that affect the degree of risk and potential for endangerment of a USDW include the following:

- The integrity of the UCZ to contain the CO_2 plume and pressure front
- The potential for vertical migration of CO_2 and/or brine along faults
- The occurrence of legacy well penetrations (i.e., artificial penetrations) through the UCZ
- The potential geomechanical stress induced by the modeled injection pressure
- The engineering design considerations for wellbore cement and casing/tubing materials of construction and completion
- Conformance to the modeled operational targets

Of these features, the key risk factor that is most critical for the design of this plan is the potential for artificial penetrations to create migration pathways through the UCZ. ExxonMobil completed a variety of technical tasks, discussed in *Section 3 – Area of Review and Corrective Action Plan*, to identify and evaluate the potential for legacy wells to exist in circumstances where CO_2/brine could potentially migrate up through a partially plugged wellbore (e.g., one with an open borehole)—or one that is inadequately plugged for CO_2 sequestration sites. Other potential risks associated with the project were deemed to be of a lower probability and consequence.

Therefore, a focused testing and monitoring approach was considered reasonable and appropriate to address the following risk scenarios:

- Migration of CO_2/brine along a fault/fault material or natural fracture impacting the USDW
- Migration of CO_2/brine along a fault/fault material or natural fracture impacting the USDW due to fault reactivation
- Migration of CO_2/brine up an unknown wellbore or one inadequately remediated
- Induced seismicity as a result of pressure increase during injection activities
- Loss of external mechanical integrity that leads to a release of CO_2 from injection well(s)
- Migration of CO_2/brine through seal(s) due to lack of seal continuity/presence
- Unanticipated structural or stratigraphic baffling creates unexpected preferential CO_2 plume migration pathways
- CO_2 composition changes and creates excess injection corrosion or unexpected chemical reactions in the injection zone

Figure 5-1 presents a summary of the risk assessment process for the life cycle of the project.

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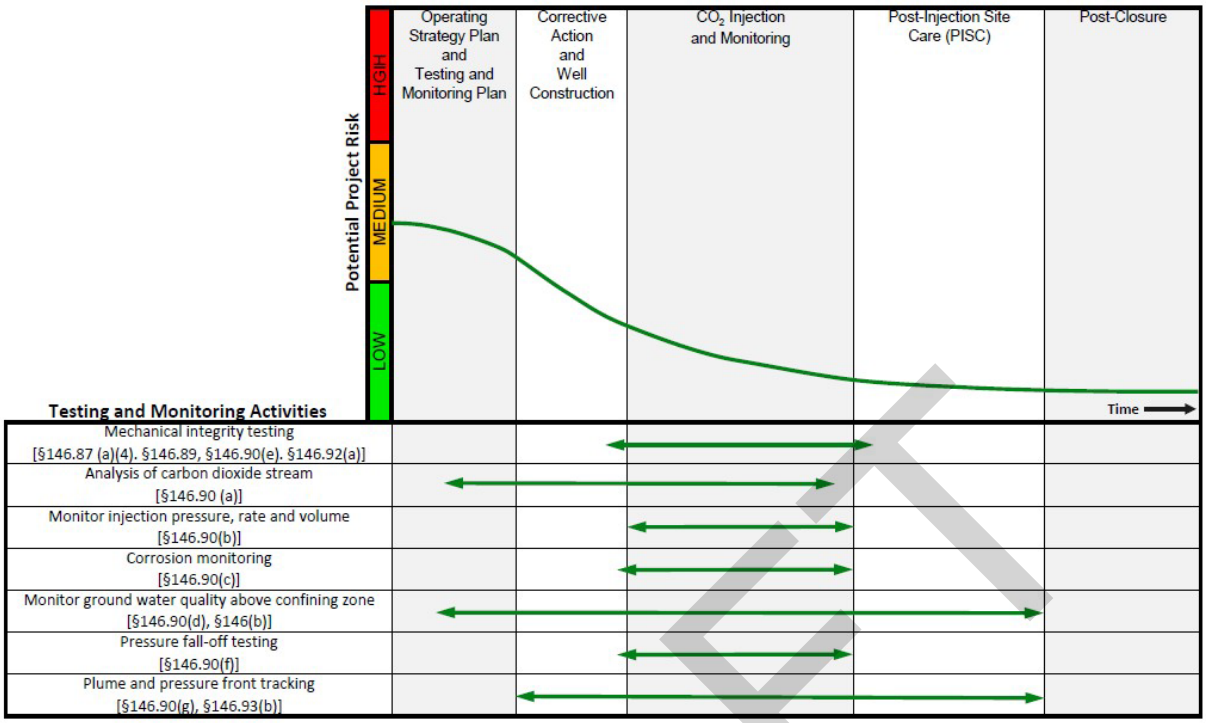


Figure 5-1 – Summary of the Risk Assessment Process for the Life Cycle of the Sunflower Project

As shown in Figure 5-1, the anticipated risk level is low at Project startup due to the implementation of best-practice mitigation measures—including injection well placement, injection interval selection, operational limitations, and corrective action for artificial penetrations. The injection well locations and injection intervals were selected to provide separation from geologic features (e.g., faults) that could potentially contribute to CO_2 or brine crossflow between the injection zone and USDW. The maximum injection pressure will be maintained below the potential hydraulic fracturing or activation pressure of a natural fault, to mitigate the potential for CO_2/brine migration through one or more seals due to mechanical fracturing or migration of CO_2/brine along faults.

State-of-the-art construction and mechanical integrity testing will be employed to reduce the potential for the loss of external mechanical integrity, to prevent potential release of CO_2. The composition of the injectate stream will be managed and monitored so that unexpected reactions with the potential to impact containment are mitigated. Monitoring and predictive reservoir modeling are being used to limit the potential for CO_2 plume and pressure front migration, to encounter artificial penetrations that have the potential for CO_2 or brine crossflow from the injection intervals to the lowermost USDW.

The Class VI Permit testing and monitoring requirements (16 TAC **§5.203** and **§5.206**) address the potential risk scenarios identified by ExxonMobil as warranting monitoring and testing. Scenarios that were found to have elevated risk will be the subject of corrective action prior to operations. Six artificial penetrations are located within or near the 5-year CO_2 plume and pressure front as

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shown in *Section 3 – Area of Review and Corrective Action Plan*, Figure 3-5 and Table 3-4. Corrective action will be performed on these wells prior to injection, mitigating the need for deployment of monitoring technologies near these locations. Five additional artificial penetrations are located within the final CO_2 plume and pressure front. A phased approach will be utilized for corrective action for these artificial penetrations as summarized in Table 3-4 of *Section 3*.

An array of data collection technologies was screened to identify the most reasonable and appropriate methods for the Testing and Monitoring Plan. The screening criteria included: (1) selection of appropriate direct and indirect mix of mature or commercially demonstrated monitoring technologies linked to identified risk scenarios; (2) cost benefit analysis of each technology to mitigate unexpected CO_2/brine migration potential; and (3) a mix between continuous and periodic technology implementation schedules. ExxonMobil recognizes mature technologies based on their Technology Readiness Levels (TRLs), as defined by the International Energy Agency in their report *Energy Technology Perspectives, 2020; Special Report on Carbon Capture Utilisation and Storage.* This scheme is applicable to any technology, including those described in Table 5-3 for implementation in the Sunflower Project. As described in Figure 5-2, ExxonMobil considers mature technologies to be those at TRL 8 (i.e., first-of-a-kind commercial demonstration with full-scale deployment in final form) and higher.

The selected mature monitoring technologies for the Sunflower Project are designed to track the CO_2 and pressure plume growth in each of the four injection intervals, in this order from bottom to top: Upper Frio (Oligocene) Sands 3, 2, and 1, and Fleming (Miocene) Sand 3 (Figure 5-3).

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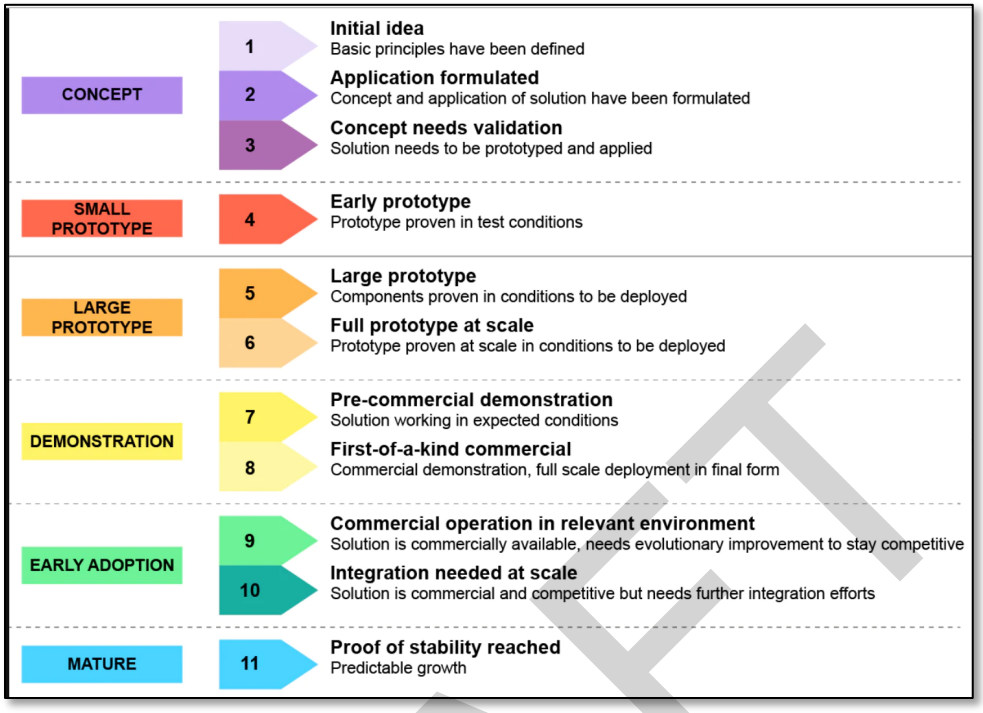


Figure 5-2 – TRLs for Selection of Monitoring Technologies

Table 5-3 provides a summary of mature technologies selected for tracking the CO_2 plume and pressure front. The Testing and Monitoring Plan is intended to be a flexible approach using appropriate technologies and techniques that are refined and adapted based on site-specific information over time. ExxonMobil will continue to assess the feasibility of emerging technologies and conduct performance evaluations to continue to investigate large-scale applications and improve the efficiency of the testing and monitoring surveillance system.

ExxonMobil will communicate with the UIC Director on plans and the potential for modifications and updates to the Testing and Monitoring Plan in the case that emergent technologies are deemed ready for adoption. Through the combination of proven and emerging technology implementation, an efficient testing and monitoring strategy will be maintained for the Sunflower Project to ensure effective monitoring of CO_2 plume and pressure front migration paths in the subsurface, and to provide reliable data for risk management, mitigation strategies, and a potential reevaluation of the AOR model.

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Table 5-3 – Summary of Monitoring Technologies for Direct and Indirect CO_2 Plume and Pressure Front Tracking

Target Zone	Requirement	Technology	Placement Location	Target Depths	Phased/Triggered Approach	Monitoring Frequency	Data Evaluation Objectives
Injection Zone	Direct per 16 TAC **§5.203(j)(2)(D)(i)**	Downhole tubing-mounted pressure and temperature gauge	Sunflower INJ No. 01, No. 02, and No. 03	Four injection intervals in Fleming and Upper Frio Formations	No	Continuous monitoring during injection operations for each injection interval	Identification of pressure differential and location of pressure front for the four injection intervals
		Tubing encapsulated conductor cable with in-line pressure and temperature gauges	Sunflower AZM/IZM No. 01	Four injection intervals, first laterally continuous water-bearing zone above UCZ	No	Continuous monitoring	Pressure front tracking
	Indirect, geophysical techniques per 16 TAC **§5.203(j)(2)(E)**	Time-lapse seismic surveys, or equivalent technologies	AOR	Four injection intervals in Fleming and Upper Frio Formations	No	Seismic baseline survey conducted prior to injection. Monitor Survey No. 01 will be performed within the first 3 years after injection, Monitor Survey No. 02 within 6 to 8 years after injection, Monitor Survey No. 03 in Year 11 at cessation of injection.	Monitoring of CO_2 plume growth in the subsurface over time
		Passive seismicity monitor station array	Selected locations within and/or around the AOR	Surface	No	Continuous monitoring	AOR-specific seismicity data collection and event analyses
Above UCZ	Direct per 16 TAC **§5.203(j)(2)(D)(i)**	Fluid sampling protocol using wireline sampling or U-tube sampling protocols as appropriate	Sunflower AZM/IZM No. 01	First water above UCZ	No	One collection of sample from wireline sampling	Baseline geochemical data
			Sunflower AZM No. 01, No. 02		No	Quarterly samples for 2 years, then annual sampling for remainder of operational phase	Detection monitoring for CO_2 plume and/or brine crossflow from injection zones to top of UCZ
	Indirect, geophysical techniques per 16 TAC **§5.203(j)(2)(E)**	Time-lapse seismic surveys, or equivalent technologies	AOR	From surface to base of Upper Frio Sand interval	No	Seismic baseline survey conducted prior to injection. Monitor Survey No. 01 will be performed within the first 3 years after injection, Monitor Survey No. 02 within 6 to 8 years after injection, Monitor Survey No. 03 in Year 11 at cessation of injection.	Detection monitoring for presence of CO_2 plume above UCZ
USDW	Direct per 16 TAC **§5.203(j)(2)(D)(ii)**	Fluid sampling	Sunflower USDW No. 01, No. 02, No. 03	USDW Groundwater samples collected just below the typical total depth of water wells completed in the area	Yes, three USDW monitoring wells prior to start of injection and additional USDW monitoring wells depending on the results of CO_2 plume and pressure front tracking as discussed in AOR reevaluations.	Pre-Operational Phase – Quarterly Operational Phase – Quarterly for 2 years, then annually for remainder of injection phase	Detection monitoring and evaluation of trends in water quality and geotechnical parameters
Soil-Gas Monitoring	Not Required	Soil-gas samples collected from the unsaturated zone	Contingent on confirmed release to USDW				
Air Monitoring	Not Required	Portable and/or stationary CO_2 detectors monitoring and recording ambient CO_2 concentrations	Contingent on confirmed release to USDW				

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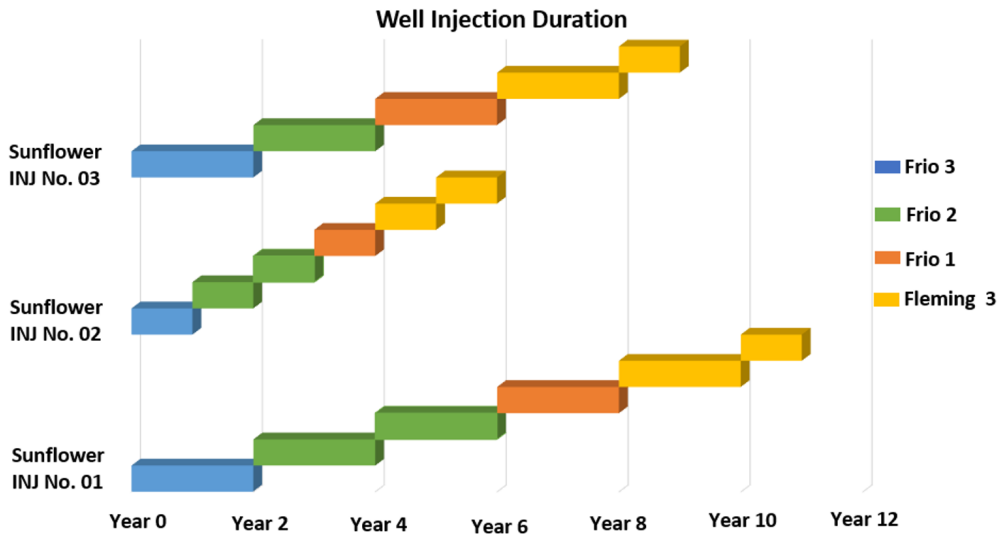
5.4.1 Use of Phased and/or Triggered Approach

The testing and monitoring plan for tracking the CO_2 plume and brine pressure front uses the phased and/or triggered approach. The goal of the approach is to provide the monitoring and surveillance data necessary to demonstrate that USDWs are protected from the potential migration of CO_2 or brine. The proposed testing and monitoring plan is aligned with the multi-staged injection approach outlined in *Section 2 – Plume Model*. A multi-stage CO_2 injection strategy, which leverages the vertical profile of the injection zone, optimizes storage capacity while minimizing plume migration and pressure buildup. Compared to a single-stage approach, multi-stage injection results in significantly smaller CO_2 plume expansion and a more controlled pressure front over time.

The initial monitoring plan is based on the model-predicted 5-year AOR and deemed appropriate to track the CO_2 plume and brine pressure front growth during that time period. Beyond that point, the AOR reevaluation process will be used to assess the adequacy of the testing and monitoring program to detect potential unexpected CO_2 or brine migration—should it occur—and make recommendations for changes and implementation of corrective measures, if necessary, to demonstrate the protection of USDWs.

Figure 5-3 provides an illustration of the staged-injection approach for the Sunflower Project. The CO_2 will be injected at up to six separate stages into four injection intervals in the Fleming and Upper Frio sands, at depths thousands of feet below the lowermost USDW. Sunflower INJ Wells No. 01, No. 02, and No. 03 will start injecting into the Upper Frio and then move to the Fleming. Multiple confining layers are present, including the Anahuac Shale and the UCZ. Additional intraformational shale layers are present within the Fleming and Upper Frio formations. *Section 4 – Well Construction Plan and Operating Conditions* provides a detailed discussion of the injection rates and schedules for each injection well and injection interval.

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Stage	Injection Formation	Maximum Injection Rate Constraint (MMTPA)			Total Per Zone (MMT)
		Sunflower INJ No. 01	Sunflower INJ No. 02	Sunflower INJ No. 03	
1	Frio 3	1.2	1.0	0.8	5.0
2	Frio 2 Lower	1.0	1.2	1.2 *	7.8
3	Frio 2 Upper	0.5	1.2		
4	Frio 1	1.0	1.0	1.0	5.0
5	Fleming 3 Lower	1.0	1.0	1.0	7.5
6	Fleming 3 Upper	1.0	1.0	0.5	
Total Per Well (MMT)		10.4	6.4	8.5	**Site Total (25.3)**

* For Sunflower INJ No.3 stages 2 & 3 are combined.

Propietary Business Information

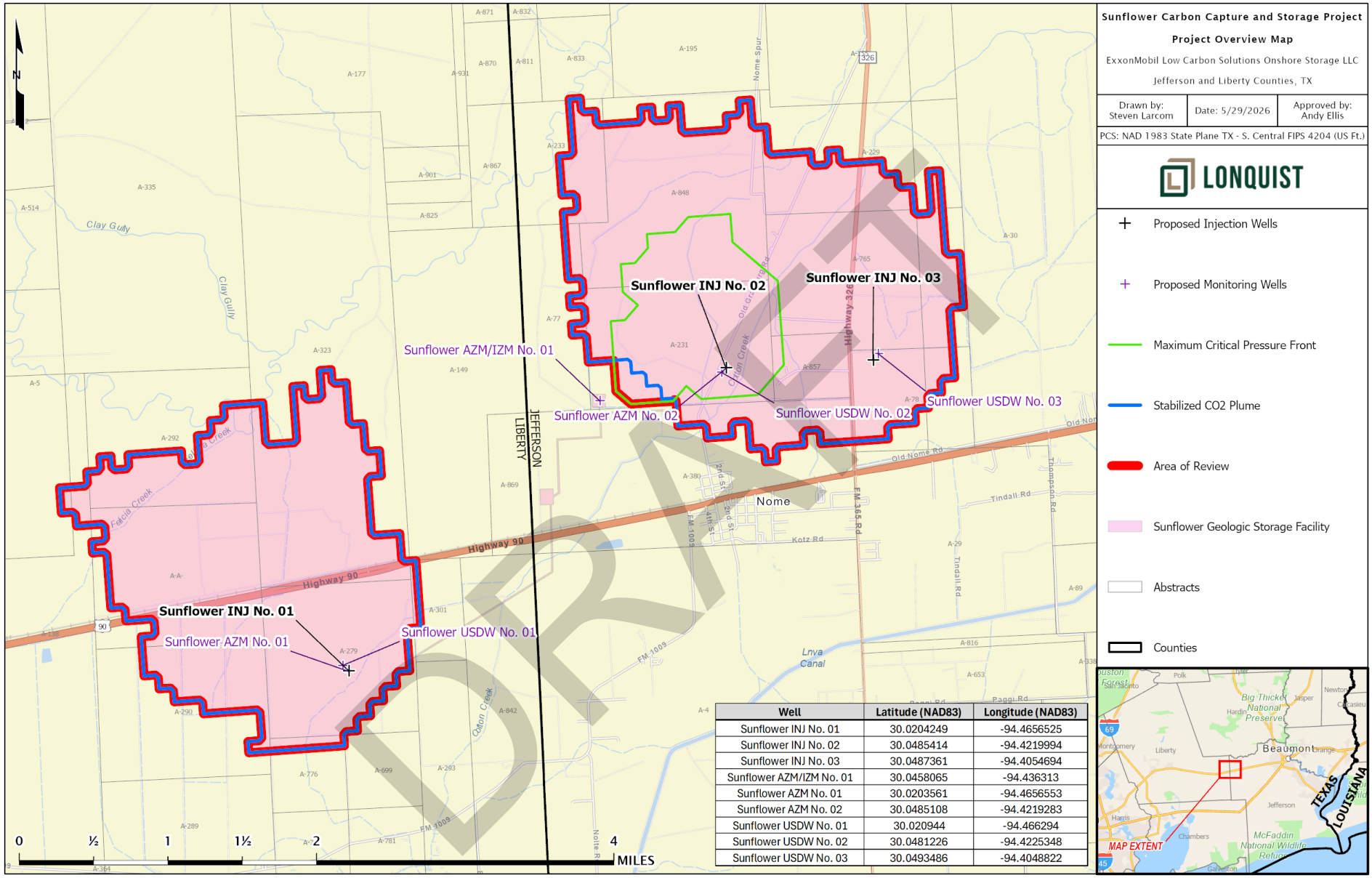
Figure 5-3 – Staged-Injection Approach to Optimize CO_2 Storage

As the CO_2 plume and pressure front expand over time, so does the deployment of monitoring technologies to gather data and assess the potential for USDW endangerment. This phased and/or triggered monitoring strategy was adopted for the Testing and Monitoring Plan based on the timing and depth of each injection interval described in Figure 5-3. This strategic approach is protective of the USDW because of the availability of mature, reliable, and accurate technologies for tracking the CO_2 plume and pressure front growth within the injection zones while minimizing the number of well penetrations through the UCZ.

The monitoring program was also constructed to align with the three operational phases of the Sunflower Project: (1) pre-operational baseline data collection phase (cross-referenced in *Section 4 – Well Construction Plan and Operating Conditions*); (2) the operational phase for the three injection wells discussed in this section; and (3) the PISC phase (discussed in *Section 7 – Post-Injection Site Care and Site Closure Plan*). Phasing will be used for the installation of the in-zone, above-zone, and USDW monitoring wells. During the pre- and early-operational phases, a selection of mature monitoring technologies will be used to not only establish the baseline seismic and pressure, and certain geochemical parameters needed to monitor the CO_2 plume and pressure front—but also to confirm the predictive reservoir modeling results, refine the model as necessary, and optimize the position of the monitoring wells. A semiannual report will be provided to the TRRC that presents the collected monitoring data and plume migration evaluations.

Surface-air and soil-gas monitoring are proposed as a triggered monitoring condition. The additional use of these technologies will be based on monitoring results obtained from the above-UCZ groundwater and USDW monitoring data.

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Well	Latitude (NAD83)	Longitude (NAD83)
Sunflower INJ No. 01	30.0204249	-94.4656525
Sunflower INJ No. 02	30.0485414	-94.4219994
Sunflower INJ No. 03	30.0487361	-94.4054694
Sunflower AZM/IZM No. 01	30.0458065	-94.436313
Sunflower AZM No. 01	30.0203561	-94.4656553
Sunflower AZM No. 02	30.0485108	-94.4219283
Sunflower USDW No. 01	30.020944	-94.466294
Sunflower USDW No. 02	30.0481226	-94.4225348
Sunflower USDW No. 03	30.0493486	-94.4048822

Figure 5-4 – Location of Injection Wells, Above-Zone Monitoring Wells, In-Zone/Above-Zone Monitoring Well, and USDW Monitoring Wells

5.4.2 Mechanical Integrity Testing

5.4.2.1 Internal Mechanical Integrity Testing – Annulus Pressure Test

In accordance with 16 TAC **§5.203(h)(1)(C)**, ExxonMobil will assess the internal mechanical integrity of each injection well by performing annulus pressure tests after the wells have been completed, prior to injection, and at least once every 5 years thereafter. During well construction and prior to the installation of the injection tubing and packer, the casing will also be pressure-tested to the maximum anticipated annulus-surface pressure to verify its integrity. Pursuant to 16 TAC **§5.203(h)(1)(E)**, ExxonMobil will perform mechanical integrity pressure tests after workovers.

The annular pressure tests are designed to demonstrate the mechanical integrity of the casing, tubing, and packer. These tests will be conducted by pressuring the annulus to a minimum of the planned surface-injection pressure described in *Section 4 – Well Construction Plan and Operating Conditions*.

The injection tubing annulus pressure will be continuously monitored at the wellhead during all other times (16 TAC **§5.203(h)(1)(C)**). The tubing annulus pressure will be recorded and reported to the regulatory permitting authority in semiannual reports to demonstrate compliance with casing integrity requirements.

5.4.2.2 External Mechanical Integrity Testing

Following the requirements of 16 TAC **§5.203(h)(1)(D)**, ExxonMobil will use a wireline-deployed temperature log or distributed temperature sensing (DTS) as a means of complying with the external mechanical integrity test (MIT) requirements on an annual basis. The UIC Director will be notified a minimum of 30 days in advance of field activities, per 16 TAC **§5.206(i)**.

The procedures for acquiring a temperature log are as follows:

- A temperature log with gamma ray and casing collar locator will be obtained prior to injection activities, to establish baseline conditions and to identify any potential local temperature anomalies that may exist.
- Shut in the well for a minimum of 24 hours, targeting 36 hours of shut-in time, if possible, based on operational needs.
- Rig up wireline and perform a temperature log from surface to total depth.
- Pull the temperature tool out of hole. If anomalies are present, re-log the well at least 8 hours after the initial pass to reestablish sufficient conditions. If none are identified, rig down wireline.

Per EPA *Geologic Sequestration of Carbon Dioxide: Underground Injection Control (UIC) Program Class VI Well Testing and Monitoring Guidance (March 2013)*, any temperature logs will be evaluated by comparing the relative differences of the log to a baseline log. If the log is comparable to the baseline log, it is considered a successful demonstration of mechanical

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integrity. If log data is inconclusive or anomalies are detected, additional logs such as an oxygen activation or pulsed neutron may be run to further investigate mechanical integrity.

5.4.2.3 Reporting Results of MIT

Annulus pressure test (internal MIT) results will be submitted to the appropriate regulatory permitting authority within 30 days of completion. The logs recorded during the external MIT will be submitted to the appropriate regulatory permitting authority, such as the UIC Director, within 30 days of the verification that the logging results are representative and acceptable.

5.4.3 Pressure Falloff Testing

Required pressure-transient falloff testing will be conducted at least once every 5 years to meet the requirements of 16 TAC **§5.203(j)(2)(G)**. The objective of periodic testing is to monitor for any changes in the near-wellbore environment that may impact permeability and reservoir pressures during active injection. A report containing the pressure falloff data and interpretation of the reservoir pressure will be submitted to the TRRC within 30 days of the conclusion of the test. Although test procedures or methods may be changed based on the request of the permittee and approval by the UIC Director, the following procedure is expected to be typical for such periodic monitoring.

5.4.3.1 Testing Method

The procedures to conduct a pressure falloff test are as follows:

- Record data regarding the test well injection at typical operating conditions (constant rate plus or minus 10%). Rate vs. time data will be recorded during the injection period. Cumulative injection volume will also be recorded. Continue the injection for a time equivalent to the projected duration of the falloff necessary to observe analyzable radial flow. Note that significant rate variations may require more complicated analysis techniques.
- Verify the operation of the permanent monitoring equipment or rig up downhole the memory pressure gauge and run in the well to a datum depth approved by the regulators.
- For pressure transient falloff, obtain the final stabilized injection rate and pressure for a minimum of 1 hour. Ensure that the injectate temperature has stabilized.
- Cease injection and monitor the pressure falloff. Continue monitoring pressure for a time sufficient to observe reservoir behavior. Wellbore pressure gradients will be obtained to establish the fluid gradient.
- Stop the test-data acquisition, rig down, and release the equipment.

5.4.3.2 Analytical Methods

Near-wellbore conditions, such as the prevailing flow regimes, well skin, reservoir properties, and boundary conditions, will be assessed using standard pressure-transient diagnostic plotting and well test simulators, as required. This assessment will be accomplished from analysis of observed pressure changes and pressure derivatives on standard diagnostic log-log and semi-log plots. Significant changes in the well or reservoir conditions will be identified by comparing pressure falloff tests performed prior to initial injection with later tests. These well parameters resulting

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from falloff testing will be compared against those used in AOR determination and site computational modeling. Notable changes in reservoir properties may dictate that an AOR reevaluation is necessary.

The pressure falloff test results will be submitted to the UIC Director within 30 days of completion of the quality assurance/quality control verification of the pressure data.

5.4.3.3 Quality Assurance/Quality Control

The surface field equipment will undergo inspection and testing prior to operation. The pressure gauges will be calibrated prior to installation per manufacturer instructions. Documentation certifying proper calibration will also be enclosed with the test results.

5.4.4 Monitoring of CO_2 Stream

Consistent with 16 TAC **§5.203(j)(2)(A)**, ExxonMobil will install and use measurement devices to analyze the chemical composition of the injection stream, to assess the potential for interactions between CO_2 and other injectate components—and compatibility with the well-completion materials. Temperature and pressure will also be measured at the sample collection point.

5.4.4.1 Sampling Frequency

Quarterly sampling of the CO_2 stream is proposed for the first 2 years of operation, after which the frequency may be reduced to twice per year in consultation with the UIC Director if the results of the CO_2 stream analyses are consistent. If a new source is introduced after transition to semiannual sampling, quarterly sampling would be reinitiated from the time the new source is included in the CO_2 stream for a period of 1 year. If a consistent stream composition is observed for a period of 1 year, sampling would be reduced to twice per year.

5.4.4.2 Sampling Methods

The quarterly measurements will be obtained by collecting representative samples of CO_2 at a sample port on the Sunflower Project's central pad, beyond the last stage of compression in the compression build or similar point. Sufficient mixing and residence time in the system will have occurred at this sampling point for the sample to be representative of the injected CO_2 stream. The sampling station will be equipped with the ability to purge and collect a gas sample into a sealed container.

The central pad is the connection point between the CO_2 pipeline and the sequestration field's distribution system.

Sampling activities will be conducted at the direction of site representatives, in accordance with the certified or accredited analytical laboratory procedures. A sample will be collected by depressurizing the stream and sampling the CO_2 as a gas in either a Tedlar® bag, a Summa cannister, or a laboratory-approved alternate. The grab sample will be sent to an independent contract laboratory for analysis.

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5.4.4.3 Analytical Plan

Table 5-4 presents the test parameters, analytical methods, and sample frequency for each test parameter.

Table 5-4 – Summary of CO_2 Sampling and Analysis Plan

Parameter/Constituents	Analytical Method(s)[1]	Frequency[2]
CO_2 Purity	GC/DID or Method 3A (Subtraction)	Quarterly
Water	GC/FTIR, Method 320, or EPA Method 4	Quarterly
Oxygen	GC/DID or Method 3A	Quarterly
Nitrogen	GC/DID or by difference	Quarterly
Sulfur Dioxide	GC	Quarterly
Hydrogen Sulfide	GC	Quarterly
Oxides of Nitrogen	GC/DT	Quarterly
Total Hydrocarbons	GC/FID	Quarterly
Carbon Monoxide	GC	Quarterly
Methane	GC/DID	Quarterly

GC = gas chromatography; DID = discharge ionization detector; FTIR = Fourier transform infrared DT = drager tube, FID = flame ionization detector

[1] A suitable alternate analytical method may be used/identified by accredited third-party lab.

[2] Proposed quarterly sampling is for the first 2 years of operation with the option to reduce frequency to twice a year after 2 years if the CO_2 stream analytical results are consistent. The addition of a new source would require a return to quarterly sampling for 1 year.

5.5 Monitoring Programs

5.5.1 Continuous injection Stream Physical Monitoring

ExxonMobil will install and use continuous measurement devices to monitor the injection pressure, rate, and mass injected; the pressure on the annulus between the tubing and the production casing; and the temperature of the CO_2 stream, as required under 16 TAC **§5.206(d)(2)(F)(i)**, **§5.206(h)(1)(C)**, and **§5.206(j)(2)(B)**. Data will also be collected to document the addition or removal of any fluid from the annulus system. Data interfaces will be created for equipment that is not linked directly to a data management system or suitable equivalent, and it will be integrated into a unique surveillance platform. In the monitoring program, the sensors, transducers, and controllers will be connected in a central platform to monitor the operating conditions, set alarms for alerting operations of malfunction, and establish safety protocols in case of abnormal conditions. Alarms will additionally be set for pressures outside of described tolerances (generally 90% of the fracture gradient and prescribed wellhead pressures), and changes in annular pressure and fluid.

Instrument calibration standards, precision, and tolerances will be determined based on manufacturer recommendations. The automated control system data will be visually monitored

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for anomalies on a regular basis. Average values will be compared to baseline and predicted values to determine if there are any significant deviations relevant to integrity or containment. The operating parameters, monitoring values, laboratory results, reports, and surveillance documents for the Sunflower Project will be stored in a database to support AOR reviews, quality assurance/quality control review programs, and routine reporting. Table 5-5 provides a summary of the typical sampling devices, locations, and data storage frequencies for the continuous monitoring program. As may become necessary, paper records may be substituted for digital records at the discretion of the operator. Suitable equivalent devices may be used as technology availability and maintenance dictate.

Table 5-5 – Sampling Devices, Locations, and Data Frequencies for Continuous Monitoring

Parameter	Device(s)	Location	Estimated Min. Sampling Frequency	Estimated Min. Recording Frequency
Surface injection pressure	Wellhead pressure logger	Surface, injection well piping	5 seconds	5 minutes
Downhole pressure gauge	Pressure gauges	Injection unit	5 seconds	5 minutes
Injection rate	Coriolis flow meter	Central pad piping	5 seconds	5 minutes
Total mass injected	Coriolis flow meter	Central pad piping	5 seconds	5 minutes
Annular pressure	Pressure gauge	Wellhead	5 seconds	5 minutes
Annulus fluid volume	Pressure gauge	Annulus system tank	5 seconds	5 minutes
CO_2 stream temperature	Temperature gauge	Wellhead, injection well flowing	5 seconds	5 minutes

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5.5.1.1 Continuous Monitoring of Injection Rate and Volume

ExxonMobil will collect continuous measurements necessary to calculate and report the injection mass flow rate and volume in compliance with 16 TAC **§5.206(j)(2)(B)**. A data management system or suitable equivalent will be used to facilitate the continuous collection of intake pressure at the central pad transfer point, the distribution system to each injection well, and the wellhead of the proposed injection wells.

A Coriolis flow meter will be used to measure the flow rate at the central pad and compute flow rates for each injection well. The meter directly measures the mass flow rate of the injected fluid. Analytical methods will be conducted at a periodic interval to determine the mass percentage concentration of CO_2 and carbon monoxide (CO). The mass percentage concentration of CO_2 and CO are multiplied by the total mass flow reading from the Coriolis flow meter to estimate the total mass of captured CO_2 and CO for a given period. The meter will be calibrated to manufacturer specifications.

ExxonMobil will review and interpret the continuously monitored parameters to validate that they are within permitted limits. The data review will also include an examination of trends to help assess the need for equipment maintenance or calibration. Semiannual reports of the monitoring data will be submitted to the regulatory permitting authority.

5.5.1.2 Continuous Monitoring of Injection Temperature and Pressure at the Injection Wells

ExxonMobil will perform continuous monitoring of the injection pressure, temperature, mass flow rate, and injection annulus pressure in compliance with 16 TAC **§5.206(j)(2)(B)**. The injected CO_2 stream pressure will be continuously monitored in the CO_2 flowline near the wellhead interface. The annulus pressure will also be continuously recorded. The combined wellhead and downhole monitoring data will be used to continuously characterize the injection stream in detail.

ExxonMobil will review and interpret the monitoring data to confirm compliance with the operational limits of the injection permit for each injection well. The data review will include an analysis of trends for operational performance evaluation and routine maintenance. Periodic reports of the monitoring data will be submitted to the UIC Director on a semi-annual basis.

5.5.1.3 Continuous Monitoring of Injection Temperature and Pressure in the Reservoir

Reservoir temperatures and pressures will be measured using a downhole gauge that will be installed in the tubing above the production packer. The temperature gauge will also continuously measure the temperature.

5.5.1.4 Continuous Monitoring of Annular Pressure and Volume (Tank Level)

The annular pressure between the tubing and the injection casing string will be monitored on a continuous basis. The pressure gauge on the annulus will be tied into the data management system or a suitable equivalent system and set to alarm if pressure or volumes move outside set tolerances. The annulus tanks in the well systems will be maintained with sufficient volumetric capacity to accommodate the anticipated volume fluctuations due to temperature and pressure variations. The annulus tanks will be equipped with a level transducer or an armored reflex sight glass and an independent liquid-fill nozzle. If any annulus fluid is added or removed, it will be recorded. An annulus tank level is to be recorded on any day when injection occurs.

5.5.1.5 Positive Annular Pressure

Per 16 TAC **§5.206(d)(2)(F)**, pressure will be maintained in the annulus at a value greater than the injection pressure. ExxonMobil will fill the annulus with a noncorrosive fluid approved by the UIC Director. A system will be set up to maintain pressure in the annulus using noncorrosive fluid or gas, and it will be tied into the alarms or a suitable equivalent system designed to signal pressure drops below set points.

5.5.2 Corrosion Monitoring

To meet the requirements of 16 TAC **§5.206(j)(2)(C),** the tubing and casing materials will be monitored during the operational period for loss of mass, thickness, cracking, pitting, and other

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signs of corrosion, to demonstrate that the well components continue to meet the minimum standards for material strength and performance.

5.5.2.1 Monitoring Location and Frequency

Corrosion coupons will be placed in continuous contact with the CO_2 stream in a selected location deemed representative of the three proposed injection wells. The samples will be exposed to the process stream conditions immediately prior to injection, using a recycle loop or sample retriever. Exposure is to be representative of conditions at the top of the tubing. Coupons will be tested quarterly.

Casing inspection logs (CILs) will be conducted on the long string casing at a minimum frequency of once every 5 years pursuant to 16 TAC **§5.305(1)(C)**.

5.5.2.2 Monitoring of Corrosion Coupon

Monitoring of well tubing and casing material corrosion will initially be conducted on a quarterly basis to evaluate the corrosion coupon monitoring system. A corrosion coupon station or rack will be provided as part of well-materials integrity monitoring. Any coupon in active use will be exposed to the stream composition to provide ongoing evaluation of material compatibility with the CO_2 stream. The results will be reported semiannually to the regulatory permitting authority, such as the UIC Director.

The coupons will be assessed for corrosion using American Society for Testing and Materials (ASTM) and Association for Materials Protection and Performance (AMPP) standards for evaluating corrosion tests (e.g., ASTM G1-03 (2017), Standard Practice for Preparing, Cleaning, and Evaluating Corrosion Test Specimens), or a suitable equivalent. When the coupons are removed, they will be inspected visually for signs of corrosion or 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.

The initial baseline measurements of the coupons will follow the recommendations of AMPP National Association of Corrosion Engineers (NACE) SP0775-2023. Coupons will be prepared from the material used to construct the injection wells. A method of coupon preparation will be chosen that does not alter the properties of the metal.

5.5.2.3 Cement Evaluation and Casing Inspection Logs

As discussed in *Section 4 – Well Construction Plan and Operating Conditions*, a cement bond log will be run after the casing has been run and cemented, and sufficient cement curing has taken place. Logging will be conducted to assess the quality of the cement. A baseline CIL will establish the initial dimensions of the wall thickness of the production casing after it is cemented. Following the installation of the completion equipment, including the tubing and packer assembly, an initial CIL will be run. The CIL will serve as the baseline survey for potential future repeat surveys with the objective of enabling the detection of possible loss of metal mass.

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Repeat CILs will only be performed if other monitoring measurements create concern about the integrity of the casing of the wells, and the technical determination is made that a repeat CIL is most suitable to address those concerns. Examples include a loss of annulus pressure and temperature measurements using the gauges installed in the wells. Changes in the recorded electromagnetic response will be analyzed to identify and localize casing corrosion.

5.5.3 Groundwater/USDW Quality Monitoring

To meet the requirements of 16 TAC **§5.203(j)(2)(D)**, ExxonMobil will monitor groundwater quality and geochemical changes above the confining zone during the period of operation. ExxonMobil's intended strategy is to monitor the first laterally continuous permeable and porous sand above the UCZ via the Sunflower AZM No. 01, Sunflower AZM No. 02, and Sunflower AZM/IZM No. 01. This would be the first location to monitor for any potential leaks before they reach the USDW. Additionally, the USDW monitor wells are located within the AOR. The depth of these USDW monitoring wells is ~350 - 500 feet to be consistent with active water wells in use within the AOR. Given the low salinity of this zone, fluctuations in composition (salinity, dissolved CO_2 concentration, etc.) will be more readily apparent compared to a fluctuation of the same magnitude in the higher salinity zone found at deeper depths within the USDW. This would reduce the uncertainty of identifying a potential leak and improve the overall effectiveness of USDW testing and monitoring.

5.5.3.1 Design of the Monitoring Well Network

The monitoring well network includes the proposed monitoring wells that will be used to support compliance with the testing and monitoring requirements under the 16 TAC 5. Combined with the monitoring of pressure buildup at each proposed injection well, the design of the monitoring well network was selected to provide a high degree of confidence in detecting vertical CO_2 migration through the confining zone, that could endanger the USDW without corrective action. The relevant site data considered for the design of the monitoring well network included the phased injection depths, rate, and volume; the geology; and the presence of the legacy wells as required by 16 TAC **§5.203(j)(2)(D)(iii)** and **(iv)**.

5.5.3.2 USDW Monitoring Well Construction

To comply with 16 TAC **§5.203(j)(2)(D)(ii)**, three USDW monitoring wells are proposed. Prior to startup, three USDW monitoring wells (Sunflower USDW No. 01, No. 02 & No. 03) will be completed at the locations shown in Figure 5-4. These locations were selected to provide baseline geochemical data in the vicinity of the three injection wells within the AOR.

The Chicot aquifer is the primary USDW aquifer within the AOR, and its relatively shallow water-bearing zones are a target for the completion of freshwater wells, typically at depths ranging from approximately 100–550 feet below ground level (BGL) in the AOR, as reported in *Appendix C-3* of *Section 3 – AOR and Corrective Action Plan*. The depth ranges of the planned Sunflower USDW No. 01, No. 02 and No. 03 were selected to be consistent with the total depths of freshwater wells in the area and will provide data to assess whether significant changes in water quality are occurring at the depth of most water wells. These three USDW monitoring wells will

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provide an initial baseline of USDW quality prior to injection and then will be used to monitor for changes in USDW quality during injection and PISC.

Potential vertical migration points were considered for the USDW monitoring wells, but the available evidence and evaluation indicated that no significant risk was apparent. For example, results from reservoir and geomechanics models showed that increased pressures near fault and/or fracture planes were found to be well below levels deemed necessary to cause transmissivity that might result in the potential for CO_2 and/or brine to migrate from the injection zones to the USDW. Therefore, no USDW monitoring wells were proposed near fault or fracture planes within the first years of project operations. The time-lapse seismic data collected during operations will be used to validate the model predictions.

5.5.3.3 Summary of Water Well Data for the AOR

Table 5-6 provides a summary of the planned USDW monitoring well construction details for Sunflower USDW No. 01, No. 02 and No. 03. The well construction details for additional USDW monitoring wells (if needed) will be consistent with the construction details in Table 5-6.

A total of 16 freshwater wells were identified in and near the AOR as listed in *Appendix C-3* of *Section 3 – AOR and Corrective Action Plan* from the Texas Water Development Board well registration list and the Submitted Drillers Report Database. *Appendix C-2* of *Section 3* illustrates the location of the water wells, each of which is completed in the Chicot aquifer with a maximum depth of approximately 538 feet BGL. For planning purposes, the extent of the CO_2 plume and pressure front relative to the water wells will be reviewed after sufficient data have been collected to assess whether additional USDW groundwater monitoring is needed for situations of potential USDW endangerment.

Table 5-6 – Summary of USDW Monitoring Well Construction Details

USDW Monitoring Well	Latitude (NAD 83)	Longitude (NAD 83)	Total Depth (ft BGL)
No. 01	30.0209444	-94.4662944	350–500
No. 02	30.0481226	-94.4225348	350–500
No. 03	30.0493486	-94.4048822	350–500

*NAD 83 – North American Datum of 1983
BGL – below ground level

Groundwater samples will be collected, and the fluid sampling parameters and frequencies for the above-zone and USDW monitoring wells are shown in Table 5-7. Additional USDW monitoring wells will be added to assess the potential for USDW endangerment, if necessary. The Sunflower USDW No. 01 – 03 monitoring wells will be completed to collect groundwater samples for the Chicot aquifer at depths from approximately 350–500 feet BGL. .

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5.5.3.4 Collection and Analysis of Groundwater Samples

Fluid samples will be taken periodically from the USDW monitoring wells and the Sunflower AZM No. 01 and No. 02. Three USDW monitoring wells target the Chicot aquifer, which is the most used aquifer in the AOR for potable and non-potable purposes. The AZM monitoring wells will target the first laterally continuous water-bearing zone above the UCZ. The initial sampling frequency for the USDW monitoring wells is quarterly. This sampling frequency is for both the pre-injection phase and the first 2 years of injection. This quarterly sampling characterizes the potential seasonal fluctuation in this USDW. After the initial phase, the sampling becomes annual, with the optimal season of data collection determined by analysis of the first years of quarterly samples.

Table 5-7 summarizes the parameters analyzed and the planned sampling frequency, which apply to the USDW and above-zone monitoring wells. Anomalous measurements will trigger resampling and additional data analysis, including a more detailed evaluation of data using statistical comparisons approved by the TRRC for detection monitoring programs. This analysis could also include geochemical modeling to compare the compositions of groundwater from before and during operations.

If warranted, other tests may be added to the evaluation if resampling and detailed analysis of the fluid samples do not satisfactorily rule out an undesired migration scenario.

Table 5-7 – USDW and Above-UCZ Monitoring Sampling Program

Parameter/Analyte	USDW Monitoring Well Frequency	Monitoring Frequency Above the UCZ
TDS, alkalinity, electrical conductivity, temperature, pH	Quarterly for first 2 years, then annually thereafter for the remainder of the injection phase of the project	Quarterly for first 2 years, then annually thereafter for the remainder of the injection phase of the project
Gas composition (CO_2, CH_4, O_2, N_2)		
Dissolved cations (i.e., As, Ba, Ca, Fe, Mg, Mn, Na, K, Pb, Zn)		
Dissolved anions (i.e., HCO_3, Br, Cl, NO_3 SO_4)		
As = arsenic; Ba = barium; Br = bromine; Ca = calcium; CH_4 = methane; Cl = chlorine; Fe = iron; HCO_3 = bicarbonate; K = potassium; Mg = magnesium; Mn = manganese; N_2 = nitrogen; NO3 = Nitrate; O_2 = oxygen; Pb = lead; SO_4 = sulfate; Zn = Zinc		

ExxonMobil will test the fluid samples and maintain results for the parameters listed in Table 5-7. If results indicate the existence of impurities in the injection stream, the significance of these constituents relative to the protection of USDW will be assessed to determine if they should be included in the analysis of the water samples. Testing results will be stored in an electronic database.

Fluid chemistry data will be monitored for deviations from baseline, predicted, and average values. If a significant variance occurs, the numerical model will be reevaluated. Potential

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geochemical signs that fluid may be unexpectedly migrating from the injection intervals may be detected upon observation of the following trends:

- Change in total dissolved solids (TDS)
- Change in signature of major cations and anions
- Increase in CO_2 concentration
- Decrease in pH
- Increase in concentration of injectate impurities

5.5.3.5 Laboratory to Be Used/Chain of Custody Procedures

The analysis of the fluid samples will be transported to an accredited and state-approved laboratory. ExxonMobil will observe standard chain of custody (COC) procedures and maintain records to allow full reconstruction of the sampling procedure, storage, and transportation, including any problems encountered.

5.5.3.6 Quality Assurance and Surveillance Measures

ExxonMobil will collect replicate samples and sample blanks for quality assurance/quality control purposes. The samples will be used to validate test results, if needed.

5.5.3.7 Plan for Guaranteeing Access to All Monitoring Locations

The placement of the well locations is optimized to be accessible from roads.

5.5.4 Upper Confining Zone/Above-Zone Monitoring

5.5.4.1 Construction of In-Zone and Above-Zone Monitoring Wells

The Sunflower AZM/IZM No. 01 will be constructed to collect pressure and temperature measurements from the four injection intervals as well as the first laterally continuous permeable and porous formation above the UCZ. The Sunflower AZM No. 01 and No. 02 will be completed with a fluid sampling capability at a depth corresponding to the first laterally continuous water-bearing formation above the UCZ and will also monitor pressure in that zone. Table 5-8 provides the completion details for Sunflower AZM/IZM No. 01, which will be equipped with a tubing encapsulated conductor (TEC) cable with in-line pressure/temperature gauges to collect continuous pressure and temperature measurements for evaluating the rate of CO_2 plume and pressure front movement. Table 5-9 provides completion details for the Sunflower AZM Nos. 01 and 02, which will monitor for pressure and geochemical changes above the UCZ. Schematics of the wells are provided in *Appendix E-2*.

The Sunflower AZM/IZM No. 01 will be completed centrally with respect to the three injection wells (Figure 5-4) for direct measurements of pressure and temperature in the injection zone.

The Sunflower AZM No. 01 and No. 02 will be equipped with a tubing-equipped U-tube fluid sampling device or similar sampling device. The above-zone reservoir will be accessed through perforations. The U-tube enables the collection of fluid samples from the above-zone monitoring interval, including any dissolved gases present under original reservoir pressure and temperature

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conditions. The U-tube samples will be collected in a pressurized cylinder to maintain gas pressure in the fluid sample for analysis. The samples will be depressurized in a controlled laboratory environment and the gas samples collected and analyzed for chemical composition.

Once operations commence, groundwater samples will be collected from the first laterally continuous water-bearing zone above the UCZ via Sunflower AZM No. 01 and No. 02 for analysis of geochemical concentrations—on a quarterly frequency for the first 2 years and annually thereafter for the remainder of the operational period.

Continuous pressure and temperature measurements will be recorded for semiannual reporting using a downhole pressure gauge in the Sunflower AZM/IZM No. 01 (illustrated in *Appendix E-2* as a TEC cable and gauges mounted behind the casing). Pressure measurements will be recorded for semiannual reporting in the Sunflower AZM No. 01 and 02.

No additional monitoring wells were deemed necessary at this time based on the model-predicted CO_2 plume movement and proposed monitoring program, the significant porosity/permeability thickness and layering present in the injection zones, and the extensive UCZ present at the site. In the event of unexpected CO_2 plume migration, the location of additional monitoring wells will be proposed through a revision to this Testing and Monitoring Plan as part of a corrective measures plan.

Table 5-8 – General Completion Details for Sunflower AZM/IZM No. 01

Monitoring Well Location Info	Sunflower AZM/IZM No. 01
NAD 83 (2011) Latitude	30.0458065
NAD 83 (2011) Longitude	-94.436313
Total Depth	7,951 ft MD

*MD – measured depth

Table 5-9 – General Completion Details for Sunflower AZM No. 01 and No. 02

Monitoring Well Location Info	Sunflower AZM No. 01	Sunflower AZM No. 02
NAD 83 (2011) Latitude	30.0203561	-94.4656553
NAD 83 (2011) Longitude	30.0485108	-94.4219283
Total Depth	3,365 ft MD	~3,365 ft MD

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Monitoring Well Location Info	Sunflower AZM No. 01	Sunflower AZM No. 02
Screened interval	~3,000 ft MD	~3,000 ft MD

*MD – measured depth

Two injection wells will also be equipped with fiber which provides temperature monitoring capability. This will allow ExxonMobil to monitor for anomalous changes in temperature which could be indicative of potential loss of containment.

5.5.5 Plume and Critical Pressure Front Monitoring

ExxonMobil plans a two-phased strategy for meeting the requirement for plume tracking consistent with 16 TAC **§5.206(j)(2)(E)**. For the initial period of operation, the rate and direction of CO_2 plume migration will be based on a combination of continuously recorded temperatures and pressures at a combination of the three injection wells and the one in-zone/above-zone monitoring well. Indirect monitoring will be performed using periodic time-lapse seismic imaging. Additionally, ExxonMobil will be exploring the adoption of emergent technologies to support plume monitoring. The Sunflower AZM No. 01 and No. 02 will be equipped with fluid sampling capabilities for above-zone fluid collection. Table 5-3 provided a summary of direct and indirect plume and pressure front monitoring technologies.

5.5.5.1 Direct Monitoring

The proposed Sunflower Project Injection Wells No. 01 through No. 03 will be equipped to continuously monitor the pressure in the active completed injection intervals as shown in *Appendix D-1* of *Section 4 – Well Construction Plan and Operating Conditions*. The continuous pressure and temperature measurements will be used to characterize injection well pressure at that location, as well as the cumulative pressure response from the other wells completed in the injection zone.

Any periods of shut-in for an injection well may be observed and treated as a falloff test by recording the shut-in wellhead pressure, bottomhole pressure, and temperature readings. This information, together with the continuous measurements obtained during regular operating conditions, will aid in updating the CO_2 plume reservoir models and plume growth forecasts.

5.5.5.2 Indirect Monitoring: Time-Lapse Seismic Surveys

ExxonMobil considers time-lapse seismic analysis to be a proven method for imaging subsurface changes from oil and gas production and enhanced oil recovery (EOR). This methodology has been applied previously by Denbury Inc. in the Frio Formation at a Gulf Coast EOR field (Holmes et al., 2023) to monitor the movement of injected CO_2 through time.

ExxonMobil will use periodic seismic data acquisitions and time-lapse data analysis as the primary indirect method for tracking the CO_2 plume migration for the Sunflower Project, consistent with the operation monitoring requirements specified in 16 TAC **§5.206(j)(2)(E)**. Existing 3D-seismic

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data represents the pre-injection subsurface conditions and will serve as the reference point for time-lapse data analysis. *Section 1.5.1* presents a description of the existing 3D-seismic data (baseline survey). Monitor surveys will be acquired during the injection stages at a frequency discussed below that will demonstrate conformance between the reservoir model simulation and site performance. An adaptive approach will be applied to monitor survey acquisition timing if the data collected during the injection period shows results within the expected range. An ongoing dialogue between ExxonMobil and the UIC Director is envisioned, marked by tying the monitoring plan potential revisions to the AoR reevaluation frequency, in adherence to reporting requirements.

For the Sunflower Project, the timing of Monitor Survey No. 01 will occur within the first 1–3 years of operation. Should at any time the acquisition of indirect monitoring data suggest deviation from expected behavior for compliance with the permits, ExxonMobil will discuss with the UIC Director and take appropriate action.

Monitor Survey No. 02 will occur approximately 6–8 years after Stage 1 start-up.

Monitor Survey No. 03 will occur at the end of injection after approximately 11 years of operations. Monitor Survey No. 03 will yield the indirect measurement of the extent of the CO_2 plume at the start of the PISC period.

A significant amount of direct and indirect monitoring data will be available by the end of the active injection period and conclusions will have been made regarding the predictive capabilities of the CO_2 plume and pressure front subsurface dynamic model for both the Upper Frio Sand and the Fleming Sand injection intervals. ExxonMobil expects the model will be a reliable predictor of the growth rate and extent of CO_2 saturation and pressure plumes. If additional seismic surveys are necessary during the PISC period to improve the model's predictive capability or show CO_2 plume stability, ExxonMobil will communicate with the UIC Director on the nature and timing of such contingent surveys.

In summary, ExxonMobil proposes the following seismic survey schedule:

- Baseline Survey: data already obtained and reprocessed leveraging EM high standards for site characterization and to represent pre-injection subsurface conditions
- Monitor Survey No. 01: to be acquired 1–3 years from the start of injection operations
- Monitor Survey No. 02: to be acquired 6–8 years from the start of injection operations
- Monitor Survey No. 03: to be acquired at the end of injection operations, 11 years from commencement of injection operations
- Contingent Additional Monitor Surveys During Operational and PISC Phases: to be determined based on the results from direct and indirect monitoring and model prediction.

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The time-lapse seismic data collected will also be used to monitor for CO_2 in the groundwater formation directly above the storage reservoir, utilizing data from the injection wells and the in-zone monitoring well, as an assurance-monitoring technique.

The timing of these monitor surveys will be refined in future updates of the monitoring plan. Over time, monitoring methods and data collection may be supplemented or replaced as advanced techniques are developed.

5.5.5.3 Seismicity Monitoring (Induced Seismicity)

Based on the projected operating conditions and regional and local geologic conditions, injection operations are not expected to result in an induced seismicity event mandating a response action. However, ExxonMobil has installed a permanent seismicity monitoring system onsite, which is being monitored by a third party to detect seismic activity prior to and during injection operations. This array has been recording baseline data since July 2026. The design of the array consists of a near-surface network of seismometers with continuous data sampling, incorporation of publicly available data, and telemetry to cloud-based storage. Near-real-time,high-resolution signal processing and quality assurance will be implemented for event detection, magnitude, and location accuracy. ExxonMobil will additionally receive notifications from USGS of recorded seismicity events for the site and surrounding area, should an event occur. If a review of the data indicates that the event was within a 5.6 mi radius of an injector ExxonMobil will notify the UIC Director to jointly determine if the events are likely to be associated with the operations, and, if so implement response actions for seismicity events contained in Table 8-2 of *Section 8 – Emergency and Remedial Response Plan*.

Appendix E:

Appendix E-1: QASP

Appendix E-2: Sunflower AZM/IZM No. 01 and Sunflower AZM Nos. 01 and 02 Monitoring Well Schematics

References:

Holmes, G., Bongiovanni, N., Wulf, T. et al. April 2023. Time Lapse Seismic in a CO2 EOR Flood and Implications for CCS Reservoir Monitoring, GeoGulf 23 Conference, Abstract, Houston, TX, Award: Thomas A. Philpott Excellence of Oral Presentation

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Appendix E – Testing and Monitoring

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Underground Injection Control – Class VI Permit Application for Sunflower Carbon Capture and Storage Project Injection Wells No. 01, No. 02, and No. 03

APPENDIX E – QUALITY ASSURANCE SURVEILLANCE PLAN

Sunflower Carbon Capture and Storage Project
Jefferson and Liberty Counties, Texas
ExxonMobil Low Carbon Solutions Onshore Storage, LLC
Amendment 2: May 2026

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Distribution Sheet

This Quality Assurance and Surveillance Plan (QASP) was prepared and approved by ExxonMobil for use in collecting information for the operation and compliance of the Sunflower Carbon Capture and Storage Project. ExxonMobil will incorporate the quality assurance and surveillance actions described in this document into the standard ExxonMobil operating program, as appropriate, for the control of work associated with the scope of data quality and detection monitoring for the project.

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E.1 Introduction

ExxonMobil Low Carbon Solutions Onshore Storage, LLC (ExxonMobil) is proposing a Sunflower Carbon Capture and Storage (CCS) Project (Sunflower Project) in Jefferson and Liberty Counties, Texas. ExxonMobil proposes to inject approximately 25.3 million metric tons of CO_2 into the Fleming and Frio formations for geological storage of CO_2 using three injection wells over an 11-year period. Figure E-1 provides the location and layout of the project and the key features within and near the area of review (AOR).

Section 5 – Testing and Monitoring Plan of this Class VI permit application was developed for collecting data for tracking the CO_2 plume and brine pressure front within the AOR. The Testing and Monitoring Plan provided the strategy and details of the data collection program in compliance with the requirements of Title 16, Texas Administrative Code (16 TAC), Part 1, Chapter 5. The Quality Assurance and Surveillance Plan (QASP) is required pursuant to 16 TAC **§5.203(a)(4)** for the purpose of establishing data collection objectives and procedures related to data quality and consistency throughout the project life cycle: the pre-operational phase, the injection operations phase, and the post-injection site care and site closure phase. Some data collection activities were also referenced in *Section 4 – Well Construction Plan and Operating Conditions* and *Section 7 – Post-Injection Site Care and Site Closure Plan*. The QASP also established data quality protocols for those sections.

E.2 Scope and Objective for the QASP

The scope of the QASP is based on the Testing and Monitoring Plan data collection activities for injectate monitoring; corrosion monitoring of the well's tubular, mechanical, and cement components; pressure falloff testing; groundwater quality monitoring; and CO_2 plume and pressure front tracking. The objective of the QASP is to provide standard procedures and practices that will be employed for collecting information and data related to the scope of activities. Quality assurance objectives were established for data management, sample collection and laboratory analysis, and reporting results as appropriate for ongoing monitoring for the Sunflower Project.

E.3 Overview of ExxonMobil's Operations Control System

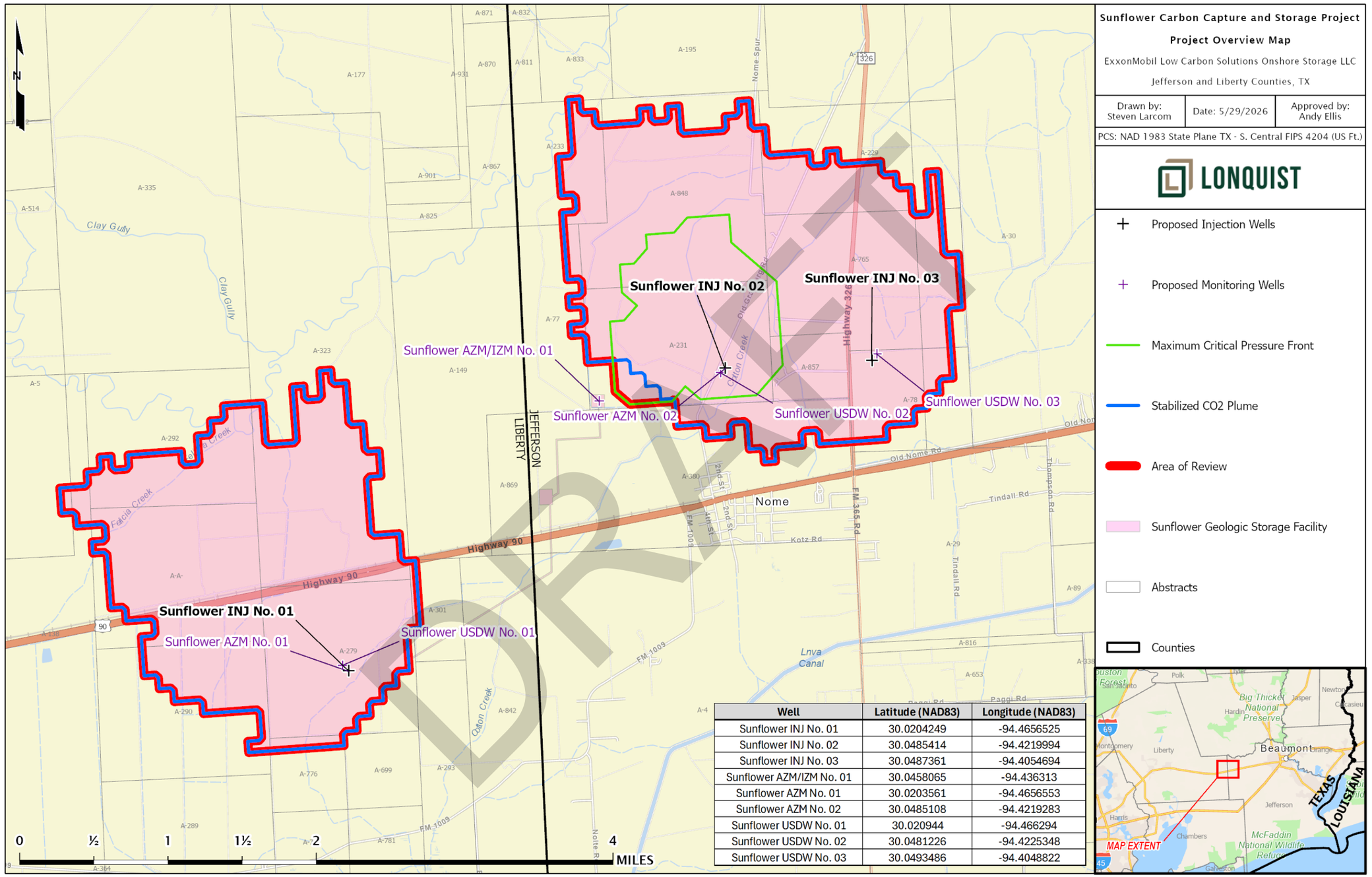
The Sunflower Project will be operated remotely by ExxonMobil's Operations Control Center (OCC). Operating philosophies have been developed that will be incorporated into operating instructions for OCC operators. The OCC is also stewarded by a robust Control Room Management Program per 16 TAC **§8.1(b)(2)**. The OCC operates and monitors the facility through a Supervisory Control and Data Acquisition (SCADA) system. Additionally, Field Operations will make periodic visits to perform surveillance, maintenance, and integrity objectives. ExxonMobil will properly operate and maintain all facilities and systems to achieve compliance with permit conditions (16 TAC **§5.206 (o)(2)(D)**).

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In alignment with the requirements for the QASP, the following testing and monitoring activities will be included in the operations control program:

- Mechanical integrity test methods
- Continuous recording of operational parameters during injection
- Corrosion monitoring
- Pressure falloff testing
- Monitoring of CO_2 stream
- CO_2 plume and pressure front tracking
    - Direct pressure front tracking
    - Plume tracking using indirect geophysical techniques
- CO_2 plume tracking using groundwater monitoring data
    - USDW monitoring wells
    - In-Zone and Above-Zone monitoring wells

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Well	Latitude (NAD83)	Longitude (NAD83)
Sunflower INJ No. 01	30.0204249	-94.4656525
Sunflower INJ No. 02	30.0485414	-94.4219994
Sunflower INJ No. 03	30.0487361	-94.4054694
Sunflower AZM/IZM No. 01	30.0458065	-94.436313
Sunflower AZM No. 01	30.0203561	-94.4656553
Sunflower AZM No. 02	30.0485108	-94.4219283
Sunflower USDW No. 01	30.020944	-94.466294
Sunflower USDW No. 02	30.0481226	-94.4225348
Sunflower USDW No. 03	30.0493486	-94.4048822

Figure E-1 – Sunflower Project Location Map

As part of the operations control plan for the project, an appropriate organizational structure, roles and responsibility matrix, and communications plan will be developed that comply with the requirements of the Class VI UIC permit, in coordination with the UIC Program director (UIC Director), for review and approval of the QASP.

E.4 Alignment of Testing and Monitoring Plan with QASP

The QASP identifies a comprehensive list of quality assurance procedures that align with the data collection and testing requirements identified in the Testing and Monitoring Plan. Table E-1 provides a summary of each test and monitoring activity in the Testing and Monitoring Plan and the associated feature described in the QASP—including the source of the data or measurement, method of data acquisition, and use of an accredited third-party laboratory for analysis, as appropriate. ExxonMobil intends for proper use, maintenance, and installation of monitoring equipment and/or methods.

Many of the measurements rely upon the use of field instrumentation. Table E-2 summarizes a list of the instruments planned for use and the data acquisition objectives for each instrument. The indirect monitoring technique for tracking the CO_2 plume is time-lapse seismic monitoring. As outlined in *Section 5 – Testing and Monitoring Plan*, a series of seismic surveys are planned to acquire seismic data for analysis. The seismic surveys will be acquired and processed by a qualified third-party contractor, and the resultant seismic data will be provided to ExxonMobil for analysis.

E.5 Criteria for Data Evaluation

Groundwater monitoring and sampling is subject to potential sources of variability, such as the following:

- Natural heterogeneity in fluid geochemical composition, total dissolved solids, and formation pressure and temperature
- Instrument variability due to calibration and drift during sampling or analytical activity
- Alternating staff/accredited labs responsible for collecting/analyzing samples
- Changes in environmental conditions during field sampling activities including temperature, rainfall, dust, nearby agricultural activities
- Typographic errors related to data input

The following criteria are provided to help identify instances when variability has been introduced during the sampling and analysis phase and is not related to actual changes in groundwater quality conditions. These criteria and/or others will be considered not only when evaluating the data usability for data qualification (if warranted) and reporting data quality, but also for decision-making purposes.

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E.5.1 Precision

Precision for physical and analytical measurement parameters is detailed within the individual laboratory's test methodology and within established detection limits. Laboratory equipment calibration and maintenance are described by the individual laboratory in a typical analytical quality assurance manual or its equivalent. Following laboratory selection, the laboratory's analytical quality assurance manual can be provided upon request. Laboratory assessment of analytical precision will be the responsibility of the individual laboratories per their standard operating procedures and the analytical methods being used.

E.5.2 Bias

An assessment of bias is applicable to laboratory analyses where a difference between the reference value and the average of measurements made on the same sample can be quantitatively measured. The potential for bias is not applicable in direct measurements including logging, temperature, and pressure. Evaluation of analytical bias will be the responsibility of the individual laboratories per their analytical quality assurance manual or equivalent. Analytical results received from individual laboratories will be reviewed to evaluate the potential for analytical bias.

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Table E-1 – Summary of Testing and Monitoring Plan

Measurement	Purpose	Location(s)	Project Phase and Frequency			Descriptive Features in QASP		
			Pre-Injection	Operation	Post-Injection Site Care	Data Source Type	Method of Data Acquisition	Lab/Custody Procedures
CO_2 stream analysis	CO_2 stream composition	Central pad	Baseline	Quarterly for first two years then semiannually	NA	One sample	Chemical analysis	Accredited laboratory receiving samples under chain of custody
CO_2 stream temperature	Monitor injection temperature	Central pad	Baseline	Continuous	NA	Temperature gauges	Direct measurement	None
Injection rate, density, and mass	Rate and volume monitoring	Central pad	NA	Continuous	NA	Coriolis flow meter	Direct measurement	None
Injection pressure	Compliance with operating permit	Surface, injection well piping	NA	Continuous	NA	Pressure gauge	Direct measurement	None
Annular pressure	Pressure monitoring and well integrity	Sunflower INJ No. 01, No. 02, and No. 03	NA	Continuous	NA	Pressure gauge	Direct measurement	None
Corrosion monitoring	Well integrity	Central pad downstream of metering skid	NA	Quarterly	NA	Corrosion coupon	Physical analysis	Accredited laboratory receiving samples under chain of custody
Internal mechanical integrity	Well integrity	Sunflower INJ No. 01, No. 02, and No. 03	Baseline	Once every 5 years	Prior to P&A	Pressure gauge	Direct measurement	None
External mechanical integrity	Well integrity	Sunflower INJ No. 01, No. 02, and No. 03	Baseline	Continuous and Annually with logs	Prior to P&A	DTS or Temperature surveys or Pulsed neutron log /OA log	Direct measurement	None
Containment and control	Assess CO_2 plume and brine pressure-front containment by monitoring above UCZ	Sunflower USDW No. 01, No. 02, and No. 03, and Sunflower AZM No. 01 and No. 02;	Baseline	Quarterly for first 2 years then annually	Annual	One sample per well	Direct measurement	Accredited laboratory receiving samples under chain of custody
Direct CO_2 plume/pressure front tracking	Demonstrate compliance with permit and calibrate plume model	Sunflower INJ No. 01, No. 02, and No. 03; Sunflower AZM/IZM Well No. 01	Baseline	Continuous	Continuous for Sunflower AZM/IZM Well No. 01	Downhole tubing-mounted pressure and temperature gauge Downhole casing-mounted pressure and temperature gauge	Direct measurement	None
Indirect CO_2 plume tracking	Demonstrate compliance with permit and calibrate plume model	Time-lapse seismic surveys	Baseline survey	Three monitor surveys	Contingent	Time-lapse seismic monitoring	Indirect measurement	None
Seismic event monitoring	Determine if CO_2 injection is inducing any seismic events to occur	Seismometers in and around the AOR	Continuous	Continuous	Continuous	Passive seismicity monitoring	Continuous	None
Pressure falloff testing	Assess injection well performance and formation permeability	Sunflower INJ No. 01, No. 02, and No. 03	NA	At least once every 5 years	None	Downhole tubing-mounted pressure and temperature gauge	Direct measurement	None

DTS = distributed temperature sensing; NA= not applicable; OA = wireline-deployed oxygen activation (OA) log; P&A = plugging and abandonment; UCZ = upper confining zone

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Table E-2 – Summary of Field Instrumentation

Monitoring Location	Instrument Type	Compliance Objective
Central pad before distribution system	Pressure and temperature gauge	Monitor the pressure and temperature of the CO_2 stream at the point of intake prior to distribution.
	Coriolis flow meter	Measure the mass flow rate of the CO_2 stream at the point of intake prior to distribution to the wellheads.
	Corrosion coupons	Measure corrosion rates for well-completion materials downstream of metering skid.
Sunflower INJ No. 01, No. 02, and No. 03	Downhole tubing-mounted pressure/temperature gauge	Measure pressure and temperature in the four injection intervals during operation and prior to injection-stage changes and for CO_2 plume and pressure front tracking
	Annular pressure testing	Measure tubing casing pressure to assess internal mechanical integrity.
	Fiber optic cable for DTS measurements	Measure temperature both in and above the injection zone to assess the potential for loss of containment. Fiber optic line will be installed from surface to approximately 150 feet from TD for INJ No. 2, and from surface to 50 feet below the Top Anahuac for INJ Nos. 1 and 3.
	Wellhead pressure gauge	Measure pressure inside the tubing at the wellhead.
	Coriolis flow meter	Measure the mass of the CO_2 stream at each injection well pad prior to injection tubing.
Sunflower USDW No. 01, No. 02, and No. 03,	Portable field meters for measuring groundwater stabilization parameters such as specific conductance, temperature, dissolved oxygen, turbidity, and pH	Measure field parameters prior to collecting groundwater samples to assess the stabilization of groundwater conditions in the screened interval prior to sample collection.
Sunflower AZM No. 01 and No. 02	Wellhead pressure gauge	Measure pressure in the first laterally continuous permeable and porous formation above the UCZ
	Wireline, U-tube assembly or portable field meters for measuring groundwater stabilization parameters such as specific conductance, temperature, dissolved oxygen, turbidity, and pH	Detection monitoring for presence of CO_2 in the first laterally continuous permeable and porous formation above the UCZ
Sunflower AZM/IZM No. 01	Tubing encapsulated conductor cable with in-line pressure/temperature gauges	Measure temperature and pressure in the four injection intervals and the first laterally continuous permeable and porous formation above the UCZ for CO_2 plume and pressure front tracking.
	DTS Interrogator and fiber cables	Measure temperature from the top of the UCZ to the bottom of the injection zone.
DTS = distributed temperature sensing; UCZ = upper confining zone		

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E.5.3 Representativeness

Representativeness is the degree to which data expresses a characteristic of a population, parameter variation at a point, or an environmental condition. Representativeness for analytical results of groundwater samples will be estimated by ion and mass balances. Ion balances with ±10% error or less will be considered valid. Mass balance assessment will be used in cases where the ion balance is greater than ±10% to help assess the source of error. For a sample and its duplicate, if the relative percent difference is greater than 10%, the sample may be considered non-representative.

To assess sample representativeness, sample collection will be performed in accordance with EPA-recommended procedures for collection and preservation, as well as EPA-recommended holding times specified within a given method.

E.5.4 Completeness

Completeness is a measure of the amount of valid data obtained from a measurement system compared to the amount that was expected under normal conditions. It is expected that the designated analytical laboratory will provide data meeting the quality control (QC) acceptance criteria for 90 percent or more for the samples tested. In addition to the laboratory internal quality assurance (QA)/QC processes, the sampling contractor will evaluate the data validation and whether samples meet the QC acceptance criteria. For direct pressure and temperature measurements, it is expected that data will be recorded no less than 90% of the time.

E.5.5 Comparability

Data comparability is defined as the degree of confidence with which one data set may be compared to another. The groundwater samples will be comparable if collection, compositing, splitting, and testing methods are the same and the measurement units are the same. Comparability for field measurements will be achieved if the test procedures and measurement units within each group of tests are the same (e.g., pH, conductivity, temperature). Operating procedures will be followed to ensure comparability, including those specified in published EPA guidance documents.

E.6 Standards for Calibration of Instrument and Equipment

The following standards for operation and care of field instruments and equipment are planned in support of quality assurance. Both field equipment and laboratory instruments will be calibrated in accordance with the manufacturer guidelines. Permanent data instruments will be calibrated prior to or during the installation process and then checked for precision and accuracy in accordance with the manufacturer's guidelines. Calibration of field instruments will consist of the measurement of instrument response to standards of known composition and concentration and may include the preparation of a standard response curve for the compound or parameter at different concentrations.

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Portable field instruments will be maintained in accordance with the procedures and schedule prescribed by the manufacturer to enable the collection of precise and accurate data. Field instruments and equipment will be acquired, inspected, and accepted for the field activity. Inspections will be conducted prior to use in accordance with the operational manuals.

E.7 Data Management System and Acquisition

Data, in the form of measurements and information about the performance of the injection system, will be collected electronically or manually and stored in an electronic data management system. This system will be aligned with the compliance requirements of the Class VI UIC permit. The electronic data collection systems are envisioned to be a part of the operational management program for the Sunflower Project. Manual data collection activities, such as groundwater monitoring, will be documented in either written or electronic data entry forms. The types of information collected include time and date of activity, person(s) performing the activity, location(s), equipment, calibration data, and field parameter values.

Overall project data quality will be managed through a system of reviews extending from field and laboratory through the data reduction and reporting process. ExxonMobil will perform a quality assurance review of the data entered into the data management system. Data acquired from the injection system may be uploaded directly into the data management system. Analytical results for CO_2 gas composition and groundwater will be obtained from the laboratory using electronic data deliverables. ExxonMobil will utilize its internal data management system for archiving project documentation, data security, and backup.

The following discussion presents the data acquisition plans for each major recording.

Acquisition of Well Completion Data

ExxonMobil employs a third-party contractor to conduct a series of tests on completed wells using downhole tools. The data obtained from these tools is used to assess the alignment of the actual well completion with the well design. Table E-3 provides a summary of representative logging tools and the anticipated data to be obtained from these tools. The quality assurance process is provided as part of the services of the third-party contractor. ExxonMobil reviews the provided test results and associated data quality reports to identify whether the data are fit for purpose.

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Table E-2 – Representative Logging Tool Specifications

Parameter	Logging Speed	Vertical Resolution	Acquired Data	Temp. Rating	Pressure Rating
Ultrasonic casing/ cement inspection	400 to 4,500 ft/hr	0.3 to 6.0 in	Image of casing and cement throughout well completion	350°F	20,000 psi
Electromagnetic	600 to 900 ft/hr	Tubular defect location and resolution: • First tubular: 1 ft • Second tubular: 2 ft • Third tubular: 3 ft • Fourth tubular: 4 ft • Fifth tubular: 4 ft	Electromagnetic log of casing thickness	350°F	15,000 psi
Cement bond log	Up to 3,600 ft/hr	3 ft	Image of cement between casing and formation	350°F	20,000 psi
Caliper	1,800 to 3,600 ft/hr	0.12 in.	Log of inside diameter of casing	350°F	20,000 psi
Temperature log	NA	1.2 in. to 6 in. depending on sampling rate	Vertical temperature profile of well	350°F	20,000 psi

*psi – pounds per square inch

E.7.1 Acquisition of CO_2 Stream Monitoring Data

Table E-4 provides the pressure gauge data-quality specifications for gauges to be located at the central injection pad. Samples of the CO_2 will be collected to monitor the chemical composition in addition to monitoring the mass flow, temperature, and pressure of the CO_2.

Table E-3 – Pressure Field Gauge – Central Injection Pad

Parameter	Value
Calibrated working pressure range	0 to 4,000 psig
Initial pressure accuracy	+/-0.04% of span (1.6 psig)
Pressure resolution	+/- 0.000061% of span (0.244 psig)
Pressure drift stability	0.2% of upper range limit (8 psig) for 10 years

*psig – pounds per square inch gauge

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Samples of CO_2 will be collected at the central pad using the sampling container types, preservation, and holding times provided in Table E-5. If multiple samples are collected, values will be averaged.

Table E-4 – Typical Summary of Sample Containers, Preservation Treatments, and Holding Times for CO_2 Gas Stream Analysis

Sample	Volume/Container Material	Preservation Technique	Sample Holding time (max)
CO_2 stream	(2) 2 L MLB polybags (1) 75 cc mini-cylinder	Sample cooler/cabinet	5 days

*L – liter; cc – cubic centimeter

The samples will be obtained at a sample port on the project's central pad and analyzed for the list of constituents and parameters in Table E-6. The central pad is the connection point between the CO_2 pipeline and the storage field's distribution system. The sampling station will be equipped with the ability to purge and collect a gas sample into a sealed container.

Table E-5 – Summary of Analytical Parameters for CO_2 Stream

Parameters	Analytical Methods[(1)]	Typical Detection Limit/Range	Typical Precisions
CO_2 Purity	GC/DID or Method 3A (Subtraction)	5%–10%	±5%
Water	GC/FTIR, Method 320, or EPA Method 4	1.0 ppm v/v / 100 ppm	±5%
Oxygen	GC/DID or Method 3A	1.0 ppm v/v / 5,000 ppm	±5%
Nitrogen	GC/DID or by difference	1.0 ppm v/v / 5,000 ppm	±5%
Sulfur Dioxide	GC	0.05 ppm v/v / 300 ppm	±5–10%
Oxides of Nitrogen	GC/DT	0.5 ppm v/v / 200 ppm	±5–10%
Hydrogen Sulfide	GC	1.0 ppm v/v /300 ppm	±5–10%
Total Hydrocarbons	GC/FID	0.1 ppm v/v / 10,000 ppm	±5–10%
Carbon Monoxide	GC	1.0 ppm v/v / 1,000 ppm	±5%
Methane	GC/DID	0.1 ppm v/v / 10,000 ppm	±5–10%

DID = discharge ionization detector; DT = drager tube; FID = flame ionization detector; FTIR = Fourier transform infrared spectroscopy; GC = gas chromatography; ppm = parts per million; v/v = volume/volume

[1] A suitable alternative analytical method may be used/identified by an accredited third-party laboratory.

The analytical methods, detection limit and range, and typical limits of precision are provided. The quality control requirements of the laboratory will be aligned for this project with the laboratory's certification process and may include routine calibrations.

E.7.2 Acquisition of Corrosion Monitoring Data

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Monitoring of well tubing and casing material corrosion will be conducted on a routine basis to evaluate the corrosion coupon monitoring system. Table E-7 provides an analytical testing plan for the corrosion coupons. As shown, ExxonMobil plans to follow ASTM Standard G1-03 (2017) [e1] and recommendations of AMPP NACE SP0775-2023 (2023). Coupons will be sent to a qualified contractor for analysis that will use AMPP NACE SP0775-2023 for assessing coupons. The typical data reported includes length, width, thickness, weight (±0.5 milligrams [mg]), coupon identification number, exposed dimensions, and calculated surface area including the edges. The contractor will provide quality control documentation with the analytical report. Holding times and preservation techniques are not applicable to corrosion coupon samples, which are maintained as physically separated to prevent abrasion.

Table E-6 – Summary of Analytical Parameters for Corrosion Coupons

Parameters	Analytical Methods	Detection Limit/Range	Typical Precisions	QC Requirements
Mass and thickness	Baseline: ASTM G1-03 (2017) [e1] After Baseline: AMPP NACE SP0775-2023	±0.2 mg	±1%	Laboratory equipment calibration to manufacturer's specification

ASTM = American Society for Testing and Materials; AMPP = Association for Materials Protection and Performance; NACE = National Association of Corrosion Engineers

E.7.3 Acquisition of Injection Well Performance Data

ExxonMobil will install and use continuous measurement devices to monitor injection pressure, rate, and mass injected; the pressure on the annulus between the tubing and the long string casing; and the temperature of the CO_2 stream, as required under 16 TAC **§5.206(d)(2)(F)(i)**, **§5.203(h)(1)(C)**, and **§5.203(j)(2)(B)**. Table E-8 provides a summary of the data acquisition and measurements limits. Data will also be collected to document the addition or removal of any fluid from the annulus system. ExxonMobil will utilize the following continuous monitoring devices:

- A Coriolis flow meter will be used to measure the flow rate at the central pad and compute flow rates for each injection well. The meter directly measures the mass flow rate of the injected fluid.
- The injected CO_2 stream pressure will be continuously monitored in the CO_2 flowline near the wellhead interface. The annulus pressure will also be continuously recorded. The combined wellhead and downhole monitoring data will be used to continuously characterize the injection stream in detail.
- Reservoir temperatures and pressures will be measured using a fiber optic cable, embedded in the cemented annulus of the long string casing, and a tubing encapsulated conductor pressure-and-temperature gauge on the injector well tubing.
- The annular pressure between the tubing and the injection casing string will be monitored on a continuous basis. The pressure gauge on the annulus will be tied into the data management system or a suitable equivalent system and set to alarm if pressure or

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volumes move outside set tolerances. The annulus tanks are to be equipped with a level transducer and sight glass. If any annulus fluid is added or removed, it will be recorded. An annulus tank level is to be recorded on any day when injection occurs.

The calibration and operating methods will be based on the manufacturer's specifications. For the Coriolis flow meter, the calibration and operating methods will also include quarterly zero-flow verification and online diagnostics as well as an 8-year cycle of off-site laboratory calibration. The Coriolis flow meter will be out of service for short periods once per quarter for the zero-flow checks.

Table E-7 – Summary of Measurement Parameters for Field Gauges

Equipment/Location	Parameter	Value
Pressure Field Gauge – Pressure Gauge (Upstream of Choke)	Calibrated working pressure range	0 to 3,000 psig
	Initial pressure accuracy	+/-0.04% of span (1.2 psig)
	Pressure resolution	+/- 0.000061% of span (0.183 psig)
	Pressure drift stability	0.2% of upper range limit (8 psig) for 10 years
Pressure Field Gauge – Wellhead Pressure Gauge (Downstream of Choke)	Calibrated working pressure range	0 to 3,000 psig
	Initial pressure accuracy	+/-0.04% of span (1.2 psig)
	Pressure resolution	+/- 0.000061% of span (0.183 psig)
	Pressure drift stability	0.2% of upper range limit (8 psig) for 10 years
Pressure Field Gauge – Downhole Pressure Gauge	Calibrated working pressure range	200 to 10,000 psi
	Initial pressure accuracy	0.015 psi
	Pressure resolution	0.006 psi/sec
	Pressure drift stability	0.02 psi/year at max pressure and temperature
Temperature Field Gauge – Downhole Temperature Gauge	Calibrated working temperature range	25–150°C
	Initial temperature accuracy	0.5°C
	Temperature resolution	0.005°C/sec
	Temperature drift stability	0.1°C/year at max temperature
Mass Flow Rate Field Gauge – Coriolis Flow Meter at Central Injection Pad and Well Pad	Calibrated working flow rate range	0 to 200,000 kg/hr
	Initial mass flow rate accuracy	+/-0.1% of rate
	Mass flow rate resolution	Pulses +/-50 ppm
	Mass flow rate drift stability	At central injection pad: zero point stability – 32 kg/hr At well pad: zero point stability – 14 kg/hr
Temperature Transmitter – Downstream of Choke	Calibrated working temperature range	0–300°F
	Initial temperature accuracy	0.06°F
	Temperature resolution	0.000183°F

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Equipment/Location	Parameter	Value
	Temperature drift stability	+/-0.1% of reading or 0.18°F, whichever is greater for 2 years

*kg/hr – kilograms per hour

E.7.4 Acquisition of Groundwater Monitoring Data

Samples of groundwater will be collected from Sunflower USDW No. 01, No. 02, and No. 03, - and from the first permeable water-bearing zone above the UCZ, in Sunflower AZM No. 01 and No. 02.

E.7.4.1 USDW Monitoring

For USDW sample collection, a decontaminated submersible pump equipped with new dedicated and disposable sampling tubing will be used. The tubing intake will be set in the middle of the screen interval. An in-line flow-through cell (AquaTROLL 6000 or similar) will be used to continuously monitor water-quality indicator parameters during well purging. A set of field measurements (Table E-9) will be collected to evaluate the trend in stability of certain parameters. The measured parameter values will be recorded in field sampling records and compared with the stabilization criteria listed in Table E-9.

Table E-8 – Field Stabilization Criteria for USDW Well Sampling

Field Parameter	Stabilization Criteria
pH	+/- 0.2 units
Temperature	+/- 3%
Specific conductance	+/- 3%
Dissolved oxygen	+/- 10%
Turbidity	Stabilized or <10 NTUs

*NTU – nephelometric turbidity unit

Once water quality parameters in the purged well have stabilized, groundwater samples will be collected using laboratory-provided sample containers. Each sample will be containerized and labeled at the time of collection. The label will contain a unique sample number identifying the sampling location and sample date. The individual sample containers will be placed in a cooler with packing material. Ice or chemical ice packs will be placed on top of the packing materials to maintain the applicable preservation temperature (typically less than 6°C and without allowing the sample to become frozen) while in transport to the laboratory. Sample containers and/or bags will be new and used as received from the selected laboratory. Table E-10 details specifications for sample containers, preservation techniques and holding times for groundwater samples. Table E-11 provides the analysis plan for groundwater samples.

Data precision for groundwater samples will be assessed by the collection and analysis of field duplicate samples. Field duplicates will be collected by taking a second sample using the same

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collection method in the field at a given location immediately following the original sample. Differences between the original and duplicate samples are indicative of variability and/or error in the sampling technique. The frequency of field duplicates is at least one sample per sample group or 10% for sample sizes above 20 samples.

Decontamination procedures will be followed between sampling at each monitoring well to reduce the potential for cross-contamination of groundwater samples. Field equipment will be cleaned and rinsed per standard field decontamination procedures between sampling locations. Nitrile gloves will be worn during groundwater sampling activities and while handling sample containers. The sampler will remove waste associated with sampling activities (tubing, personal protective equipment, consumables) from the Sunflower Project area.

For each sampling event, the field sampling activities will be recorded at each sampling location, with calibration of field instruments, details of well purging process, field parameter measurements, sample collection date and time, QA/QC sampling, and details of sample handling, storage, and shipping. The samples will be shipped under a chain of custody process, signed by the sampler, and upon transfer of custody to a commercial delivery service or the laboratory, tracking information will be retained. The samples will be shipped to one or more accredited laboratories for analysis.

First Water-Bearing Zone Above UCZ

Sunflower AZM Nos. 01 and 02 will be equipped with the capability to sample fluids. The above-zone reservoir will be accessed through perforations. The sampling depth will correspond to the first laterally continuous permeable and porous formation above the UCZ. Actual sampling depth will be determined based on the as-drilled depths. Monitoring will be quarterly for the first 2 years and then annually for the remainder of the operational phase.

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Table E-9 – Summary of Sample Containers, Preservation Treatments, and Holding Times for Groundwater Samples

Target Parameters	Volume/Container Material	Preservation Technique	Sample Holding Time
EPA Method 6020A Dissolved cations (As, Ba, Ca, Fe, Mg, Mn, Pb, K, Na, Zn)	1 liter, plastic	0–6°C	60 days
EPA Method 300.0 Dissolved anions (HCO_3, Br, Cl, NO_3, SO_4)	1 liter, plastic	0–6°C	28 days
Method SM 2540C Total dissolved solids	1 liter, plastic	0–6°C	7 days
Method SM 2320B Alkalinity Bicarbonate (HCO_3)	500 mL, plastic	0–6°C	7 days
RSK-175 Gas composition (CO_2)	Three 40 mL VOA vials	0–6°C	14 days
RSK-175 Gas composition (CH_4)	Two 40 mL VOA vials	0–6°C, hydrochloric acid	14 days
Calculated from TKN Method 351.2 Nitrite/Nitrate 353.2	Three 250 mL, plastic	0–6°C, sulfuric acid	48 hours
Field Methods: Electrical conductivity, temperature, pH, DO, ORP, turbidity	Field measurement	Not Applicable	Not Applicable
Note: The listed sample container sizes and preservation techniques may be revised based on input from the accredited laboratory selected to do the work. DO = dissolved oxygen; ORP = oxidation-reduction potential; VOA = volatile organic analysis			

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Table E-10 – Summary of Analytical and Field Parameters for Fluid Samples in USDW and Above the UCZ

Parameters	Analytical Methods [1,2]	Typical Detection Limit or Range [3]	Typical Precisions [3]	QC Requirements [2]
Dissolved cations: As, Ba, Ca, Fe, Mg, Mn, Pb, K, Na, Zn	EPA Method 6020A	0.001 to 2 mg/L [4]	±20%	Daily calibration; blanks, duplicates, and matrix spikes at 10% or greater frequency
Dissolved anions: HCO_3, Br, Cl, NO_3, SO_4	EPA Method 300.0	0.001 to 2 mg/L [4]	±20%	
Total dissolved solids	Method SM 2540C	10 mg/L	±20%	
Alkalinity Bicarbonate (HCO_3)	Method SM 2320B	2 mg/L	±200%	
pH (field)	Field measurement	2–12 s.u. [5]	±0.2	Factory calibration and user calibration per manufacturer's instructions, duplicates
Electrical conductivity (field)	Field measurement	0–100 mS/cm [5]	±1%	
Temperature (field)	Field measurement	-10 to -55 °C [5]	±0.10	
Dissolved oxygen (field)	Field measurement	0-50 mg/L	±0.10 mg/L	
Gas composition (CO_2)	RSK-175 or ASTM D513-16 [6] depending on laboratory availability	0.1 µg/L	±25%	Daily calibration; blanks, duplicates, and matrix spikes at 10% or greater frequency
Gas composition (CH_4)	RSK-175	0.1 µg/L	±20%	
Gas composition (N_2)	TKN Method 351.2; Nitrite/Nitrate 353.2; or RSK-175 depending on laboratory availability	0.1 mg N	±20%	

[1] An equivalent method may be employed with the prior approval of the UIC Director.
[2] The listed analytical methods and QC requirements may be revised based on input from the accredited laboratories or field instrumentation selected to do the work.
[3] The exact detection limit, range, and precision can vary depending on the sample matrix and the conditions under which the analysis is performed. Precision may also be affected by equipment utilized in analytical procedures by the laboratory.
[4] These are analyte, dilution, and matrix dependent.
[5] These are dependent on manufacturer specification and calibrated range.
[6] ASTM 2017b
µg/L = micrograms per liter; mg N = milligrams nitrogen; mS/cm = milliSiemens per centimeter

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E.7.5 Sample Custody for CO_2 and Groundwater Samples

Possession of samples collected in the field will be traceable from the time of collection until analysis in the laboratory. The chain of custody (COC) form will be completed daily for samples collected during the sampling event and will include project name and number, sample identification number and location, name(s) of individual(s) who collected the sample(s), type of sample, number and type of containers, date and time of collection, required analyses, preservatives, shipping or courier data, and signatures documenting transfer of sample custody. From sample collection through laboratory analysis to the final evidence files, the procedures for sample handling and custody are described below. The method for demonstrating custody is that a sample or evidence file is in one's custody if it is:

1. In one's physical possession.
2. In one's view during their possession.
3. In one's physical possession and placed in a secured location.
4. In a secured area restricted to authorized personnel only.

The COC form is typically provided by the laboratory with the sample kit. Once the sample containers are filled, the COC form will always accompany the sample. Individuals receiving and relinquishing the samples will sign, date, and note the time of transfer on the record. A commercial delivery service will be identified by company name. Samples will remain in the physical possession of the person to whom they are assigned until the samples are shipped to the laboratory or are stored prior to shipping. The COC form will accompany the samples to the laboratory.

E.7.6 Acquisition of CO_2 Plume and Brine Pressure Front Tracking Data

Sunflower AZM/IZM Well No. 01 will be equipped with a tubing encapsulated conductor cable with in-line pressure/temperature gauges to collect continuous pressure and temperature measurements for evaluating the rate of CO_2 plume and pressure front movement. This system will also provide data for assessing internal mechanical integrity. Sunflower INJ No. 01, No. 02 and No. 03 will contain a downhole pressure/temperature gauge for monitoring. Table E-12 provides a list of pressure and temperature gauge specifications for Sunflower Project Injection Wells No. 01, No. 02, and No. 03, and Sunflower AZM/IZM Well No. 01.

Table E-11 – Downhole Pressure and Temperature Gauge Specifications

Parameter	Value
Calibrated working pressure range	200 to 10,000 psi
Initial pressure accuracy	0.015 psi
Pressure resolution	0.006 psi/sec
Pressure drift stability	0.02 psi/year at max pressure and temperature
Calibrated working temperature range	25–150°C

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Parameter	Value
Initial temperature accuracy	0.5°C
Temperature resolution	0.005°C/sec
Temperature drift stability	0.1°C/year at 177°C
Max temperature	177°C
Instrument calibration frequency	Per manufacturer's specifications

This well and each CO_2 injection well will also be equipped with a DTS cable to assess external mechanical integrity. Table E-13 provides the specifications for the cable.

Table E-12 – DTS Cable Specifications

Parameter	Logging Speed	Vertical Resolution	Temperature Rating	Pressure Rating
Distributed Temperature Sensing	12 seconds	0.5-meter	-82–177°C	Not Applicable

E.8 Data Validation and Usability

Data validation procedures will be performed for both field and laboratory data to assess whether the requirements of the specified QC acceptance criteria were met. Checklists, forms, and calculations may be developed to meet the Class VI UIC permit requirements for the Sunflower Project. ExxonMobil and/or its designated contractor(s) will provide verification and validation of data generated with the project. This process may include the following elements:

1. Review the cover letter signed by the Laboratory Project Manager (or designee) to assess the laboratory narrative report regarding the overall performance of the laboratory and potential deviations or uncertainties in the data.
2. Review the case narrative discussing any technical problems or deviations from the analytical methods (e.g., did the laboratory receive the samples in good condition). Samples are considered in good condition if they meet temperature and preservative requirements, and the sample receipt condition is acceptable (i.e., the bottles are not broken and the cooler custody seals are intact).
3. Review date and time of receipt relative to holding time requirements.
4. Review COC forms to verify that samples were maintained under COC protocol with signatures from the field personnel and the lab personnel.
5. Compare sampling dates to sample extraction and analysis dates to check that these procedures were completed within proper holding times.
6. Review target constituent list, analytical methods, and result units for alignment with permit requirements.
7. Review lab summary/chronicle describing client ID/analysis, laboratory identification number, prep number, collection date, extraction/prep date, analysis date, and laboratory management sign-off.

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8. Review sample data report including the results listed by analytical method with sample preparation, extraction, cleanup, digestion, and analytical methods; analysis and extraction dates; analyst initials; qualifiers; and qualifier definitions.
9. Review QC summary report including date of analyses, parameters assessed, system monitoring compound summary, method blank data, sample duplicates and control samples, surrogate spike recoveries, and matrix spike/matrix spike duplicate (MS/MSD) results.
10. Review the laboratory case narrative and any corrective actions necessary and data quality assessment items.

The data quality indicators of precision, accuracy, representativeness, completeness, comparability, and sensitivity associated with newly collected data will be reviewed and an assessment made regarding the usability of the data. Data validation may include the review and evaluation of multiple data characteristics including the unit(s) of measurement, sample holding times, and QA/QC results (such as field duplicates, trip blanks, matrix spike samples). After sufficient data have been collected, additional methods, such as those described in the EPA Unified Guidance (EPA 2009), may be used to examine variations and trends in the data.

If at any point the occurrence of erroneous data becomes apparent, corrective actions will be taken to identify the cause of the error, recommend a feasible corrective action, seek approval if needed to implement corrective action, and implement the corrective action. Field team members may identify problems during sampling, and laboratory analysts may identify problems during chemical analyses. Field staff will be responsible for testing equipment and performing corrective actions on broken or malfunctioning field equipment. If corrective action cannot be taken in the field, then equipment will be repaired or replaced. Significant corrective actions affecting analytical results will be documented in field activity reports and re-measurement/re-sampling may occur as appropriate.

E.9 Self-Assessment of QASP

The quality system described in the QASP will be assessed to reduce the potential for questionable data to be used in the demonstration of regulatory compliance. The scope of internal assessments may include the following:

- Surveillance of scheduled field activities including sample collection, sample handling, logging, and indirect data collection (e.g., seismic data)
- Review of laboratory data management activities
- Examination of data reporting systems
- Verification of instrument and equipment acceptability including maintenance and calibration frequency
- Reevaluation of analytical method implementation, including CO_2 stream and corrosion evaluation methods

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- Evaluation of external organization/contractor adherence to application elements of this QASP

ExxonMobil may contract the collection of samples, conduct well logging, and perform other activities as outlined in the Testing and Monitoring Plan. Each organization gathering data will be responsible for conducting their internal assessments so that data acquisition is aligned with the Testing and Monitoring Plan. In the event that issues requiring corrective action are identified, those issues will be addressed, and corrective actions will be designed and implemented. Documentation of such corrective actions will be maintained in the archives of the data management system.

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E.10 References

AMPP. 2023. Preparation, Installation, Analysis, and Interpretation of Corrosion Coupons in Hydrocarbon Operations. Standard NACE SP0775-2023.

ASTM (ASTM International). 2017a. "Standard G1-03(2017)[e1]: Standard Practice for Preparing, Cleaning, and Evaluating Corrosion Test Specimens."
[e1] – NOTE – Editorially updated references in Section 2 in December 2017

ASTM (ASTM International). 2017b. "Standard D513-16: Standard Test Methods for Total and Dissolved Carbon Dioxide in Water."

EPA. 2009. Statistical Analysis of Groundwater Monitoring Data at RCRA Facilities Unified Guidance. EPA 530/R-09-007.

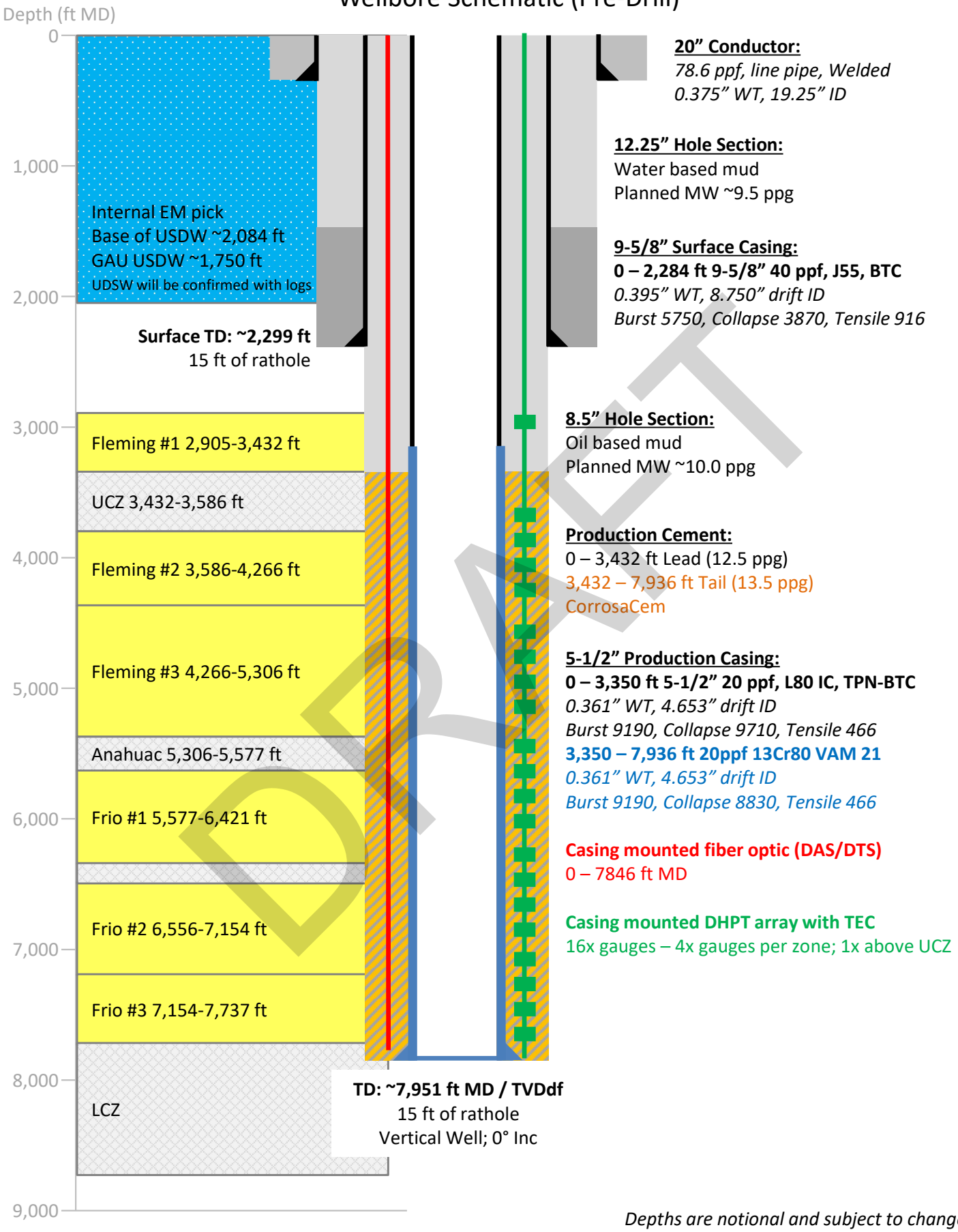
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Appendix E2 – Sunflower A□M□I□M □ o□□□ and Sunflower A□M □ os□□□ and □□ Schematics

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Sunflower AZM/IZM Well No. 01

Wellbore Schematic (Pre-Drill)



20" Conductor:
78.6 ppf, line pipe, Welded
0.375" WT, 19.25" ID

12.25" Hole Section:
Water based mud
Planned MW ~9.5 ppg

9-5/8" Surface Casing:
0 – 2,284 ft 9-5/8" 40 ppf, J55, BTC
0.395" WT, 8.750" drift ID
Burst 5750, Collapse 3870, Tensile 916

8.5" Hole Section:
Oil based mud
Planned MW ~10.0 ppg

Production Cement:
0 – 3,432 ft Lead (12.5 ppg)
3,432 – 7,936 ft Tail (13.5 ppg)
CorrosaCem

5-1/2" Production Casing:
0 – 3,350 ft 5-1/2" 20 ppf, L80 IC, TPN-BTC
0.361" WT, 4.653" drift ID
Burst 9190, Collapse 9710, Tensile 466
3,350 – 7,936 ft 20ppf 13Cr80 VAM 21
0.361" WT, 4.653" drift ID
Burst 9190, Collapse 8830, Tensile 466

Casing mounted fiber optic (DAS/DTS)
0 – 7846 ft MD

Casing mounted DHPT array with TEC
16x gauges – 4x gauges per zone; 1x above UCZ

Depths are notional and subject to change based on as-drilled conditions

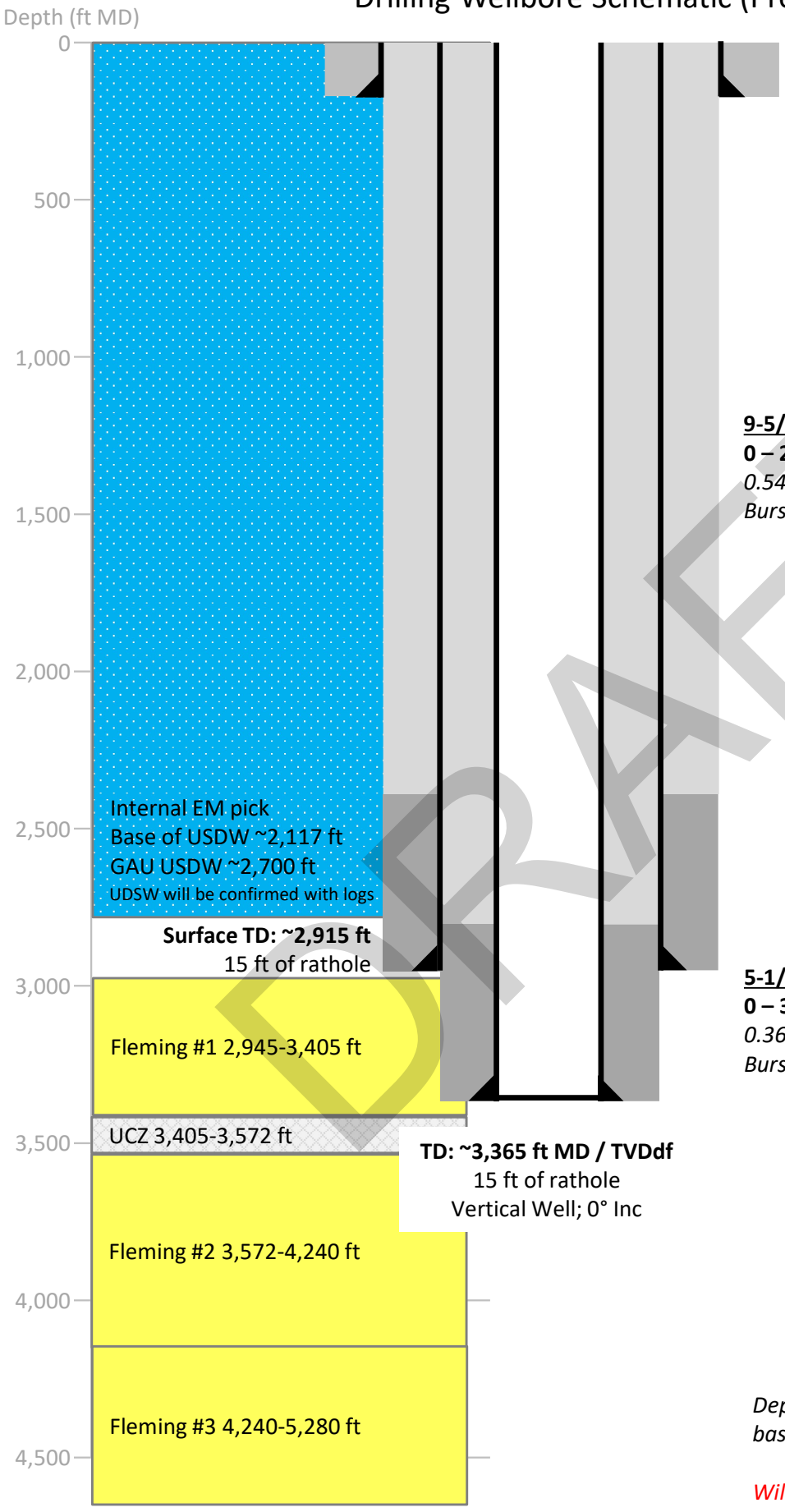
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Sunflower AZM Well No. 01 – Injector 1 Pad

Drilling Wellbore Schematic (Pre-Drill)



20" Conductor:
78.6 ppf, line pipe, Welded
0.375" WT, 19.25" ID

9-5/8" Surface Casing:
0 – 2,900 ft 9-5/8" 53.5 ppf, T95, VAM21
0.545" WT, 8.500" drift ID
Burst 9,410psi, Collapse 7,340psi, Tensile 1,477klb

5-1/2" Production Casing:
0 – 3,350 ft 5-1/2" 20 ppf, L80 IC, BTC-TPN
0.361" WT, 4.653" drift ID
Burst 9,190psi, Collapse 9,710psi, Tensile 466klb

Depths are notional and subject to change based on as-drilled conditions

Will not plan to penetrate the UCZ

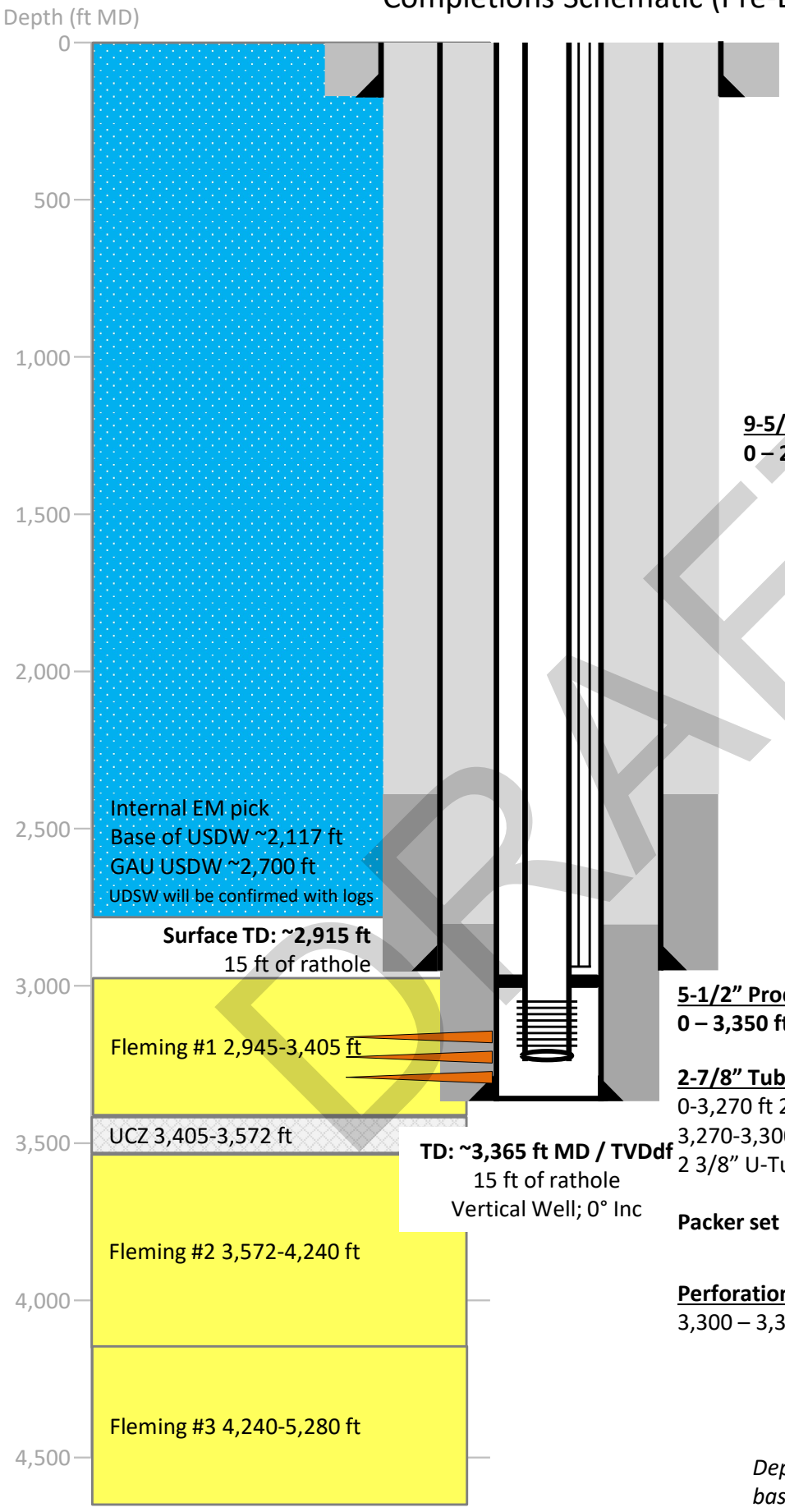
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Sunflower AZM Well No. 01 – Injector 1 Pad

Completions Schematic (Pre-Drill)



20" Conductor

9-5/8" Surface Casing:
0 – 2,900 ft 9-5/8" 53.5 ppf, T95, VAM21

5-1/2" Production Casing:
0 – 3,350 ft 5-1/2" 20 ppf, L80 IC, BTC-TPN

2-7/8" Tubing
0-3,270 ft 2-7/8" 6.5 ppf L80 EUE 8RD
3,270-3,300 ft 2-7/8" 6.5 ppf L80 EUE 8RD Screen
2 3/8" U-Tube lines mounted to tubing from 0-3,250 ft

Packer set at 3,260 ft

Perforations:
3,300 – 3,320 ft (1st permeable sand above UCZ)

Depths are notional and subject to change based on as-drilled conditions

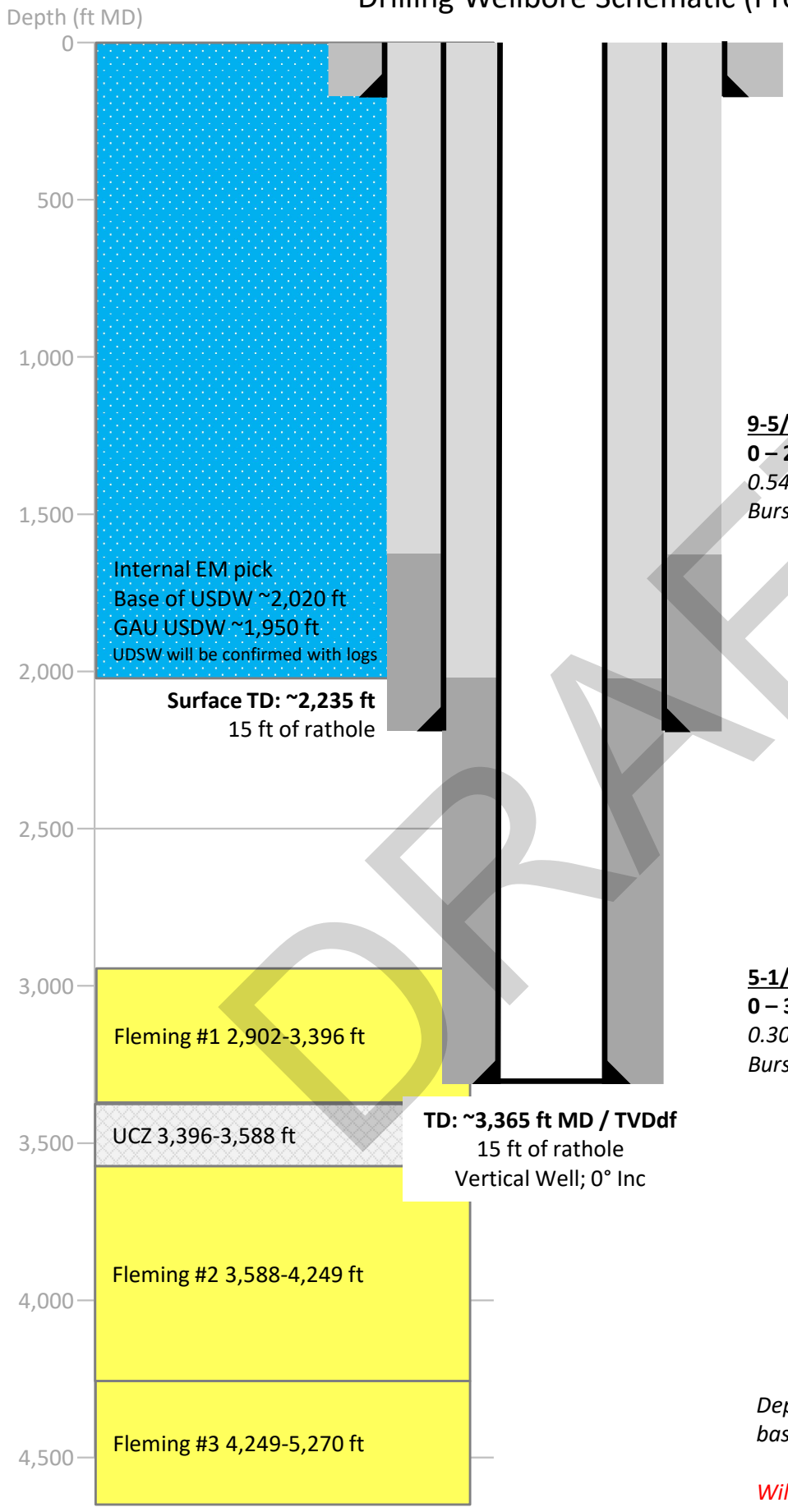
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Sunflower AZM Well No. 02 – Injector 2 Pad

Drilling Wellbore Schematic (Pre-Drill)



20" Conductor:
78.6 ppf, line pipe, Welded
0.375" WT, 19.25" ID

9-5/8" Surface Casing:
0 – 2,220 ft 9-5/8" 53.5 ppf, T95, VAM21
0.545" WT, 8.500" drift ID
Burst 9,410psi, Collapse 7,340psi, Tensile 1,477klb

5-1/2" Production Casing:
0 – 3,350 ft 5-1/2" 17 ppf, L80, VAM TOP HC
0.304" WT, 4.767" drift ID
Burst 7,740psi, Collapse 6,290psi, Tensile 397klb

Depths are notional and subject to change based on as-drilled conditions

Will not plan to penetrate the UCZ

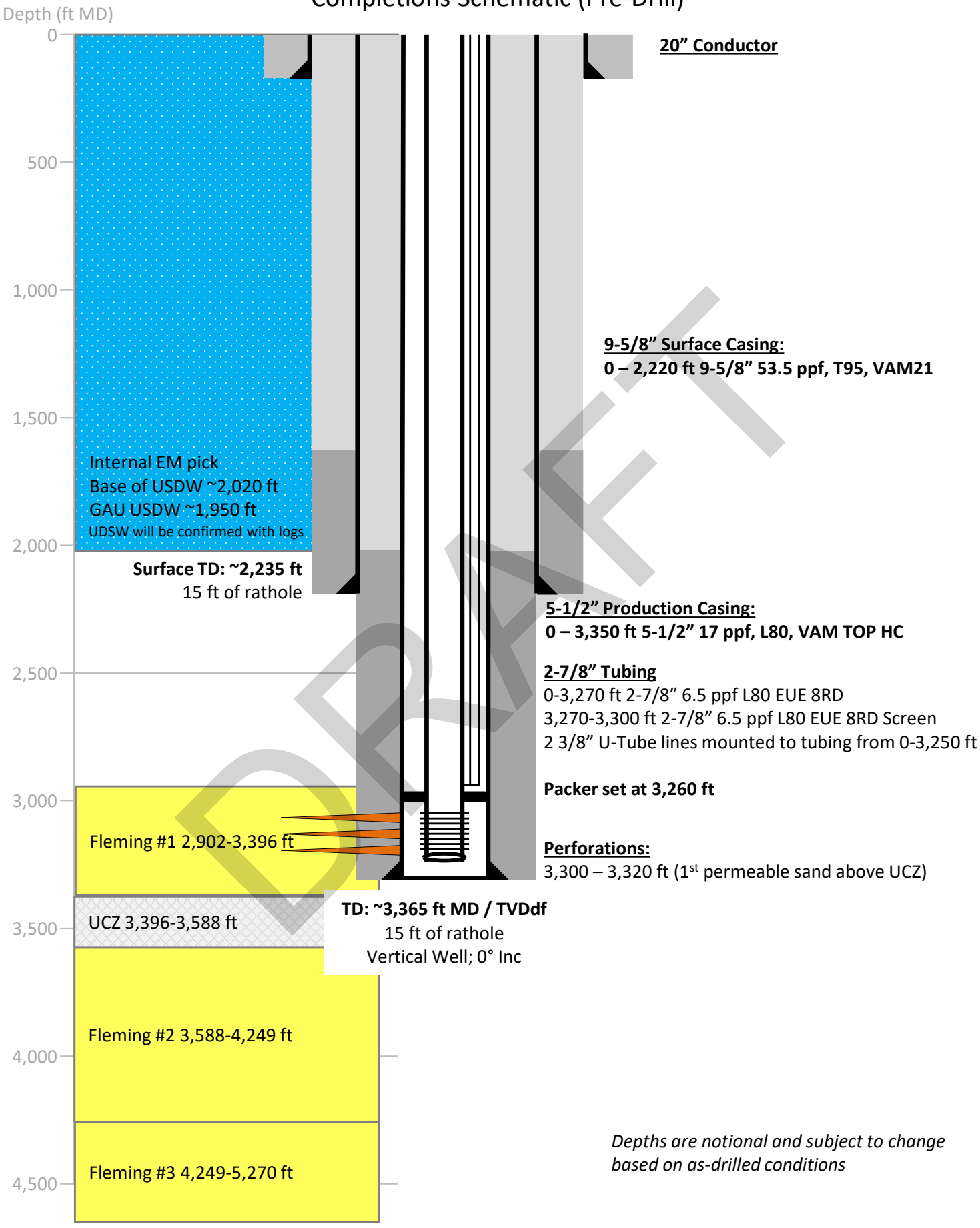
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Sunflower AZM Well No. 02 – Injector 2 Pad

Completions Schematic (Pre-Drill)



Depths are notional and subject to change based on as-drilled conditions

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Railroad Commission of Texas

Attachment G – Well(s) Plugging Plan

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Underground Injection Control – Class VI Permit Application for Sunflower Carbon Capture and Storage Project Injection Wells No. 01, No. 02, and No. 03

SECTION 6 – INJECTION WELL PLUGGING PLAN

Sunflower Carbon Capture and Storage Project
Jefferson and Liberty Counties, Texas
ExxonMobil Low Carbon Solutions Onshore Storage, LLC
Amendment 3: August 2026

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6.1 Injection Well Plugging Plan

ExxonMobil Low Carbon Solutions Onshore Storage, LLC (ExxonMobil) is undertaking the Sunflower Carbon Capture and Storage (CCS) Project (Sunflower Project) in Jefferson and Liberty Counties, Texas, to sequester CO_2 using three injection wells. This section for the Class VI Underground Injection Control (UIC) permit application for the proposed project was prepared to meet the requirements of Title 16, Texas Administrative Code (16 TAC), Part 1, Chapter 5, for plugging and abandonment (P&A) of the Sunflower CCS Project Injection Wells No. 01, No. 02, and No. 03. The purpose of the Injection Well Plugging Plan is to demonstrate the actions that ExxonMobil will take to mitigate potential impacts to underground sources of drinking water (USDWs) during the post-injection period.

For plugging the injection wells, ExxonMobil has selected materials that are compatible with the corrosive properties of the injection fluid to maintain the mechanical integrity of the plugs and well casing. The planned plugging procedures are aligned with best practices for restoring the upper confining zone (UCZ) integrity at each injection well location. As outlined in *Section 4 – Well Construction Plan and Operating Conditions*, ExxonMobil has a staged perforation schedule for the proposed injection wells to optimize the storage of CO_2. As a result, multiple injection-well workover events will be undertaken to isolate one injection stage to the next, prior to permanent abandonment operations. Once the storage capacity has been reached, the last injection stage and the remainder of the injection wells will be plugged for final abandonment.

6.2 Objectives

ExxonMobil will plug and abandon the proposed injection wells to restore the UCZ and provide a barrier sufficient to contain CO_2 and brine in the permitted injection zone—and to isolate the USDW.

The Injection Well Plugging Plan and procedures were designed to meet the following objectives:

- Measure the bottomhole reservoir pressure prior to conducting plugging activities (16 TAC **§5.203(k)(2)(B)**).
- Assess the mechanical integrity of the long string casing by using appropriate testing methods to demonstrate isolation consistent with 16 TAC **§5.203(k)(2)(C)**.
- Select the type, grade, and quantity of material to be used in plugging, to withstand contact with CO_2 and acidified liquids in the injection stages (16 TAC **§5.203(k)(1)(C)**).
- Detail the methods, locations, and types of plugs used within the wells (16 TAC **§5.203(k)(1)(B)** and **§5.203(k)(1)(D)**).

6.3 Preparation of Wells Prior to Plugging

ExxonMobil will repair deficiencies identified during the life of the proposed injection wells, to mitigate potential leaks to USDWs (16 TAC **§5.206(d)(2)(F)(ii)**). Historical mechanical integrity

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test (MIT) data and prior remedial measures will be considered prior to plugging operations. If required, those remedial activities will be included in an amendment to this plan.

6.3.1 Flushing the Well with Kill Weight Fluid

Pressure control will be accomplished using kill weight brine that is weighted and compatible with the injectate and formation fluids. The kill weight brine fluids will be circulated through the injection wells to remove fluids or fine debris that could have a significant impact on the integrity of cementing operations (16 TAC **§5.203(k)(2)(C)**).

6.3.2 Removal of Well Components and Obstructions

Prior to plugging, uncemented and non-permanent components of the wells will be removed. The surface and long string casings will be cemented to the surface during well construction per *Section 4 – Well Construction Plan and Operating Conditions* and will remain in place.

6.3.3 Planned Tests or Measures to Determine Bottomhole Pressure

Prior to each interim plug-back from total depth and prior to permanent abandonment, ExxonMobil will measure the bottomhole reservoir pressure using either the downhole pressure temperature (DHPT) gauge installed above the packer or other suitable means of pressure measurements. The bottomhole reservoir pressure will be used to estimate the density of kill weight brine needed to establish static equilibrium prior to plug placement.

6.3.4 Planned External MITs

The MIT will be used to identify the potential for significant fluid movement in the casing, tubing, or packer toward the USDW (16 TAC **§5.203(h)**). ExxonMobil will conduct at least one of the tests listed in Table 6-1 as part of the monitoring program, to verify external mechanical integrity as required in 16 TAC **§5.203(k)(2)(C)**. Note that internal mechanical integrity will be accomplished via pressure test.

Table 6- 1 – External MIT Methods

Test Description	Method of Testing
Temperature Log	Wireline Log
Distributed Temperature Sensing	Fiber Optic Reading
Casing Inspection Log	Wireline Log
Oxygen Activation Log	Wireline Log

The MIT results will be documented and provided to the UIC Program director.

6.3.5 CO_2-Compatible Materials

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In accordance with 16 TAC **§5.203(k)(1)(A)** and **§5.203(k)(1)(C)**, a cement that is compatible with CO_2 will be used in all cement plugs. ExxonMobil will evaluate potential cement options prior to implementing the cementing operations, with the intent to provide a barrier that can withstand the temperature, pressure, and chemical interactions.

The compilation of published research, experimental data, and industry experience highlighted in American Petroleum Institute (API) Bulletin 5100 provides technical clarity on the suitability of ordinary Portland cement (OPC) as a well construction material for CCS applications and other environments where it may be exposed to CO_2. While chemical and physical alterations do occur in the presence of carbonic acid—a product of the reaction between CO_2 and water—the rate and depth of alteration are negligible for long-term storage objectives. The preponderance of literature referenced in the bulletin concludes that, when sound well construction and cement placement techniques are followed and operationally induced wellbore stresses are considered, the alteration of OPC by CO_2 does not compromise well integrity— making OPC a barrier material that is sound in environments with highly saturated CO_2. Additionally, the literature referenced in the bulletin states that where minor defects of mechanical damage are present, the reaction products of CO_2 and OPC can exhibit self-healing properties.

Beyond this overall conclusion, API Bulletin 5100 (2025) also states that, "*While current literature and experimental data support the use of OPC in CO_2-exposed applications, this conclusion does not eliminate the need to account for site-specific well conditions when designing and optimizing OPC barrier systems. Factors that can affect performance include temperature exposure; post-set well stresses; formation lithologies; formation fluid compositions; and CO_2 stream composition*" (Wu, Stiles and Gupta 2025). These factors are addressed below.

Regarding temperature exposure, the maximum anticipated bottom hole temperature expected for the Sunflower wells is ~170˚ F API Bulletin 5100 Table 1 – Summary of Experimental Results of Alteration Rates of OPC Under Influence of CO2, shows a test case at ~170˚ F run on Class H cement. Based on the experiment, a penetration depth of 0.79m after 10,000 years (0.079 mm/yr.) was predicted.

Furthermore, ExxonMobil conducted internal testing of the impact of CO_2 on cement at 30- and 90- day durations and presented results supporting the conclusions of API Bulletin 5100 (2025) at a March 2025 CCUS SPE conference. ExxonMobil's experiment-based prediction of the carbonation rate results in less penetration than the noted API 5100 example.

To further evaluate long term effects, ExxonMobil repeated internal testing on cement samples at 180 days. The 180-day testing reaffirmed the findings of the 30- and 90-day tests and further supported the conclustions presented in API Bulletin 5100. In fact, the longer term 180-day testing indicates that carbonization occurs more slowly than predicted by extrapolation of short term data, as there was no significant increase in carbonization depth between test intervals. Additionally, all tested speciemens maintained sufficient compressive strength to qualify as a barrier under API cement barrier requirements.

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Importantly, alteration (penetration) should not be interpreted as degradation. Rather, it indicates the depth to which the cement and carbonic acid have reacted, or the depth to which carbonation of the cement has occurred. The reaction forms $CaCO_3$ (limestone) which is harder and less permeable than the original cement. Internal cement testing performed at 200^0F showed that the gas permeability of a Class H cement dropped from 0.016mD to 0.0015mD after 30 days of brine and CO_2 exposure. As per API Bulletin 5100 (2025), "*In practical terms, when OPC is used for zonal isolation in the annulus, the cement column is long enough that the extrapolated time required for CO_2 to migrate through the entire length of the cement sheath exceeds long-term storage objectives*."

Regarding stress, the primary stress will be from the original pressure test of the casing up to a maximum of 5000psi. Subsequent tests will be done to 200psi above injection pressure. The cement will be fully set at the time of pressure test with a minimum of eight hours waiting time. Note that while damage to the cement is not expected, cement bond logs will be run to verify cement quality and yearly mechanical integrity tests will be run to identify any potential behind pipe fluid migration.

Formation lithology across the injection interval consists of sand and shale intervals that will not impact the cement. Formation fluid is high salinity brine (100mg/L chlorides). The cement will not be exposed to the formation fluid during setting due to overbalance, mud filter cake, and cement fluid loss additive which aids in development of a filter cake for the cement. Once the well is perforated and cement is exposed to the brine, the chlorides in the brine will not react with the cement after it has been set.

Finally, the worst-case injection gas composition is CO_2: >97.0%, O_2: <50ppm, H_2S: <50ppm, SO_x: <15ppm | NO_x: <15ppm. API Bulletin 5100 (2025) addresses the interaction between the CO_2 and cement where a protective carbonated layer will develop which has lower permeability than the original cement. Cement is fully oxidized and O_2 will not react with it. To address H_2S and SO_x content in the injection gas, a high sulfate resistant Class H cement will be used to prevent post-set degradation due to sulfate alteration. Both H_2S and SO_x can react with the cement to form calcium sulfate (gypsum). Calcium sulfate then reacts with tricalcium aluminate in the cement to form a crystal that has potential to expand and impact cement quality. High sulfate resistant Class H cement limits the amount of allowable tricalcium aluminate in the cement to prevent significant sulfate damage. SO_x and NO_x mixed with water can lower the pH; however, the small amount available (<15ppm each) does not have a meaningful effect on the pH already altered by the CO_2.

Overall, both API Bulletin 5100 (2025) and ExxonMobil's internal testing support the conclusion that OPC-based cement systems remain suitable barrier materials for CO_2 service. The anticipated temperature, stress conditions, formation lithology, formation fluid composition, and injection gas composition for the Sunflower Facility fall within conditions for which OPC performance has been demonstrated to maintain long-term well integrity.

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While ExxonMobil deems OPC as the fit for purpose technical solution for the Sunflower CCS Project justified and supported by API 5100 and ExxonMobil's own 30-, 60-, and 180-day testing which has been provided to the Texas Railroad Commission, presented and published at industry conference, and both having been summarized in this permit, CorrosaCem – or suitable equivalent - is being proposed for the plug across the UCZ to address regulator feedback on any uncertainty of approval through the permitting process with OPC at the confining zone. *Section 4.4.3* in *Section 4 – Well Construction and Operating Conditions* presents additional discussion on OPC.

A list of common cement additives is provided in Table 6-2 for the blended Portland cement, to improve setting time, reduce porosity, and improve overall strength if needed. Not all additives listed will be utilized. ExxonMobil will provide specifics at the time of plugging, including additives utilized and cement density, and will retain in the plugging reports duplicate samples of the cement used for each plug.

Table 6- 2 – Common Cement Additives

Additive Type/Category	Common Additives
Fluid-loss additive	• Cellulosic polymers • Polyamines • Sulfonated aromatic polymers • Polyvinyl pyrrolidone • Polyvinyl alcohol • Acrylamide methyl propane sulfonate copolymers and terpolymers • Bentonite • Latexes • Crosslinked polyvinyl pyrrolidone
Dispersant	• Polynapthalene sulfonate • Polymelamine sulfonate
Retarder	• Lignosulfonates • Hydroxycarboxylic acids • Cellulose derivatives • Organophosphonates • Certain inorganic compounds
Accelerator	• Calcium chloride • Sodium chloride • Sodium silicates
Antifoam agent	• Polyglycol ethers • Silicones

6.3.6 Planned Site Restoration Activities

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After the injection wells have been plugged and abandoned, the wellhead equipment and surface facilities will be removed from the Sunflower Project site. The surface will be restored to a condition agreed upon by the landowner and by the UIC Director, as appropriate.

6.4 Injection Well Zonal Isolation and Final P&A

As discussed above, a plug will be set for injection zone isolation and the final P&A will occur at the end of the Sunflower Project. The following details outline the procedures for plugs to be installed. The volume and depth of the plugs will depend on the final geology and downhole conditions of the proposed injection wells as assessed during construction, as required by 16 TAC **§5.203(k)(1)(A)** and **§5.203(k)(1)(B)**.

6.4.1 Zonal Isolation and Intermediate Plug-Back Plan

The proposed injection wells will be completed in multiple intervals within the gross injection zone. Each injection interval will be used for a discrete period (or stage) as described in *Section 4 – Well Construction Plan and Operating Conditions*.

When a current completion interval has reached the end of its injection period for each well, that set of perforations will be isolated and abandoned. The general procedure for zonal isolation of completion stages within each injection well is defined below.

6.4.1.1 Pre-Zonal Isolation Activities

ExxonMobil will comply with reporting and notification provisions for the UIC Director, which require a 60-day advanced written notice before planned recompletion efforts are undertaken (16 TAC **§5.203(k)(3)(A)**). A similar notice of recompletion will be communicated to the Railroad Commission of Texas (TRRC).

Prior to initiating zonal isolation activities, the bottomhole reservoir pressure will be measured using the DHPT gauge installed above the packer (16 TAC **§5.203(k)(2)(A)**) or other appropriate methods. Schematics of the initial completion plans for the three proposed injection wells are presented in *Appendix D*.

6.4.1.2 Zonal Isolation Activities

A barrier will be set above the injection zone to be isolated. This is generally completed via a bridge plug or a permanent packer with plug-in nipple profile completed with approximately 20 feet of cement. The plug integrity will be assessed by conducting a pressure test or tagging. The perforations will not be squeezed.

6.4.2 Final P&A

After injection operations cease and post-operational monitoring in the injection wells is completed, the wells will be prepared for final P&A—the general procedures for which are described below.

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6.4.2.1 Pre-Plugging Activities (Notifications, Permits, and Inspections)

ExxonMobil will comply with reporting and notification provisions and provide written notification to the UIC Director 60 days before planned plugging efforts. If changes have been made to the original approved Injection Well Plugging Plan, ExxonMobil will provide the amended plan (16 TAC **§5.203(k)(3)(A)**). A Notice of Intention to Plug and Abandon Form W-3A will be submitted to the TRRC District Office 3 and the Austin Office at least 5 days before plugging operations are planned to commence. In accordance with 16 TAC **§5.203(k)(4)**, a plugging report will be submitted to the UIC Director and TRRC within 60 days after plugging. Plugging Record Form W-3 will be filed, in duplicate, with TRRC District Office 3 within 30 days after plugging.

6.4.2.2 Plugging Procedure, Injection Wells

The following sequence of plugging procedures is planned:

Please note, these plug depths referenced in Tables 6-3 through 6-6 are based off of water depths listed in the Groundwater Advisory Unit (GAU) letters for each injection well and will likely be amended once the wells are drilled. As such, plug depths may be revised to ensure proper isolation of each protected water strata as required under 16 TAC **§5.203(k) and §3.14**.

1. Check tubing and casing pressures. Determine the bottomhole pressure (BHP) and record measurable annulus pressures (16 TAC **§5.203(k)(2)(A)**).
2. Pump kill weight brine while not exceeding the maximum allowed surface injection pressure.
3. Rig up the slickline unit, run in hole with appropriate blanking plug into lower-profile nipple beneath the packer.
4. Move in and rig up the workover unit.
5. Release tubing from the packer.
6. Rig up slick line, dump 20 feet of cement on top of the packer.
7. Pull out and lay down 7-inch tubing and cables to the next cement plug depth.
8. Pump a minimum of 130 feet of blended CorrosaCem – or suitable equivalent - plug across the UCZ (16 TAC **§5.203(k)(1)**).
9. Pull out and lay down 7-inch tubing and cables to the next cement plug depth.
10. Pump a blended OPC balanced cement plug at the base of the surface casing with a 130-foot cement plug (16 TAC **§5.203(k)(1)**).
11. Pull out and lay down 7-inch tubing and cables to the next cement plug depth.
12. Pump a blended OPC balanced cement plug across the base of the USDW with a 130-foot cement plug (16 TAC **§5.203(k)(1)**).
13. Pull out and lay down 7-inch tubing and cables to the next cement plug depth.
14. Pump a blended OPC balanced cement plug across the base of usable quality water (BUQW) with a 130-foot cement plug (16 TAC **§5.203(k)(1)**).
15. Pull out and lay down 7-inch tubing and cables to the next cement plug depth.
16. Pump a blended OPC balanced cement plug at the base of the superior quality water (SQW) with a 130-foot cement plug (16 TAC **§5.203(k)(1)**).
17. Pull out and lay down 7-inch tubing and cables to the next cement plug depth.
18. Pump the surface cement plug with at least 30 feet of cement (16 TAC **§5.203(k)(1)**).
19. Cut and cap the casing to a minimum of 5 feet below ground level (16 TAC **§5.203(k)(1)**).

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20. Rig down and move off the location.
21. Perform site closure requirements (16 TAC **§5.203(m)**).

Note: All plug verification(s) (pressure test/tag) will be conducted as per regulatory requirements

6.4.2.3 Plugging Details, Injection Well No. 01

Table 6-3 provides the plugging details for Injection Well No. 01 (16 TAC **§5.203(k)(1)(A)**, **§5.203(k)(1)(B)**, **§5.203(k)(1)(C)**, and **§5.203(k)(1)(D)**); *Appendix F* shows the final plugged schematic.

Table 6- 3– Plugging Details for Injection Well No. 01

Plugging Description	UCZ Plug	Surface Casing Shoe Plug	USDW Plug*	BUQW Plug*	SQW Plug*	Surface Plug
Plug Number	1	2	3	4	5	6
Diameter of Boring in Which Plug Will Be Placed	8.681 in.	8.681 in.	8.681 in.	8.681	8.681 in.	8.681 in.
Depth to Bottom of Tubing or Drill Pipe or Mechanical Base (MD)	3,455 ft KB	2,950 ft KB	2,750 ft KB	2,500 ft KB	900 ft KB	30 ft KB
Sacks of Cement to Be Used (each plug)	48	52	52	52	52	11
Slurry Volume to Be Pumped (bbl)	9.5	9.5	9.5	9.5	9.5	2
Slurry Weight (lb/gal)[1]	15.0-16.5	15.0-16.5	15.0-16.5	15.0-16.5	15.0-16.5	15.0-16.5
Top of Plug (MD)	3,325 ft KB	2,820 ft KB	2,620 ft KB	2,370 ft KB	770 ft KB	0 ft KB
Bottom of Plug (MD)	3,455 ft KB	2,950 ft KB	2,750 ft KB	2,500 ft KB	900 ft KB	30 ft KB
Type of Cement or Other Material	CorrosaCem	Portland	Portland	Portland	Portland	Portland
Method of Emplacement	Circulation	Circulation	Circulation	Circulation	Circulation	Circulation
New Plug?	Yes	Yes	Yes	Yes	Yes	Yes

bbl = barrels; lb/gal = pounds per gallon; MD = measured depth from kelly bushing (KB)
[1] Proposed slurry density may be modified as needed due to field conditions and vendor availability.
Depth of plugs to be determined at time of operations.
*To be determined by the GAU upon drilling of well

6.4.2.4 Plugging Details, Injection Well No. 02

Table 6-4 provides the plugging details for Injection Well No. 02 (16 TAC **§5.203(k)(1)(A)**, **§5.203(k)(1)(B)**, **§5.203(k)(1)(C)**, and **§5.203(k)(1)(D)**); *Appendix F* shows the final plugged schematic.

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Table 6- 4– Plugging Details for Injection Well No. 02

Plugging Description	UCZ Plug	Surface Casing Shoe Plug	USDW Plug*	BUQW Plug*	SQW Plug*	Surface Plug
Plug Number	1	2	3	4	5	6
Diameter of Boring in Which Plug Will Be Placed	8.681 in.	8.681 in.	8.681 in.	8.681 in.	8.681 in.	8.681 in.
Depth to Bottom of Tubing or Drill Pipe or Mechanical Base (MD)	3,446 ft KB	2,270 ft KB	2,000 ft KB	1,750 ft KB	900 ft KB	30 ft KB
Sacks of Cement to Be Used (each plug)	48	52	52	52	52	11
Slurry Volume to Be Pumped (bbl)	9.5	9.5	9.5	9.5	9.5	2
Slurry Weight (lb/gal)[1]	15.0-16.5	15.0-16.5	15.0-16.5	15.0-16.5	15.0-16.5	15.0-16.5
Top of Plug (MD)	3,316 ft KB	2,140 ft KB	1,870 ft KB	1,620 ft KB	770 ft KB	0 ft KB
Bottom of Plug (MD)	3,446 ft KB	2,270 ft KB	2,000 ft KB	1,750 ft KB	900 ft KB	30 ft KB
Type of Cement or Other Material	CorrosaCem	Portland	Portland	Portland	Portland	Portland
Method of Emplacement	Circulation	Circulation	Circulation	Circulation	Circulation	Circulation
New Plug?	Yes	Yes	Yes	Yes	Yes	Yes

[1] Proposed slurry density may be modified as needed due to field conditions and vendor availability.
Depth of plugs to be determined at time of operations.
*To be determined by the GAU upon drilling of well

6.4.2.5 Plugging Details, Injection Well No. 03

Table 6-5 provides the plugging details for Injection Well No. 03 (16 TAC **§5.203(k)(1)(A)**, **§5.203(k)(1)(B)**, **§5.203(k)(1)(C)**, and **§5.203(k)(1)(D)**); *Appendix F* shows the final plugged schematic.

Table 6- 5– Plugging Details for Injection Well No. 03

Plugging Description	UCZ Plug	Surface Casing Shoe Plug	USDW Plug*	BUQW Plug*	SQW Plug*	Surface Plug
Plug Number	1	2	3	4	5	6
Diameter of Boring in which Plug Will Be Placed	8.681 in.	8.681 in.	8.681 in.	8.681 in.	8.681 in.	8.681 in.
Depth to Bottom of Tubing or Drill Pipe	3,475 ft KB	2,200 ft KB	2,000 ft KB	1,750 ft KB	900 ft KB	30 ft KB

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Plugging Description	UCZ Plug	Surface Casing Shoe Plug	USDW Plug*	BUQW Plug*	SQW Plug*	Surface Plug
or Mechanical Base (MD)						
Sacks of Cement to Be Used (each plug)	48	52	52	52	52	11
Slurry Volume to Be Pumped (bbl)	9.5	9.5	9.5	9.5	9.5	2
Slurry Weight (lb/gal)[1]	15.0-16.5	15.0-16.5	15.0-16.5	15.0-16.5	15.0-16.5	15.0-16.5
Top of Plug (MD)	3,345 ft KB	2,070 ft KB	1,870 ft KB	1,620 ft KB	770 ft KB	0 ft KB
Bottom of Plug (MD)	3,475 ft KB	2,200 ft KB	2,000 ft KB	1,750 ft KB	900 ft KB	30 ft KB
Type of Cement or Other Material	CorrosaCem	Portland	Portland	Portland	Portland	Portland
Method of Emplacement	Circulation	Circulation	Circulation	Circulation	Circulation	Circulation
New Plug?	Yes	Yes	Yes	Yes	Yes	Yes

[1] Proposed slurry density may be modified as needed due to field conditions and vendor availability.
Depth of plugs to be determined at time of operations.
*To be determined by the GAU upon drilling of well

6.5 Notifications and Record Keeping

The procedures described above are subject to modification during execution, as necessary, for implementation of plugging operations that protect worker safety and the USDW. ExxonMobil will submit a revised plan to the UIC director in the event it finds it necessary to change the approved plugging plan. Completed plugging forms, records, and lab information will be supplied to the regulatory agencies as required by the permit. The plugging report will be certified as accurate by ExxonMobil and the plugging contractor and will be submitted to the UIC Director and EPA Region 6 (16 TAC**§5.207(b)(2)**) within 60 days after plugging is completed (16 TAC **§5.203(k)(4)**).

Well plugging reports, post-injection site care data (including data and information used to develop the demonstration of the alternative post-injection site care time frame), and the site closure report collected pursuant to the requirements in 16 TAC **§5.203(k)(6)**) and **§5.203(m)**, will be retained by ExxonMobil. Site closure and reporting are discussed in *Section 7 – Post-Injection Site Care and Site Closure Plan*.

The plugging report will provide the following information:

- Results of tests to determine BHP and mechanical integrity
- Type and number of plugs used
- Cement type, grade, weight, and quantity of material for plugs

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- Method of cement plug emplacement
- Top and bottom of each cement plug

6.6 Monitoring Well P&A

The Sunflower IZM/AZM No. 01 monitoring well and Sunflower AZM Nos. 01 and 02 will be plugged in accordance with 16 TAC **§5.203(k)** to not allow movement of injection or formation fluids that could endanger USDWs. Specific monitoring wells will remain in place after the proposed injection wells have been plugged and abandoned for use in monitoring activities associated with the Post-Injection Site Care and Site Closure Plan. ExxonMobil will assess the monitoring well plugging procedures prior to P&A in relation to this plan. Documentation of appropriate P&A of the monitoring wells will be submitted to the UIC Director in accordance with 16 TAC **§5.203(k)(4)**. The USDW monitoring wells do not penetrate the BUQW and will be plugged in accordance with 16 TAC Chapter 76 and certified at the time of plugging (16 TAC **§5.203(k)(5) and** 16 TAC **§5.203(k)(6)**) unless the landowner's preference is to take ownership.

6.6.1 Plugging Details, Deep Monitoring Wells

Tables 6-6 and 6-7 provide the plugging details for Sunflower AZM/IZM No. 01 and Sunflower AZM Nos. 01 and 02 (16 TAC **§5.203(k)(1)(A)**, **§5.203(k)(1)(B)**, **§5.203(k)(1)(C)**, and **§5.203(k)(1)(D)**); *Appendix F* shows the final plugged schematics.

Table 6- 6– Plugging Details for Sunflower AZM/IZM No. 01

Plugging Description	UCZ Plug	Surface Casing Shoe Plug	USDW Plug*	BUQW Plug*	SQW Plug*	Surface Plug
Plug Number	1	2	3	4	5	6
Diameter of Boring in which Plug Will Be Placed	4.778 in.	4.778 in.	4.778 in.	4.778 in.	4.778 in.	4.778 in.
Depth to Bottom of Tubing or Drill Pipe or Mechanical Base (MD)	3,482 ft KB	2,334 ft KB	1,800 ft KB	1,500 ft KB	850 ft KB	30 ft KB
Sacks of Cement to Be Used (each plug)	15	16	16	16	16	6
Slurry Volume to Be Pumped (bbl)	2.9	2.9	2.9	2.9	2.9	1
Slurry Weight (lb/gal)[1]	15.0-16.5	15.0-16.5	15.0-16.5	15.0-16.5	15.0-16.5	15.0-16.5
Top of Plug (MD)	3,352 ft KB	2,204 ft KB	1,670 ft KB	1,370 ft KB	720 ft KB	0 ft KB
Bottom of Plug (MD)	3,482 ft KB	2,334 ft KB	1,800 ft KB	1,500 ft KB	850 ft KB	30 ft KB

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Plugging Description	UCZ Plug	Surface Casing Shoe Plug	USDW Plug*	BUQW Plug*	SQW Plug*	Surface Plug
Type of Cement or Other Material	CorrosaCem	Portland	Portland	Portland	Portland	Portland
Method of Emplacement	Circulation	Circulation	Circulation	Circulation	Circulation	Circulation
New Plug?	Yes	Yes	Yes	Yes	Yes	Yes
[1] Proposed slurry density may be modified as needed due to field conditions and vendor availability. Depth of plugs to be determined at time of operations. *To be determined by the GAU upon drilling of well						

Table 6- 7– Plugging Details for Sunflower AZM No. 01

Plugging Description	Surface Casing Shoe Plug	USDW Plug*	BUQW Plug*	SQW Plug*	Surface Plug
Plug Number	1	2	3	4	5
Diameter of Boring in which Plug Will Be Placed	4.778 in.	4.778 in.	4.778 in.	4.778 in.	4.778 in.
Depth to Bottom of Tubing or Drill Pipe or Mechanical Base (MD)	2,950 ft KB	2,750 ft KB	2,500 ft KB	900 ft KB	30 ft KB
Sacks of Cement to Be Used (each plug)	16	16	16	16	6
Slurry Volume to Be Pumped (bbl)	2.9	2.9	2.9	2.9	1
Slurry Weight (lb/gal)[1]	15.0-16.5	15.0-16.5	15.0-16.5	15.0-16.5	15.0-16.5
Top of Plug (MD)	2,820 ft KB	2,620 ft KB	2,370 ft KB	770 ft KB	0 ft KB
Bottom of Plug (MD)	2,950 ft KB	2,750 ft KB	2,500 ft KB	900 ft KB	30 ft KB
Type of Cement or Other Material	Portland	Portland	Portland	Portland	Portland
Method of Emplacement	Circulation	Circulation	Circulation	Circulation	Circulation
New Plug?	Yes	Yes	Yes	Yes	Yes

Table 6- 8– Plugging Details for Sunflower AZM No. 02

Plugging Description	Surface Casing Shoe Plug	USDW Plug*	BUQW Plug*	SQW Plug*	Surface Plug
Plug Number	1	2	3	4	5
Diameter of Boring in which Plug Will Be Placed	4.778 in.	4.778 in.	4.778 in.	4.778 in.	4.778 in.
Depth to Bottom of Tubing or Drill Pipe or Mechanical Base (MD)	2,270 ft KB	2,000 ft KB	1,750 ft KB	900 ft KB	30 ft KB

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Plugging Description	Surface Casing Shoe Plug	USDW Plug*	BUQW Plug*	SQW Plug*	Surface Plug
Sacks of Cement to Be Used (each plug)	16	16	16	16	6
Slurry Volume to Be Pumped (bbl)	2.9	2.9	2.9	2.9	1
Slurry Weight (lb/gal)[1]	15.0-16.5	15.0-16.5	15.0-16.5	15.0-16.5	15.0-16.5
Top of Plug (MD)	2,140 ft KB	1,870 ft KB	1,620 ft KB	770 ft KB	0 ft KB
Bottom of Plug (MD)	2,270 ft KB	2,000 ft KB	1,750 ft KB	900 ft KB	30 ft KB
Type of Cement or Other Material	Portland	Portland	Portland	Portland	Portland
Method of Emplacement	Circulation	Circulation	Circulation	Circulation	Circulation
New Plug?	Yes	Yes	Yes	Yes	Yes

6.6.2 Plugging Procedure for the Sunflower AZM/IZM No. 01

1. Check casing pressures. Determine BHP via appropriate methods and record measurable annulus pressures. Move in and rig up the workover unit.
2. Run in hole with cement stinger to UCZ plug depth. Pump 130 feet of blended CorrosaCem – or suitable equivalent - balanced cement plug.
3. Pull out of hole to next cement plug depth. Pump 130 feet of blended OPC balanced cement plug across the shoe of the 9 5/8-inch casing.
4. Pull out of hole to next cement plug depth. Pump 130 feet of blended OPC balanced cement plug across the across the base of the USDW.
5. Pull out of hole to next cement plug depth. Pump 130 feet of blended OPC balanced cement plug across the across the base of the BUQW.
6. Pull out of hole to next cement plug depth. Pump 130 feet of blended OPC balanced cement plug across the across the base of the SQW.
7. Pull out of hole to next plug. Pump surface cement plug with at least 30 feet of OPC.
8. Cut and cap casing to a minimum of 5 feet below the ground level.
9. Rig down and move off of the location.
10. Perform site closure requirements (16 TAC §5.203(m)).

Note: All plug verification(s) (pressure test/tag) will be conducted as per regulatory requirements

6.6.3 Plugging Procedure for the Sunflower AZM Nos. 01 and 02

1. Check casing pressures. Determine BHP via appropriate methods and record measurable annulus pressures. Move in and rig up the workover unit.
2. Unsting the packer and pull out with the tubing.
3. Run in hole with cement stinger to surface shoe. Pump 130 feet of blended OPC balanced cement plug across the shoe of the 9 5/8-inch casing.
4. Pull out of hole to next cement plug depth. Pump 130 feet of blended OPC balanced cement plug across the across the base of the USDW.
5. Pull out of hole to next cement plug depth. Pump 130 feet of blended OPC balanced cement plug across the across the base of the BUQW.

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6. Pull out of hole to next cement plug depth. Pump 130 feet of blended OPC balanced cement plug across the across the base of the SQW.
7. Pull out of hole to next plug. Pump surface cement plug with at least 30 feet of OPC.
8. Cut and cap casing to a minimum of 5 feet below the ground level.
9. Rig down and move off of the location.
10. Perform site closure requirements (16 TAC §5.203(m)).

Note: All plug verification(s) (pressure test/tag) will be conducted as per regulatory requirements

6.6.4 Plugging Procedure for the Sunflower USDW Nos. 01, 02, and 03

The Sunflower USDW No. 01 through 03 will be plugged and certified in accordance with the requirements of 16 TAC Chapter 76 unless the landowner wishes to take ownership.

6.7 Amendments to the P&A Plan

The Injection Well Plugging Plan will be amended to account for changes in conditions that trigger modification to the area of review. ExxonMobil will inquire with the UIC Director to confirm whether such changes in condition warrant amendments to this plan. If changes have been made to the plan, the revised plan will be submitted when notifying the UIC Director of the intent to plug the well at least 60 days prior to conducting the plugging activity per 16 TAC **§5.203(k)(3)(A)**.

Appendix F – Injection Well Plugging Plan

Appendix F-1: Plugging Wellbore Schematics

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Appendix F – Injection Well Plugging Plan

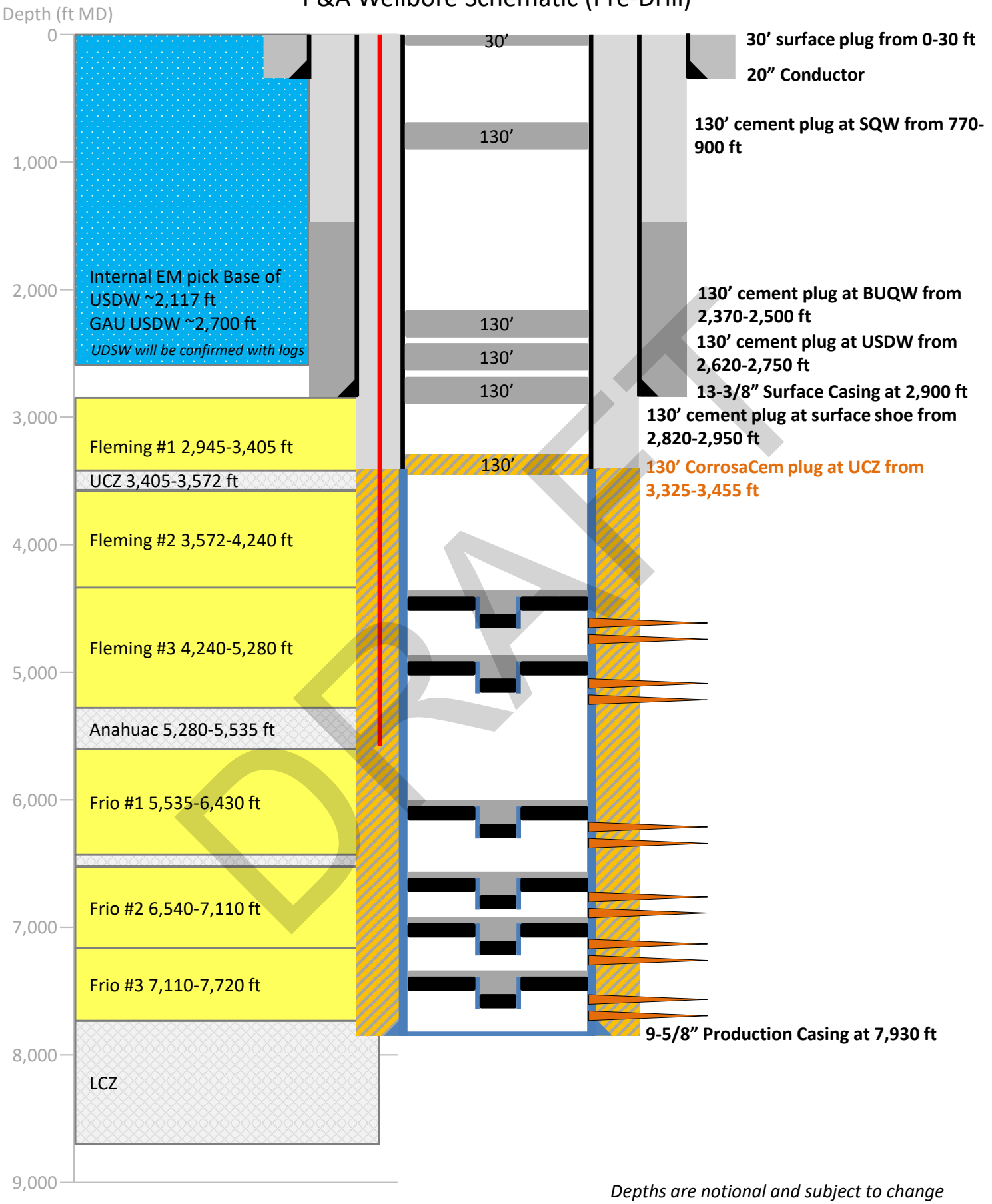
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Appendix F1 – Plugging Wellbore Schematics

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Sunflower CCS Project Injection Well No. 01

P&A Wellbore Schematic (Pre-Drill)



Depths are notional and subject to change based on as-drilled conditions

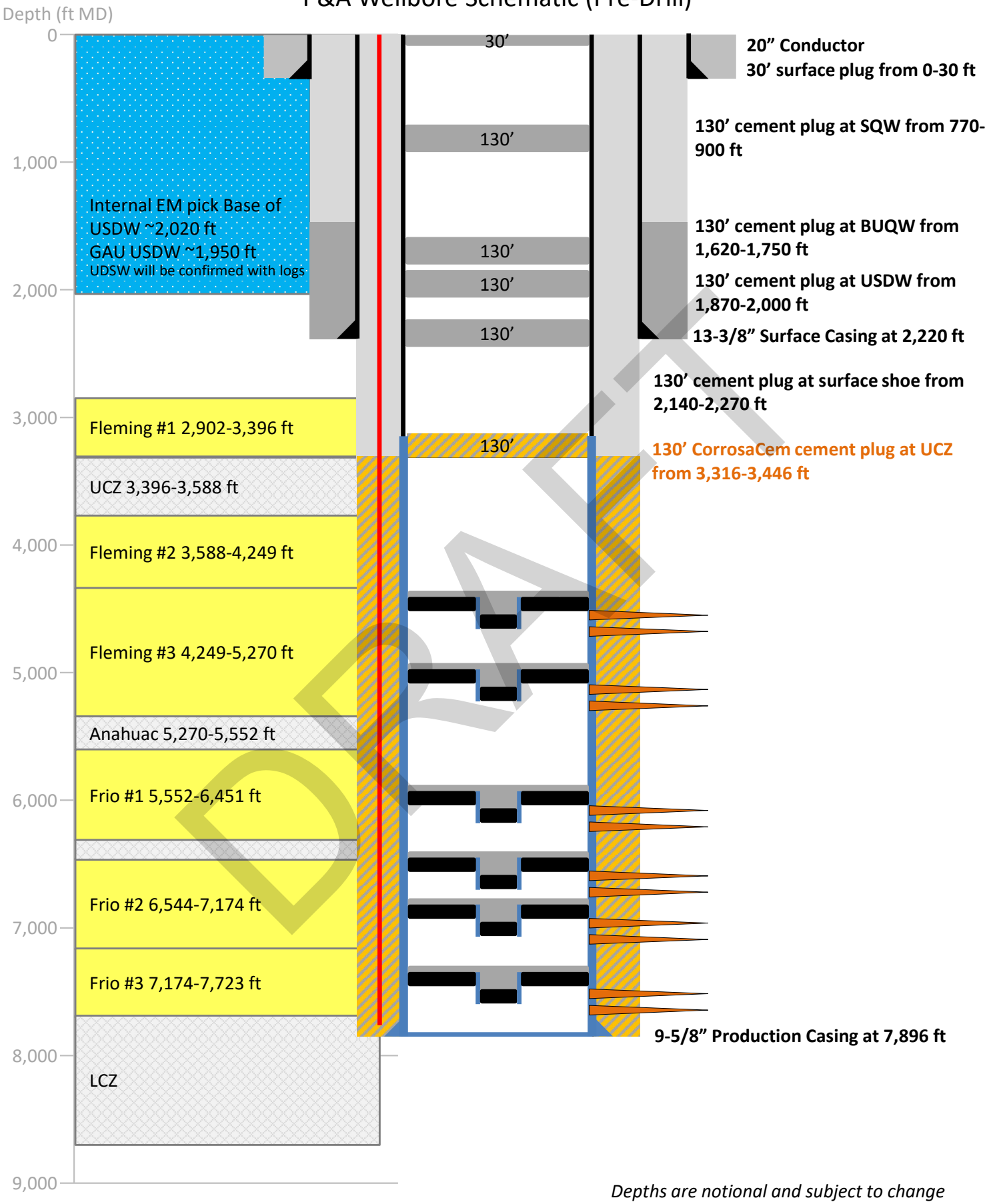
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Sunflower CCS Project Injection Well No. 02

P&A Wellbore Schematic (Pre-Drill)



Depths are notional and subject to change based on as-drilled conditions

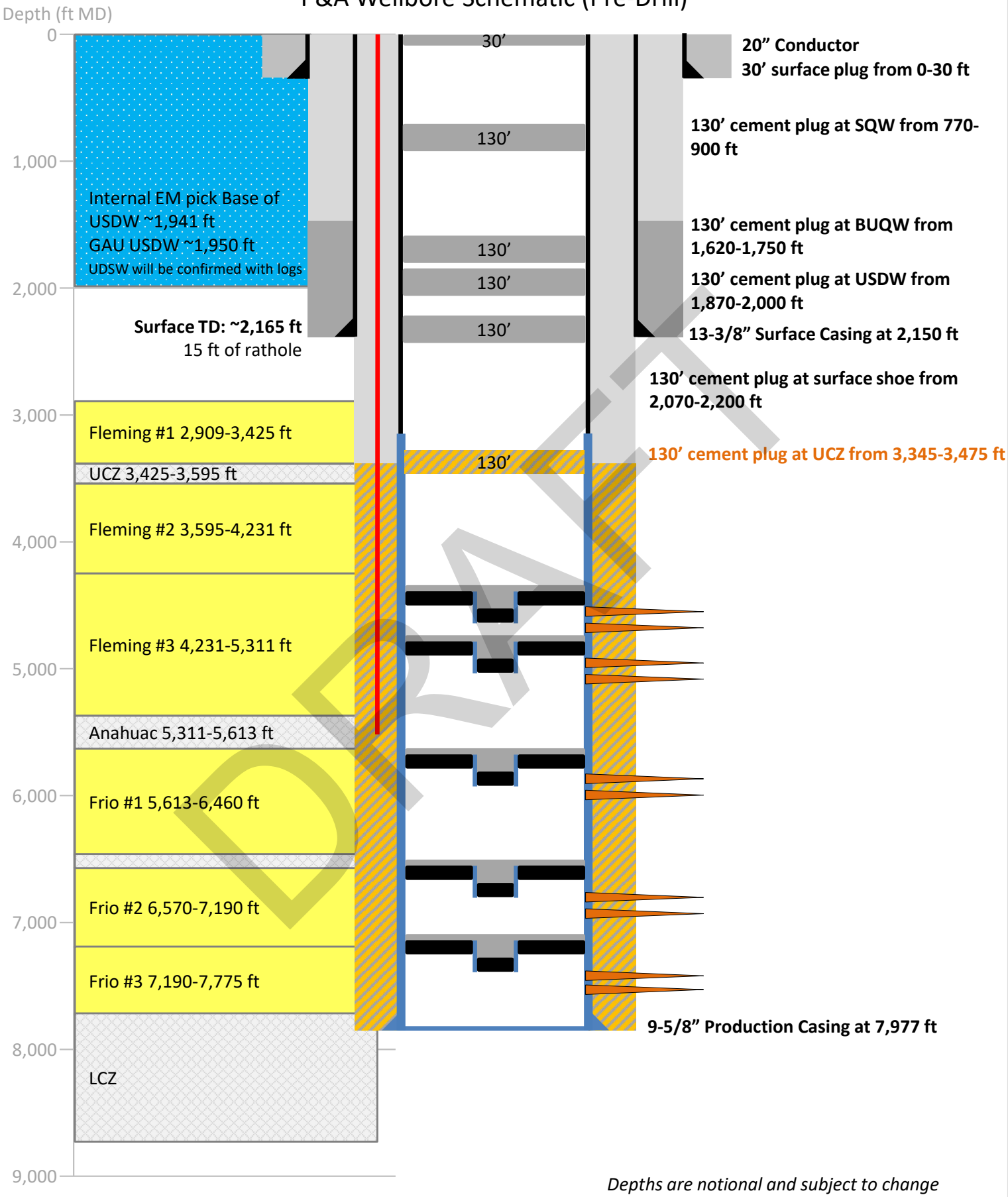
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Sunflower CCS Project Injection Well No. 03

P&A Wellbore Schematic (Pre-Drill)



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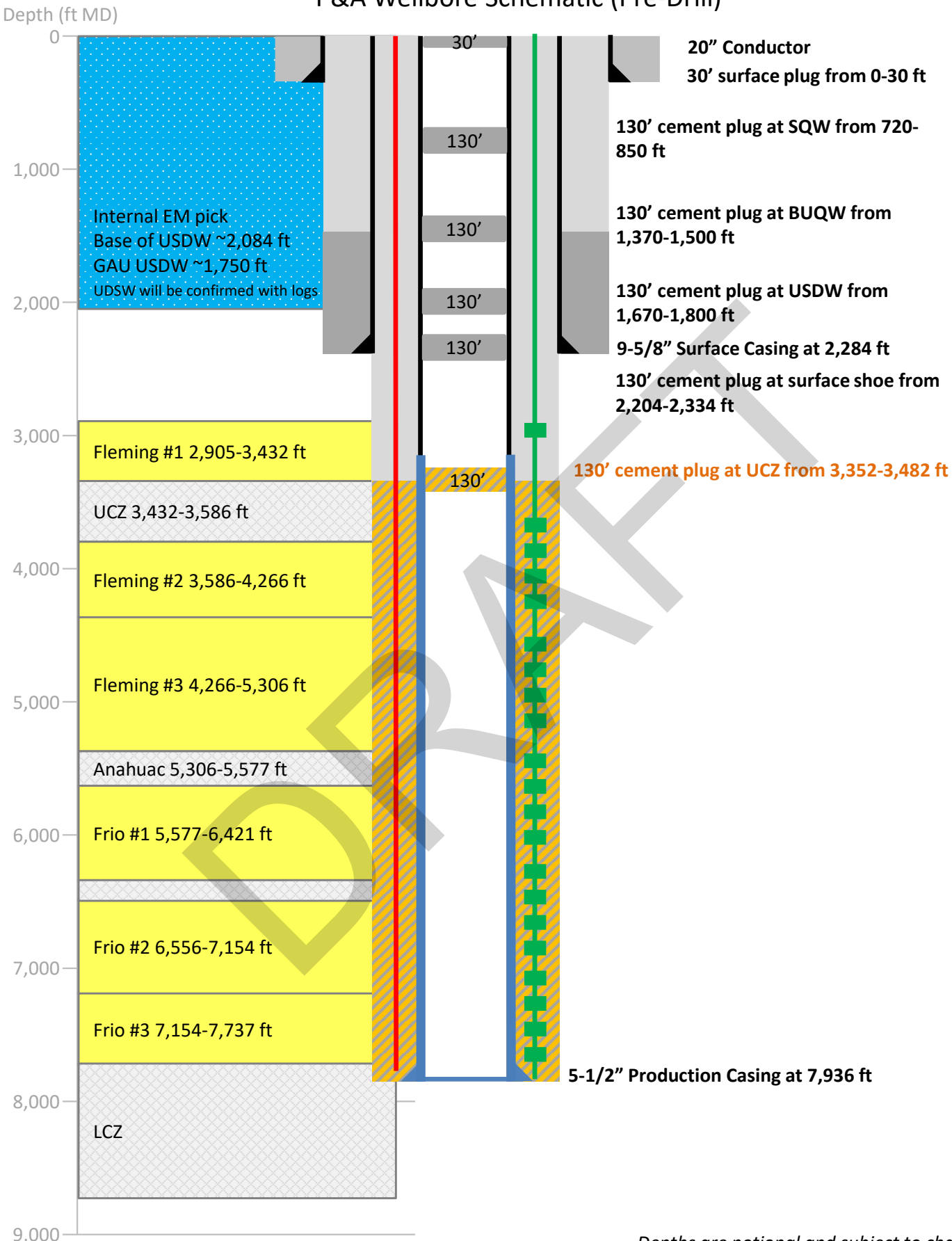
Depths are notional and subject to change based on as-drilled conditions

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Sunflower AZM/IZM Well No. 01

P&A Wellbore Schematic (Pre-Drill)



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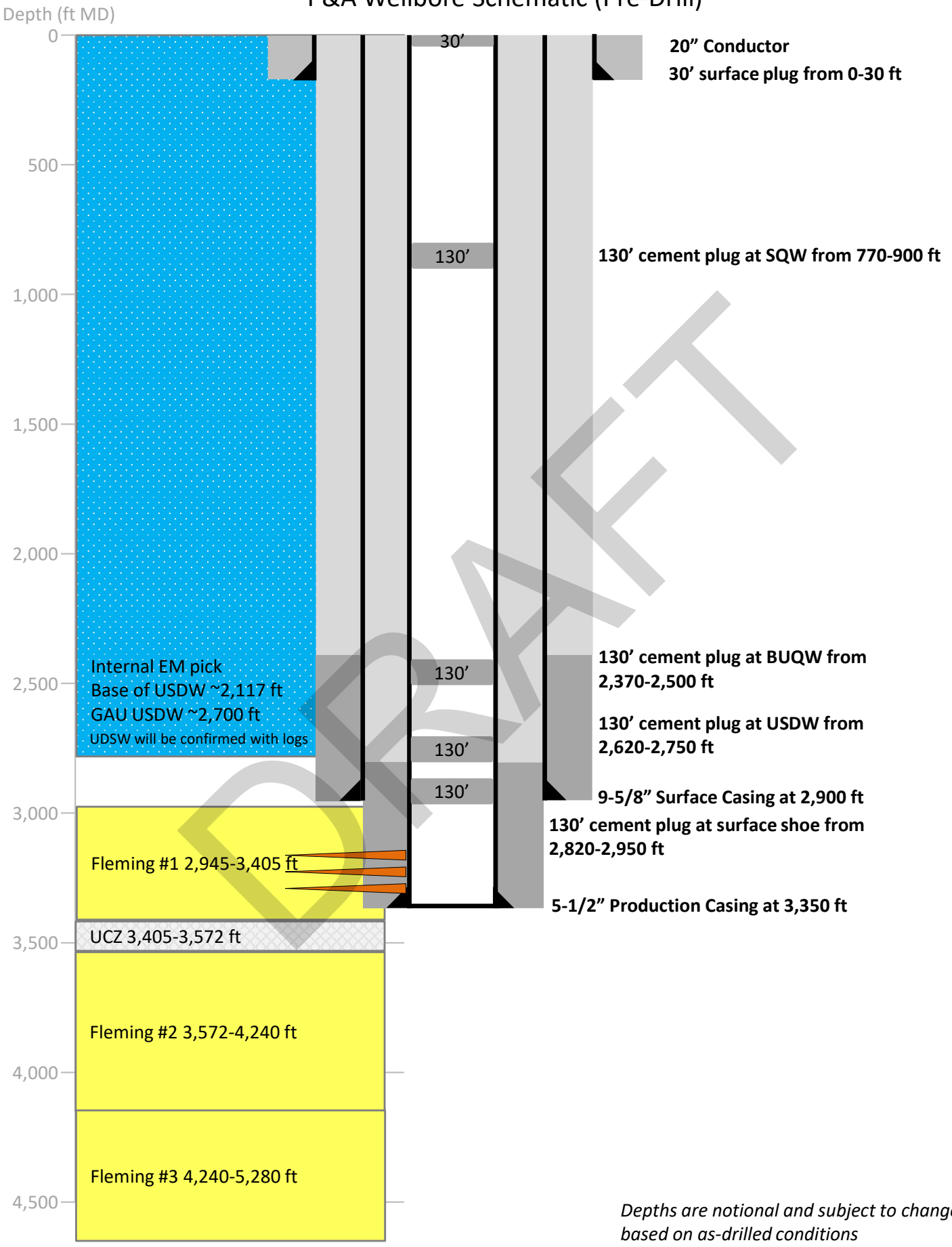
Depths are notional and subject to change based on as-drilled conditions

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Sunflower AZM Well No. 01 – Injector 1 Pad

P&A Wellbore Schematic (Pre-Drill)



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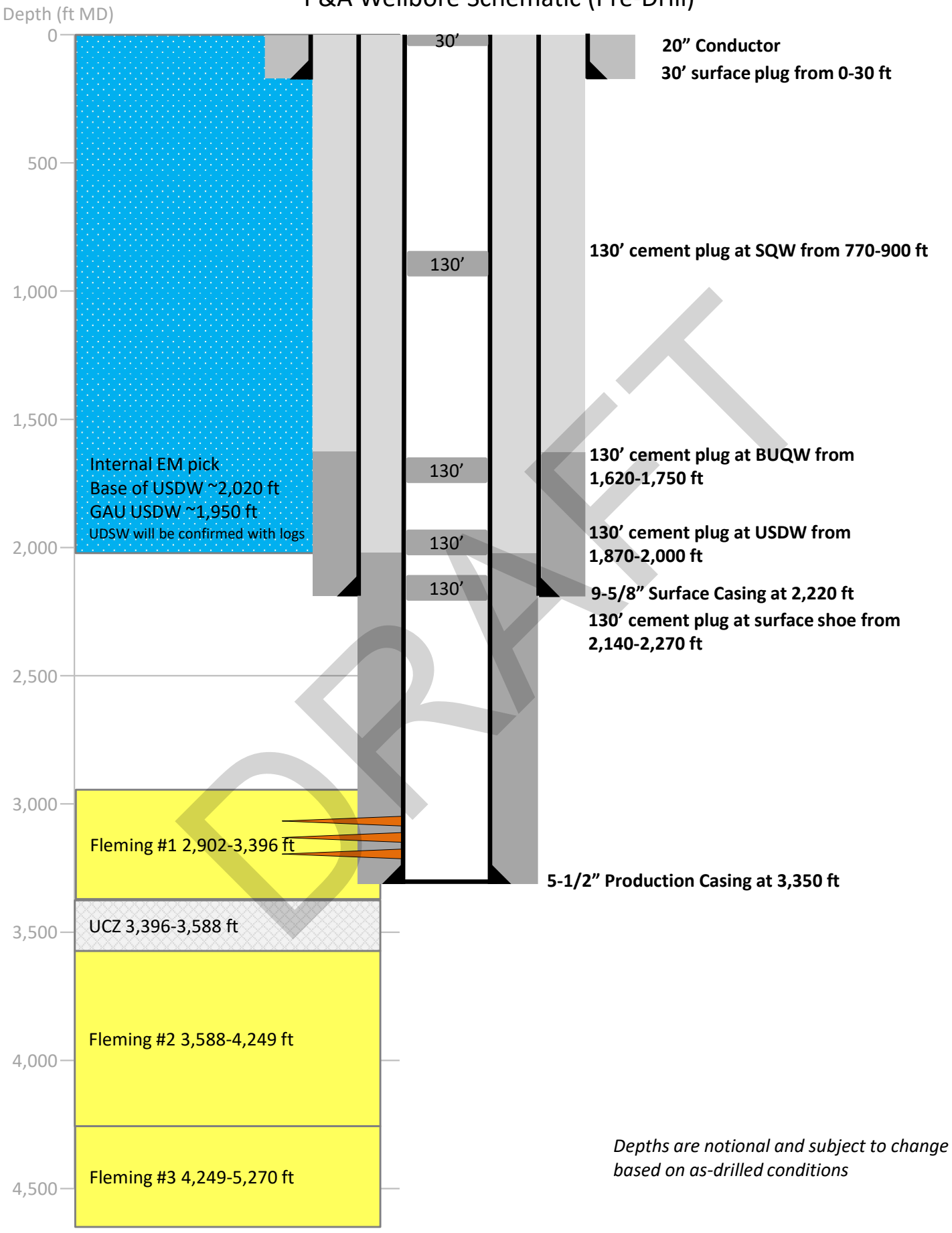
Depths are notional and subject to change based on as-drilled conditions

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Sunflower 2 AZM No. 02

P&A Wellbore Schematic (Pre-Drill)



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Depths are notional and subject to change based on as-drilled conditions

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Railroad Commission of Texas

Attachment H – Emergency and Remedial Response Plan

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Underground Injection Control – Class VI Permit Application for Sunflower Carbon Capture and Storage Project Injection Wells No. 01, No. 02, and No. 03

SECTION 8 – EMERGENCY AND REMEDIAL RESPONSE PLAN

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Sunflower Carbon Capture and Storage Project
Jefferson and Liberty Counties, Texas
ExxonMobil Low Carbon Solutions Onshore Storage, LLC
Amendment 3: August 2026

SECTION 8 – EMERGENCY AND REMEDIAL RESPONSE PLAN

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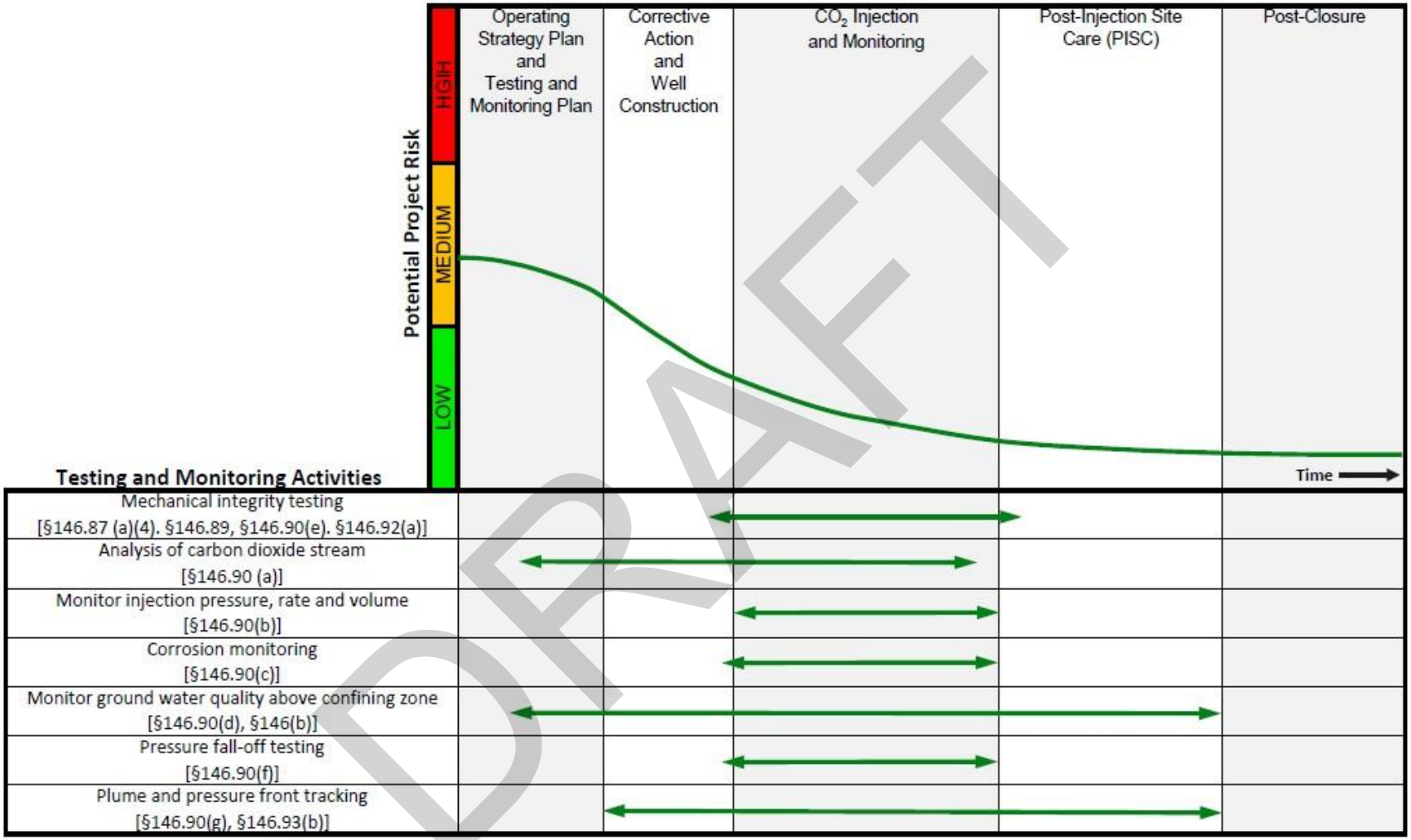
8.1 Emergency and Remedial Response Plan

This Emergency and Remedial Response Plan (ERRP) accounts for the entire AOR and was developed in compliance with the requirements of Title 16, Texas Administrative Code (16 TAC), Part 1, Chapter 5, to develop and maintain an ERRP that describes actions to be taken to address movement of the injection or formation fluids that may cause endangerment to an underground source of drinking water (USDW) during the construction, operation, and post-injection site care periods of the Sunflower Carbon Capture and Storage (CCS) Project (Sunflower Project). Under 16 TAC **§5.203(j)(2)(E)**), the actions described in the ERRP are to be implemented immediately to address a rare event where the movement of the injection fluid or formation fluid endangers a USDW. ExxonMobil Low Carbon Solutions Onshore Storage, LLC (ExxonMobil) prepared this ERRP to provide both the scope of actions to be taken and the schedule under which the actions would be expected to be implemented.

ExxonMobil is undertaking the project in Jefferson and Liberty Counties, Texas, to sequester approximately 25.3 million metric tons (MMT) of CO_2 over 11 years. The ERRP was developed for injection of CO_2 into the proposed Sunflower Project Injection Wells No. 01, No. 02, and No. 03.

ExxonMobil will use engineering design and planning safeguards (Figure 8-1) to reduce the potential for the occurrence of a rare emergency and remedial response event. These steps are based on ExxonMobil's global experience and expertise with risk management for rare events in site selection, well drilling and completion, and reservoir operations. Additionally, the site will employ the use of gates and locks to provide security measures against unauthorized activity pursuant to 16 TAC **§5.203(l)(3)(B)**.

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Figure 8-1 – Testing and Monitoring Safeguards

8.2 Overview

ExxonMobil took the findings from *Section 1 – Site Characterization* and *Section 3 – Area of Review and Corrective Action Plan* and identified hypothetical risk scenarios that could—in the rare event of occurrence—pose a threat to USDWs. ExxonMobil's risk assessment process was used to estimate the probability and consequence of each risk scenario based on the experience and judgment of the risk subject matter experts for the project. The ERRP will apply over the life of the project, including throughout the post-injection site care period per 16 TAC **§5.203(l)**.

This ERRP describes the actions that ExxonMobil plans to perform in the event of an emergency that could endanger public health and safety or any USDW during the construction, operation, or post-injection site care periods.

If ExxonMobil obtains verified evidence that the injected CO_2 stream and associated pressure front may cause an endangerment to a USDW, ExxonMobil will perform the following actions:

1. Initiate the shutdown plan for the injection well(s).
2. Take all steps reasonably necessary to identify and characterize the release.
3. Notify the permitting agency's Underground Injection Control (UIC) Program director (UIC Director) of the emergency event within 24 hours.
4. Implement the approved ERRP.
5. Prepare and submit an incident report to the UIC Director

Where the phrase "initiate the shutdown plan" is used, the following protocol will be employed. First, ExxonMobil will implement the steps needed to immediately cease injection. In some circumstances (e.g., for safety reasons), ExxonMobil will, in consultation with the UIC Director, gradually ramp down injection as appropriate as part of the process of immediately ceasing injection. Additionally, ExxonMobil will coordinate with the UIC Director to determine if an emergency scenario does not warrant shutdown for the wells (e.g., because there is not an endangerment to a USDW).

8.3 Identification of Resources and Infrastructure in AOR and Flood Hazard Risk

Figure 8-2 illustrates resources and infrastructure near the area of review (AOR). As shown, the resources and infrastructure are primarily related to agricultural crop production and undeveloped rural acreage with some residential development. The infrastructure development is primarily in the form of county roads, pipelines, and power transmission lines to service the developed areas.

Figure 8-3 displays the proposed injection wells and the AOR with respect to flood hazard areas. There is digital coverage of the FEMA flood hazard layer for Liberty County, but not Jefferson County. Jefferson County flood zones are shown using georeferenced FIRM panels. Sunflower INJ No. 01 is Zone X (unshaded), which corresponds to areas determined to be outside of the 500-year floodplain (0.2% annual chance of a flood). Sunflower INJ No. 02 is in

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Zone A2, which is an area of 100-year flood. Sunflower INJ No. 03 is in Zone C, which is defined as an area of minimal flooding. The three injection wells are, therefore, located in areas of minimal flood hazard.

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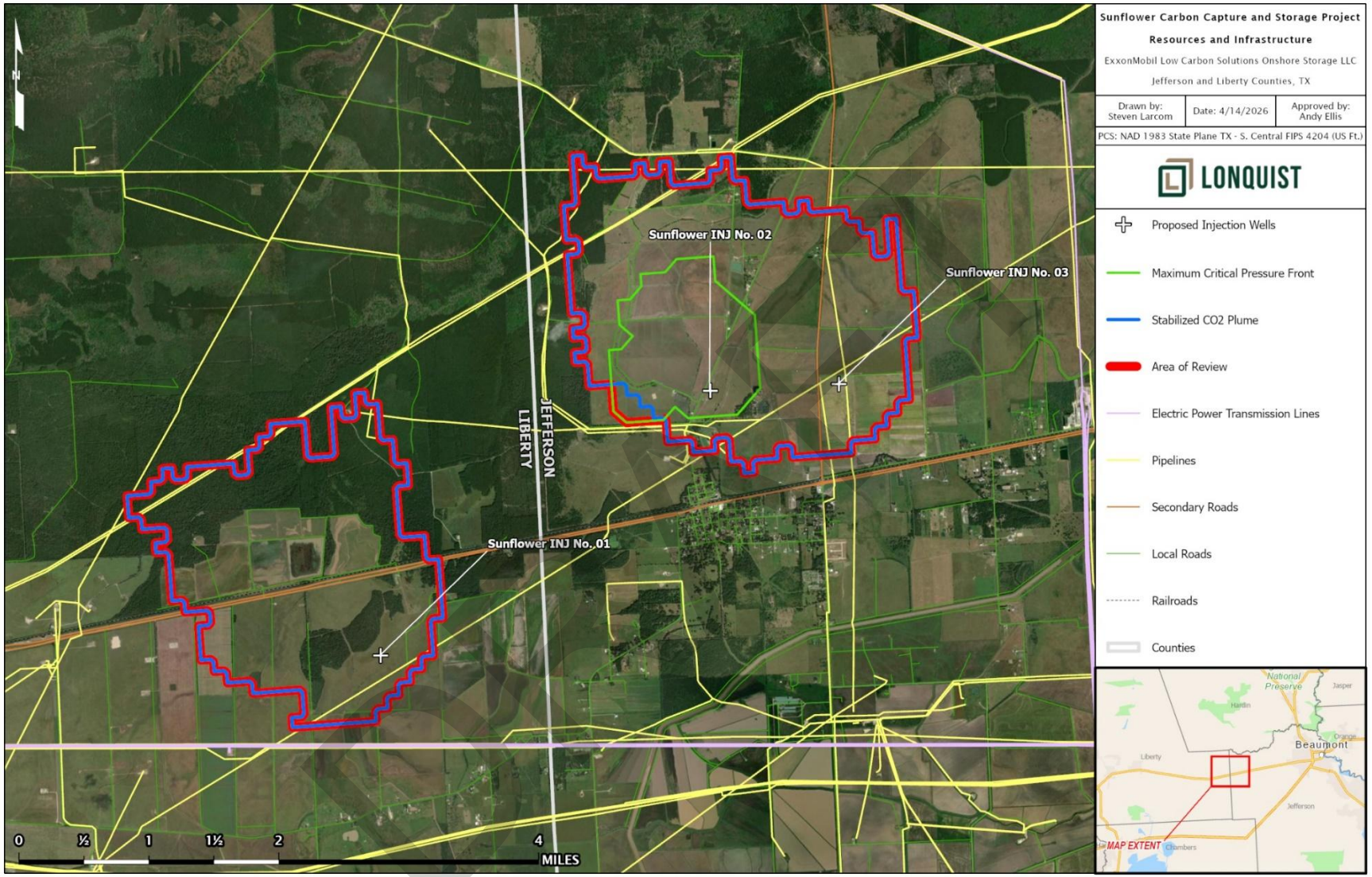


Figure 8-2 – Map of Resources and Infrastructure Within the AOR

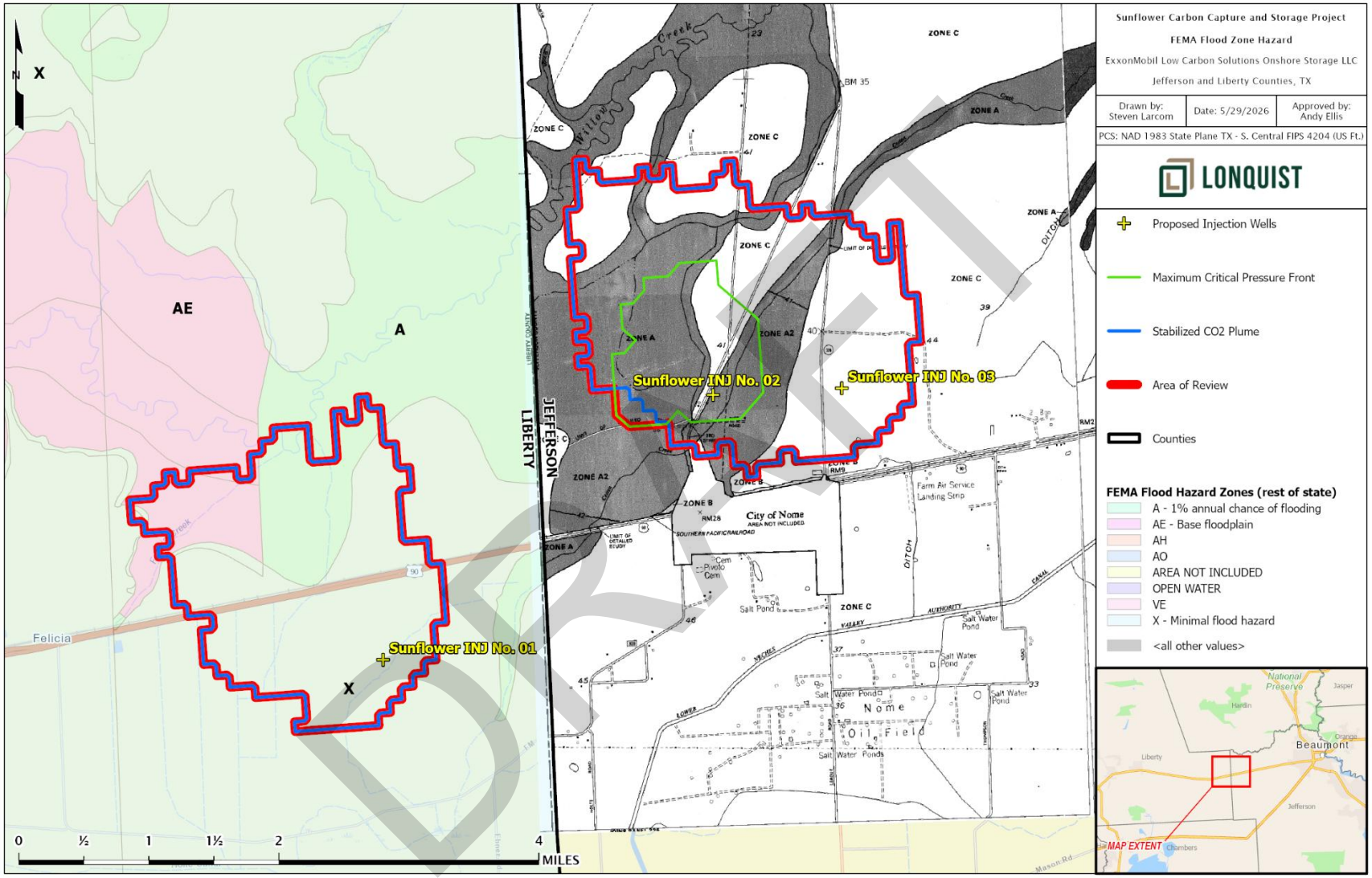


Figure 8-3 – FEMA Flood Zone Hazard Map Within the AOR

Potential Risk Scenarios

The following are events that could potentially result in an emergency response:

- Fluid leakage into USDW
- An equipment integrity, control system, or monitoring system failure, such as damage to a wellhead, valve, pipe, or flange connection that may cause a CO_2 release to the atmosphere
- A natural disaster or other unplanned event (e.g., hurricane, tornado, lightning strike, earthquake)

Response actions will depend on the severity of the event(s) triggering an emergency response. "Emergency events" are categorized as shown in Table 8-1.

Table 8-1 – Degrees of Risk for Emergency Events

Emergency Condition	Definition
Major	Event poses immediate substantial risk to human health, resources, or infrastructure. Emergency actions involving local authorities (evacuation or isolation of areas) should be initiated.
Serious	Event poses a potential, significant near-term risk to human health, resources, or infrastructure if conditions worsen, or no response actions are taken.
Minor	Event poses no immediate risk to human health, resources, or infrastructure—but could escalate if not addressed.

8.4 Emergency Identification and Response Actions

Steps to identify and characterize an emergency event will depend on specific issues identified and the severity of the event. The potential risk scenarios are detailed below.

8.4.1 Well Integrity Failure

Integrity failure of an injection or monitoring well may have occurred with the potential to endanger USDWs if monitoring results identify a loss of mechanical integrity, or automatic shutdown devices are activated as follows:

- Wellhead pressure exceeds the maximum injection pressure specified in the permit.
- Annulus pressure indicates a loss of external or internal well containment.

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Emergency Condition: Minor to major, depending on the results of the investigation into the incident and identified remedial activities

Timing of Event: Construction, pre-injection, injection, and post-injection phases

Avoidance Measures:

- Proper well design, construction, inspection, and maintenance
- Routine mechanical integrity testing
- Routine inspection of monitoring equipment

Detection Methods:

- Well pressure monitoring
- Annulus pressure and fluid-level monitoring
- Monitoring drilling-fluid returns and parameters during well construction and workovers

Potential Response Actions:

- Notify the UIC Director within 24 hours of the emergency event.
- Determine the severity of the event based on the information available within 24 hours of notification.
- Investigate the source and extent of the problem and determine an appropriate course of action to repair and/or remediate the issue.
- Prepare and submit an incident report to the UIC Director in an acceptable format.
- For a major or serious emergency:
  - Initiate the shutdown plan.
  - If contamination is detected, identify and implement appropriate remedial actions (in consultation with the UIC Director).
  - Implement the start-up plan once necessary remedial actions are completed and as agreed to by the UIC Director.
- For a minor emergency:
  - Conduct an assessment to determine whether there has been a loss of mechanical integrity.
  - If there has been a loss of mechanical integrity, initiate the shutdown plan.
- ExxonMobil may enact the following remedial actions to control the flow of injected CO_2 and/or associated reservoir fluids outside the permitted injection zone or USDW:
  - Cease injection of CO_2.
  - Pump heavy fluid into the injection well(s).
  - Perform workover operations on the well(s).
  - Develop and perform relief well-flowback operations.

Response Personnel: Drilling, workover, or injection crew; supervisory personnel

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Equipment: Depending on the severity of the event, the equipment required may include a workover rig, drilling rig, casing and cementing equipment, drilling fluids/muds/kill fluids, logging equipment, and surface monitoring equipment.

8.4.2 Injection Well Monitoring Equipment Failure

The failure of monitoring equipment for wellhead pressure, temperature, and/or annulus pressure may indicate a problem that could endanger USDWs.

Emergency Condition: Minor to major, depending on the results of the investigation into the incident and identified remedial activities

Timing of Event: Injection, post-injection phases

Avoidance Measures:

- Preventative and routine maintenance of monitoring equipment
- Backup monitoring equipment

Detection Methods:

- Continuous monitoring and recording of well parameters (*Section 5 – Testing and Monitoring Plan*)

Potential Response Actions:

- Notify the UIC Director within 24 hours of the emergency event.
- Determine the severity of the event based on the information available within 24 hours of notification.
- Investigate the source and extent of the problem and determine an appropriate course of action to repair and/or remediate the issue.
- Prepare and submit an incident report to the UIC Director in an acceptable format.
- For a major or serious emergency:
  - Initiate the shutdown plan.
  - If contamination is detected, identify and implement appropriate remedial actions (in consultation with the UIC Director).
  - Implement the start-up plan once necessary remedial actions are completed and as agreed to by UIC Director.
- For a minor emergency:
  - Conduct an assessment to determine whether there has been a loss of mechanical integrity.
  - If there has been a loss of mechanical integrity, initiate the shutdown plan.
  - Implement the start-up plan once necessary remedial actions are completed and as agreed to by the UIC Director.

Response Personnel: Supervisory personnel, maintenance technicians, contract personnel

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Equipment: Applicable equipment for repair and/or replacement of monitoring systems

8.4.3 Fluid (CO_2, Brine, Formation Fluid) Leakage to USDW

Elevated concentrations of indicator parameter(s) in groundwater sample(s) as identified in the Testing and Monitoring Plan—or other verified evidence—indicate a fluid (CO_2 or brine) leakage into a USDW.

Emergency Condition: Major, due to potential endangerment of USDWs

Timing of Event: Injection, post-injection phases

Avoidance Measures:

- Following the methods and sampling schedules as specified in the Testing and Monitoring Plan (*Section 5*).

Detection Methods:

- Elevated concentrations of indicator parameters in USDW samples
- Anomalies in the results of any monitoring outlined in the Testing and Monitoring Plan or during the post-injection site care period may be cause for additional samples to be taken in the USDW to investigate a potential leakage.

Potential Response Actions:

- Notify the UIC Director within 24 hours of the emergency event.
- Determine the severity of the event based on the information available within 24 hours of notification.
- Investigate the source and extent of the problem and determine an appropriate course of action to repair and/or remediate the issue.
- Prepare and submit an incident report to the UIC Director in an acceptable format.
- For all emergencies (major):
  - Initiate the shutdown plan.
  - Collect confirmation samples from the USDW(s).
  - If the presence of indicator parameters is confirmed, develop (in consultation with the UIC Director) a case-specific work plan to:
    - Install additional groundwater monitoring points near the affected groundwater well(s) to delineate the extent of impact.
    - Remediate unacceptable impacts to the affected USDW.
  - Arrange for an alternate potable water supply if the USDW was being utilized and drinking water standards for contaminants have been exceeded.
  - ExxonMobil will immediately enact the notification process.

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- Proceed with efforts to remediate the USDW to mitigate any unsafe conditions (e.g., install system to intercept, extract, and dispose of brine or brine-contaminated water, and "pump and treat" to aerate CO_2-laden water).
- Continue groundwater remediation and monitoring on a frequent basis (frequency to be determined by ExxonMobil and the UIC Director) until the unacceptable adverse USDW impact has been fully addressed.
- Implement the start-up plan once necessary remedial actions are completed and as agreed to by the UIC Director.

Response Personnel: Supervisory personnel, environmental professionals/subcontractors

Equipment: Depending on the severity of the event, response equipment may include water testing and treatment/sampling equipment, and water supply equipment

8.4.4 Fluid (CO_2, Brine, Formation Fluid) Leakage to Surface

Elevated concentrations of indicator parameter(s) in surface water, soil gas, ambient air sample(s), if triggered, as specified in the Testing and Monitoring Plan—or other verified evidence—indicate a CO_2 or brine leakage to the surface.

Emergency Condition: Major, due to potential contamination of surface water, soil, and ambient air

Timing of Event: Injection, post-injection phases

Avoidance Measures:

- Following the methods and sampling schedules as specified in the Testing and Monitoring Plan (*Section 5*)

Detection Methods:

- Elevated concentrations of indicator parameters in surface water, soil gas, and ambient air samples which may be implemented as a triggered response to confirmed USDW contamination.
- Anomalies in the results of any monitoring outlined in the Testing and Monitoring Plan or during the post-injection site care period may be cause for additional samples to be taken to investigate a potential leakage.

Potential Response Actions:

- Notify the UIC Director within 24 hours of the emergency event.
- Determine the severity of the event based on the information available within 24 hours of notification.
- Investigate the source and extent of the problem and determine an appropriate course of action to repair and/or remediate the issue.

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- Prepare and submit an incident report to the UIC Director in an acceptable format.
- For all emergencies (major):
  - Initiate the shutdown plan.
  - If the presence of indicator parameters is confirmed, develop (in consultation with the UIC Director) a case-specific work plan to:
    - Install additional groundwater monitoring points near the affected groundwater well(s) to delineate the extent of impact.
    - Remediate unacceptable impacts to the affected ground surface(s).
  - ExxonMobil will communicate to the relevant public authorities about an event that may require emergency response—so that the public understands the emergency event—and if there are any environmental, health, or safety concerns.
  - Proceed with efforts to remediate or mitigate any unsafe conditions (e.g., surface cleanup methods such as removal of brine via vacuum truck, soil excavation, or soil treatment).
  - Continue groundwater remediation and monitoring on a frequent basis (the frequency to be determined by ExxonMobil and the UIC Director) until the unacceptable adverse surface impact has been fully addressed.
  - Implement the start-up plan once necessary remedial actions are completed and as agreed to by the UIC Director.

Response Personnel: Supervisory personnel, environmental professionals/subcontractors

Equipment: Depending on the severity of the event, response equipment may include sampling equipment for surface water, soil gas, ambient air, and surface water remediation equipment.

8.4.5 Induced or Natural Seismicity Event

Natural or induced seismicity events of sufficient magnitude to create damage were found to be highly improbable for the site location for this project which will be operating under conditions that are below the fracture pressure. In the very rare chance that such seismicity conditions occurred, the consequences could be of significance regarding the integrity of the artificial penetrations of the upper confining zone (UCZ) and the natural faults and fractures. Therefore, the following response actions were developed to gather information regarding the potential for CO_2 and brine confinement issues to arise under such events.

ExxonMobil has installed a permanent seismicity monitoring system onsite, which is being monitored by a third party to detect seismic activity prior to and during injection operations. ExxonMobil will additionally receive notifications from USGS of recorded seismicity events for the site and surrounding area, should an event occur. If a review of the data indicates that the event was within a 5.6 mi radius of an injector ExxonMobil will notify the UIC Director to jointly determine if the events are likely to be associated with the operations, and if so, implement response actions for seismicity events as contained in Table 8-2.

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Table 8-2 – Response Actions for Seismicity Events

Threshold Condition[1]	Response Action for Epicenter Within a 100 Square Mile Area (5.6-Mile Radius) of an Injection Well[2]
Seismic event above magnitude 2.0 and below magnitude 3.0	• Monitor well pressure, temperature, and annulus pressure to assess if well operation within permitted status and assess the potential for mechanical integrity issues to have occurred from the seismic event. • Otherwise, continue normal operation within permitted levels and review seismicity data. • Report findings to the UIC Director as appropriate.
Seismic event greater than or equal to magnitude 3.0	• Communicate with facility personnel and local authorities about the operating condition of the injection wells and initiate correspondence with other nearby operators. • Monitor well pressure, temperature, and annulus pressure to verify well operation within permitted status and assess the potential for mechanical integrity issues to have occurred from the seismic event. • If evidence of mechanical integrity issues, cease injection, notify the UIC Program Director within 24 hours, and, if the loss of mechanical integrity may endanger the USDW, implement the emergency and remedial response plan approved by the UIC Program Director. • Collect fluid samples from the above-zone monitoring wells and USDW monitoring wells. • Review seismicity and operational data to identify potential source areas for a release above the UCZ. • Within 30 days of the triggering seismic event, determine causality and, if deemed causally related, propose appropriate corrective measures to project operations. • Report findings to the UIC Director and implement corrective measures if warranted. • Operations will resume upon UIC Director concurrence that necessary remedial or corrective measures have been taken so that the risk to the USDW is in compliance with EPA standards for protection of human health and the environment.

[1] Specified magnitudes determined by local or U.S. Geological Survey (USGS) seismic monitoring stations or reported by the U.S. Geological Survey National Earthquake Information Center using the national seismic network.
[2] Based on Railroad Commission of Texas Seismicity Review (RRC, 2024): https://www.rrc.texas.gov/oil-and-gas/applications-and-permits/injection-storage-permits/oil-and-gas-waste-disposal/injection-disposal-permit-procedures/seismicity-review

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8.4.6 Natural Disaster and Other Unplanned Events

A natural disaster (e.g., hurricane, tornado, lightning strike) affecting the normal operation of the injection well(s) could impact site operations by loss of well integrity, fluid leakage, and/or equipment malfunction. Weather-related events may affect surface facilities.

Due to the proximity of the location to the Gulf of Mexico, hurricanes and severe storms involving tornadoes are the most likely natural disasters/severe weather events to occur at the facility.

Emergency Condition: Minor to major, depending on the type and severity of the natural disaster. Any immediate, near-term, or prolonged risk to human health, resources, or infrastructure will be assessed immediately to determine emergency actions that will be taken.

Timing of Event: Construction, pre-injection, injection, and post-injection phases

Avoidance Measures:

- Preparation measures may be taken by monitoring current and predicted conditions.

Detection Methods:

- Weather forecast monitoring

Potential Response Actions: If a natural disaster occurs that affects the normal operation of the injection well, ExxonMobil will perform the following:

- Notify the UIC Director within 24 hours of the emergency event.
- Determine the severity of the event based on the information available within 24 hours of notification.
- Investigate the extent of the problem and determine an appropriate course of action to repair and/or remediate any issues caused by or resulting from the disaster.
- Prepare and submit an incident report to the UIC Director in an acceptable format.
- For a major or serious emergency:
  - Initiate the shutdown plan.
  - Notify the UIC Director within 24 hours of an emergency event.
  - Limit facility access to authorized personnel only.
  - Monitor well pressure, temperature, and annulus pressure to verify well integrity and determine the cause and extent of any failure.
  - If contamination or endangerment of the USDW is detected, ExxonMobil will identify and implement appropriate remedial actions (in consultation with the UIC Director).
  - Implement the start-up plan once necessary remedial actions are completed and as agreed to by UIC Director.
- For a minor emergency:
  - Conduct an assessment to determine whether there has been a loss of mechanical integrity.
  - If there has been a loss of mechanical integrity, initiate the shutdown plan.
  - Limit access to authorized personnel only.
  - Monitor well pressure, temperature, and annulus pressure to verify well integrity and determine the cause and extent of any failure.
  - Implement the start-up plan once necessary remedial actions are completed and as agreed to by UIC Director.

Response Personnel: Supervisory personnel, and applicable personnel to diagnose, repair, and remediate as needed

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Equipment: Applicable equipment to diagnose, repair, and remediate as needed

8.5 Response Personnel and Equipment

Site personnel, project personnel, and local authorities will be relied upon to implement this ERRP and will be dispatched in the case of an emergency. In the event of an emergency, appropriate city, county, and state emergency responders and agencies may be notified based on the severity of the risk. Contact information for ExxonMobil Emergency Authorities and state and local emergency services are outlined in Tables 8-3 and 8-4, respectively.

A site-specific emergency notification chart will be developed and maintained during the life of the project. ExxonMobil will provide the current site-specific emergency contact list to the UIC Director.

Table 8-3 – Contact Information of ExxonMobil Emergency Authorities

Name	Title	Telephone Number
Propietary Business Information	Low Carbon Solutions (LCS) U.S. Gulf Coast Venture Executive	Propietary Business Information
	Emergency Response & Preparedness Manager	
	Advisor, Public & Government Affairs – Low Carbon Solutions	

Table 8-4 – Emergency Services

Agency	Telephone Number
Liberty County Emergency Services District (ESD) 2	936-536-1334
Liberty County ESD 7	936-298-2828
Liberty County Sheriff	911 or 936-336-4500
Liberty County Public Health Unit	936-336-3859
Liberty County Office of Emergency Management and Homeland Security	936-334-3219
Liberty County Local Emergency Planning Committee	409-277-8720 or 936-334-3219
Liberty County EMS	911
Liberty County EMS	911
Jefferson County ESD 3	911 or 409-752-5100
Jefferson County ESD 4	911 or 409-796-3036
Jefferson County Sheriff	911 or 409-835-8411
Jefferson County Public Health Unit #1	409-835-8530

Agency	Telephone Number
Jefferson County Office of Emergency Management	409-835-8757
Jefferson County Local Emergency Planning Committee	409-835-8757
Texas Division of Emergency Management	512-424-2208
Texas Department of Public Safety	512-424-2000
State of Texas Spill-Reporting Hotline	800-832-8224
Texas Parks and Wildlife Department	512-389-4800
EPA Region 6	800-887-6063 or 214-665-2760
Texas Commission on Environmental Quality (TCEQ)	512-239-1000
TCEQ Office of Water	512-239-6696
National Response Center	800-424-8802
State of Texas Spill-Reporting Hotline	800-832-8224
EPA National Response Center (24 hours)	800-424-8802

Necessary equipment for emergency and remedial response may vary depending on the event. Generally, no specialized equipment will be required for response actions (such as cessation of injection, well shut-in, and evacuation). If specialized equipment (such as a drilling rig or logging equipment) is required, ExxonMobil will be responsible for its procurement.

8.6 Communications Plan and Emergency Notification Procedures

As appropriate, ExxonMobil will communicate to the relevant public authorities about an event that may require emergency responseso that the public understands the emergency event and if there are any environmental, health, or safety concerns. Based on the emergency event, ExxonMobil will determine the appropriate information, timing, and communication method for the event. This information may include the following:

- Description of the event
- Severity
- Potential impact to the environment
- Investigation steps
- Mitigation actions taken or planned
- Current status

ExxonMobil will notify the UIC Director and relevant state/local emergency management agencies of any event that requires an emergency response and that has the potential to impact the public immediately, within 24 hours. Agencies which may be contacted are listed in Table 8-4. ExxonMobil will coordinate with the appropriate agencies to inform the public on steps to be taken in the event of an emergency and, if deemed necessary, request assistance from said agencies or coordinate removal of the public from an area of exposure.

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If required, ExxonMobil will also communicate with other entities who may need to be informed about or act in response to the event. These may include local water purveyors or operators, CO_2 suppliers, pipeline operators, oil and gas operators, landowners, regional response teams, and other departments or authorities as guided by the UIC Director.

Pursuant to **TAC §5.203(l)(3)(F)**, ExxonMobil has performed substantial community outreach and sponsored, hosted, or materially participated in multiple events which discussed Emergency Response and provided advanced briefing to members of the public, both inside and outside the AOR, on the the proposed Sunflower CCS project including discussions on the hazards and characteristics of CO_2. Since October 2025, ExxonMobil has participated in eight events reaching over 240 residents within the AOR. Additionally, ExxonMobil has delivered CCS presentations and educational activities at five events in Jefferon Couny reaching over 4,100 attendees. ExxonMobil will continue to conduct community outreach events to inform the public about the planned Sunflower CCS project. These events focus on the public within the AOR but extend beyond the AOR as part of ExxonMobil's broader community education and benefits plan.

Our efforts focus on providing clear, accurate information about CCS, its environmental benefits, and the safety measures in place to protect the community. Key aspects of our education involve briefing the public within the AOR and beyond the AOR on subjects such as:

- What is Carbon Capture and Storage (CCS)?
- What is CO_2?
- What is the scope of ExxonMobil's Sunflower CCS project?
- How does ExxonMobil ensure drinking water is protected and unaffected by CCS?
- How is CO_2 permanently stored?
- What does ExxonMobil do to monitor, verify, and report on the status of the CO_2 stored?

In April 2026, we launched the Sunflower CCS project website (https://texas.exxonmobilpipeline.com/our-work/sunflower-project), which offers a project overview, map, FAQs about CCS and community safety, information on first responder training for CO_2-specific hazards, and updates on our community engagement and investments.

To further inform the community, we have placed an information sign at the project site on Old Grayburg Road in Nome, informational postcards at Nome City Hall, and contact cards at the U.S. Post Office in Nome. These materials encourage residents to contact us via email, phone, or by scanning a QR code for more information.

Starting in June 2026, a Community Liaison will host office hours twice a week at Nome City Hall to answer questions and provide CCS educational materials.

ExxonMobil is committed to supporting the communities within the AOR. We have contributed over $800,000 to emergency response and preparedness efforts at the local emergency service

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districts, and an additional $102,000 to support education and STEM resources for students in Hardin-Jefferson ISD and community safety initiatives.

8.7 Plan Review

The UIC Director will evaluate this proposed ERRP to verify that it meets the requirements of 16 TAC **§5.203(l)** and that the plan accounts for all site-specific conditions.
This ERRP will be reviewed as follows:

- At least once every 5 years following its approval by the permitting agency
- Within 1 year of any AOR reevaluation (16 TAC **§5.207(a)(2)(E)**)
- Following any significant changes to the facility, such as addition of injection or monitoring wells, on a schedule determined by the UIC Director (16 TAC **§5,207(a)(2)(E)**)
- When required by the UIC Director (16 TAC **§5.207(a)(3)**)

If the review indicates that no amendments to the ERRP are necessary, ExxonMobil will provide the permitting agency with the documentation supporting the "no amendment necessary" determination. If the review indicates that amendments to the ERRP are necessary, amendments will be made and submitted to the permitting agency within 30 days following an event that initiates the ERRP review procedure.

The amended plan must be approved by the UIC Director and would then be incorporated into the Class VI permit. If significant changes to the plan are needed, the UIC Director may need to modify the permit. A permit modification under 16 TAC **§5.202** would require notification of the public and an opportunity for comment. Minor changes to the plan, as defined under 16 TAC **§5.202**, do not require a permit modification or a public process.

8.8 Staff Training and Exercise Procedures

ExxonMobil will train all personnel on the knowledge they need to conduct their job safely. Incident Command System (ICS) training is required for personnel who are named in either the Spill Management Team in a Facility Plan or the Emergency and Remedial Response Plan—or who are reasonably expected to fulfill a supervisory role in the management of an incident/emergency. All personnel expected to participate in an emergency response will be trained annually on the hazardous substances that they may encounter during an emergency response, and will be provided training on mitigating those hazards.

Hazardous Waste Operations (HAZWOPER) and Emergency Response Operations level training is required for personnel who are required to participate in the active response to an incident/emergency. The training program administrator will certify personnel as HAZWOPER trained through the completion of comprehensive quarterly training, hands-on training, response drill participation, and applicable on-the-job experiences.

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Training and Personnel Competency is one of the 11 elements of ExxonMobil's Operations Integrity Management System (OIMS). Storage site operations are conducted in accordance with this corporate framework, specifically OIMS 5.4 – Training, which establishes requirements for managing personnel competency and training. The objective of OIMS 5.4 is to ensure that personnel are competent to perform their assigned responsibilities in a manner that supports safe, secure, and environmentally sound operations, and that complies with all applicable legal and regulatory requirements. This element requires that personnel receive appropriate training and demonstrate competency prior to performing safety-critical tasks. The intended outcome is to reduce the likelihood and severity of Safety, Security, Health, and Environmental (SSHE) incidents attributable to inadequate training or competency.

Operations personnel attend and have attended multiple trainings per year related to both ExxonMobil procedures and site-specific procedures. Training is delivered through a combination of instructor-led, computer-based, and on-the-job methods. All training completion and competency records are documented and maintained to ensure traceability, auditability, and compliance verification.

All personnel working at storage sites are required to complete training on the site-specific Emergency and Remedial Response (ERR) Plan. ERR training includes a tabletop exercise conducted in coordination with local emergency response agencies. This exercise is designed to validate communication protocols, confirm roles and responsibilities under the Incident Command System (ICS), and ensure an effective and coordinated response capability. Operations personnel are required to participate in ERR training annually. For CO_2 storage sites, the next scheduled ERR exercise is October 1, 2026. In accordance with OIMS 5.4 requirements, ERR plans are reviewed annually and formally updated at a minimum of every five years.

Operating Instructions (OI) are governed under Element 6 – Operating and Maintaining Assets within OIMS. Control Room Operators (CROs) and Field Operators are required to complete training and demonstrate competency in both standard Operating Instructions and Local Operating Instructions (LOI) prior to startup and prior to performing applicable tasks. Refresher training is conducted as needed to maintain competency.

Site activities are further supported by a structured Work Management System that includes daily safety meetings, pre-job briefings and safety meetings, Job Safety Analyses (JSAs), simultaneous operations (SIMOPS) reviews, and muster procedures. These processes ensure that hazards are systematically identified, communicated, and mitigated prior to and during work execution. Contractor and third-party personnel are required to adhere to site safety requirements and are provided with appropriate orientation and training prior to commencing work.

Training schedules, dates, and course outlines for CO2 storage sites are available upon request.

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Additionally, ExxonMobil will offer appropriate training and provide response plans to emergency first responders as required by organizations with geographic and logistical jurisdiction at the facility including steps to be taken in case of an emergency. Safety is ExxonMobil's number one priority. The Sunflower CCS Project has been designed to mitigate any potential risks and while an emergency event is highly unlikely, ExxonMobil understands the critical importance of preparedness. To date, ExxonMobil has provided world-class emergency response training to over 100 first responders in Liberty and Jefferson Counties. This training includes Texas A&M Engineering Extension Services (TEEX) training, National Association of State Fire Marshals (NASFM) training, and Mobile CO_2 Trailer training, among others.

Appendix G-3 is included as a supplement to this Section 8 - Emergency and Remedial Response Plan and as supporting evidence to show the level of work and planning ExxonMobil performs for Emergency Response planning. A similar plan will be developed for the Sunflower project.

Appendix G – Emergency And Remedial Response Plan

Appendix G-1: FEMA Flood Zone Hazard Map
Appendix G-2: Infrastructure and Resources Map
Appendix G-3: Integrated Contingency Plan

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Railroad Commission of Texas

Attachment I – Post Injection Site Care and Site Closure Plan

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Underground Injection Control – Class VI Permit Application for Sunflower Carbon Capture and Storage Project Injection Wells No. 01, No. 02, and No. 03

SECTION 7 – POST-INJECTION SITE CARE AND SITE CLOSURE PLAN

Sunflower Carbon Capture and Storage Project
Jefferson and Liberty Counties, Texas
ExxonMobil Low Carbon Solutions Onshore Storage, LLC
Amendment 2: May 2026

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SECTION 7 – POST-INJECTION SITE CARE AND SITE CLOSURE PLAN

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7.1 Introduction

The Post-Injection Site Care (PISC) and Site Closure Plan for the Sunflower Carbon Capture and Storage (CCS) Project (Sunflower Project) Injection Wells No. 01, No. 02, and No. 03 was prepared to meet the requirements of Title 16, Texas Administrative Code (16 TAC), Part 1, Chapter 5. ExxonMobil Low Carbon Solutions Onshore Storage, LLC (ExxonMobil) is undertaking the project in Jefferson and Liberty Counties, Texas, to sequester approximately 25.3 million metric tons per annum (MMT) of CO_2 over 11 years.

The PISC Plan describes the activities that will occur once injection operations have ceased, and the project moves into maintaining a non-endangerment condition for underground sources of drinking water (USDWs). The Site Closure Plan will be implemented once ExxonMobil demonstrates to the Underground Injection Control (UIC) Program director (UIC Director) that no additional monitoring is required to demonstrate protection of USDWs, and that the testing and monitoring system can be dismantled. ExxonMobil's strategy for PISC monitoring is based on the same systems and processes described in *Section 5 – Testing and Monitoring Plan*. The major monitoring elements include continued measurements of the CO_2 plume and pressure front location and monitoring the USDW and groundwater above the upper confining zone (UCZ). The data collected from this activity will be used to confirm compliance with the water-quality objectives for the project, and generate information needed to support the final non-endangerment demonstration and subsequent site closure. Pursuant to1 6 TAC **§5.203(m)(8)(A)**, the analyses and tests performed to support the demonstration will be accurate, reproducible, and performed in accordance with *Appendix E.1 – Quality Assurance and Surveillance Plan.* The end of the project will occur once the closure activities have been documented and approved by the UIC Director.

Upon cessation of injection, ExxonMobil will either submit an amended plan or demonstrate to the UIC Director through monitoring data and modeling results that no amendment to the plan is needed (16 TAC **§5.206 (k)(1)(C)**).

7.2 Objectives

The PISC and Site Closure Plan has been developed to meet the following objectives as outlined in 16 TAC **§5.203** and **§5.206**:

- Describe the pressure differential between pre-injection and predicted post-injection pressures in the injection zones, as well as the predicted positions of the CO_2 plume and associated pressure front at site closure.
- Describe the post-injection monitoring locations, methods, and proposed frequencies to demonstrate non-endangerment to the USDW over the time frame of the PISC.
- Identify the pre-closure, plugging, and site-restoration steps to achieve approval for site closure.

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- Outline the documentation and recordkeeping practices that will provide the information for decision-making purposes.

ExxonMobil will not cease post-injection monitoring until the non-endangerment demonstration pursuant to 16 TAC **§5.206(k)(2)** has been approved by the UIC Director. ExxonMobil will monitor groundwater quality and track the position of the CO_2 plume and pressure front for 50 years after cessation of injection, unless a lesser period is approved by the UIC Director. Once the non-endangerment demonstration has been approved, ExxonMobil will plug the monitoring wells, restore each well pad to the surface owner's agreed-upon condition, and submit a Site Closure Report to the UIC Director.

7.3 Calculation of Pre- and Post-Injection Pressure Differentials

As described in 16 TAC **§5.203(m)(7)(B)**, the Class VI non-endangerment demonstration will establish that pressure has declined to a level that no longer poses potential endangerment of USDWs. For the purposes of this section, ExxonMobil evaluated the pressure differentials by comparing the pre-operating pressure with the post-injection pressure differentials predicted by the plume model. The predicted pressure differential between pre-injection and the modeled post-injection pressures are favorable, showing a steep and continuous decline in pressure toward pre-operational baseline conditions. The primary mechanisms responsible for the anticipated pressure decay rates are the injection sequencing plan, the geological conditions of the injection zones (e.g., net sand thickness, permeability, porosity) and confining zones, and the projected CO_2 storage volume for the Sunflower Project site.

A staged injection sequence is planned for the proposed injection wells to optimize the storage of CO_2 in the injection intervals. *Section 3 – Area of Review and Corrective Action Plan* and *Section 4 – Well Construction Plan and Operating Conditions* provide detailed discussions of the injection sequencing strategy. Figure 7-1 summarizes the injection sequence schedule for the proposed injection period. The actual injection period will depend on the issuance of the permits for each injection well.

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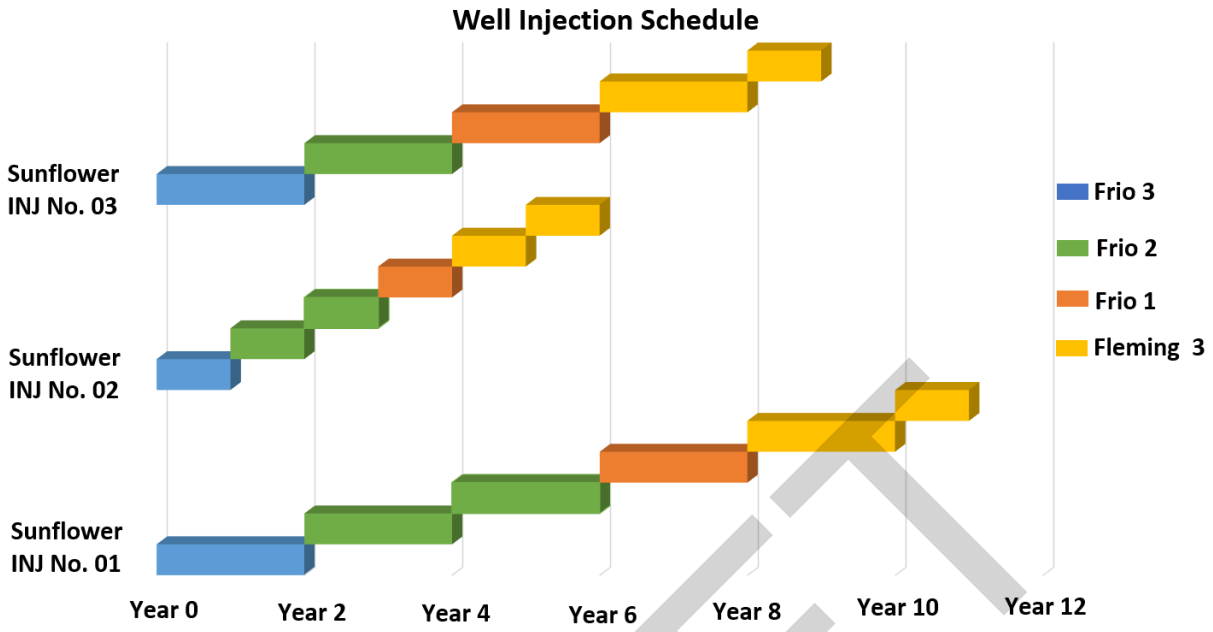
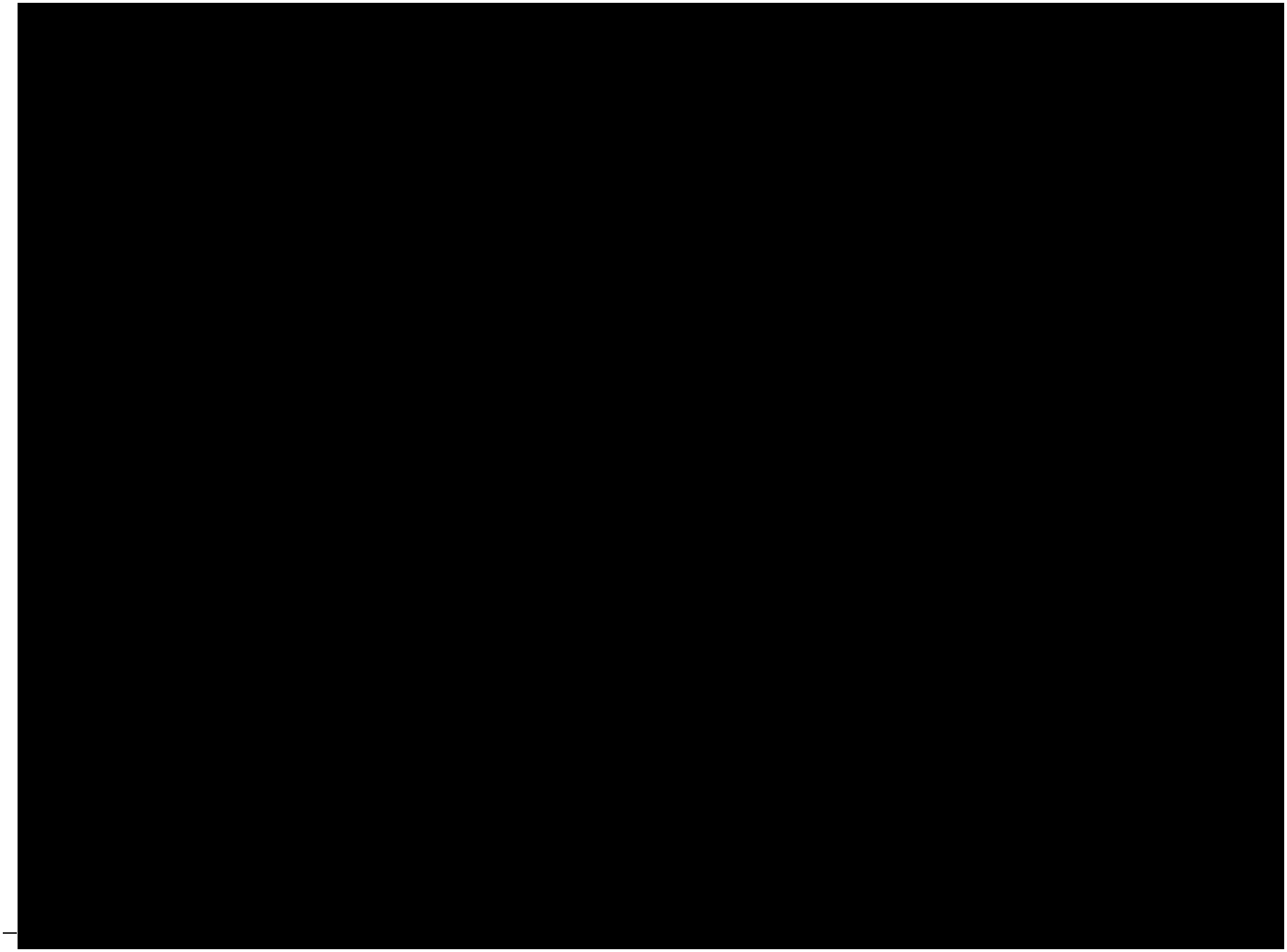


Figure 7-1 – Proposed Injection Interval Schedule

Table 7-1 provides the model-predicted average pressure differential (16 TAC **§5.203(m)(2)**) and the change in injection pressures in each injection interval over time pursuant to 16 TAC **§5.203(m)(7)(B)**. The pressure stabilization occurs almost immediately after injection cease.

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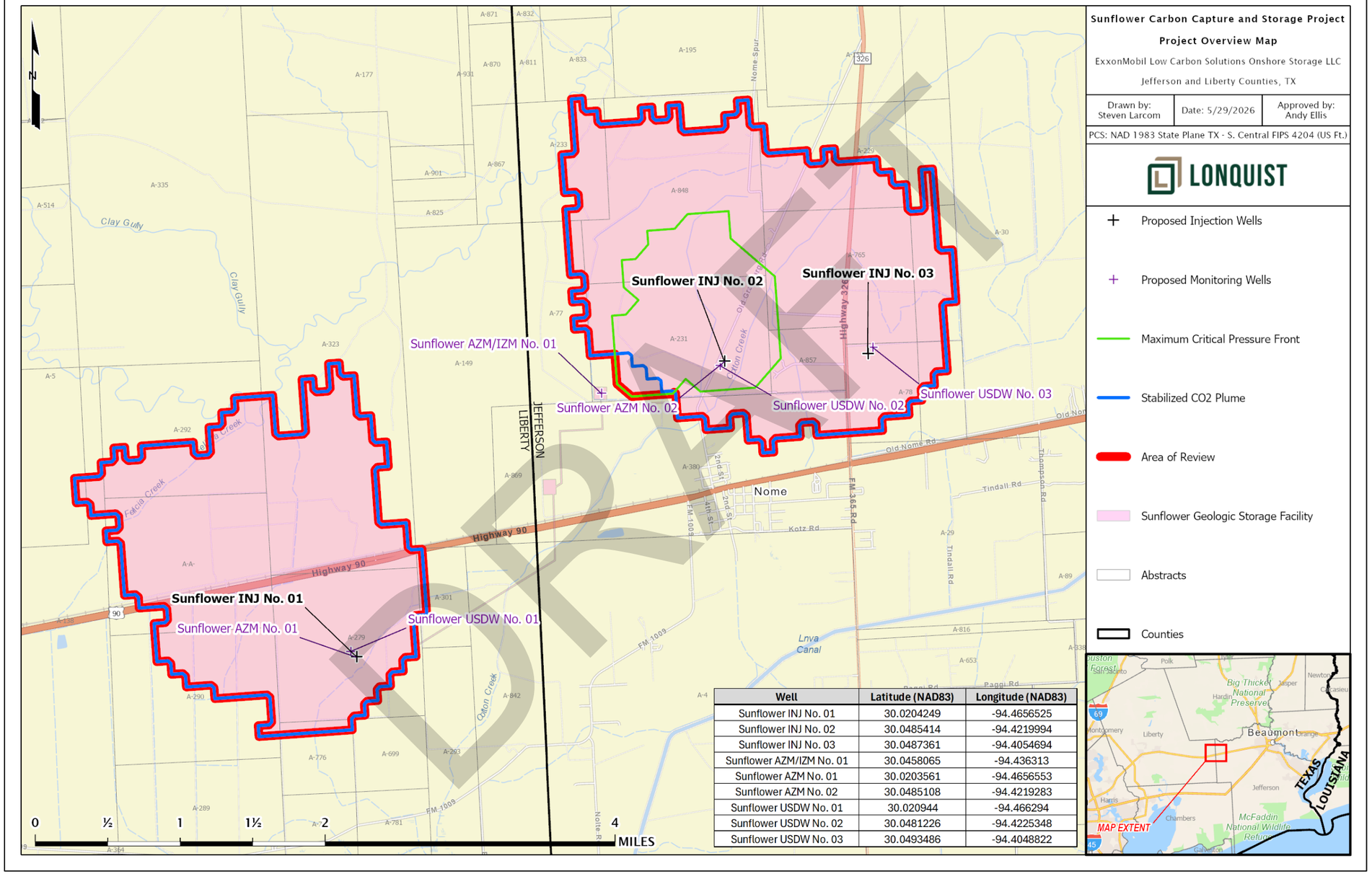


7.4 Predicted Position of the CO_2 Plume and Pressure Front at Site Closure

Pursuant to 16 TAC **§5.203(d)(1)(A)(i)**, the area of review (AOR) was delineated using computational modeling that accounts for all phases of CO_2 (e.g., supercritical, dissolved, etc.) under proposed operational conditions. The predictive model was appropriate, tailored to site conditions (including CO2 stream composition), calibrated with existing information, and used reasonably conservative values and modeling assumptions as further outlined in *Section 1 – Site Characterization* and *Section 2 – Plume Model* (16 TAC **§5.203(m)(8)(C) through (E)**). The AOR consists of both the CO_2 plume and the extent of the pressure front. The following discussion provides the predicted evolution of both the CO_2 plume and pressure front throughout the course of the 50-year PISC time frame.

Figure 7-2 shows the extent of the AOR and its subcomponents 11 years from the start of injection and 50 years from the cessation of injection. Based on the model, the CO_2 plume stabilization is predicted to occur approximately 50 years after injection ceases, with pressure differentials below the critical pressure threshold, thereby reducing the potential for USDW endangerment. The CO_2 plume from the proposed injection wells is based on the maximum extent of any injection interval. The maximum extent of the pressure front represents a composite of the maximum extent of the pressure front at any point in time for the injection intervals during all stages of injection operation.

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Well	Latitude (NAD83)	Longitude (NAD83)
Sunflower INJ No. 01	30.0204249	-94.4656525
Sunflower INJ No. 02	30.0485414	-94.4219994
Sunflower INJ No. 03	30.0487361	-94.4054694
Sunflower AZM/IZM No. 01	30.0458065	-94.436313
Sunflower AZM No. 01	30.0203561	-94.4656553
Sunflower AZM No. 02	30.0485108	-94.4219283
Sunflower USDW No. 01	30.020944	-94.466294
Sunflower USDW No. 02	30.0481226	-94.4225348
Sunflower USDW No. 03	30.0493486	-94.4048822

Figure 7-2 – Extent of Maximum CO_2 Plume and Pressure Front Stabilized in Year 50 from End of Injection

7.5 Post-Injection Site Care Monitoring Plan

Post-injection site care monitoring is required by 16 TAC **§5.206(k)(2)** to demonstrate that the geologic storage facility will not endanger the USDW. Much like the operational phase, direct and indirect forms of monitoring will be used to track the evolution of the CO_2 plume and pressure front after cessation of CO_2 injection. The strategy for the PISC monitoring is to rely on a core set of monitoring locations established during the operational phase of the project.

The following set of core monitoring locations was assumed to be installed and monitored pursuant to the Testing and Monitoring Plan (*Section 5*) and found sufficient pursuant to the AOR reevaluation process:

- In-zone monitoring at Sunflower INJ No. 01 through No. 03 for direct monitoring
- Sunflower AZM/IZM No. 01 for direct in-zone monitoring and above-zone monitoring of temperature and pressure
- Sunflower AZM No. 01 and No. 02 for above-zone pressure monitoring and fluid sampling
- Sunflower USDW Wells No. 01, No. 02, and No. 03 for direct monitoring of the USDW

Figure 7-2 illustrated the locations of these monitoring wells. If additional monitoring locations are added during the course of the injection operations under the direction of the UIC Director, this core set of monitoring wells will be updated to reflect the monitoring system in place at the close of the injection phase of the project.

Monitoring of the pressure front and CO_2 plume will occur for at least 50 years from the cessation of injection unless an alternate duration is approved by the UIC Director. ExxonMobil is proposing a schedule to submit PISC monitoring results annually and within 30 days of the anniversary date of injection cessation. **16 TAC §5.203(m)(5)**.

The following discussion provides details on the elements of the PISC monitoring strategy outlined above.

7.5.1 PISC and Site Closure Plan Reviews and Amendments

As required by 16 TAC **§5.206(k)(1)(B)** and **(C)**, ExxonMobil will submit an amended PISC and Site Closure Plan or demonstrate that no amendment is needed upon cessation of injection. Amendments to the plan, or the demonstration that no revisions are necessary, will be based on monitoring data collected during injection and the most-recent AOR delineation.

During PISC monitoring, ExxonMobil will conduct periodic reviews to incorporate new monitoring data, changes to the site computational model that may warrant changes in PISC monitoring, and/or changes in the methodology proposed to demonstrate non-endangerment of the USDW. This approach will also support the use of new technologies that may be available in the future that would facilitate a higher level of performance than the existing system. Pursuant to 16 TAC

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§5.206(g) and as described in *Section 3 – Area of Review and Corrective Action Plan*, ExxonMobil will reevaluate the AOR periodically by comparing model predictions with monitoring results.

Following an AOR reevaluation process, if the AOR and Corrective Action Plan are amended, ExxonMobil will review the PISC and Site Closure Plan to determine whether any updates are needed to ensure consistency across all plans. ExxonMobil may submit an amended PISC that describes how changes to the model affect predictions of pressure dissipation, plume migration rates, CO_2 trapping, and additional processes that need to be accounted for in the non-endangerment demonstration.

In accordance with 16 TAC **§5.206(k)(1)(B)**, at any time during the life of the project, ExxonMobil may modify and resubmit the PISC and Site Closure Plan for the UIC Director's approval within 30 days of such change.

7.5.2 Monitoring Above the UCZ and USDW

During the injection phase, periodic monitoring of groundwater quality for significant geochemical changes above the UCZ is required by 16 TAC **§5.203(j)(2)(D)(i)** for the purpose of detecting potential leakage through the UCZ. In accordance with 16 TAC **§5.206(k)(3)(B)** and **(C)**, groundwater quality and geochemical characteristics will be monitored in the first laterally continuous permeable and porous formation above the UCZ at Sunflower AZM No. 1 and No. 02 and in the USDW at Sunflower USDW No. 01, No. 02, and No. 03 during the post-injection period.

ExxonMobil's strategy for monitoring groundwater above the UCZ is a risk-based approach correlated to modeled CO_2 plume and injection-zone characteristics. By the time the PISC monitoring program is initiated, the risk-mitigating effects of the injection sequence plan, the operating strategy, and the corrective actions taken on artificial penetrations will likely have demonstrated protection of the USDW throughout the operational phase of the project. The list of analyses to be performed at these monitoring wells is summarized in Table 7-2 based on the same approach used for the operational phase of the project.

Table 7-3 provides a summary of indirect monitoring technologies to be used for above-zone CO_2 plume and pressure front monitoring during the PISC phase of the project. This monitoring strategy is consistent with the details and rationale provided in *Section 5 – Testing and Monitoring Plan*. The results of the monitoring activities will be submitted in the annual report for the year in which they occur—and within 30 days of the anniversary date of injection cessation or through an alternate schedule agreed upon with the UIC Director.

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Table 7-2 – Direct Above-Zone Monitoring and USDW Sampling and Analysis Program

Target Formation	Monitoring Activity	Monitoring Location(s)	Frequency[1]	Geochemical Analyses
USDW (Chicot Aquifer)	Water Level Gauging and Collection of Fluid Samples	Sunflower USDW No. 01, No. 02, and No. 03	Annual	Total dissolved solids, alkalinity, electrical conductivity, temperature, pH, gas composition (CO_2, CH_4, O_2, N_2), dissolved cations (i.e., As, Ba, Ca, Fe, Mg, Mn, Na, other relevant metals), and dissolved anions (i.e., HCO_3, Br, Cl, F, SO_4)
First Laterally Continuous Permeable Formation Above the UCZ	Collection of Fluid Samples and Pressure	Sunflower AZM No. 01 and No. 02	Annual	
	Pressure, Temperature	Sunflower AZM/IZM No. 01	Continuous	

As = arsenic; Ba = barium; Br = bromine; Ca = calcium; CH_4 = methane; Cl = chlorine; CO_2 = carbon dioxide; F = fluorine; Fe = iron; HCO_3 = bicarbonate; Mg = magnesium; Mn = manganese; N_2 = Nitrogen; Na = sodium; O_2 = oxygen; SO_4 = sulfate

[1] The word "continuous" as used to express the frequency of measures collected during monitoring equipment operation is defined as the instrument's normal data collection frequency as defined by the manufacturer. The frequency will vary by instrument and application. Measurements that are collected "continuously" will be averaged across a reasonable and appropriate time interval for reporting the detection monitoring results during the operational phase of the Sunflower Project.

Table 7-3 – Indirect Above-Zone Monitoring Program

Testing/Monitoring Activity	Frequency	Reporting Schedule	Comment
Indirect plume monitoring by time-lapse seismic surveys or equivalent technologies	Monitor Survey No. 03 will occur at the end of the operational period, 11 years after the start of operation. Contingent additional monitor surveys during the PISC phase are to be determined based on the results from the direct and indirect monitoring and model prediction.	After the collected time-lapse data has been integrated into the geologic and plume models	The frequency and method of indirect plume monitoring will be determined in conjunction with the UIC Director.

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The analytical methods and quality assurance/quality control measures discussed in *Section 5 – Testing and Monitoring Plan* for collecting and analyzing fluid samples will apply to the data collection program of the PISC, as appropriate.

7.5.3 In-Zone CO_2 Plume and Pressure Front Tracking

ExxonMobil proposes to use direct and indirect methods to track the extent of the CO_2 plume and pressure front in the injection zone during the PISC period. Direct monitoring in the injection zone includes continuous pressure and temperature measurements for Sunflower AZM/IZM No. 01. Indirect monitoring technologies include a geophysical survey to indirectly monitor subsurface conditions. By the start of the PISC phase of the Sunflower Project, the direct and indirect monitoring activities will have been used for approximately 11 years—making them a proven set of monitoring technologies for detection monitoring of CO_2 plume and brine crossflow potential.

Table 7-4 describes the proposed CO_2 and pressure plume tracking methods for the PISC Plan. The water quality and geochemical parameters to be analyzed are presented in Table 7-5, consistent with *Section 5 – Testing and Monitoring Plan*, which includes additional information on the monitoring methods described and how deviations would be identified.

Table 7-4 – Direct and Indirect In-Zone Monitoring Program for PISC

Monitoring Element	Strategy
Time Period	Immediately following and for up to 50 years from cessation of injection operations
Monitored Locations, Conditions, and Frequency	• Sunflower AZM/IZM No. 01: continuous pressure and temperature throughout the injection zone • Sunflower AZM No. 01 and No. 02: annual fluid samples for water quality and geochemical parameters • Sunflower USDW No. 01, No. 02, and No. 03: annual fluid samples for water quality and geochemical parameters • Time-lapse seismic surveys or equivalent technologies for the AOR from the surface to the base of the Upper Frio sand. Monitor Survey No. 03 will occur at the end of the operational period, a total of 11 years after the start of operation. The need for additional surface seismic surveys during the PISC phase of the project will be determined based on the results from direct and indirect monitoring and model prediction.
Planned Changes in Monitoring Techniques	None. The model-predicted rapid decrease in CO_2 plume movement and pressure significantly reduces the potential for USDW endangerment following injection and eliminates the need for additional monitoring.
Triggers	*Section 3 – AOR and Corrective Action Plan* provides a list of triggers for the AOR reevaluation process. Those triggers are applicable to the monitoring program.

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Table 7-5 – USDW and Above-zone Monitoring and Sampling Program During the PISC Phase

Monitoring Well	Frequency	Parameter/Analyte
Sunflower AZM No. 01 and No. 02	Annually	• Total dissolved solids • Alkalinity • Electrical conductivity • Temperature • pH • Gas composition (CO_2, CH_4, O_2, N_2) • Dissolved cations (As, Ba, Ca, Fe, Mg, Mn, Na, and other relevant metals) • Dissolved anions (i.e. HCO_3, Br, Cl, NO_3, SO_4)
Sunflower USDW No. 01, No. 02, and No. 03		

7.5.4 Submitting PISC Monitoring Results

In accordance with 16 TAC **§5.203(m)(5)**, ExxonMobil will submit PISC monitoring data to the UIC Director in annual reports within 30 days following the anniversary of the date that injection ceases. The annual reports will contain information and data generated during the reporting period, such as the following:

- A list of monitoring events performed during the reporting period and the associated dates
- A brief description of sampling/testing/analytical locations, elevations/depths, equipment, and procedures, indicating whether (and why) departures from the procedures specified in the PISC and Site Closure Plan occurred
- Changes to the monitoring program that took place during the reporting period (e.g., repair to monitoring wells, implementation of approved changes in the frequency of monitoring activities based on criteria established in the PISC and Site Closure Plan and on approval of the UIC Director)
- Synthesis and interpretation of the results that describe trends in parameter values or the lack of trends, alignment between actual and plume model predictions, the appearance of anomalous or unexpected results, and progress toward attaining the EPA and Railroad Commission of Texas (TRRC) criteria for non-endangerment
- Map(s) and cross section(s) showing the AOR, monitoring locations, and interpreted extent of the separate-phase CO_2 plume and the pressure front
- Any recommended changes to the PISC and Site Closure Plan to continue protection of the USDWs

7.6 Demonstration of Non-Endangerment of USDW

Prior to the approval of the site closure authorization and in accordance with 16 TAC **§5.206(k)(3)**, ExxonMobil will provide documentation demonstrate that no additional monitoring is needed to

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assure that the geologic storage facility will not endanger the USDW. The non-endangerment demonstration will be based on monitoring data and a demonstration that the structure of the confining zones, combined with the geochemical conditions of the subsurface, have effectively permanently sequestered the stored CO_2. This information will be used to demonstrate that additional monitoring is not needed to ensure non-endangerment of the USDW and that the project has met the compliance obligations to receive authorization for site closure.

This demonstration will be in the form of a detailed report submitted to the UIC Director that synthesizes site- and project-specific information and demonstrates a current understanding of system behavior at the time of the non-endangerment demonstration. The following subsections outline the type of information to be presented in the non-endangerment demonstration report.

ExxonMobil will engage the UIC Director as soon as the available data are aligned with the criteria for site closure, which may ultimately be less than the default PISC duration of 50 years pursuant to 16 TAC **§5.206(k)(3)**.

7.6.1 Introduction and Overview for Non-Endangerment Demonstration

A summary of relevant background information will be provided in the introduction section of the report, including the operational history of the injection project, the date of the non-endangerment demonstration relative to the post-injection period outlined in this PISC and Site Closure Plan, and a general overview of how monitoring and modeling results will be used together to support a demonstration of USDW non-endangerment.

7.6.2 Summary of Existing Monitoring Data

The monitoring data collected throughout the project's life cycle will be summarized and used to describe how the UCZ functioned as a barrier to mitigate endangerment of the USDW, and how the CO_2 is effectively trapped in the injection zones. The non-endangerment demonstration will include a summary of previous monitoring data collected at the site, pursuant to the details in *Section 4 – Well Construction Plan and Operating Conditions* and *Section 5 – Testing and Monitoring Plan*, as well as the PISC and Site Closure Plan.

Data submittals will be in a format acceptable to the UIC Director 16 TAC **§5.207(b)(2)** and will include the following:

- An explanation of monitoring activities, including the dates of all monitoring events and changes to the monitoring program over time
- An explanation of the monitoring infrastructure that has existed at the site
- A comparison with baseline data collected during the site characterization to assess trends in key parameters that support the proposal for site closure

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7.6.3 Summary of Computational Modeling History

A series of data sources detailed in *Section 5 – Testing and Monitoring Plan* will be used to update the computational model at least once every 5 years—more frequently if warranted. The following measured data will be utilized to update the computational model to demonstrate non-endangerment:

- In-zone temperature and pressure data
- Injection rate and volume data
- CO_2 plume location based on indirect geophysical monitoring
- Above-zone monitoring data regarding the performance of the UCZ

The procedure used to reevaluate the AOR will be based on the data collected between reevaluations and the well conditions at the time of reevaluation. The post-injection data will include historical injection rates, pressures, pressure falloff, and historical operational parameters of the three proposed injection wells. ExxonMobil will rely on a process of history matching the plume model results with the actual monitoring data. The measured data will be used as a calibration point for the plume model, and the input parameters adjusted to provide a reasonable match between the two data sets. Through this or a similar process, ExxonMobil will provide a validation of the model performance for the CO_2 plume and pressure front.

Items satisfying **§5.203(m)(7)(C) through §5.203(m)(7)(G)** can be found in other sections of this permit application.

- **§5.203(m)(7)(C)** The predicted CO2 injection rate and duration within each injection zone per well is shown in Figure 2-46 through 2-48. In addition, Figure 2-45 includes total million metric tons (MMT) stored per well and per zone.
- **§5.203(m)(7)(D)** Site specific processes of CO2 trapping mechanisms can be found in section 2.4
- **§5.203(m)(7)(E)** At stable plume (50 years post cessation of injection) Figure 2-2 shows the breakdown of the percentage of injected CO2 stored per trapping mechanism
- **§5.203(m)(7)(F)** Research studies used to verify information can be found in section 2.4
- **§5.203(m)(7)(G)** Please refer to section 1.3.2 and Appendix B3 for details on the UCZ.

7.6.4 Evaluation of Reservoir Pressure

The non-endangerment demonstration will include an evaluation of the residual pressure and the potential for continued trends in pressure dissipation that might endanger USDWs in the future. Information will be provided to describe how the pressure and buoyancy effects on plume and pressure migration decayed over time, and how the residual levels comply with the requirements for non-endangerment. This evaluation will consider the most-recent AOR delineation/modeling results and pressure monitoring data. The same model that supported the delineation of the AOR or a similar model approved by the UIC Director will be used for this

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modeling, as it will be verified (or calibrated) by actual monitoring and operational data via AOR reevaluations.

7.6.5 Evaluation of the CO_2 Plume

The non-endangerment demonstration will include an evaluation of the gas-phase CO_2 plume and the dissolved-phase CO_2 plume, as appropriate. The evaluation of the potential CO_2 plumes will rely on monitoring data, including geochemical and geophysical analyses and the most recent AOR modeling results. Direct measurements of the temperature and pressure of CO_2 in the injection zone, as well as the results of geophysical measurements, will be used to confirm plume location and demonstrate plume migration rates.

7.6.6 Evaluation of Emergencies or Other Events

Eleven artificial penetrations of the UCZ were noted in *Section 3 – Area of Review and Corrective Action Plan*—each of which will be remediated as also described in *Section 3*. If any subsequent artificial penetrations are discovered to have potential to threaten USDW, they will be remediated using the same procedures so that no artificial penetrations of concern remain at the time of site closure.

The data and evaluation methods specified pursuant to the requirements of *Section 5 – Testing and Monitoring Plan* as well as the PISC Plan provide the basis for demonstrating that no future endangerment of the USDW is likely to occur.

7.7 Site Closure Plan

ExxonMobil will conduct site closure activities to meet the requirements of 16 TAC **§5.206(k)(4)** through **(l)(5)** as described below. ExxonMobil will submit a final Site Closure Plan and notify the UIC Director at least 120 days prior to its intent to close the site. Once the UIC Director has approved closure of the site, ExxonMobil will plug all injection and monitoring wells and submit a site closure report to the TRRC. The activities, as described below, represent the planned activities based on information provided to TRRC. The actual Site Closure Plan may employ different methods and procedures.

Additionally, ExxonMobil will record a notation on the deed to the site that the land has been used to sequester CO_2. Site closure activities will also include removing all surface equipment and restoring the site to its prior land surface condition.

7.7.1 Pre-Closure

In accordance with 16 TAC **§5.206(k)(4)**, a notice of intent to close the site will be submitted to the UIC Director at least 120 days prior to the commencement of closure operations. If any changes are made to the original PISC and Site Closure Plan, a revised plan will also be submitted.

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Relevant notifications and applications, such as plugging requests, will be submitted and approved by the appropriate agency prior to commencing such activities.

The site closure notice submitted to the UIC Director will include the following:

- Facility information, name, and location
- A list of contact personnel for allowing timely direct communication to resolve any pressing issues
- A projected closure date, no less than 120 days following the site closure notification submission, unless the UIC Director has approved a different period prior to notice submission

7.7.2 Plugging Activities

Sunflower INJ No. 01 through No. 03, Sunflower AZM/IZM No. 01, Sunflower USDW No. 01 through No. 03, and Sunflower AZM No. 01 and No. 02 (including additional wells that may be installed during the operation or post-operation phase of the Sunflower Project) will be plugged in accordance with applicable Texas requirements. The plugging plan for the injection and monitoring wells which penetrate the base of the usable quality of water is further discussed in *Section 6 – Injection Well Plugging Plan*. After injection ceases and after the appropriate post-injection monitoring period is complete, the monitoring wells will be plugged and abandoned to meet the requirements of 16 TAC **§5.203(k)** and in compliance with applicable state requirements. Additionally, per 16 TAC **§5.203(k)(5) and (6)**, ExxonMobil will certify and plug the Sunflower USDW No. 01, No. 02, and No. 03 in accordance with 16 TAC Chapter 76. In certain instances, the landowner may ask for the wells to remain active and assume ownership at the time of site closure. Should such an agreement exist between the landowner and ExxonMobil at the time of site closure, ExxonMobil will transfer ownership of the wells to the landowner.

The plugging procedure and materials will be designed to mitigate fluid movement and protect the USDW. Prior to plugging the wells, the necessary procedural revisions to address new information will be submitted to the UIC Director for review and approval. The final plugging plans will be submitted to the UIC Director no later than 60 days prior to the plugging of the wells. Following receipt of the approved plugging plans, the wells which penetrate the base of usable quality of water will be logged and pressure-tested to ensure mechanical integrity. If a loss of mechanical integrity is discovered, the mechanical integrity will be restored prior to proceeding with plugging operations. The casing in these wells will be left in place and will not be retrieved at abandonment. A combination of bridge plugs and cement plugs will be set to plug the wells. All casing strings will be cut at least 3 feet below ground level. A steel plate with the required permit information will be welded to the top of the casing to meet the requirements of the TRRC.

7.7.3 Site Restoration

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Once the injection and monitoring wells are plugged and abandoned, the surface equipment will be decommissioned and removed from the well site, which will then be restored to a condition agreed upon with the surface owner.

7.7.4 Documentation of Site Closure

Within 90 days of site closure, a final report will be submitted to the UIC Director per the requirements of 16 TAC **§5.206(k)(6)** and include the following:

- Documentation of appropriate injection and monitoring well plugging, including a copy of the survey plats. (16 TAC **§5.206(k)(6)(A)**]). A copy of the plat will be filed with both the TRRC and the EPA Regional Office.
- The survey plat, indicating the locations of the injection wells relative to permanently surveyed benchmarks and including the location of the monitoring wells
- Documentation of the well-plugging report, to be filed with the TRRC 16 TAC **§5.206(k)(6)(B)**
- Post-injection monitoring records, summarized
- Records of the nature, composition, and volume of the CO_2 stream for the injection period, summarized 16 TAC **§5.206(k)(6)(C)**

Pursuant to 16 TAC **§5.206(l)**, a record of notation in the Sunflower Project facilities and infrastructure will be filed on the property deed to provide notice to landowners of the following:

- The land having been used to sequester CO_2
- The name of the state agency with which the survey plat was filed (TRRC) and the EPA Regional Office (Region VI) at which it was submitted
- The total volume of CO_2 injected, the injection zones into which it was injected, and the period over which injection occurred

As required by 16 TAC **§5.206(m)**, ExxonMobil will retain all records collected during the PISC period for 10 years following site closure. At the end of the retention period, ExxonMobil will deliver all records to the UIC Director for retention at a location designated by the director for that purpose.

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Railroad Commission of Texas

Attachment J – Financial Assurance Demonstration

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Underground Injection Control – Class VI Permit Application for Sunflower Carbon Capture and Storage Project Injection Wells No. 01, No. 02, and No. 03

SECTION 9 – FINANCIAL ASSURANCE

Sunflower Carbon Capture and Storage Project
Jefferson and Liberty Counties, Texas
ExxonMobil Low Carbon Solutions Onshore Storage, LLC
Amendment 2: May 2026

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SECTION 9 – FINANCIAL ASSURANCE

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9.1 Financial Assurance

ExxonMobil Low Carbon Solutions Onshore Storage, LLC (ExxonMobil) is undertaking the Sunflower Carbon Capture and Storage (CCS) Project (Sunflower Project) in Jefferson and Liberty Counties, Texas, to sequester approximately 25.3 million metric tons (MMT) of CO_2 using three injection wells over an 11-year injection period. Under the Title 16, Texas Administrative Code (16 TAC), Part 1, Chapter 5, **§5.203** and **§5.205**, owners or operators of geologic sequestration (GS) injection wells are required to demonstrate financial responsibility for GS activities.[1] Consistent with these regulatory requirements, ExxonMobil has prepared this document to demonstrate financial responsibility for the injection wells that comprise the Sunflower Project.

The sections that follow summarize the project's GS activities, as well as the qualifying financial instrument that ExxonMobil proposes to use, to demonstrate financial responsibility for the following project phases: (1) Corrective Action; (2) Well Plugging; (3) Post-Injection Site Care (PISC) and Site Closure; and (4) Emergency and Remedial Response (ERR).

9.2 Facility Information

Facility Name:	Sunflower CCS Project
Facility Contact:	[redacted] Controller ExxonMobil Low Carbon Solutions Onshore Storage, LLC
Project Site Name:	Sunflower Carbon Capture and Storage Project
Project Location	Jefferson and Liberty Counties, Texas
Well Name and Number	**Sunflower Project Injection Well No. 01**
Well Name and Number	**Sunflower Project Injection Well No. 02**
Well Name and Number	**Sunflower Project Injection Well No. 03**

9.3 Financial Assurance Demonstration

Pursuant to 16 TAC **§5.205**, ExxonMobil requests approval from the Texas Underground Injection Control (UIC) Program director (UIC Director) or their designee to use a performance bond, for the purposes of demonstrating financial responsibility for corrective action, well plugging, PISC and site closure, and ERR for the entire AOR. A copy of the draft performance bond is in *Appendix H* along with the independently audited, most recent annual and quarterly reports filed with the Securities Exchange Commission (SEC), the cost estimates certified by a Texas professional

[1] The use of the term "geologic sequestration activities" is unique to this section of the application. It is used to provide additional clarity on which activities of the project's life cycle necessitate financial assurance, as opposed to those that do not—consistent with EPA guidance for financial assurance.

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engineer (PE), and a document showing the proposed bonding company's authority to do business in Texas. ExxonMobil plans to work with the Director through the permitting approval process to ensure the proposed Financial Assurance satisfies the requirements of 16 TAC **§5.205(c)**.

ExxonMobil will provide annually to the Director evidence of financial responsibility and demonstrate and maintain financial responsibility until the Director determines the facility has reached the end of the PISC period (16 TAC **§5.205(b)(1)**).

Pursuant to 16 TAC **§5.205 (D)(1) – (3)**, ExxonMobil will notify the Director of adverse financial conditions that may affect the ability to carry out injection well plugging and pos-injection storage facility care and closure and file any notice of bankruptcy by certified mail.

9.4 Estimated Coverage Amounts

The total current cost estimate for the Sunflower Project's GS activities necessitating financial assurance is $31,488,275 in 2026 dollars. Pursuant to 16 TAC **§5.205(c)(2)(C)(i)**, ExxonMobil is requesting the Director approve the above dollar amount of the financial assurance. This estimate, separated into the four project phases, assumes the hiring of independent, third-party contractors to perform the required activities or to procure the goods associated with the performance of each GS activity as follows:

1. Phased corrective action for artificial penetrations in the area of review (AOR) remaining after initiating operations
2. Well plugging[2] to occur after 11 years of site injection
3. PISC: beginning after 11 years of site injection and ending with Site Closure 50 years after injection ends
4. ERR: beginning after site injection and ending with site closure

Table 9-1 summarizes the total estimated cost of performing each GS activity, along with the timeline for which financial assurance coverage is expected to be needed. The values included in this demonstration of financial responsibility are based on cost estimates developed as part of the Class VI permit application process. These values are subject to change during the life of the project to account for inflation of costs and changes to the project that may affect the cost of covered activities.

Per 16 TAC **§5.205(c)(2)(E)**, ExxonMobil will, during the active life of the Sunflower Project, adjust the cost estimate for inflation within 60 days prior to the anniversary date of the establishment of the financial assurance instrument. In addition, ExxonMobil will provide to the UIC Director written updates of adjustments to the cost estimate within 60 days of any amendments to the

[2] Financial responsibility coverages for well plugging reflect the current estimated cost for plugging the three injection wells and three monitoring wells related to the project.

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AOR and Corrective Action Plan (16 TAC **§5.203** and **§5.206**), the Injection Well Plugging Plan (16 TAC **§5.203**), the PISC and Site Closure Plan (16 TAC **§5.203** and **§5.206**), and the Emergency and Remedial Response Plan (ERRP) (16 TAC **§5.203, §5.206,** and **§5.207**). Furthermore, ExxonMobil will comply with 16 TAC **§3.78** for monitoring wells which penetrate the base of the usable quality of water.

ExxonMobil will adjust the value of its financial assurance instruments in response to any changes in cost estimates and will resubmit its revised demonstration of financial responsibility to the UIC Director or their designee for review and approval. ExxonMobil will not adjust the established coverage values of any financial assurance instrument without prior approval from the UIC Director or their designee.

Table 9- 1 – Summary of Financial Assurance Coverage Values by GS Activity

GS Activity	Estimated Financial Assurance Coverage Value
Corrective Action	$6,518,400
Well Plugging	$3,880,375
PISC and Site Closure	$10,029,500
PISC Regulatory Fee (16 TAC **§5.205(a)(3)**)	$2,500,000
ERR	$8,560,000
TOTAL:	$31,488,275
Note: *Section 3 – Area of Review and Corrective Action Plan*, *Section 5 – Testing and Monitoring Plan*, Section 6 – *Injection Well Plugging Plan*, and *Section 8 – Emergency and Remedial Response Plan* provide detailed discussions of work to be undertaken, which formed the cost basis for the financial assurance coverage values summarized in this table	

9.5 Corrective Action

The Corrective Action Plan is discussed in detail in *Section 3 – Area of Review and Corrective Action Plan*. Per the requirements of 16 TAC **§5.203** and **§5.206**, the plan specifically outlines both a plugging plan for the artificial penetrations found within the CO_2 plume and brine pressure front, and the recompletion schedule whereby the wellbore modifications will have been completed. ExxonMobil is proposing a phased approach to Corrective Action. Of the eleven legacy wells requiring corrective action, six are located within or very near the anticipated the 5-year plume or 5-year pressure front and will be remediated prior to injection. This leaves five legacy wells to be remediated after operations begin. A complete list of the eleven legacy wells along with their proposed remediation schedule can be found in Table 3-2.

For the planned activities at the Sunflower Project, workovers on the legacy wells found to have sufficient deficiency as to represent a potential loss of CO_2 or brine containment within the first 5 years will be reentered and plugged prior to receiving approval from the UIC Director to inject. Five corrective actions are expected to be needed beyond the model-predicted 5-year extent of the AOR. The estimated financial assurance coverage value for this GS activity for the 5 phased wells is shown in Table 9-2.

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This financial responsibility demonstration will be updated annually to account for any changes in expected financial coverage values and to confirm that the financial instrument(s) then in place remain adequate for use.

Table 9- 2– Summary of Corrective Action Costs Underpinning Financial Assurance Coverages

CA Cost Group	Estimated Cost
Corrective Action for 5 phased legacy wells listed in Table 3-2	
Workover Rig	[redacted]
Kill/Buffer Fluid/Fluids	[redacted]
Disposal	[redacted]
Down Hole Tools	[redacted]
Pipe Rental/Purchase	[redacted]
Personnel	[redacted]
Wireline	[redacted]
Other Services	[redacted]
Cement and Pumping Services	[redacted]
Equipment Rentals	[redacted]
Pad/Road Upgrade	[redacted]
Contingency	[redacted]
TOTAL	$6,518,400

9.6 Well Plugging

9.6.1 Injection Well Plugging

Plugging and abandonment (P&A) of the injection wells at the Sunflower Project will meet the requirements of 16 TAC **§5.203**. The P&A plan for the injection wells was designed to reduce the potential for movement of CO_2 or brine from the injection zone through the upper confining zone (UCZ) and toward underground sources of drinking water (USDWs).

A detailed P&A plan is discussed in *Section 6 – Injection Well Plugging Plan*. In alignment with the requirements for the plan, the estimated financial assurance coverage value includes costs for logs/wireline to be run in the wellbores before cementing occurs, if necessary. The expenses relating to personnel and equipment have been accounted for in Table 9-3.

9.6.2 Monitoring Well Plugging

The P&A of the one above-zone/in-zone monitoring well, three USDW monitoring wells, and two above-zone monitoring wells associated with the Sunflower Project will also meet the requirements of 16 TAC **§5.203** for wells which penetrate the base of usable quality of water and

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16 TAC Chapter 76 for wells which do not. As detailed in *Section 6 – Injection Well Plugging Plan*, the P&A of the monitoring wells was designed to protect USDWs from potential endangerment. The estimated financial assurance coverage value for this GS activity includes the costs for logs and wireline to be run in the in-zone monitoring well before cementing occurs to the extent necessary. The expenses relating to personnel and equipment have been accounted for in Table 9-3.

Table 9- 3– Summary of Estimated Well Plugging Costs Underpinning Financial Assurance Coverages

Plugging Cost Group	Estimated Financial Assurance Coverage Value
Injection Well Plugging (three wells) Total Estimate of $2,182,125	
Workover Rig	[redacted]
Kill/Buffer Fluid	[redacted]
Personnel	[redacted]
Wireline	[redacted]
Other Services	[redacted]
Cement and Pumping Services	[redacted]
Equipment Rentals	[redacted]
Pad/Road Upgrade	[redacted]
Contingency	[redacted]
In-Zone/Above Zone Monitoring Well Total Estimate of $573,000	
Workover Rig	[redacted]
Wireline	[redacted]
Personnel	[redacted]
Other Services	[redacted]
Cement and Pumping Services	[redacted]
Equipment Rentals	[redacted]
Pad/Road Upgrade	[redacted]
Contingency	[redacted]
Above Zone Monitoring Wells (two wells) Total Estimate of $985,000	
Workover Rig	[redacted]
Wireline	[redacted]
Personnel	[redacted]
Other Services	[redacted]
Cement and Pumping Services	[redacted]
Equipment Rentals	[redacted]
Pad/Road Upgrade	[redacted]
Contingency	[redacted]

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USDW Monitoring Wells (three wells) Total Estimate of $140,250	
Workover Rig	[redacted]
Personnel	[redacted]
Cement and Pumping Services	[redacted]
Other Services	[redacted]
Rentals	[redacted]
Site Restoration	[redacted]
Contingency	[redacted]
TOTAL	**$3,880,375**

9.7 Post-Injection Site Care and Site Closure Plan

The PISC and Site Closure Plan has been designed to meet the requirements of 16 TAC **§5.203** and **§5.206**. The estimated financial assurance coverage value for this GS activity includes the cost categories summarized in Table 9-4, while the plan itself is discussed in *Section 7 – Post-Injection Site Care and Site Closure Plan*.

9.7.1 Post-Injection Monitoring

As discussed in *Section 5 – Testing and Monitoring Plan*, surface seismic and pressure and temperature monitoring will be conducted during operations and after the end of injection—to assess the integrity of the wells and to track the migration of the CO_2 plume and brine pressure front.

9.7.2 Site Closure Plan

Site closure will occur when the UIC Director has released the owner from PISC duties and the demonstration of non-endangerment for USDWs has been approved. The estimated financial assurance coverage value for this GS activity is summarized in Table 9-4 and reflects the expected amount to decommission and close the site.

Table 9- 4– Summary of Estimated PISC and Site Closure Costs Underpinning Financial Assurance Coverages

PISC/Closure Category	Estimated Cost
Site Care	**$9,285,000**
Geochemical Sampling	[redacted]
Pressure Monitoring	[redacted]
Geophysical Monitoring (DAS-VSP)	[redacted]
Reporting	**$185,000**
Site Closure	[redacted]
Demonstration of Non-Endangerment	[redacted]
Monitoring Well Plugging and Abandonment	[redacted]
Facility Closure	**$559,500**

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PISC/Closure Category	Estimated Cost
Post-Injection Site Care and Site Closure Total	$ 10,029,500

9.8 Emergency and Remedial Response

The ERRP, discussed in *Section 8 – Emergency and Remedial Response Plan*, is designed to satisfy the requirements of 16 TAC **§5.203, §5.206,** and **§5.207**, which necessitates an ERRP that describes actions ExxonMobil will take to address movement of injection or formation fluids that may cause an endangerment to a USDW during the construction, operation, and PISC periods.

The financial assurance coverage value for ERR is estimated to be $8,560,000 in 2025 dollars and is summarized in Table 9-5. This estimate assumes coverage for the following event-based risk activities at the Sunflower Project: the mechanical integrity of injection well casing or cement seals, artificial penetrations of the UCZ, mechanical integrity of operating equipment, and natural features affecting sealing properties of the UCZ. Details regarding the approach used to develop the risk-based scenarios, the levels of severity considered, and the actions to be taken to avoid, monitor, respond to, and notify about the occurrence of risk events are summarized in detail in *Section 8*. Table 9-6 outlines the risked cost estimates for the Emergency and Remedial Response portion of the Financial Assurance cost estimate.

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Table 9- 5– Summary of Estimated ERR Costs Underpinning Financial Assurance Coverages

GS Activity	Estimated Financial Assurance Coverage Value
Mechanical Integrity of Injection Well Casing or Cement Seals	[redacted]
Artificial Penetrations of UCZ	[redacted]
Mechanical Integrity of Operating Equipment	[redacted]
Natural Features Affecting Sealing Properties of the UCZ	[redacted]
Accidents/Unplanned Events	[redacted]
TOTAL:	$8,560,000

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Appendix H – Financial Assurance:

Appendix H-1: Independently Audited, Most Recent Annual Report Filed with SEC
Appendix H-2: Most Recent Quarterly Report Filed with SEC
Appendix H-3: Draft Performance Bond
Appendix H-4: Texas Certification for Bonding Company
Appendix H-5: Cost Estimate and PE Certification

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Appendix H: Financial Assurance

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Appendix H1: Independency Audited, Most Recent Annual Report Filed with SEC

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2025

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

ExxonMobil

FORM 10-K
☑ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2025

or

☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from _____ to _____

Commission File Number 1-2256

Exxon Mobil Corporation

(Exact name of registrant as specified in its charter)

New Jersey	**13-5409005**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification Number)

22777 Springwoods Village Parkway, Spring, Texas 77389-1425

(Address of principal executive offices) (Zip Code)

(972) 940-6000

(Registrant's telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Trading Symbol	Name of Each Exchange on Which Registered
Common Stock, without par value	**XOM**	**New York Stock Exchange**
0.524% Notes due 2028	**XOM28**	**New York Stock Exchange**
0.835% Notes due 2032	**XOM32**	**New York Stock Exchange**
1.408% Notes due 2039	**XOM39A**	**New York Stock Exchange**

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☑ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☑

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☑ No ☐

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☑ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer	☑	Accelerated filer	☐
Non-accelerated filer	☐	Smaller reporting company	☐
		Emerging growth company	☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Indicate by check mark whether the registrant has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7262(b)) by the registered public accounting firm that prepared or issued its audit report. ☑

If securities are registered pursuant to Section 12(b) of the Act, indicate by check mark whether the financial statements of the registrant included in the filing reflect the correction of an error to previously issued financial statements. ☐

Indicate by check mark whether any of those error corrections are restatements that required a recovery analysis of incentive-based compensation received by any of the registrant's executive officers during the relevant recovery period pursuant to §240.10D-1(b). ☐

Indicate by check mark whether the registrant is a shell company (as defined by Rule 12b-2 of the Act). Yes ☐ No ☑

The aggregate market value of the voting stock held by non-affiliates of the registrant on June 30, 2025, the last business day of the registrant's most recently completed second fiscal quarter, based on the closing price on that date of $107.80 on the New York Stock Exchange composite tape, was in excess of $460 billion.

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Class	Outstanding as of January 31, 2026
Common stock, without par value	4,166,763,453

Documents Incorporated by Reference: Proxy Statement for the 2026 Annual Meeting of Shareholders (Part III)

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EXXON MOBIL CORPORATION
FORM 10-K
FOR THE FISCAL YEAR ENDED DECEMBER 31, 2025

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PART I

ITEM 1. BUSINESS

Exxon Mobil Corporation was incorporated in the State of New Jersey in 1882. Divisions and affiliated companies of ExxonMobil operate or market products in the United States and most other countries of the world. Our principal business involves exploration for, and production of, crude oil and natural gas; manufacture, trade, transport and sale of crude oil, natural gas, petroleum products, petrochemicals, and a wide variety of specialty products; and pursuit of lower-emission and other new business opportunities, including carbon capture and storage, hydrogen and ammonia, lower-emission fuels, Proxxima™ resin systems, carbon materials, low-carbon data centers, and lithium. Affiliates of ExxonMobil conduct extensive research programs in support of these businesses.

Exxon Mobil Corporation's divisions and affiliates have many names, including *ExxonMobil*, *Exxon*, *Esso, Mobil* or *XTO*. For convenience and simplicity, in this report the terms *ExxonMobil, Exxon, Esso, Mobil, and XTO*, as well as terms like *Corporation*, *Company*, *our*, *we,* and *its*, are sometimes used as abbreviated references to specific affiliates or groups of affiliates. The precise meaning depends on the context in question.

The energy and petrochemical industries are highly competitive, both within the industries and also with other industries in supplying the energy, fuel, and chemical needs of industrial and individual consumers. Certain industry participants, including ExxonMobil, are expanding the scope of investments in lower-emission energy and emission-reduction services and technologies. The Corporation competes with other firms in the sale or purchase of needed goods and services in many national and international markets and employs all methods of competition which are lawful and appropriate for such purposes.

Operating data and industry segment information for the Corporation are contained in the Financial Section of this report under the following: “Management's Discussion and Analysis of Financial Condition and Results of Operations: Business Results” and Note 3. Information on oil and gas reserves is contained in the “Oil and Gas Reserves” part of the “Supplemental Information on Oil and Gas Exploration and Production Activities” portion of the Financial Section of this report.

ExxonMobil has a long-standing commitment to the development of proprietary technology. We have a wide array of research programs designed to meet the needs identified in each of our businesses. ExxonMobil held over 8 thousand active patents worldwide at the end of 2025. Although technology is an important contributor to the overall operations and results of our Company, the profitability of each business segment is not dependent on any individual patent, trade secret, trademark, license, franchise, or concession.

ExxonMobil operates in a highly complex, competitive, and changing global energy business environment where decisions and risks play out over time horizons that are often decades in length. This long-term orientation underpins the Corporation's philosophy on talent development.

Talent development begins with recruiting exceptional candidates and continues with individually planned experiences and training designed to facilitate broad development and a deep understanding of our business across the business cycle. Our career-oriented approach to talent development results in strong retention and an average length of service of about 30 years for our career employees. Compensation, benefits, and workplace programs support the Corporation's talent management approach, and are designed to attract and retain employees for a career through compensation that is market competitive, long-term oriented, and highly differentiated by individual performance.

With over 59 percent of our global employees from outside the U.S. and more than 160 nationalities represented across the Company, we encourage and respect diversity of thought, ideas, and perspective from our workforce. We are focused on building an engaged, global workforce; grounded in meritocracy, we strive to have every employee reach their potential over a long-term career by providing unrivaled opportunities for personal and professional growth through impactful work meeting society's essential needs.

The number of regular employees was 58 thousand, 61 thousand, and 62 thousand at years ended 2025, 2024, and 2023, respectively. Regular employees are defined as active executive, management, professional, technical, administrative, and wage employees who work full time or part time for the Corporation and are covered by the Corporation’s benefit plans and programs.

As discussed in Item 1A in this report, compliance with existing and potential future government regulations, including taxes, environmental regulations, and other government regulations and policies that directly or indirectly affect the production and sale of our products, may have material effects on the capital expenditures, earnings, and competitive position of ExxonMobil. For additional information on the Corporation's worldwide environmental expenditures, see "Management's Discussion and Analysis of Financial Condition and Results of Operations: Environmental Matters" in the Financial Section of this report.

Information concerning the source and availability of raw materials used in the Corporation’s business, the extent of seasonality in the business, the possibility of renegotiation of profits or termination of contracts at the election of governments, and risks attendant to foreign operations may be found in Item 1A and Item 2 in this report.

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ExxonMobil maintains a website at exxonmobil.com. Our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and any amendments to those reports filed or furnished pursuant to Section 13(a) of the Securities Exchange Act of 1934 are made available through our website as soon as reasonably practical after we electronically file or furnish the reports to the Securities and Exchange Commission (SEC). Also available on the Corporation's website are the Company's Corporate Governance Guidelines, Code of Ethics and Business Conduct, and additional policies as well as the charters of the audit, compensation, and other committees of the Board of Directors. Information on our website is not incorporated into this report.

The SEC maintains an internet site (http://www.sec.gov) that contains reports, proxy and information statements, and other information regarding issuers that file electronically with the SEC.

ITEM 1A. RISK FACTORS

ExxonMobil's financial and operating results are subject to a variety of risks inherent in the global oil, gas, and petrochemical businesses and the pursuit of lower-emission and other new business opportunities. Many of these risk factors are not within the Company's control and could adversely affect our business, our financial and operating results, or our financial condition. These risk factors include:

Supply and Demand

The oil, gas, and petrochemical businesses are fundamentally commodity businesses. This means ExxonMobil's operations and earnings may be significantly affected by changes in oil, gas, and petrochemical prices and by changes in margins on refined products. Oil, gas, petrochemical, and product prices and margins in turn depend on local, regional, and global events or conditions that affect supply and demand for the relevant commodity or product. Any material decline in oil or natural gas prices could have a material adverse effect on the Company's operations, results, financial condition, and proved reserves, especially in the Upstream segment. On the other hand, a material increase in oil or natural gas prices could have a material adverse effect on the Company's operations and results, especially in the Energy Products, Chemical Products, and Specialty Products segments. Our pursuit of lower-emission and other new business opportunities, including carbon capture and storage, hydrogen and ammonia, lower-emission fuels, Proxxima™ resin systems, carbon materials, low-carbon data centers, and lithium also depends on the growth and development of markets for those products and services, including implementation of supportive and stable government policies and developments in existing and new technology to enable those products and services to be provided on a cost-effective basis at commercial scale. See "Climate Change and Energy Transition" in this Item 1A.

Economic conditions. The demand for energy and petrochemicals is generally linked closely with broad-based economic activities and levels of prosperity. The occurrence of economic downturns, recessions or other periods of low or negative economic growth will typically have a direct adverse impact on our results. Other factors that affect general economic conditions in the world or in a major region, such as changes in population growth rates or living standards, periods of civil unrest or armed hostilities, escalating geopolitical volatility, government regulation or austerity programs, national or regional trade tariffs, trade sanctions or trade controls, international monetary and currency exchange rate fluctuations, decoupling of economies, disruption, realignment, or breaking of current or historical trade or military alliances or global trade or supply chain networks, changes in international trade patterns or shipping routes, or a broader breakdown in global trade, security or public health, can also impact the supply and demand for energy and petrochemicals. Sovereign debt downgrades, defaults, extended government shutdowns, inability to access debt markets due to rating, banking, or legal constraints, liquidity crises, market bubbles and corrections, the breakup or restructuring of fiscal, monetary, or political systems such as the European Union, de-dollarization in global trade or the growth or use of alternative common currencies, and other events or conditions that impair the functioning of financial markets and institutions also pose risks to ExxonMobil, including risks to the safety of our financial assets and to the ability of our partners, suppliers, and customers to fulfill their commitments to ExxonMobil. Our future business, including earnings, cash flows, and financing needs, may also be affected by the occurrence, severity, pace, and rate of recovery of future public health epidemics or pandemics or other natural or human events beyond our control; the responsive actions taken by governments and others; and the resulting effects on regional and global markets and economies.

Other demand-related factors. Other factors that may affect the demand for oil, gas, petrochemicals or our other products, and therefore our results, include technological improvements in energy efficiency; seasonal weather patterns; increased competitiveness of, or government policy support for, alternative energy sources or potential substitutes for our products; changes in technology that alter fuel choices, such as technological advances in energy storage or other critical areas that make wind, solar, nuclear, or other alternatives more competitive for power generation; government actions to increase strategic reserves to enhance energy security; increased demand for artificial intelligence (AI), including the construction and expansion of AI data centers; changes in customer or consumer preferences for our products, including consumer demand for alternative-fueled or electric transportation or alternatives to plastic products; and broad-based changes in personal income levels. See also "Climate Change and Energy Transition" below.

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Other supply-related factors. Commodity prices and margins also vary depending on a number of factors affecting supply. For example, increased supply from the development of new or previously inaccessible oil and gas supply sources and technologies to enhance recovery from existing sources tends to reduce commodity prices to the extent such supply increases are not offset by commensurate growth in demand. Similarly, increases in industry refining or petrochemical manufacturing capacity relative to demand tend to reduce margins on the affected products. World oil, gas, and petrochemical supply levels can also be affected by factors that reduce available supplies, such as the level of, and adherence by, participating countries to production quotas established by OPEC or OPEC+ and other agreements among sovereigns; government policies, including actions intended to reduce greenhouse gas emissions, that restrict oil and gas production or increase associated production, reporting or compliance costs; collective actions by non-governmental organizations and financial institutions to withhold funding or support from oil and gas producers; the occurrence of wars or hostile actions, including disruption of land or sea transportation routes; natural disasters; disruptions in competitors' operations; and logistics constraints or unexpected unavailability of distribution channels that may disrupt supplies. There also may be new or emerging factors that could increase global oil, gas, and petrochemical supply levels in the short or long term, such as government policies and actions intended to boost or expand development of domestic or foreign oil and gas reserves or accelerate the pace of production reaching markets, including access to previously unavailable, sanctioned, or protected oil and gas resources or the availability or opening of new shipping routes. Dynamic and unpredictable world events may lead to new oil and gas opportunities becoming available or current opportunities becoming less available or unavailable, and such events may adversely affect our business and results. Technological change can also alter the relative costs for competitors to find, produce and refine oil and gas, and to manufacture petrochemicals.

Other market factors. ExxonMobil's business results are also exposed to potential negative impacts due to changes in interest rates, inflation, currency exchange rates, changes in usage of the U.S. dollar in global trade, and other local or regional market conditions. In addition to direct potential impacts on our costs and revenues, market factors such as rates of inflation may indirectly impact our results to the extent such factors reduce general rates of economic growth and therefore energy demand, as discussed under "Economic conditions." Market factors may also result in losses from commodity derivatives and other instruments we use to hedge price exposures or for commodity and treasury trading activities. Additional information regarding the potential future impact of market factors on our businesses is included or incorporated by reference under Item 7A in this report.

Government and Political Factors

ExxonMobil's results can be adversely affected by political or regulatory developments affecting our businesses or operations.

Access limitations. A number of countries limit access to their oil and gas resources, including by restricting leasing, licensing, or permitting activities directly or indirectly through the influence on these processes by well-funded local or international groups opposing the development of these resources. They also may place resources off-limits from development altogether. Restrictions on production of oil and gas could increase to the extent governments view such measures as a viable approach for pursuing national and global energy, security, and climate policies. Restrictions on foreign investment in the oil and gas sector tend to increase in times of high commodity prices or when national governments may have less need for outside sources of private capital. Many countries also restrict the import or export of certain products based on point of origin, and such restrictions may increase during periods of escalating geopolitical or trade tensions.

Restrictions on doing business. ExxonMobil is subject to laws and sanctions imposed by the United States and by other jurisdictions where we do business that may prohibit ExxonMobil or its affiliates from doing business in certain countries or with certain counterparties or restrict or impede the kind of business that may be conducted, including acquiring and divesting certain assets or importing or exporting certain materials or products. Such restrictions may provide a competitive advantage to competitors who may not be subject to comparable restrictions.

Lack of legal certainty. Some countries in which we do, or seek to do, business lack well-developed legal systems, lack political or governmental stability, may be subject to regime changes, have not yet adopted clear legal frameworks, may be unable to maintain clear regulatory frameworks in the face of pressure on their systems from well-funded local or international groups opposing development of their resources, or may have evolving and unharmonized standards that vary or conflict across jurisdictions. Lack of legal certainty exposes us to increased risk of adverse or unpredictable actions by government officials, may reduce our ability to comply timely or cost-effectively with evolving standards or requirements, and also makes it more difficult for us to enforce our contracts. In some cases, these risks can be partially offset by agreements to arbitrate disputes in an international forum, but the adequacy of this remedy may still depend on the local legal system to enforce an award.

Regulatory and litigation risks. Even in countries with well-developed legal systems where ExxonMobil does business, we remain exposed to changes in law or interpretation or enforcement of settled law, including changes that result from concerted efforts to increase our legal exposure by groups opposed to the products we provide or international treaties and accords or changes by local jurisdictions encroaching on national regulatory frameworks or global issues or changes resulting from imposition of extraterritorial laws and regulations, and changes in government policy or priorities that could adversely affect our results, such as:

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- increases or changes in taxes, duties, or government royalty rates, including retroactive claims, punitive taxes on oil, gas and petrochemical operations, windfall profit taxes, or global minimum taxes;
- price controls;

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- changes in environmental, advertising, insurance or other regulations or laws that penalize us for past or current production of legal and/or permitted products and operations, increase our cost of operation or compliance or reduce or delay available business opportunities, including changes in laws or regulations affecting offshore drilling operations, standards to complete decommissioning, standards for water use or availability, production of our products, emissions, hydraulic fracturing, or production or use of new or recycled plastics, as well as laws and regulations affecting trading, carbon capture and storage, hydrogen and ammonia, lower-emission fuels, Proxxima™ resin systems, carbon materials, low-carbon data centers, or lithium;
- actions by governments, policy-makers, regulators, or other actors to delay or deny necessary licenses and permits, restrict the availability of oil and gas leases, investment opportunities, or the transportation or export of our products, pause, reduce, or retract government incentives for emissions reductions, disrupt or impact reliability as a result of policy decisions on types and pricing of energy available, or otherwise require changes in the Company's business or strategy that could result in reduced returns;
- regulatory interpretations that exclude or disfavor our products under government policies or programs intended to support new or developing markets or technologies, or that otherwise are not technology-neutral;
- adoption of regulations mandating efficiency standards, emission standards, procurement standards, the use of alternative fuels, or uncompetitive fuel components;
- use of regulatory or legal standards by any nation or supranational body as a foreign policy tool;
- unstable policies or shifting regulations impacting new or emerging markets;
- adoption of disclosure regulations that could create competitive disadvantages, require us to incur disproportionate costs, increase legal risk due to a need to rely on uncertain estimates or extrapolations (such as emissions of third parties) and lack of uniform standards across jurisdictions, require us to make statements we disagree with, or require us to disclose competitively sensitive commercial information or to violate the non-disclosure laws of other countries; and
- government actions to cancel contracts, redenominate the official currency, renounce or default on obligations, impose unwarranted penalties, renegotiate terms unilaterally, expropriate assets, or compel a change in production plans.

Legal remedies available to compensate us for expropriation or other takings may be inadequate.

We also may be adversely affected by the outcome of litigation, including class actions or arbitrations, especially in countries such as the United States that permit large and unpredictable punitive and non-economic damage awards. Other jurisdictions adopting similar models to impose liability schemes on our products or operations may present similar risks. We also may be adversely affected by government investigations or enforcement proceedings alleging non-compliance with applicable laws or regulations, or by state and local government actors as well as private plaintiffs acting in parallel that attempt to use the legal system to promote public policy agendas (including seeking to reduce the production and sale of hydrocarbon products through litigation targeting the Company or other industry participants), gain political notoriety, or obtain monetary awards from the Company. The continued adoption of similar legal practices in the European Union or elsewhere would broaden this risk.

Security concerns. Successful operation of particular facilities or projects may be disrupted by civil unrest, military conflict, acts of sabotage, piracy, terrorism, cybersecurity attacks, the application of national security laws or policies that result in restricting our ability to do business in a particular jurisdiction or region, strikes or protests, and other local, national, regional, or global security concerns. Such concerns may be directed specifically at our Company, our industry, or as part of broader movements and may require us to incur greater costs for security or to shut down operations for a period of time.

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Climate Change and Energy Transition

Net-zero scenarios. Driven by concern over the risks of climate change, a number of countries have adopted, or are considering the adoption of, broad-reaching regulatory frameworks seeking to report on or reduce greenhouse gas emissions, including emissions from the production and use of oil and gas and their products, as well as increase the use of, or support for, different emission-reduction technologies. These actions are being taken both independently by national and regional governments and within the framework of United Nations Conference of the Parties summits under which many countries of the world have endorsed objectives to reduce the atmospheric concentration of carbon dioxide (CO2) over the coming decades, with an ambition ultimately to achieve "net zero." Net zero means that emissions of greenhouse gases from human activities would be balanced by actions that remove such gases from the atmosphere. Expectations for transition of the world's energy system to lower-emission sources, and ultimately net-zero, derive from hypothetical scenarios that reflect many assumptions about the future, including supportive policy and technology advancements, and reflect substantial uncertainties. The Company seeks opportunities to play a leading role in the energy transition, including the Company's announced ambition ultimately to achieve net zero with respect to Scope 1 and 2 emissions from our operated assets with continued technology development and government policy support, which carries risks that the transition, including underlying technologies, government policies, and markets as discussed in more detail below, will not be available or develop at the pace or in the manner expected by current net-zero scenarios. Without supportive policies and the innovations they drive, net zero will remain out of reach – for society and for ExxonMobil. Society's progress continues to lag in these areas. The success of our strategy in a lower-emissions future will also depend on our ability to recognize key signposts of changes in the global energy system on a timely basis, and our corresponding ability to direct investment to the technologies and businesses, at the appropriate stage of development, to best capitalize on our competitive strengths.

Greenhouse gas restrictions. Government actions intended to reduce greenhouse gas emissions include adoption of cap and trade regimes, carbon taxes, carbon accounting, carbon-based import duties or other trade tariffs, minimum renewable usage requirements, restrictive permitting, increased mileage and other efficiency standards, mandates for sales of electric vehicles, restrictions on sales of gasoline-only vehicles, mandates for disclosure of plans to reduce emissions or reduce the use or production of certain products, mandates for use of specific fuels or technologies, and other incentives or mandates designed to support certain technologies for transitioning to lower-emission energy sources. Political actors, non-governmental organizations, and their agents also increasingly seek to collectively advance climate change objectives indirectly, such as by seeking to reduce the availability or increase the cost of financing and investment in the oil and gas sector. These actions include delaying or blocking needed infrastructure, utilizing shareholder governance mechanisms against companies or their shareholders or financial institutions in an effort to deter investment in oil and gas activities, and taking other actions intended to promote changes in business strategy for oil and gas companies. Depending on how policies are formulated and applied, such policies could negatively affect our investment returns, make our hydrocarbon-based products more expensive or less competitive, lengthen project implementation times, and reduce demand for hydrocarbons, as well as shift hydrocarbon demand toward relatively lower-carbon alternatives. Current, pending, and potential greenhouse gas regulations or policies may also increase our compliance costs, such as for monitoring or sequestering emissions and complying with increased or mandatory disclosure or due diligence requirements and government-mandated energy transition plans.

Technology and lower-emission solutions. Achieving societal ambitions to reduce greenhouse gas emissions and ultimately achieve net zero will require new technologies and added infrastructure to reduce the cost and increase the scalability of solutions to reduce emissions, as well as technologies such as carbon capture and storage (CCS). CCS technologies, focused initially on capturing and sequestering CO2 emissions from high-carbon intensity industrial activities, can assist in meeting society's objective to mitigate atmospheric greenhouse gas levels while also helping to ensure the availability of the reliable and affordable energy the world requires. ExxonMobil has established a Low Carbon Solutions (LCS) business unit and is continuing efforts in our existing businesses to advance the development and deployment of these technologies and projects, including CCS, hydrogen and ammonia, lower-emission fuels, Proxxima™ resin systems, advanced energy-saving materials, low-carbon data centers, lithium, and other technologies. The Company's efforts include both in-house research and development as well as collaborative efforts with leading universities and with commercial partners involved in new energy technologies. Our future results and ability to grow our business, help others meet their emission-reduction goals, and succeed in a lower-emissions future will depend in part on the success of these research and collaboration efforts and on our ability to adapt and apply the strengths of our current business model to providing the energy products of the future in a cost-competitive manner.

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Policy and market development. The scale of the world's energy system means that, in addition to developments in technology as discussed above, meeting society's needs for energy and reducing emissions will require appropriate support from governments and private participants throughout the global economy. Our ability to develop and deploy CCS and other new energy technologies at commercial scale, and the growth and future returns of LCS and other emerging businesses in which we invest, will depend in part on the development of stable and supportive government policies and markets. Failure or delay of these policies or markets to materialize or be maintained could adversely impact or delay these investments. Policy and other actions that result in restricting the availability of hydrocarbon products without a commensurate reduction in demand may have unpredictable adverse effects, including increased commodity price volatility; periods of significantly higher commodity prices and resulting inflationary pressures; and local or regional energy shortages. Such effects in turn may depress economic growth or lead to rapid or conflicting shifts in policy by different actors, with resulting adverse effects on our businesses. In addition, the existence of supportive policies in any jurisdiction is not a guarantee that those policies will continue in the future. See also the discussion of "Supply and Demand," "Government and Political Factors," and "Operational and Other Factors" in this Item 1A.

Operational and Other Factors

In addition to external economic and political factors, our future business results also depend on our ability to successfully manage those factors that are, at least in part, within our control, including our investment into existing and new businesses. The extent to which we manage these factors will impact our performance relative to competition. For projects in which we are not the operator, we depend on the management effectiveness of one or more co-venturers whom we do not control.

Exploration and development program. Our ability to maintain and grow our oil and gas production depends on the success of our exploration and development efforts. Among other factors, we must continuously improve our ability to identify the most promising resource prospects and apply our project management expertise to bring discovered resources online as scheduled and within budget.

Project and portfolio management. The long-term success of ExxonMobil's Upstream and Product Solutions businesses, as well as the future success of LCS and other emerging investments, depends on complex, long-term, capital-intensive projects. These projects in turn require a high degree of project management expertise to maximize efficiency. Specific factors that can affect the performance of major projects include our ability to: negotiate successfully with joint venturers, partners, governments, suppliers, customers, or others; protect and enforce our contractual and legal rights, including with our joint venture partners, host governments, and others; model and optimize reservoir performance and production reliability; develop markets for project outputs, whether through long-term contracts or the development of effective spot markets; qualify for certain incentives available under supportive government policies for emerging markets and technologies; manage changes in operating conditions and costs, including costs of third-party equipment or services such as drilling rigs and shipping, supply chain disruptions, and inflationary cost pressures; prevent, to the extent possible, and respond effectively to unforeseen technical difficulties that could delay project start-up, incur or escalate costs, or cause unscheduled project downtime; and influence the performance of project operators where ExxonMobil does not perform that role. In addition to the effective management of individual projects, ExxonMobil's success, including our ability to mitigate risk and provide attractive returns to shareholders, depends on our ability to successfully manage our overall portfolio, including diversification among types and locations of our projects, products produced, and strategies to acquire or divest assets. We may not be able to acquire or divest assets at a price or on the timeline we contemplate in our strategies. Additionally, we may retain certain liabilities following a divestment and could be held liable for past use or for different liabilities than anticipated, including reversion of decommissioning or other liabilities upon bankruptcy or other default of successors in title.

The term "project" as used in this report can refer to a variety of different activities and does not necessarily have the same meaning as in any government payment transparency reports.

Operational efficiency. An important component of ExxonMobil's competitive performance, especially given the commodity-based nature of many of our businesses, is our ability to operate efficiently, including our ability to manage expenses, improve production yields on an ongoing basis, and successfully integrate and achieve the anticipated synergies of acquisitions. This requires continuous management focus, including technology integration and improvements, cost control, productivity enhancements, harmonizing functions, policies, procedures and processes, regular reappraisal of our asset portfolio, and the recruitment, development, and retention of high caliber employees.

Research and development and technological change. To maintain our competitive position, especially in light of the technological nature of our businesses, the dynamic and rapidly evolving technological landscape, and the need for continuous efficiency improvement, ExxonMobil's technology, research, and development organizations must be successful and able to adapt to a changing market, regulatory, and policy environment, both nationally and internationally, including continuous improvement in the efficiency of hydraulic fracturing technology and developing technologies to help reduce greenhouse gas emissions. To remain competitive, we must also continuously adapt and capture the benefits of new and emerging technologies, such as AI, including successfully applying advances in the ability to process and integrate large amounts of data to our businesses and decision-making processes.

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Safety, business controls, and risk management. Our results depend on management's ability to minimize the inherent risks of oil, gas, and petrochemical operations, as well as potential risks related to new energy and other technologies, to effectively control our business activities, including trading, and to minimize the potential for human error. We apply rigorous management systems and continuous focus on workplace safety, spills avoidance, and other adverse environmental events. For example, we work to minimize spills through a combined program of effective operations integrity management, ongoing upgrades, key equipment replacements, and comprehensive inspection and surveillance. Similarly, we are implementing cost-effective new technologies and adopting new operating practices to reduce emissions, not only in response to government requirements but also to address community priorities. We employ a robust and actively evolving enterprise risk management system to identify and manage risk across our businesses. We also maintain a disciplined framework of internal controls and apply a controls management system for monitoring compliance with this framework. Substantial liabilities and other adverse impacts could result if we do not timely identify and mitigate applicable risks, or if our management systems and controls do not function as intended.

Cybersecurity. ExxonMobil is regularly subject to attempted cybersecurity disruptions from a variety of sources including state-sponsored actors. See Item 1C in this report for information on ExxonMobil's program for managing cybersecurity risks. If the measures we are taking to protect against cybersecurity disruptions prove to be insufficient or if our proprietary data is otherwise not protected, ExxonMobil, as well as our customers, employees, or third parties, could be adversely affected. We have limited ability to influence third parties, including our partners, suppliers, and service providers (including providers of cloud-hosting services for our data or applications), to implement strong cybersecurity controls and are exposed to potential harm from cybersecurity events that may affect their operations. Cybersecurity disruptions could cause physical harm to people or the environment; damage or destroy assets; compromise business systems; result in proprietary information being altered, lost, or stolen; result in employee, customer, or third-party information being compromised; or otherwise disrupt our business operations. We could incur significant costs to remedy the effects of a major cybersecurity disruption in addition to costs in connection with resulting regulatory actions, litigation, or reputational harm.

Preparedness. Our operations may be disrupted by severe weather events, natural disasters, human error, and similar events. For example, hurricanes may damage our offshore production facilities or coastal refining and petrochemical plants in vulnerable areas. Our facilities are designed, engineered, constructed, and operated to withstand a variety of extreme climatic and other conditions, with safety factors built in to cover a number of uncertainties, including those associated with wave, wind, and current intensity, marine ice flow patterns, permafrost stability, storm surge magnitude, temperature extremes, extreme rainfall events, and earthquakes. Our consideration of changing weather conditions and inclusion of safety factors in design cover the engineering uncertainties that climate change and other events may potentially introduce. Our ability to mitigate the adverse impacts of these events depends in part upon the effectiveness of our robust facility engineering, our rigorous disaster preparedness and response, and business continuity planning.

Insurance limitations. The ability of the Corporation to insure against many of the risks it faces as described in this Item 1A is limited by the availability and cost of coverage, which may not be economic, as well as the capacity of the applicable insurance markets, which may not be sufficient.

Competition. As noted in Item 1 above, the energy and petrochemical industries are highly competitive. We face competition not only from other private firms, but also from state-owned companies that are increasingly competing for opportunities outside of their home countries and as partners with other private firms. In some cases, these state-owned companies may pursue opportunities in furtherance of strategic, national, or supranational objectives of their government owners, with less focus on financial returns than companies owned by private shareholders, such as ExxonMobil. Technology and expertise provided by industry service companies or AI may also enhance the competitiveness of firms that may not have the internal resources and capabilities of ExxonMobil or reduce the need for resource-owning countries to partner with private-sector oil and gas companies in order to monetize national resources. As described in more detail above, our hydrocarbon-based energy products are also subject to growing and, in many cases, government-supported competition from alternative energy sources. In addition, as we enter new markets in pursuit of lower-emission and other new business opportunities, we will need to compete effectively with established competitors in these markets, as well as with new market entrants seeking to capitalize on these opportunities, while successfully navigating changing market conditions or technologies.

Reputation. Our reputation is an important corporate asset. Factors that could have a negative impact on our reputation include an operating incident or significant cybersecurity disruption; changes in consumer views concerning our products; changes in consumer media preferences from traditional mainstream media to decentralized and personalized media; a perception by investors or others that the Corporation is making insufficient progress with respect to our ambition to play a leading role in the energy transition, or that pursuit of this ambition may result in allocation of capital to investments with reduced returns; divergent and evolving societal views and investor pressures regarding a future energy transition; and other adverse events such as those described in this Item 1A. Negative impacts on our reputation could in turn make it more difficult for us to compete successfully for new opportunities, obtain necessary regulatory approvals, obtain financing, and attract talent, or they could reduce customer or consumer demand for our branded products. ExxonMobil's reputation may also be harmed by events which negatively affect the image of our industry as a whole.

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Projections, estimates, and descriptions of ExxonMobil's plans and objectives included or incorporated in Items 1, 1A, 1C, 2, 5, 7, and 7A of this report are forward-looking statements. Actual future results, including project completion dates, production rates, capital expenditures, costs, and business plans could differ materially due to, among other things, the factors discussed above and elsewhere in this report.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 1C. CYBERSECURITY

The Corporation recognizes the importance of cybersecurity in achieving its business objectives, safeguarding its assets, and managing its daily operations. Accordingly, the Corporation integrates cybersecurity risks into its overall enterprise risk management system. The Audit Committee oversees the Corporation's risk management approach and structure, which includes an annual review of the Corporation's cybersecurity program.

The Corporation's cybersecurity program is managed by the Corporation's Vice President of Information Technology (IT), with support from cross-functional teams led by ExxonMobil IT and operational technology (OT) cybersecurity operations managers (collectively, Cybersecurity Operations Managers). The Cybersecurity Operations Managers are responsible for the day-to-day management and effective functioning of the cybersecurity program, including the prevention, detection, investigation, and response to cybersecurity threats and incidents. The Cybersecurity Operations Managers collectively have many years of experience in cybersecurity operations.

IT management provides regular reports to the Corporation's senior management throughout the year, and to the Audit Committee or the Board of Directors, as appropriate, in its annual cybersecurity review. Such reports typically address, among other things, the Corporation's cybersecurity strategy, initiatives, key security metrics, penetration testing and benchmarking learnings, and business response plans as well as the evolving cybersecurity threat landscape.

The Corporation's cybersecurity program includes multi-layered technological capabilities designed to prevent and detect cybersecurity disruptions and leverages industry standard frameworks, including the National Institute of Standards and Technology Cybersecurity Framework. The cybersecurity program incorporates an incident response plan to engage cross-functionally across the Corporation and report cybersecurity incidents to appropriate levels of management, including senior management, and the Audit Committee or Board of Directors, based on potential impact. The Corporation conducts annual cybersecurity awareness training and routinely tests cybersecurity awareness and business preparedness for response and recovery, which are developed based on real-world threats. In addition, the Corporation exchanges threat information with governmental and industry groups and proactively engages independent, third-party cybersecurity experts to test, evaluate, and recommend improvements on the effectiveness and resiliency of its cybersecurity program through penetration testing, breach assessments, regular cybersecurity incident drill testing, threat information sharing, and industry benchmarking. The Corporation takes a risk-based approach with respect to its third-party service providers, tailoring processes according to the nature and sensitivity of the data or systems accessed by such third-party service providers, and performing additional risk screenings and procedures, as appropriate.

As of the date of this report, we have not identified any risks from known cybersecurity threats, including as a result of any prior cybersecurity incidents, that have materially affected, or are reasonably likely to materially affect the Corporation, including our business strategy, results of operations, or financial condition.

While the Corporation believes its cybersecurity program to be appropriate for managing constantly evolving cybersecurity risks, no program can fully protect against all possible adverse events. For additional information on these risks and potential consequences if the measures we are taking prove to be insufficient or if our proprietary data is otherwise not protected, see "Item 1A. Risk Factors: Operational and Other Factors -- Cybersecurity" in this report.

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ITEM 2. PROPERTIES

Information with regard to oil and gas producing activities follows:

1. Disclosure of Reserves

A. Summary of Oil and Gas Reserves at Year-End 2025

The table below summarizes the oil-equivalent proved reserves in each geographic area and by product type for consolidated subsidiaries and equity companies. Natural gas is converted to an oil-equivalent basis at six billion cubic feet per one million barrels. The Corporation has reported proved reserves on the basis of the average of the first-day-of-the-month price for each month during the last 12-month period. No major discovery or other favorable or adverse event has occurred since December 31, 2025, that would cause a significant change in the estimated proved reserves as of that date.

Proved Reserves	Crude Oil (million bbls)	Natural Gas Liquids (million bbls)	Bitumen (million bbls)	Synthetic Oil (million bbls)	Natural Gas (billion cubic ft)	Oil-Equivalent Total All Products (million bbls)
Developed						
Consolidated Subsidiaries						
United States	1,552	1,075	—	—	11,206	4,495
Canada/Other Americas [(1)]	586	1	2,230	288	356	3,164
Europe	3	—	—	—	338	60
Africa	185	—	—	—	111	204
Asia	1,871	44	—	—	2,010	2,251
Australia/Oceania	32	6	—	—	3,057	548
Total Consolidated	4,229	1,126	2,230	288	17,078	10,722
Equity Companies						
United States	5	3	—	—	48	16
Europe	2	—	—	—	207	36
Africa	7	—	—	—	775	136
Asia	462	134	—	—	4,782	1,394
Total Equity Company	476	137	—	—	5,812	1,582
Total Developed	**4,705**	**1,263**	**2,230**	**288**	**22,890**	**12,304**
Undeveloped						
Consolidated Subsidiaries						
United States	1,558	988	—	—	5,581	3,476
Canada/Other Americas [(1)]	609	—	100	—	171	737
Europe	—	—	—	—	—	—
Africa	32	—	—	—	2	32
Asia	1,089	23	—	—	189	1,143
Australia/Oceania	28	2	—	—	2,653	472
Total Consolidated	3,316	1,013	100	—	8,596	5,860
Equity Companies						
United States	—	—	—	—	—	—
Europe	3	—	—	—	56	12
Africa	—	—	—	—	—	—
Asia	163	161	—	—	4,866	1,135
Total Equity Company	166	161	—	—	4,922	1,147
Total Undeveloped	**3,482**	**1,174**	**100**	**—**	**13,518**	**7,007**
Total Proved Reserves	**8,187**	**2,437**	**2,330**	**288**	**36,408**	**19,311**

[(1)] Other Americas includes proved developed reserves of 486 million barrels of crude oil and 228 billion cubic feet of natural gas, as well as proved undeveloped reserves of 587 million barrels of crude oil and 162 billion cubic feet of natural gas.

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In the preceding reserves information, consolidated subsidiary and equity company reserves are reported separately. However, the Corporation operates its business with the same view of equity company reserves as it has for reserves from consolidated subsidiaries.

The Corporation anticipates several projects will come online over the next few years providing additional production capacity. However, actual volumes will vary from year to year due to the timing of individual project start-ups, operational outages, reservoir performance, regulatory changes, the impact of fiscal and commercial terms, asset sales, weather events, price effects on production sharing contracts, changes in the amount and timing of capital investments that may vary depending on the oil and gas price environment, international trade patterns and relations, and other factors described in Item 1A.

The estimation of proved reserves, which is based on the requirement of reasonable certainty, is an ongoing process based on rigorous technical evaluations, commercial and market assessments, and detailed analysis of reservoir and well performance. Furthermore, the Corporation only records proved reserves for projects which have received significant funding commitments by management toward the development of the reserves. Although the Corporation is reasonably certain that proved reserves will be produced, the timing and amount recovered can be affected by a number of factors including completion of development projects, reservoir performance, regulatory approvals, government policies, consumer preferences, and significant changes in crude oil and natural gas price levels. In addition, proved reserves could be affected by an extended period of low prices which could reduce the level of the Corporation's capital spending and also impact our partners' capacity to fund their share of joint projects.

B. Technologies Used in Establishing Proved Reserves Additions in 2025

Additions to ExxonMobil's proved reserves in 2025 were based on estimates generated through the integration of available and appropriate geological, engineering and production data, utilizing well-established technologies that have been demonstrated in the field to yield repeatable and consistent results.

Data used in these integrated assessments included information obtained directly from the subsurface via wellbores, such as well logs, reservoir core samples, fluid samples, static and dynamic pressure information, production test data, and surveillance and performance information. The data utilized also included subsurface information obtained through indirect measurements, including high-quality 3-D and 4-D seismic data, calibrated with available well control information. The tools used to interpret the data included seismic processing software, reservoir modeling and simulation software, and data analysis packages.

In some circumstances, where appropriate analog reservoirs were available, reservoir parameters from these analogs were used to increase the quality of, and confidence in, the reserves estimates.

C. Qualifications of Reserves Technical Oversight Group and Internal Controls over Proved Reserves

ExxonMobil has a dedicated Global Reserves and Resources group that provides technical oversight and is separate from the operating organization. Primary responsibilities of this group include oversight of the reserves estimation process for compliance with Securities and Exchange Commission (SEC) rules and regulations, review of annual changes in reserves estimates, and the reporting of ExxonMobil's proved reserves. This group also maintains the official company reserves estimates for ExxonMobil's proved reserves of crude oil, natural gas liquids, bitumen, synthetic oil, and natural gas. In addition, the group provides training to personnel involved in the reserves estimation and reporting process within ExxonMobil and its affiliates. The current Global Reserves and Resources Manager has more than 30 years of experience in reservoir engineering and reserves assessment, has a degree in Engineering, and serves on the Oil and Gas Reserves Committee of the Society of Petroleum Engineers. The group is staffed with individuals that have an average of more than 15 years of technical experience in the petroleum industry, including expertise in the classification and categorization of reserves under SEC guidelines. This group includes individuals who hold degrees in either Engineering or Geology.

The Global Reserves and Resources group maintains a central database containing the official company reserves estimates. Appropriate controls, including limitations on database access and update capabilities, are in place to ensure data integrity within this central database. An annual review of the system's controls is performed by internal audit. Key components of the reserves estimation process include technical evaluations, commercial and market assessments, analysis of well and field performance, and long-standing approval guidelines. No changes may be made to the reserves estimates in the central database, including additions of any new initial reserves estimates or subsequent revisions, unless these changes have been thoroughly reviewed and evaluated by duly authorized geoscience and engineering professionals within the operating organization. In addition, changes to reserves estimates that exceed certain thresholds require further review and approval by the appropriate level of management within the operating organization before the changes may be made in the central database. Endorsement by the Global Reserves and Resources group for all proved reserves changes is a mandatory component of this review process. After all changes are made, reviews are held with senior management for final endorsement.

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2. Proved Undeveloped Reserves

At year-end 2025, approximately 7.0 billion oil-equivalent barrels (GOEB) of ExxonMobil's proved reserves were classified as proved undeveloped. This represents 36 percent of the 19.3 GOEB reported in proved reserves. This compares to 7.4 GOEB of proved undeveloped reserves reported at the end of 2024. During the year, ExxonMobil conducted development activities that resulted in the transfer of approximately 1.4 GOEB from proved undeveloped to proved developed reserves by year-end. The largest transfers were related to development activities in the United States, Guyana, Kazakhstan, the United Arab Emirates, Qatar, and Canada. In 2025, extensions and discoveries, primarily in the United States and Guyana, resulted in the addition of approximately 2.0 GOEB of proved undeveloped reserves. Also, the Corporation reclassified approximately 1.0 GOEB of proved undeveloped reserves which no longer met the SEC definition of proved reserves, primarily in the United States.

Overall, investments of $19.0 billion were made by the Corporation during 2025 to progress the development of reported proved undeveloped reserves, including $18.8 billion for oil and gas producing activities, along with additional investments for other non-oil and gas producing activities such as the construction of support infrastructure and other related facilities.

One of ExxonMobil's requirements for reporting proved reserves is that management has made significant funding commitments toward the development of the reserves. ExxonMobil has a disciplined investment strategy and many major fields require long lead-time in order to be developed. Development projects typically take several years from the time of recording proved undeveloped reserves to the start of production and can exceed five years for large and complex projects. Proved undeveloped reserves in Australia and the United Arab Emirates have remained undeveloped for five years or more primarily due to constraints on the capacity of infrastructure, as well as the time required to complete development for very large projects. The Corporation is reasonably certain that these proved reserves will be produced; however, the timing and amount recovered can be affected by a number of factors including completion of development projects, reservoir performance, regulatory approvals, government policies, consumer preferences, the pace of co-venturer/government funding, changes in the amount and timing of capital investments, and significant changes in crude oil and natural gas price levels. Of the proved undeveloped reserves that have been reported for five or more years, over 80 percent are contained in the aforementioned countries. In Australia, proved undeveloped reserves are associated with future compression for the Gorgon Jansz LNG project. In the United Arab Emirates, proved undeveloped reserves are associated with an approved development plan and continued drilling investment for the producing Upper Zakum field.

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3. Oil and Gas Production, Production Prices and Production Costs

A. Oil and Gas Production

The table below summarizes production by final product sold and by geographic area for the last three years.

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(thousands of barrels daily)	2025		2024		2023	
	Crude Oil	NGL	Crude Oil	NGL	Crude Oil	NGL
Crude oil and natural gas liquids production						
Consolidated Subsidiaries						
United States	1,005	514	862	383	556	238
Canada/Other Americas [1]	381	1	346	2	240	2
Europe	2	—	2	—	2	—
Africa	141	—	206	2	216	4
Asia	445	28	422	26	417	28
Australia/Oceania	18	7	20	10	24	12
Total Consolidated Subsidiaries	1,992	550	1,858	423	1,455	284
Equity Companies						
United States	2	1	2	1	8	1
Europe	1	—	1	—	2	—
Africa	1	—	1	—	1	—
Asia	266	61	206	59	216	60
Total Equity Companies	270	62	210	60	227	61
Total crude oil and natural gas liquids production	**2,262**	**612**	**2,068**	**483**	**1,682**	**345**
Bitumen production						
Consolidated Subsidiaries						
Canada/Other Americas	385		374		355	
Synthetic oil production						
Consolidated Subsidiaries						
Canada/Other Americas	68		62		67	
Total liquids production	**3,329**		**2,987**		**2,449**	
(millions of cubic feet daily)						
Natural gas production available for sale						
Consolidated Subsidiaries						
United States	3,346		2,869		2,292	
Canada/Other Americas [1]	27		101		96	
Europe	228		252		266	
Africa	2		45		35	
Asia	968		907		915	
Australia/Oceania	1,283		1,264		1,298	
Total Consolidated Subsidiaries	5,854		5,438		4,902	
Equity Companies						
United States	18		18		19	
Europe	71		100		148	
Africa	112		107		90	
Asia	2,386		2,415		2,575	
Total Equity Companies	2,587		2,640		2,832	
Total natural gas production available for sale	**8,442**		**8,078**		**7,734**	
(thousands of oil-equivalent barrels daily)						
Oil-equivalent production	**4,736**		**4,333**		**3,738**	

[1] Other Americas includes crude oil production for 2025, 2024, and 2023 of 320 thousand, 285 thousand, and 178 thousand barrels daily, respectively; and natural gas production available for sale for 2025, 2024, and 2023 of 4 million, 76 million, and 67 million cubic feet daily, respectively.

Due to rounding, numbers presented may not add up precisely to the totals indicated.

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B. Production Prices and Production Costs

The table below summarizes average production prices and average production costs by geographic area and by product type for the last three years.

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(dollars per unit)	United States	Canada/ Other Americas	Europe	Africa	Asia	Australia/ Oceania	Total
2025							
Consolidated Subsidiaries							
Average production prices							
Crude oil, per barrel	63.19	67.75	63.24	69.20	68.26	66.21	65.64
NGL, per barrel	20.87	28.98	47.44	—	30.83	47.75	21.71
Natural gas, per thousand cubic feet	1.07	1.21	11.91	1.90	2.27	7.72	3.15
Bitumen, per barrel	—	46.13	—	—	—	—	46.13
Synthetic oil, per barrel	—	63.61	—	—	—	—	63.61
Average production costs, per oil-equivalent barrel - total	11.07	15.63	30.70	20.38	5.15	5.60	11.29
Average production costs, per barrel - bitumen	—	19.95	—	—	—	—	19.95
Average production costs, per barrel - synthetic oil	—	40.41	—	—	—	—	40.41
Equity Companies							
Average production prices							
Crude oil, per barrel	62.71	—	63.64	66.94	61.75	—	61.79
NGL, per barrel	20.77	—	—	—	40.91	—	40.62
Natural gas, per thousand cubic feet	2.71	—	11.75	5.51	6.79	—	6.84
Average production costs, per oil-equivalent barrel - total	30.49	—	102.43	4.48	2.53	—	4.49
Total							
Average production prices							
Crude oil, per barrel	63.19	67.75	63.39	69.19	65.84	66.21	65.18
NGL, per barrel	20.87	28.98	47.44	—	37.75	47.75	23.64
Natural gas, per thousand cubic feet	1.08	1.21	11.88	5.46	5.48	7.72	4.28
Bitumen, per barrel	—	46.13	—	—	—	—	46.13
Synthetic oil, per barrel	—	63.61	—	—	—	—	63.61
Average production costs, per oil-equivalent barrel - total	11.13	15.63	48.26	18.43	3.75	5.60	10.20
Average production costs, per barrel - bitumen	—	19.95	—	—	—	—	19.95
Average production costs, per barrel - synthetic oil	—	40.41	—	—	—	—	40.41
2024							
Consolidated Subsidiaries							
Average production prices							
Crude oil, per barrel	73.36	79.47	74.07	81.29	78.40	79.83	76.57
NGL, per barrel	23.08	30.43	63.29	50.51	32.34	38.74	24.32
Natural gas, per thousand cubic feet	0.37	1.72	10.56	2.25	2.55	8.47	3.13
Bitumen, per barrel	—	54.02	—	—	—	—	54.02
Synthetic oil, per barrel	—	74.16	—	—	—	—	74.16
Average production costs, per oil-equivalent barrel - total	10.89	16.20	25.18	21.85	5.31	6.92	11.70
Average production costs, per barrel - bitumen	—	21.16	—	—	—	—	21.16
Average production costs, per barrel - synthetic oil	—	44.44	—	—	—	—	44.44
Equity Companies							
Average production prices							
Crude oil, per barrel	73.91	—	76.34	73.99	73.17	—	73.21
NGL, per barrel	19.94	—	—	—	47.63	—	47.19
Natural gas, per thousand cubic feet	1.59	—	9.19	4.10	7.52	—	7.41
Average production costs, per oil-equivalent barrel - total	26.41	—	63.76	7.27	2.70	—	4.57
Total							
Average production prices							
Crude oil, per barrel	73.36	79.47	75.06	81.25	76.69	79.83	76.23
NGL, per barrel	23.07	30.43	63.29	50.51	43.01	38.74	27.16
Natural gas, per thousand cubic feet	0.37	1.72	10.17	3.55	6.17	8.47	4.53
Bitumen, per barrel	—	54.02	—	—	—	—	54.02
Synthetic oil, per barrel	—	74.16	—	—	—	—	74.16
Average production costs, per oil-equivalent barrel - total	10.94	16.20	36.41	20.68	3.93	6.92	10.53
Average production costs, per barrel - bitumen	—	21.16	—	—	—	—	21.16
Average production costs, per barrel - synthetic oil	—	44.44	—	—	—	—	44.44

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(dollars per unit)	United States	Canada/ Other Americas	Europe	Africa	Asia	Australia/ Oceania	Total
2023							
Consolidated Subsidiaries							
Average production prices							
Crude oil, per barrel	75.45	80.51	71.99	82.70	79.50	70.26	78.43
NGL, per barrel	23.88	24.44	64.10	44.72	29.81	34.35	25.12
Natural gas, per thousand cubic feet	1.16	2.57	13.64	2.04	2.40	9.31	4.26
Bitumen, per barrel	—	49.64	—	—	—	—	49.64
Synthetic oil, per barrel	—	77.56	—	—	—	—	77.56
Average production costs, per oil-equivalent barrel - total	9.70	19.94	36.37	20.70	5.26	5.55	12.05
Average production costs, per barrel - bitumen	—	23.80	—	—	—	—	23.80
Average production costs, per barrel - synthetic oil	—	45.91	—	—	—	—	45.91
Equity Companies							
Average production prices							
Crude oil, per barrel	75.48	—	77.82	71.92	74.59	—	74.63
NGL, per barrel	19.13	—	—	—	45.64	—	45.19
Natural gas, per thousand cubic feet	5.25	—	22.22	5.89	8.54	—	9.15
Average production costs, per oil-equivalent barrel - total	53.49	—	43.99	6.74	2.77	—	5.09
Total							
Average production prices							
Crude oil, per barrel	75.45	80.51	74.13	82.66	77.83	70.26	77.92
NGL, per barrel	23.86	24.44	64.10	44.72	40.59	34.35	28.66
Natural gas, per thousand cubic feet	1.19	2.57	16.71	4.81	6.93	9.31	6.05
Bitumen, per barrel	—	49.64	—	—	—	—	49.64
Synthetic oil, per barrel	—	77.56	—	—	—	—	77.56
Average production costs, per oil-equivalent barrel - total	10.15	19.94	39.09	19.79	3.91	5.55	10.63
Average production costs, per barrel - bitumen	—	23.80	—	—	—	—	23.80
Average production costs, per barrel - synthetic oil	—	45.91	—	—	—	—	45.91

Natural gas is converted to an oil-equivalent basis at six million cubic feet per one thousand barrels.

Average production prices have been calculated by using sales quantities from the Corporation's own production as the divisor. Average production costs have been computed by using net production quantities for the divisor. The volumes of crude oil and natural gas liquids (NGL) production used for this computation are shown in the oil and gas production table in section 3.A. The volumes of natural gas used in the calculation are the production volumes of natural gas available for sale and are also shown in section 3.A. The natural gas available for sale volumes are different from those shown in the reserves table in the "Oil and Gas Reserves" part of the "Supplemental Information on Oil and Gas Exploration and Production Activities" portion of the Financial Section of this report due to volumes consumed or flared.

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4. Drilling and Other Exploratory and Development Activities

A. Number of Net Productive and Dry Wells Drilled

	2025	2024	2023
Net Productive Exploratory Wells Drilled			
Consolidated Subsidiaries			
United States	2	2	—
Canada/Other Americas	1	3	1
Europe	1	—	1
Africa	—	—	—
Asia	—	—	—
Australia/Oceania	—	—	—
Total Consolidated Subsidiaries	4	5	2
Equity Companies			
United States	—	—	—
Europe	—	—	—
Africa	—	—	—
Asia	—	—	—
Total Equity Companies	—	—	—
Total productive exploratory wells drilled	**4**	**5**	**2**
Net Dry Exploratory Wells Drilled			
Consolidated Subsidiaries			
United States	—	—	1
Canada/Other Americas	1	3	3
Europe	1	—	—
Africa	1	—	—
Asia	—	—	—
Australia/Oceania	—	—	—
Total Consolidated Subsidiaries	3	3	4
Equity Companies			
United States	—	—	—
Europe	—	—	—
Africa	—	—	—
Asia	—	—	—
Total Equity Companies	—	—	—
Total dry exploratory wells drilled	**3**	**3**	**4**

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	2025	2024	2023
Net Productive Development Wells Drilled			
Consolidated Subsidiaries			
United States	698	533	446
Canada/Other Americas	14	22	47
Europe	1	1	1
Africa	1	4	4
Asia	5	6	5
Australia/Oceania	1	1	—
Total Consolidated Subsidiaries	720	567	503
Equity Companies			
United States	1	1	2
Europe	1	—	—
Africa	—	—	—
Asia	3	3	6
Total Equity Companies	5	4	8
Total productive development wells drilled	**725**	**571**	**511**
Net Dry Development Wells Drilled			
Consolidated Subsidiaries			
United States	—	10	—
Canada/Other Americas	—	—	—
Europe	—	—	—
Africa	—	1	—
Asia	1	—	—
Australia/Oceania	—	—	—
Total Consolidated Subsidiaries	1	11	—
Equity Companies			
United States	—	—	—
Europe	—	—	—
Africa	—	—	—
Asia	—	—	—
Total Equity Companies	—	—	—
Total dry development wells drilled	**1**	**11**	**—**
Total number of net wells drilled	**733**	**590**	**517**

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B. Exploratory and Development Activities Regarding Oil and Gas Resources Extracted by Mining Technologies

Syncrude Operations. Syncrude is a joint venture established to recover shallow deposits of oil sands using open-pit mining methods to extract the crude bitumen, and then upgrade it to produce a high-quality, light (32 degrees API), sweet, synthetic crude oil. Imperial Oil Limited is the owner of a 25 percent interest in the joint venture. Exxon Mobil Corporation has a 69.6 percent interest in Imperial Oil Limited. In 2025, the Company's share of net production of synthetic crude oil was about 68 thousand barrels per day and share of net acreage was about 55 thousand acres in the Athabasca oil sands deposit.

Kearl Operations. Kearl is a joint venture established to recover shallow deposits of oil sands using open-pit mining methods to extract the crude bitumen. Imperial Oil Limited holds a 70.96 percent interest in the joint venture and ExxonMobil Canada Properties holds the other 29.04 percent. Exxon Mobil Corporation has a 69.6 percent interest in Imperial Oil Limited and a 100 percent interest in ExxonMobil Canada Properties. Kearl is comprised of six oil sands leases covering about 49 thousand acres in the Athabasca oil sands deposit.

Kearl is located approximately 40 miles north of Fort McMurray, Alberta, Canada. Bitumen is extracted from oil sands and processed through bitumen extraction and froth treatment trains. The product, a blend of bitumen and diluent, is shipped to our refineries and to other third parties. Diluent is natural gas condensate or other light hydrocarbons added to the crude bitumen to facilitate transportation. During 2025, average net production at Kearl was about 264 thousand barrels per day.

5. Present Activities

A. Wells Drilling

Wells Drilling	Year-End 2025		Year-End 2024	
	Gross	Net	Gross	Net
Consolidated Subsidiaries				
United States	638	492	809	648
Canada/Other Americas	33	20	19	9
Europe	—	—	1	1
Africa	2	—	5	1
Asia	9	2	13	5
Australia/Oceania	1	—	1	—
Total Consolidated Subsidiaries	683	514	848	664
Equity Companies				
United States	38	—	15	—
Europe	—	—	—	—
Africa	—	—	—	—
Asia	23	4	43	4
Total Equity Companies	61	4	58	4
Total gross and net wells drilling	**744**	**518**	**906**	**668**

B. Review of Principal Ongoing Activities

United States

During 2025, ExxonMobil was active in areas onshore and offshore in the lower 48 states and in Alaska. During the year, development activities focused on liquids-rich opportunities in the onshore U.S., primarily in the Permian Basin of West Texas and New Mexico, bringing total U.S. net production to 2.1 million oil-equivalent barrels per day. Development activities also continued on the Golden Pass LNG export project, including mechanical completion of Train 1 in late 2025.

Oil and gas exploration and production rights are acquired from mineral interest owners through a lease. Mineral interest owners include the Federal and State governments, as well as private mineral interest owners. Leases typically have a primary term ranging from one to 10 years, and a production period beyond the primary term that normally remains in effect until production

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ceases. Under certain circumstances, a lease may be held beyond its primary term even if production has not commenced. In some instances a “fee interest” is acquired in private property where the underlying mineral interests and rights are purchased and owned outright.

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Canada / Other Americas

Production operations for the region are mainly in Canada, Guyana, and Brazil. Total operations in Canada provided 519 thousand oil-equivalent barrels per day in net production, where oil and gas operations are active onshore in Alberta and offshore in Newfoundland and Labrador. In Situ Bitumen operations also continue in Alberta. Canadian onshore licenses or leases are acquired for varying periods of time, with renewals or extensions possible. These licenses or leases generally define a specified scope of work and are held by production. Canadian offshore production licenses are valid for 25 years, with rights of extension for continued production. Significant discovery licenses in the offshore relating to currently undeveloped discoveries do not have a definite term.

In Guyana, the Yellowtail development commenced operations with the ONE GUYANA floating production, storage and offloading vessel, and development activities continued on the Uaru and Whiptail projects. The Hammerhead project was funded in 2025. The Petroleum Activities Act 2023 authorizes the Government of Guyana to license and enter petroleum agreements for petroleum exploration, development, production, and storage operations. The Act enables petroleum agreements to provide for an exploration period to be established by subsidiary legislation by the Minister (typically up to 10 years) and provide for a production period of 20 years for an oil field and 30 years for a gas field, each with a renewal period of up to 10 years.

Brazil commenced operations in the Bacalhau Phase 1 development with the start-up of the floating production, storage and offloading vessel.

Europe

The Pegasus-1 exploratory well was drilled offshore Cyprus and encountered a gas-bearing reservoir. Evaluations are ongoing to develop potential commercialization options.

Africa

ExxonMobil continued to participate in the Coral South Floating LNG in Mozambique, while operations continued in three producing deepwater blocks in Angola and three producing deepwater blocks in Nigeria. In Angola, a total of 1.6 net acres were relinquished and Block 15 amended its Production Sharing Agreement to extend the production license to 2037.

Asia

In 2025, ExxonMobil exited Thailand operations, while production activities continued throughout the region. Kazakhstan operations take place onshore and offshore through our partnerships in Tengiz and Kashagan. During the year, the Tengiz Expansion Project was completed and production ramped up to name-plate capacity. In Qatar, ExxonMobil participated in 45.7 million tonnes per year of gross liquefied natural gas capacity and 3.4 billion cubic feet per day of flowing gas capacity. Development activities continued on the North Field East and North Field Production Sustainment projects. Ongoing activities in the United Arab Emirates continued on the phased development of the Upper Zakum field.

Australia / Oceania

In Australia, development activities progressed on the Jansz-Io Compression Project and the Gorgon Stage 3 project was fully funded. Australia and Papua New Guinea account for 22.5 million metric tons of LNG per year.

Worldwide Exploration

Exploration activities were under way in several countries in which ExxonMobil has no established production operations and thus are not included above. Net acreage totaled 15.8 million acres at year-end 2025.

6. Delivery Commitments

ExxonMobil sells crude oil and natural gas from its producing operations under a variety of contractual obligations, some of which may specify the delivery of a fixed and determinable quantity for periods longer than one year. ExxonMobil also enters into natural gas sales contracts where the source of the natural gas used to fulfill the contract can be a combination of our own production and the spot market. Worldwide, we are contractually committed to deliver approximately 73 million barrels of oil and 2.9 trillion cubic feet of natural gas for the period from 2026 through 2028. We expect to fulfill the majority of these delivery commitments with production from our proved developed reserves. Any remaining commitments will be fulfilled with production from our proved undeveloped reserves and purchases on the open market as necessary.

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7. Oil and Gas Properties, Wells, Operations and Acreage

A. Gross and Net Productive Wells

Gross and Net Productive Wells	Year-End 2025				Year-End 2024			
	Oil		Gas		Oil		Gas	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Consolidated Subsidiaries								
United States	25,816	15,760	3,270	1,833	30,333	17,078	7,579	4,340
Canada/Other Americas	4,143	4,067	2,815	983	4,092	4,025	2,865	1,017
Europe	363	106	352	192	371	113	359	192
Africa	352	94	—	—	359	94	—	—
Asia	797	244	140	83	789	243	151	87
Australia/Oceania	46	8	103	38	326	48	104	40
Total Consolidated Subsidiaries	31,517	20,279	6,680	3,129	36,270	21,601	11,058	5,676
Equity Companies								
United States	2,551	322	3,291	323	2,573	329	3,303	326
Europe	57	20	174	64	57	20	332	102
Africa	—	—	6	2	—	—	6	2
Asia	239	60	142	36	233	58	150	31
Total Equity Companies	2,847	402	3,613	425	2,863	407	3,791	461
Total gross and net productive wells	**34,364**	**20,681**	**10,293**	**3,554**	**39,133**	**22,008**	**14,849**	**6,137**

There were 22,778 gross and 20,151 net operated wells at year-end 2025 and 25,610 gross and 22,837 net operated wells at year-end 2024. The number of wells with multiple completions was 418 gross in 2025 and 434 gross in 2024.

B. Gross and Net Developed Acreage

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Gross and Net Developed Acreage *(thousands of acres)*	Year-End 2025		Year-End 2024	
	Gross	Net	Gross	Net
Consolidated Subsidiaries				
United States	7,715	5,083	10,668	7,021
Canada/Other Americas [(1)]	1,849	1,300	1,903	1,342
Europe	918	546	954	555
Africa	1,455	428	1,455	428
Asia	1,424	422	1,473	427
Australia/Oceania	3,142	1,043	3,142	1,043
Total Consolidated Subsidiaries	16,503	8,822	19,595	10,816
Equity Companies				
United States	581	113	581	113
Europe	2,612	921	3,590	1,109
Africa	178	44	178	44
Asia	630	148	665	152
Total Equity Companies	4,001	1,226	5,014	1,418
Total gross and net developed acreage	**20,504**	**10,048**	**24,609**	**12,234**

[(1)] Includes developed acreage in Other Americas of 348 gross and 151 net thousands of acres for 2025 and 379 gross and 190 net thousands of acres for 2024.

Separate acreage data for oil and gas are not maintained because, in many instances, both are produced from the same acreage.

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C. Gross and Net Undeveloped Acreage

Gross and Net Undeveloped Acreage *(thousands of acres)*	Year-End 2025		Year-End 2024	
	Gross	Net	Gross	Net
Consolidated Subsidiaries				
United States	5,189	2,086	6,707	2,632
Canada/Other Americas [(1)]	21,599	10,760	21,457	9,842
Europe	11,908	7,752	11,988	7,770
Africa	12,712	8,060	17,476	11,301
Asia	745	215	766	227
Australia/Oceania	3,346	1,661	3,554	1,805
Total Consolidated Subsidiaries	55,499	30,534	61,948	33,577
Equity Companies				
United States	—	—	—	—
Europe	—	—	381	110
Africa	418	104	418	104
Asia	298	19	298	19
Total Equity Companies	716	123	1,097	233
Total gross and net undeveloped acreage	**56,215**	**30,657**	**63,045**	**33,810**

[(1)] Includes undeveloped acreage in Other Americas of 15,407 gross and 7,527 net thousands of acres for 2025 and 14,914 gross and 6,381 net thousands of acres for 2024.

ExxonMobil's investment in developed and undeveloped acreage is comprised of numerous concessions, blocks, and leases. The terms and conditions under which the Corporation maintains exploration and/or production rights to the acreage are property-specific, contractually defined, and vary significantly from property to property. Work programs are designed to ensure that the exploration potential of any property is fully evaluated before expiration. In some instances, the Corporation may elect to relinquish acreage in advance of the contractual expiration date if the evaluation process is complete and there is not a business basis for extension. In cases where additional time may be required to fully evaluate acreage, the Corporation has generally been successful in obtaining extensions. The scheduled expiration of leases and concessions for undeveloped acreage over the next three years is not expected to have a material adverse impact on the Corporation.

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Information with regard to refining and chemical capacity:

ExxonMobil manufactures, trades, and sells petroleum and petrochemical products. Our refining and chemical operations are highly integrated and encompass a global network of manufacturing plants, transportation systems, and distribution centers that provide a range of fuels, specialty products, feedstocks, olefins, polyolefins, and a wide variety of other products to our customers around the world.

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Capacity At Year-End 2025 [1]

			ExxonMobil Interest %	ExxonMobil's Share of Refining Capacity [2]	Ethylene	Polyethylene	Polypropylene
				(thousands of barrels daily)	*(millions of metric tons per year)*		
United States							
Joliet	Illinois	■	100	267	—	—	—
Baton Rouge	Louisiana	■ ▲ ●	100	523	1.1	1.3	1.0
Baytown	Texas	■ ▲ ●	100	565	4.0	—	0.8
Beaumont	Texas	■ ▲ ●	100	612	0.9	1.7	—
Corpus Christi	Texas	●	50	—	0.9	0.7	—
Mont Belvieu	Texas	●	100	—	—	2.3	—
Total United States				1,967	6.9	6.0	1.8
Canada							
Strathcona	Alberta	■	69.6	197	—	—	—
Nanticoke	Ontario	■	69.6	113	—	—	—
Sarnia	Ontario	■ ●	69.6	124	0.3	0.5	—
Total Canada				434	0.3	0.5	—
Europe							
Antwerp	Belgium	■ ●	100	318	—	0.4	—
Meerhout	Belgium	●	100	—	—	0.5	—
Karlsruhe	Germany	■	25	78	—	—	—
Rotterdam	Netherlands	■ ▲ ●	100	192	—	—	—
Fawley	United Kingdom	■ ▲ ●	100	265	—	—	—
Fife [3]	United Kingdom	●	50	—	0.4	—	—
Total Europe				853	0.4	0.9	—
Asia Pacific							
Fujian	China	■ ●	25	67	0.3	0.2	0.2
Huizhou	China	●	100	—	1.6	1.7	0.9
Singapore	Singapore	■ ▲ ●	100	592	1.9	1.9	1.0
Total Asia Pacific				659	3.8	3.8	2.1
Middle East							
Al Jubail	Saudi Arabia	▲ ●	50	—	0.7	0.7	—
Yanbu	Saudi Arabia	■ ●	50	200	1.0	0.7	0.2
Total Middle East				200	1.7	1.4	0.2
Total Worldwide				**4,113**	**13.1**	**12.5**	**4.1**

■ Energy Products ▲ Specialty Products ● Chemical Products

[1] ExxonMobil share reflects 100 percent for operations of ExxonMobil and majority-owned subsidiaries. For companies owned 50 percent or less, ExxonMobil share is the greater of ExxonMobil's interest or that portion of distillation capacity normally available to ExxonMobil.

[2] Refining capacity data is based on 100 percent of rated refinery process unit stream-day capacities to process inputs to atmospheric distillation units under normal operating conditions, less the impact of shutdowns for regular repair and maintenance activities, averaged over an extended period of time. The listing excludes refining capacity for a minor interest held through equity securities in the Laffan Refinery in Qatar for which results are reported in the Upstream segment.

[3] The Corporation announced the planned closure of the Fife Ethylene Plant, with shutdown activities expected to be completed in 2026.

Due to rounding, numbers presented above may not add up precisely to the totals indicated.

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Information with regard to retail fuel sites:

Within the Energy Products segment, retail fuels sites sell products and services throughout the world through our *Exxon*, *Esso,* and *Mobil* brands.

Number of Retail Fuel Sites At Year-End 2025

	Owned/leased	Distributors/resellers	Total
United States	—	10,206	10,206
Canada	—	2,561	2,561
Europe	169	3,430	3,599
Asia Pacific	188	932	1,120
Latin America	—	579	579
Middle East/Africa	168	300	468
Worldwide	**525**	**18,008**	**18,533**

ITEM 3. LEGAL PROCEEDINGS

ExxonMobil has elected to use a $1 million threshold for disclosing environmental proceedings.

Refer to the relevant portions of Note 7 of the Financial Section of this report for additional information on legal proceedings.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

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Information about our Executive Officers (positions and ages as of February 18, 2026)

Name	Age	Current and Prior Positions (up to five years)
Darren W. Woods	61	**Chairman of the Board and Chief Executive Officer** (since January 1, 2017) **Director and President** (since January 1, 2016)
Neil A. Chapman	63	**Senior Vice President** (since January 1, 2018)
Neil A. Hansen	51	**Senior Vice President and Chief Financial Officer** (since February 1, 2026) President, Global Business Solutions (May 1, 2025 - January 31, 2026) Senior Vice President, Energy Products, ExxonMobil Product Solutions Company (April 1, 2022 - April 30, 2025) Vice President, Europe, Africa & Middle East Fuels, ExxonMobil Fuels & Lubricants Company (March 15, 2020 - March 31, 2022)
Jack P. Williams, Jr.	62	**Senior Vice President** (since June 1, 2014)
Daniel L. Ammann	53	**Vice President** (since May 1, 2022) President, ExxonMobil Upstream Company (since February 1, 2025) President, Low Carbon Solutions (May 1, 2022 - December 31, 2024) Chief Executive Officer, Cruise LLC (January 2019 - December 2021)
James R. Chapman	56	**Vice President, Treasurer and Investor Relations** (since May 1, 2024) Vice President, Tax and Treasurer (November 28, 2022 - April 30, 2024) Dominion Energy, Inc. (prior to November 28, 2022): Executive Vice President, Chief Financial Officer and Treasurer (January 2019 - November 2022)
Matt R. Crocker	52	**Vice President** (since May 1, 2025) President, Global Business Solutions (November 1, 2023 - April 30, 2025) Senior Vice President, Strategy, Product and New Assets, Low Carbon Solutions (May 1, 2022 - October 31, 2023) Senior Vice President, Fuels and Lubricants, ExxonMobil Fuels & Lubricants Company (September 1, 2020 - April 30, 2022)
Len M. Fox	62	**Vice President, Controller and Tax** (since May 1, 2024) Vice President and Controller (March 1, 2021 - April 30, 2024)
Jon M. Gibbs	54	**Senior President, ExxonMobil Global Operations** (since January 1, 2026) President, ExxonMobil Global Projects Company (April 1, 2021 - December 31, 2025) Senior Vice President, Global Project Delivery, ExxonMobil Global Projects Company (July 1, 2020 - March 31, 2021)
Staale Gjervik	52	**President, ExxonMobil Global Projects Company** (since January 1, 2026) President, ExxonMobil Supply Chain (May 1, 2023 - December 31, 2025) President, ExxonMobil Global Services Company (July 1, 2020 - April 30, 2023)
Darrin L. Talley	61	**Vice President, Corporate Strategic Planning** (since April 1, 2022) President, ExxonMobil Research and Engineering Company (April 1, 2020 - March 31, 2022)
Jeffrey A. Taylor	61	**Vice President, General Counsel and Corporate Secretary** (since July 1, 2024) Deputy General Counsel (May 9, 2024 - June 30, 2024) Executive Vice President and General Counsel, Fox Corporation (March 1, 2021 - May 8, 2024) Executive Vice President and Chief Litigation Counsel, Fox Corporation (March 1, 2019 - February 28, 2021)

Officers are generally elected by the Board of Directors at its meeting on the day of each annual election of directors, with each such officer serving until a successor has been elected and qualified. The above-named officers are required to file reports under Section 16 of the Securities Exchange Act of 1934.

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PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

The principal exchange where ExxonMobil common stock (XOM) is traded is the New York Stock Exchange, although the stock is traded on other exchanges in and outside the United States.

There were 276,536 registered shareholders of ExxonMobil common stock at December 31, 2025. At January 31, 2026, the registered shareholders of ExxonMobil common stock numbered 273,961.

On January 29, 2026, the Corporation declared a $1.03 dividend per common share, payable March 10, 2026.

Reference is made to Item 12 in Part III of this report.

Issuer Purchases of Equity Securities for Quarter Ended December 31, 2025

	Total Number of Shares Purchased [1]	Average Price Paid per Share [2]	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs [3]	Approximate Dollar Value of Shares that May Yet Be Purchased Under the Program (Billions of dollars) [4]
October 2025	16,203,130	$113.58	16,203,068	$23.3
November 2025	13,456,104	$116.69	13,025,924	$21.8
December 2025	16,753,598	$117.81	14,908,290	$20.0
Total	**46,412,832**	**$116.01**	**44,137,282**	

[1] *Includes shares withheld from participants in the Company's incentive program for personal income taxes.*

[2] *Excludes 1% U.S. excise tax on stock repurchases.*

[3] *Purchases were made under terms intended to qualify for exemption under Rules 10b-18 and 10b5-1.*

[4] *The Corporation completed share repurchases of $20 billion in 2025. In its 2025 Corporate Plan Update released December 9, 2025, the Corporation stated that it expects share repurchases of $20 billion in 2026, assuming reasonable market conditions.*

During the fourth quarter, the Corporation did not issue or sell any unregistered equity securities.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Reference is made to the section entitled "Management's Discussion and Analysis of Financial Condition and Results of Operations" in the Financial Section of this report.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Reference is made to the section entitled "Market Risks" in the Financial Section of this report. All statements, other than historical information incorporated in this Item 7A, are forward-looking statements. The actual impact of future market changes could differ materially due to, among other things, factors discussed in this report.

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ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Reference is made to the following in the Financial Section of this report:

- Consolidated financial statements, together with the report thereon of PricewaterhouseCoopers LLP (PCAOB ID 238) dated February 18, 2026, beginning with the section entitled "Report of Independent Registered Public Accounting Firm" and continuing through Note 20;
- "Supplemental Information on Oil and Gas Exploration and Production Activities" (unaudited); and
- "Frequently Used Terms" (unaudited).

Financial Statement Schedules have been omitted because they are not applicable or the required information is shown in the consolidated financial statements or notes thereto.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Management's Evaluation of Disclosure Controls and Procedures

As indicated in the certifications in Exhibit 31 of this report, the Corporation's Chief Executive Officer, Chief Financial Officer, and Principal Accounting Officer have evaluated the Corporation's disclosure controls and procedures as of December 31, 2025. Based on that evaluation, these officers have concluded that the Corporation's disclosure controls and procedures are effective in ensuring that information required to be disclosed by the Corporation in the reports that it files or submits under the Securities Exchange Act of 1934, as amended, is accumulated and communicated to them in a manner that allows for timely decisions regarding required disclosures and are effective in ensuring that such information is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission's rules and forms.

Management's Report on Internal Control over Financial Reporting

Management, including the Corporation's Chief Executive Officer, Chief Financial Officer, and Principal Accounting Officer, is responsible for establishing and maintaining adequate internal control over the Corporation's financial reporting. Management conducted an evaluation of the effectiveness of internal control over financial reporting based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that Exxon Mobil Corporation's internal control over financial reporting was effective as of December 31, 2025.

PricewaterhouseCoopers LLP, an independent registered public accounting firm, audited the effectiveness of the Corporation's internal control over financial reporting as of December 31, 2025, as stated in their report included in the Financial Section of this report.

Changes in Internal Control over Financial Reporting

There were no changes during the Corporation's last fiscal quarter that materially affected, or are reasonably likely to materially affect, the Corporation's internal control over financial reporting.

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ITEM 9B. OTHER INFORMATION

During the three months ended December 31, 2025, none of the Company's directors or officers adopted or terminated a "Rule 10b5-1 trading arrangement" or "non-Rule 10b5-1 trading arrangement," as each term is defined in Item 408(a) of Regulation S-K.

ITEM 9C. DISCLOSURE REGARDING FOREIGN JURISDICTIONS THAT PREVENT INSPECTIONS

Not applicable.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Reference is made to the section of this report titled "Information about our Executive Officers."

Incorporated by reference to the following from the registrant's definitive proxy statement for the 2026 annual meeting of shareholders (the "2026 Proxy Statement"):

- The section entitled "Election of Directors;"
- The portion entitled "Delinquent Section 16(a) Reports" of the section entitled "Director and Executive Officer Stock Ownership;"
- The portions entitled "Director Qualifications," "Director Nomination Process and Board Succession," and "Code of Ethics and Business Conduct" of the section entitled "Corporate Governance;" and
- The "Director Independence" portion, "Board Meetings and Annual Meeting Attendance" portion, the membership table of the portion entitled "Board Committees," the "Nominating and Governance Committee" portion and the "Audit Committee" portion of the section entitled "Corporate Governance."

The Corporation has adopted an Insider Trading Policy governing the purchase, sale, and/or other dispositions of its securities by its directors, officers, and employees, and the Corporation itself, that the Corporation believes is reasonably designed to promote compliance with insider trading laws, rules and regulations, and the exchange listing standards applicable to the Corporation. A copy of the Corporation's Insider Trading Policy is filed as Exhibit 19 to this report.

ITEM 11. EXECUTIVE COMPENSATION

Incorporated by reference to the sections entitled "Director Compensation," "Compensation Committee Report," "Compensation Discussion and Analysis," "Executive Compensation Tables," "Pay Ratio," and "Pay Versus Performance" of the registrant's 2026 Proxy Statement.

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ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The information required under Item 403 of Regulation S-K is incorporated by reference to the sections entitled "Certain Beneficial Owners" and "Director and Executive Officer Stock Ownership" of the registrant's 2026 Proxy Statement.

Equity Compensation Plan Information

Plan Category	(a) Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants and Rights	(b) Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights	(c) Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans [Excluding Securities Reflected in Column (a)]
Equity compensation plans approved by security holders	45,870,110 [(1)]	—	50,547,885 [(2)(3)]
Equity compensation plans not approved by security holders	—	—	—
Total	**45,870,110**	**—**	**50,547,885**

[(1)] The number of restricted stock units to be settled in shares.

[(2)] Available shares can be granted in the form of restricted stock or other stock-based awards. Includes 40,903,325 shares available for award under the 2003 Incentive Program, 218,700 shares available for award under the 2004 Non-Employee Director Restricted Stock Plan, and 9,425,860 shares available for award under the Pioneer Natural Resources Company Amended and Restated 2006 Long Term Incentive Plan.

[(3)] Under the 2004 Non-Employee Director Restricted Stock Plan approved by shareholders in May 2004, and the related standing resolution adopted by the Board, each non-employee director automatically receives 8,000 shares of restricted stock when first elected to the Board and, if the director remains in office, an additional 2,500 restricted shares each following year. While on the Board, each non-employee director receives the same cash dividends on restricted shares as a holder of regular common stock, but the director is not allowed to sell the shares. The restricted shares may be forfeited if the director leaves the Board early.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Incorporated by reference to the portion entitled "Director Independence" of the section entitled "Corporate Governance" and the portion entitled "Related Person Transactions and Procedures" of the section entitled "Director and Executive Officer Stock Ownership" of the registrant's 2026 Proxy Statement.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

Incorporated by reference to the portion entitled "Audit Committee" of the section entitled "Corporate Governance" and the section entitled "Ratification of Independent Auditors" of the registrant's 2026 Proxy Statement.

PART IV

ITEM 15. EXHIBIT AND FINANCIAL STATEMENT SCHEDULES

(a) (1) and (2) Financial Statements:

See Table of Contents of the Financial Section of this report.

(b) (3) Exhibits:

See Index to Exhibits of this report.

ITEM 16. FORM 10-K SUMMARY

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None.

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FINANCIAL SECTION

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BUSINESS PROFILE

Financial	Earnings (Loss) After Income Taxes 2025	Earnings (Loss) After Income Taxes 2024	Average Capital Employed (Non-GAAP) 2025	Average Capital Employed (Non-GAAP) 2024	Return on Average Capital Employed (Non-GAAP) 2025	Return on Average Capital Employed (Non-GAAP) 2024	Cash Capital Expenditures (Non-GAAP) 2025	Cash Capital Expenditures (Non-GAAP) 2024
	(millions of dollars)		*(millions of dollars)*		*(percent)*		*(millions of dollars)*	
Upstream								
United States	5,063	6,426	118,142	85,285	4.3	7.5	15,907	11,276
Non-U.S.	16,291	18,964	91,792	93,390	17.7	20.3	8,752	8,985
Total	21,354	25,390	209,934	178,675	10.2	14.2	24,659	20,261
Energy Products								
United States	2,992	2,099	13,495	13,190	22.2	15.9	752	705
Non-U.S.	4,431	1,934	24,188	21,135	18.3	9.2	955	1,513
Total	7,423	4,033	37,683	34,325	19.7	11.7	1,707	2,218
Chemical Products								
United States	903	1,627	14,207	14,277	6.4	11.4	843	671
Non-U.S.	(103)	950	15,303	14,760	(0.7)	6.4	552	1,212
Total	800	2,577	29,510	29,037	2.7	8.9	1,395	1,883
Specialty Products								
United States	1,200	1,576	2,025	2,035	59.3	77.4	381	145
Non-U.S.	1,657	1,476	6,048	6,183	27.4	23.9	242	263
Total	2,857	3,052	8,073	8,218	35.4	37.1	623	408
Corporate and Financing	(3,590)	(1,372)	20,575	27,847	—	—	613	877
Corporate total	**28,844**	**33,680**	**305,775**	**278,102**	**9.3**	**12.7**	**28,997**	**25,647**

See Frequently Used Terms for a definition and calculation of capital employed, return on average capital employed, and cash capital expenditures.

Due to rounding, numbers presented may not add up precisely to the totals indicated.

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Operating	2025	2024
Net liquids production *(thousands of barrels daily)*		
United States	1,522	1,248
Non-U.S.	1,805	1,739
Total	3,329	2,987
Natural gas production available for sale *(millions of cubic feet daily)*		
United States	3,364	2,887
Non-U.S.	5,077	5,191
Total	8,442	8,078
Oil-equivalent production [1] *(thousands of oil-equivalent barrels daily)*	4,736	4,333

	2025	2024
Refinery throughput *(thousands of barrels daily)*		
United States	1,927	1,865
Non-U.S.	2,052	2,035
Total	3,979	3,900
Energy Products sales [2] *(thousands of barrels daily)*		
United States	2,852	2,722
Non-U.S.	2,740	2,696
Total	5,593	5,418
Chemical Products sales [2] *(thousands of metric tons)*		
United States	6,977	7,038
Non-U.S.	14,326	12,354
Total	21,303	19,392
Specialty Products sales [2] *(thousands of metric tons)*		
United States	1,894	1,922
Non-U.S.	5,897	5,745
Total	7,791	7,666

[1] Natural gas is converted to an oil-equivalent basis at six million cubic feet per one thousand barrels.

[2] Data reported net of purchases/sales contracts with the same counterparty.

Due to rounding, numbers presented may not add up precisely to the totals indicated.

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FINANCIAL INFORMATION

(millions of dollars, except where stated otherwise)	2025	2024	2023
Sales and other operating revenue	323,905	339,247	334,697
Net income (loss) attributable to ExxonMobil	28,844	33,680	36,010
Earnings (loss) per common share (dollars)	6.70	7.84	8.89
Earnings (loss) per common share – assuming dilution (dollars)	6.70	7.84	8.89
Earnings (loss) to average ExxonMobil share of equity (percent)	11.0	14.4	18.0
Working capital	11,052	21,683	31,293
Ratio of current assets to current liabilities (times)	1.15	1.31	1.48
Additions to property, plant, and equipment [(1)]	31,476	109,332	29,038
Property, plant, and equipment, less allowances	299,373	294,318	214,940
Total assets	448,980	453,475	376,317
Exploration expenses, including dry holes	1,007	826	751
Research and development costs	1,228	987	879
Long-term debt	34,241	36,755	37,483
Total debt	43,537	41,710	41,573
Debt to capital (percent)	14.0	13.4	16.4
Net debt to capital (percent) [(2)]	11.0	6.5	4.5
ExxonMobil share of equity at year-end	259,386	263,705	204,802
ExxonMobil share of equity per common share (dollars)	62.07	60.58	51.57
Weighted-average number of common shares outstanding (millions)	4,305	4,298	4,052
Number of regular employees at year-end (thousands) [(3)]	57.9	60.9	61.5

[(1)] *Includes non-cash additions. See Note 20 for additions resulting from the Pioneer acquisition in 2024.*

[(2)] *Net debt is total debt less cash and cash equivalents excluding restricted cash. Net debt to capital ratio is net debt divided by net debt plus total equity. Total debt is the sum of notes and loans payable and long-term debt, as reported in the Consolidated Balance Sheet.*

[(3)] *Regular employees are defined as active executive, management, professional, technical, administrative, and wage employees who work full time or part time for the Corporation and are covered by the Corporation's benefit plans and programs.*

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FREQUENTLY USED TERMS

Listed below are definitions of several of ExxonMobil's key business and financial performance measures. These definitions are provided to facilitate understanding of the terms and their calculations.

Cash Flow from Operations and Asset Sales (Non-GAAP)

Cash flow from operations and asset sales is the sum of the net cash provided by operating activities and proceeds from asset sales and returns of investments from the Consolidated Statement of Cash Flows. This cash flow reflects the total sources of cash both from operating the Corporation's assets and from the divesting of assets. The Corporation employs a long-standing and regular, disciplined review process to ensure that assets are contributing to the Corporation's strategic objectives. Assets are divested when they are no longer meeting these objectives or are worth considerably more to others. Because of the regular nature of this activity, the Company believes it is useful for investors to consider proceeds associated with the sales of subsidiaries; property, plant, and equipment; and sales and returns of investments together with cash provided by operating activities when evaluating cash available for investment in the business and financing activities, including shareholder distributions.

Cash Flow From Operations and Asset Sales *(millions of dollars)*	2025	2024	2023
Net cash provided by operating activities	51,970	55,022	55,369
Proceeds associated with sales of subsidiaries, property, plant, and equipment, and sales and returns of investments	3,158	4,987	4,078
Cash flow from operations and asset sales (Non-GAAP)	**55,128**	**60,009**	**59,447**

Capital Employed (Non-GAAP)

Capital employed is a measure of net investment. When viewed from the perspective of how the capital is used by the businesses, it includes ExxonMobil's net share of property, plant, and equipment, and other assets less liabilities, excluding both short-term and long-term debt. When viewed from the perspective of the sources of capital employed in total for the Corporation, it includes ExxonMobil's share of total debt and equity. Both of these views include ExxonMobil's share of amounts applicable to equity companies, which the Corporation believes should be included to provide a more comprehensive measure of capital employed.

Capital Employed *(millions of dollars)*	2025	2024	2023
Business uses: asset and liability perspective			
Total assets	448,980	453,475	376,317
Less liabilities and noncontrolling interests share of assets and liabilities			
Total current liabilities excluding notes and loans payable	(63,034)	(65,352)	(61,226)
Total long-term liabilities excluding long-term debt	(75,783)	(75,807)	(60,980)
Noncontrolling interests share of assets and liabilities	(8,895)	(8,069)	(8,878)
Add ExxonMobil share of debt-financed equity company net assets	2,793	3,242	3,481
Total capital employed (Non-GAAP)	**304,061**	**307,489**	**248,714**
Total corporate sources: debt and equity perspective			
Notes and loans payable	9,296	4,955	4,090
Long-term debt	34,241	36,755	37,483
ExxonMobil share of equity	259,386	263,705	204,802
Less noncontrolling interests share of total debt	(1,655)	(1,168)	(1,142)
Add ExxonMobil share of equity company debt	2,793	3,242	3,481
Total capital employed (Non-GAAP)	**304,061**	**307,489**	**248,714**

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FREQUENTLY USED TERMS

Return on Average Capital Employed (Non-GAAP)

Return on average capital employed (ROCE) is a performance measure ratio. From the perspective of the business segments, ROCE is annual business segment earnings divided by average business segment capital employed (average of beginning and end-of-year amounts). These segment earnings include ExxonMobil's share of segment earnings of equity companies, consistent with our capital employed definition, and exclude the cost of financing. The Corporation's total ROCE is net income attributable to ExxonMobil excluding the after-tax cost of financing, divided by total corporate average capital employed. The Corporation has consistently applied its ROCE definition for many years and views it as one of the best measures of historical capital productivity in our capital-intensive, long-term industry. Additional measures, which are more cash flow based, are used to make investment decisions.

Return on Average Capital Employed *(millions of dollars)*	2025	2024	2023
Net income (loss) attributable to ExxonMobil	28,844	33,680	36,010
Financing costs (after-tax)			
Gross third-party debt	(1,360)	(1,106)	(1,175)
ExxonMobil share of equity companies	(165)	(196)	(307)
All other financing costs – net	2,072	(252)	931
Total financing costs	547	(1,554)	(551)
Earnings (loss) excluding financing costs (Non-GAAP)	**28,297**	**35,234**	**36,561**
Average capital employed (Non-GAAP)	305,775	278,102	243,440
Return on average capital employed – Corporate total (Non-GAAP)	**9.3%**	**12.7%**	**15.0%**

Selected Earnings Driver Definitions

The updated earnings drivers introduced in the first quarter of 2024 provide additional visibility into our business results. The Company evaluates these drivers periodically to determine if any enhancements may provide helpful insights to the market. Listed below are descriptions of the earnings drivers:

Advantaged Volume Growth. Represents earnings impacts from change in volume/mix from advantaged assets, advantaged projects, and high-value products.

- *Advantaged Assets (Advantaged growth projects)*. Includes Permian, Guyana, and LNG.
- *Advantaged Projects.* Includes capital projects and programs of work that contribute to Energy, Chemical, and/or Specialty Products segments that drive integration of segments/businesses, increase yield of higher value products, or deliver higher than average returns.
- *High-Value Products.* Includes performance products and lower-emission fuels. Performance products (performance chemicals, performance lubricants) refers to products that provide differentiated performance for multiple applications through enhanced properties versus commodity alternatives and bring significant additional value to customers and end-users. Lower-emission fuels refers to fuels with lower life cycle emissions than conventional transportation fuels for gasoline, diesel, and jet transport.

Base Volume. Represents all volume/mix drivers not included in Advantaged Volume Growth defined above.

Structural Cost Savings. Represents after-tax earnings effects of Structural Cost Savings as defined on the next page, including cash operating expenses related to divestments.

Expenses. Represents all expenses otherwise not included in other earnings drivers.

Timing Effects. Represents timing effects that are primarily related to unsettled derivatives (mark-to-market) and other earnings impacts driven by timing differences between the settlement of derivatives and their offsetting physical commodity realizations (due to LIFO inventory accounting).

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FREQUENTLY USED TERMS

Structural Cost Savings (Non-GAAP)

Structural Cost Savings describes decreases in cash opex excluding energy and production taxes as a result of operational efficiencies, workforce reductions, divestment-related reductions, and other cost-savings measures that are expected to be sustainable compared to 2019 levels. Relative to 2019, estimated cumulative structural cost savings totaled $15.1 billion, which included an additional $3.0 billion in 2025. The total change between periods in expenses below will reflect both Structural Cost Savings and other changes in spend, including market drivers, such as inflation and foreign exchange impacts, as well as changes in activity levels and costs associated with new operations, mergers and acquisitions, new business venture developments, and early-stage projects. Structural Cost Savings from new operations, mergers and acquisitions, and new business venture developments are included in the cumulative Structural Cost Savings. Estimates of cumulative annual Structural Cost Savings may be revised depending on whether cost reductions realized in prior periods are determined to be sustainable compared to 2019 levels. Structural Cost Savings are stewarded internally to support management's oversight of spending over time. This measure is useful for investors to understand the Corporation's efforts to optimize spending through disciplined expense management.

Calculation of Structural Cost Savings *(billions of dollars)*	2019				2025
Components of Operating Costs					
From ExxonMobil's Consolidated Statement of Income (U.S. GAAP)					
Production and manufacturing expenses	36.8				42.4
Selling, general and administrative expenses	11.4				11.1
Depreciation and depletion (includes impairments)	19.0				26.0
Exploration expenses, including dry holes	1.3				1.0
Non-service pension and postretirement benefit expense	1.2				0.4
Subtotal	**69.7**				**81.0**
ExxonMobil's share of equity company expenses (Non-GAAP)	9.1				10.6
Total Adjusted Operating Costs (Non-GAAP)	**78.8**				**91.6**
Total Adjusted Operating Costs (Non-GAAP)	**78.8**				**91.6**
Less:					
Depreciation and depletion (includes impairments)	19.0				26.0
Non-service pension and postretirement benefit expense	1.2				0.4
Other adjustments (includes equity company depreciation and depletion)	3.6				6.2
Total Cash Operating Expenses (Cash Opex) (Non-GAAP)	**55.0**				**59.0**
Energy and production taxes (Non-GAAP)	11.0				14.9

		Market	**Activity/ Other**	**Structural Cost Savings**	
Total Cash Operating Expenses (Cash Opex) excluding Energy and Production Taxes (Non-GAAP)	**44.0**	**+4.9**	**+10.3**	**-15.1**	**44.1**

Due to rounding, numbers presented may not add up precisely to the totals indicated.

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FREQUENTLY USED TERMS

Earnings (loss) excluding Identified Items (Non-GAAP)

Earnings (loss) excluding Identified Items are earnings (loss) excluding individually significant non-operational events with, typically, an absolute Corporate total earnings impact of at least $250 million in a given quarter. The earnings (loss) impact of an identified item for an individual segment in a given quarter may be less than $250 million when the item impacts several periods or several segments. Earnings/(loss) excluding Identified Items does include non-operational earnings events or impacts that are generally below the $250 million threshold utilized for identified items. Management uses these figures to improve comparability of the underlying business across multiple periods by isolating and removing significant non-operational events from business results. The Corporation believes this view provides investors increased transparency into business results and trends and provides investors with a view of the business as seen through the eyes of management. Earnings (loss) excluding Identified Items is not meant to be viewed in isolation or as a substitute for net income (loss) attributable to ExxonMobil as prepared in accordance with U.S. GAAP.

Upstream		2025			2024			2023	
(millions of dollars)	U.S.	Non-U.S.	Total	U.S.	Non-U.S.	Total	U.S.	Non-U.S.	Total
Earnings (loss) (U.S. GAAP)	5,063	16,291	21,354	6,426	18,964	25,390	4,202	17,106	21,308
Impairments	(662)	(422)	(1,084)	(360)	(48)	(408)	(1,978)	(686)	(2,664)
Gain/(loss) on sale of assets	—	—	—	—	385	385	305	—	305
Tax-related items	192	—	192	—	238	238	184	(126)	58
Identified Items	(471)	(422)	(893)	(360)	575	215	(1,489)	(812)	(2,301)
Earnings (loss) excluding Identified Items (Non-GAAP)	**5,534**	**16,713**	**22,247**	**6,786**	**18,389**	**25,175**	**5,691**	**17,918**	**23,609**

Energy Products		2025			2024			2023	
(millions of dollars)	U.S.	Non-U.S.	Total	U.S.	Non-U.S.	Total	U.S.	Non-U.S.	Total
Earnings (loss) (U.S. GAAP)	2,992	4,431	7,423	2,099	1,934	4,033	6,123	6,019	12,142
Impairments	(153)	(113)	(266)	(34)	(59)	(93)	—	—	—
Gain/(loss) on sale of assets	—	720	720	—	—	—	—	—	—
Tax-related items	34	(6)	28	—	172	172	192	(48)	144
Identified Items	(118)	601	483	(34)	113	79	192	(48)	144
Earnings (loss) excluding Identified Items (Non-GAAP)	**3,110**	**3,830**	**6,940**	**2,133**	**1,821**	**3,954**	**5,931**	**6,067**	**11,998**

Chemical Products		2025			2024			2023	
(millions of dollars)	U.S.	Non-U.S.	Total	U.S.	Non-U.S.	Total	U.S.	Non-U.S.	Total
Earnings (loss) (U.S. GAAP)	903	(103)	800	1,627	950	2,577	1,626	11	1,637
Impairments	(130)	(190)	(320)	(43)	(52)	(95)	(21)	(273)	(294)
Tax-related items	50	—	50	—	—	—	53	—	53
Other	—	—	—	—	—	—	—	(147)	(147)
Identified Items	(80)	(190)	(270)	(43)	(52)	(95)	32	(420)	(388)
Earnings (loss) excluding Identified Items (Non-GAAP)	**983**	**87**	**1,070**	**1,670**	**1,002**	**2,672**	**1,594**	**431**	**2,025**

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Specialty Products		2025			2024			2023	
(millions of dollars)	U.S.	Non-U.S.	Total	U.S.	Non-U.S.	Total	U.S.	Non-U.S.	Total
Earnings (loss) (U.S. GAAP)	1,200	1,657	2,857	1,576	1,476	3,052	1,536	1,178	2,714
Impairments	(18)	(12)	(30)	(4)	(8)	(12)	—	(82)	(82)
Tax-related items	30	—	30	—	(1)	(1)	12	5	17
Other	—	—	—	—	—	—	—	(28)	(28)
Identified Items	12	(12)	—	(4)	(9)	(13)	12	(105)	(93)
Earnings (loss) excluding Identified Items (Non-GAAP)	**1,188**	**1,669**	**2,857**	**1,580**	**1,485**	**3,065**	**1,524**	**1,283**	**2,807**

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FREQUENTLY USED TERMS

Corporate and Financing *(millions of dollars)*	2025	2024	2023
Earnings (loss) (U.S. GAAP)	(3,590)	(1,372)	(1,791)
Impairments	(155)	—	—
Gain/(loss) on sale of assets	—	30	—
Tax-related items	(11)	—	76
Restructuring charges	(419)	—	—
Identified Items	(585)	30	76
Earnings (loss) excluding Identified Items (Non-GAAP)	**(3,005)**	**(1,402)**	**(1,867)**

Corporate Total *(millions of dollars)*	2025	2024	2023
Net income (loss) attributable to ExxonMobil (U.S. GAAP)	28,844	33,680	36,010
Impairments	(1,855)	(608)	(3,040)
Gain/(loss) on sale of assets	720	415	305
Tax-related items	288	409	348
Restructuring charges	(419)	—	—
Other	—	—	(175)
Identified Items	(1,265)	216	(2,562)
Earnings (loss) excluding Identified Items (Non-GAAP)	**30,109**	**33,464**	**38,572**

References in this discussion to Corporate earnings (loss) mean net income (loss) attributable to ExxonMobil (U.S. GAAP) from the Consolidated Statement of Income. Unless otherwise indicated, references to earnings (loss), Upstream, Energy Products, Chemical Products, Specialty Products, and Corporate and Financing earnings (loss), and earnings (loss) per share are ExxonMobil's share after excluding amounts attributable to noncontrolling interests.

Due to rounding, numbers presented may not add up precisely to the totals indicated.

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Cash Capital Expenditures (Non-GAAP)

Cash capital expenditures (Cash Capex) are the sum of additions to property, plant, and equipment; additional investments and advances; and other investing activities including collection of advances; reduced by inflows from noncontrolling interests for major projects, each from the Consolidated Statement of Cash Flows. The Company believes it is a useful measure for investors to understand the cash impact of investments in the business, which is in line with industry practice.

(millions of dollars)	2025	2024
Additions to property, plant, and equipment	28,358	24,306
Additional investments and advances	4,133	3,299
Other investing activities including collection of advances	(3,406)	(1,926)
Inflows from noncontrolling interests for major projects	(88)	(32)
Total Cash Capex (Non-GAAP)	**28,997**	**25,647**

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

FORWARD-LOOKING STATEMENTS

Statements related to future events; projections; descriptions of strategic, operating, and financial plans and objectives; statements of future ambitions and plans; future earnings power; potential addressable markets; and other statements of future events or conditions are forward-looking statements. Similarly, discussion of roadmaps or future plans related to carbon capture, transportation and storage, hydrogen and ammonia, lower-emission fuels, direct air capture, Proxxima™ resin systems, carbon materials, low-carbon data centers, lithium, and other future plans to reduce emissions and emissions intensity of ExxonMobil, its affiliates, and third parties are dependent on future market factors, such as continued technological progress, stable policy support, and timely rule-making and permitting, and represent forward-looking statements.

Actual future results, including financial and operating performance; potential earnings, cash flow, dividends or shareholder returns, including the timing and amounts of share repurchases; total capital expenditures and mix, including allocations of capital to low-carbon and other new investments; realization and maintenance of structural cost reductions and efficiency gains, including the ability to offset inflationary pressure; plans to reduce future emissions and emissions intensity, including ambitions to reach Scope 1 and Scope 2 net zero from operated assets by 2050, to reach Scope 1 and 2 net zero in integrated Upstream Permian Basin unconventional operated assets by 2035, to eliminate routine flaring in-line with World Bank Zero Routine Flaring, to reach near-zero methane emissions from operated assets and other methane initiatives, and to meet ExxonMobil's emission reduction plans and goals, divestment and start-up plans, and associated project plans as well as technology advances, including the timing and outcome of projects to capture, transport and store CO2, produce hydrogen and ammonia, produce lower-emission fuels, produce Proxxima™ resin systems, produce carbon materials, produce lithium, and use plastic waste as feedstock for advanced recycling; future debt levels and credit ratings; business and project plans, timing, costs, capacities and profitability; resource recoveries and production rates; and planned Denbury and Pioneer integrated benefits, could differ materially due to a number of factors.

These include global or regional changes or imbalances in the supply and demand for oil, natural gas, petrochemicals, and feedstocks and other market factors; economic conditions and seasonal fluctuations that impact prices, differentials, and volume/mix for our products; developments or changes in local, national, or international laws, regulations, taxes, trade sanctions, trade tariffs, or policies affecting our business, such as government policies supporting lower-carbon and new market investment opportunities, the punitive European taxes on the oil and gas sector and unequal support for different technological methods of emissions reduction or evolving, ambiguous, and unharmonized voluntary and mandatory standards or extraterritorial laws and regulations imposed by various jurisdictions related to sustainability and greenhouse gas reporting; timely granting of governmental permits, licenses, and certifications; uncertain impacts of deregulation on the legal and regulatory environment; changes in interest and exchange rates; variable impacts of trading activities on our margins and results each quarter; actions of co-venturers or partners, competitors, and commercial counterparties, including suppliers and customers; government actions in pursuit of national energy and security policies and priorities affecting our business; the outcome of commercial negotiations, including final agreed terms and conditions; the outcome of competitive bidding and project awards; the ability to access debt markets on favorable terms or at all; the occurrence, pace, rate of recovery and effects of public health crises; adoption of regulatory incentives consistent with law; reservoir performance and optimization, including variability and timing factors applicable to unconventional resources, the success of new unconventional technologies, and the ability of new technologies to improve recovery relative to competitors; the level, outcome, and timing of exploration and development projects and decisions to invest in future reserves and resources; timely completion of construction projects and commencement of start-up operations, including reliance on third-party suppliers and service providers; final management approval of future projects and any changes in the scope, terms, costs, or assumptions of such projects as approved; the actions of governments, non-governmental organizations, or other actors against our core business activities and acquisitions, divestitures or financing opportunities; war, civil unrest, armed hostilities, attacks against the Company or industry, and other geopolitical or security disturbances, including disruption of land or sea transportation routes or distribution or shipping channels; decoupling of economies, disruption, realignment, or breaking of current or historical trade or military alliances or global trade or supply chain networks; escalating geopolitical volatility, including regime changes; expropriations, seizures, or capacity, insurance, shipping, import or export limitations imposed directly or indirectly by governments or laws; opportunities for potential acquisitions, investments or divestments and satisfaction of applicable conditions to closing, including timely regulatory approvals; the capture of efficiencies within and between business lines and the ability to maintain near-term cost reductions as ongoing efficiencies without impairing our competitive positioning; unforeseen technical or operating disruptions or difficulties and unplanned maintenance; the development and competitiveness of alternative energy and emission reduction technologies; consumer preferences including willingness and ability to pay for reduced emission products; the results of research programs and the ability to bring new technologies to commercial scale on a cost-competitive basis; and other factors discussed under Item 1A.

Forward-looking and other statements regarding environmental and other sustainability efforts and aspirations are not an indication that these statements are material to investors or require disclosure in our filing with the SEC or any other regulatory authority. In addition, historical, current, and forward-looking environmental and other sustainability-related statements may be based on standards for

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measuring progress that are still developing, internal controls and processes that continue to evolve, and assumptions that are subject to change in the future, including future rule-making.

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MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Energy demand models are forward-looking by nature and aim to replicate system dynamics of the global energy system, requiring simplifications. The reference to any scenario in this report, including any potential net-zero scenarios, does not imply ExxonMobil views any particular scenario as likely to occur. In addition, energy demand scenarios require assumptions on a variety of parameters. As such, the outcome of any given scenario using an energy demand model comes with a high degree of uncertainty. Third-party scenarios discussed in this report reflect the modeling assumptions and outputs of their respective authors, not ExxonMobil, and their use by ExxonMobil is not an endorsement by ExxonMobil of their underlying assumptions, likelihood, or probability. Investment decisions are made on the basis of ExxonMobil's separate planning process. Any use of the modeling of a third-party organization within this report does not constitute or imply an endorsement by ExxonMobil of any or all of the positions or activities of such organization.

Actions needed to advance ExxonMobil's 2030 greenhouse gas emission-reductions plans are incorporated into its medium-term business plans, which are updated annually. The reference case for planning beyond 2030 is based on ExxonMobil's Global Outlook (Outlook) research and publication. The Outlook is reflective of the existing global policy environment and an assumption of increasing policy stringency and technology improvement to 2050. Current trends for policy stringency and development of lower-emission solutions are not yet on a pathway to achieve net-zero by 2050. As such, the Outlook does not project the degree of required future policy and technology advancement and deployment for the world, or ExxonMobil, to meet net zero by 2050. As future policies and technology advancements emerge, they will be incorporated into the Outlook, and ExxonMobil's business plans will be updated accordingly. References to projects or opportunities may not reflect investment decisions made by ExxonMobil or its affiliates. Individual projects or opportunities may advance based on a number of factors, including availability of stable and supportive policy, permitting, technological advancement for cost-effective abatement, insights from the Corporate planning process, and alignment with our partners and other stakeholders. Capital investment guidance in lower-emission investments is based on our Corporate Plan; however, actual investment levels will be subject to the availability of the opportunity set, public policy support, and focused on returns.

The term "project" as used in this report can refer to a variety of different activities and does not necessarily have the same meaning as in any government payment transparency reports.

OVERVIEW

The following discussion and analysis of ExxonMobil's financial results, as well as the accompanying financial statements and related notes to consolidated financial statements to which they refer, are the responsibility of the management of Exxon Mobil Corporation. The Corporation's accounting and financial reporting fairly reflect its integrated business model involving exploration for, and production of, crude oil and natural gas; manufacture, trade, transport and sale of crude oil, natural gas, petroleum products, petrochemicals, and a wide variety of specialty products; and pursuit of lower-emission and other new business opportunities, including carbon capture and storage, hydrogen and ammonia, lower-emission fuels, Proxxima™ resin systems, carbon materials, low-carbon data centers, and lithium. ExxonMobil's reportable segments are Upstream, Energy Products, Chemical Products, and Specialty Products. Where applicable, ExxonMobil voluntarily discloses additional U.S., non-U.S., and regional splits to help investors better understand the Company's operations.

The Company is organized along three businesses – Upstream, Product Solutions, and Low Carbon Solutions, aligning along market-focused value chains. Product Solutions consists of Energy Products, Chemical Products, and Specialty Products. Low Carbon Solutions is included in Corporate and Financing as the business continues to mature through commercialization and deployment of technology. The businesses are supported by centralized service-delivery groups, including Global Projects, Technology and Engineering, Global Operations, Sustainability, Global Trading, Supply Chain, and Global Business Solutions.

ExxonMobil, with its resource base, financial strength, disciplined investment approach, and technology portfolio, is well-positioned to participate in substantial investments to develop new supplies of reliable and affordable lower-emission energy and other critical products. The Company's integrated business model, with significant investments in the Upstream, Energy Products, Chemical Products, and Specialty Products segments and Low Carbon Solutions businesses, generally reduces the Corporation's risk from changes in commodity prices. While commodity prices depend on supply and demand and may be volatile on a short-term basis, ExxonMobil's investment decisions are grounded on fundamentals reflected in our long-term business outlook, and use a disciplined approach in selecting and pursuing the most attractive investment opportunities which target a low cost of supply to ensure long-term competitiveness. The annual Corporate Plan process establishes the economic assumptions used for evaluating investments and sets operating and capital objectives. The Global Outlook (Outlook), developed annually, is the foundation for the Corporate Plan assumptions. Price ranges for crude oil and natural gas, including price differentials, refinery and chemical margins, volumes, development and operating costs, including greenhouse gas emissions pricing, and foreign currency exchange rates are part of the Corporate Plan assumptions developed annually. Corporate Plan volume projections are based on individual field production profiles,

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which are also updated at least annually. Major investment opportunities are evaluated over a range of potential market conditions. All major investments are reappraised to ensure we learn from our decisions, and the development and execution of the project. Lessons learned are incorporated in future projects.

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MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

BUSINESS ENVIRONMENT

Long-Term Business Outlook

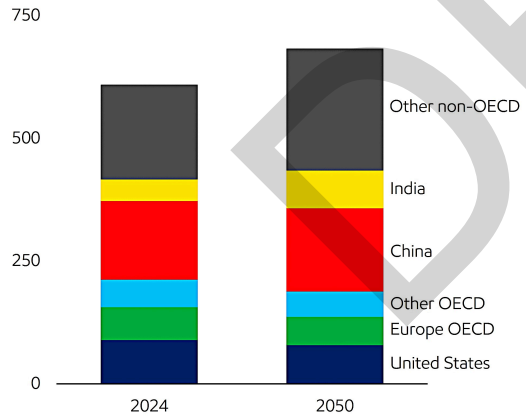
ExxonMobil's business planning is underpinned by a deep understanding of long-term market fundamentals. These fundamentals include supply and demand trends; the scale and variety of energy needs worldwide; capability, practicality, and affordability of energy alternatives, including lower-carbon solutions; greenhouse gas emission-reduction technologies; and relevant government policies. The Outlook considers these fundamentals to form the basis for the Company's long-term business planning, investment decisions, and research programs. The Outlook reflects the Company's view of global energy demand and supply through 2050. It is a projection based on current trends in technology, government policies, consumer preferences, geopolitics, and economic development.

In addition, ExxonMobil considers a range of scenarios, including remote scenarios, to help inform perspective of the future and enhance strategic thinking over time. Included in the range of these scenarios are the Intergovernmental Panel on Climate Change (IPCC) Likely Below 2°C scenarios and three scenarios from the International Energy Agency (IEA): IEA Stated Policies Scenario (STEPS; 2025 World Energy Outlook (WEO)), which reflects a sector-by-sector assessment of current policy in place and those announced by governments; IEA Announced Pledges Scenario (APS; 2024 WEO), which reflects aspirational government targets met on time and in full; and IEA Net Zero Emissions by 2050 Scenario (NZE; 2025 WEO), which the IEA describes as highly ambitious and challenging, acknowledging that society is not currently on the IEA NZE pathway. No single transition pathway can be reasonably predicted, given the wide range of uncertainties. Key unknowns include yet-to-be-developed or changes in developed government policies, market conditions, and advances in technology that may influence the cost, pace, and potential availability of certain pathways. Scenarios that employ a full complement of technology options are likely to provide the most economically efficient pathways.

Using our own experts and third-party sources, we monitor a variety of signposts that may indicate a potential shift in the energy transition. For example, the regional pace of the transition could be influenced by the cost of new technologies compared to existing or alternative energy sources. To effectively evaluate the pace of change, ExxonMobil uses many scenarios to help identify signposts that provide leading indicators of future developments and allow for timely adjustments to future versions of the Outlook.

Developing countries projected to drive energy demand growth

Primary energy - Quadrillion Btu



Source: ExxonMobil 2025 Global Outlook

By 2050, the world's population is projected to be around 9.7 billion people, or nearly 2 billion more than in 2024. Coincident with this population increase, the Outlook projects worldwide economic growth to average approximately 2.5 percent per year, with economic output nearly doubling by 2050 compared to 2024. As economies and populations grow, and as living standards improve for billions of people, the need for energy is expected to continue to rise. Even with significant efficiency gains, global energy demand is projected to rise by over 10 percent from 2024 to 2050. This increase in energy demand is expected to be driven by developing countries (i.e., those that are not member nations of the Organization for Economic Co-operation and Development (OECD)). By contrast, energy use in developed nations is expected to decline by more than 10 percent as efficiency improves.

As expanding prosperity drives global energy demand higher, increasing use of energy-efficient technologies and practices as well as lower-emission products will continue to help significantly reduce energy consumption and CO2 emissions per unit of economic output over time. Substantial efficiency gains are likely in all key aspects of the world's economy through 2050, affecting energy requirements for power generation, transportation, industrial applications, and residential and commercial needs.

Under our Outlook, global electricity demand is expected to increase more than 70 percent from 2024 to 2050, with developing countries likely to account for approximately 80 percent of the increase. Consistent with this projection, power generation is expected to remain the largest and fastest growing major segment of global primary energy demand, supported by a wide variety of energy sources. The share of coal-fired generation is expected to decline substantially to approximately 15 percent of the world's electricity in 2050, versus approximately 35 percent in 2024, in part due to policies to improve air quality as well as reduce greenhouse gas emissions to address risks related to climate change. From 2024 to 2050, the amount of electricity supplied using natural gas, nuclear power, and renewables is expected to more than double, accounting for the entire growth in electricity supplies and offsetting the reduction of coal. Electricity from wind and solar is expected to increase nearly 400 percent, helping total renewables (including other sources, e.g., hydropower) to account for approximately 90 percent of the increase in electricity supplies through 2050. Total

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renewables are expected to reach over 50 percent of global electricity supplies by 2050. Natural gas and nuclear are expected to be about 20 percent and 10 percent, respectively, of global electricity supplies by 2050. Supplies of electricity by energy type will reflect significant differences across regions reflecting a wide range of factors, including the cost and availability of various energy supplies and policy developments.

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MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Energy for transportation - including cars, trucks, ships, trains, and airplanes - is expected to increase by nearly 25 percent from 2024 to 2050. Transportation energy demand is expected to account for over 50 percent of the growth in liquid fuels demand worldwide over this period. Light-duty vehicle demand for liquid fuels is projected to have peaked this decade, and then decline to levels seen in the early-2010s by 2050, as the impact of better fuel economy and significant growth in electric cars, led by China, Europe, and the United States, work to offset growth in the worldwide car fleet of about 60 percent. By 2050, light-duty vehicles are expected to account for around 20 percent of global liquid fuels demand. During the same time period, nearly all the world's commercial transportation fleets are expected to continue to run on liquid fuels, including biofuels, which are expected to be widely available and offer practical advantages in providing a large quantity of energy in small volumes.

Almost half of the world's energy use is dedicated to industrial activity. As the global middle class continues to grow, demand for durable products, appliances, and consumable goods will increase. Industry uses energy products both as a fuel and as a feedstock for chemicals, asphalt, lubricants, waxes, and other specialty products. The Outlook anticipates technology advances, as well as the increasing shift toward cleaner forms of energy, such as electricity and natural gas, with coal declining. Demand for oil will continue to grow as a feedstock for industry.

As populations grow and prosperity rises, more energy will be needed to power homes, offices, schools, shopping centers, hospitals, et cetera Combined residential and commercial energy demand is projected to rise by around 15 percent through 2050. Led by the growing economies of developing nations, average worldwide household electricity use is expected to rise more than 60 percent between 2024 and 2050.

Liquid fuels provide the largest share of global energy supplies today reflecting broad-based availability, affordability, ease of transportation, and fitness as a practical solution to meet a wide variety of needs. By 2050, global demand for liquid fuels is projected to grow to nearly 115 million oil-equivalent barrels per day, an increase of about 10 percent from 2024. The non-OECD share of global liquid fuels demand is expected to increase to about 70 percent by 2050, as liquid fuels demand in the OECD is expected to decline by more than 25 percent. Much of the global liquid fuels demand today is met by crude production from conventional sources; these supplies will remain important, and significant development activity is expected to offset much of the natural declines from these fields. At the same time, a variety of supply sources - including tight oil, deepwater, oil sands, natural gas liquids, and biofuels - are expected to grow to help meet rising demand. Timely investments will remain critical to meeting global needs with reliable and affordable supplies.

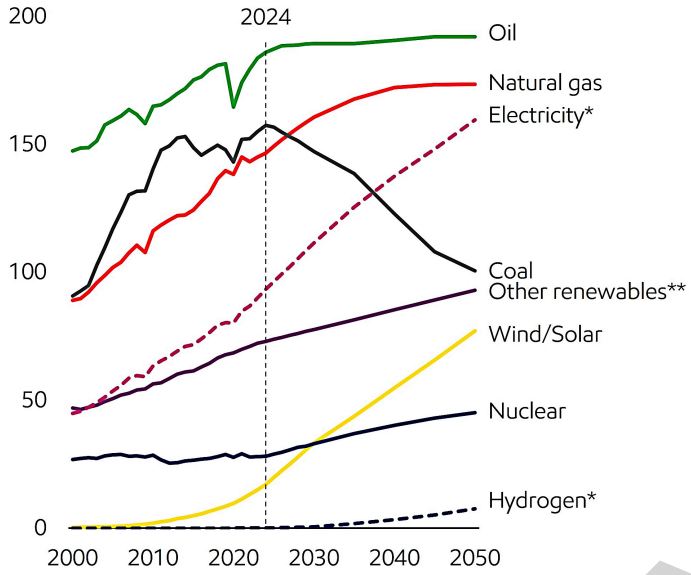
Natural gas is a lower-emission, versatile, and practical fuel for a wide variety of applications. Global natural gas demand is expected to rise nearly 20 percent from 2024 to 2050, with approximately 70 percent of that increase coming from the Asia Pacific region. Significant growth in supplies of unconventional gas - the natural gas found in shale and other tight rock formations - will help meet these needs. In total, over 40 percent of the growth in natural gas supplies is expected to come from unconventional sources. At the same time, conventionally-produced natural gas is likely to remain the cornerstone of global supply, meeting around two-thirds of worldwide demand in 2050. LNG trade will expand significantly, meeting about 75 percent of the increase in global demand growth, with much of this supply expected to help meet rising demand in the Asia Pacific region.

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MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

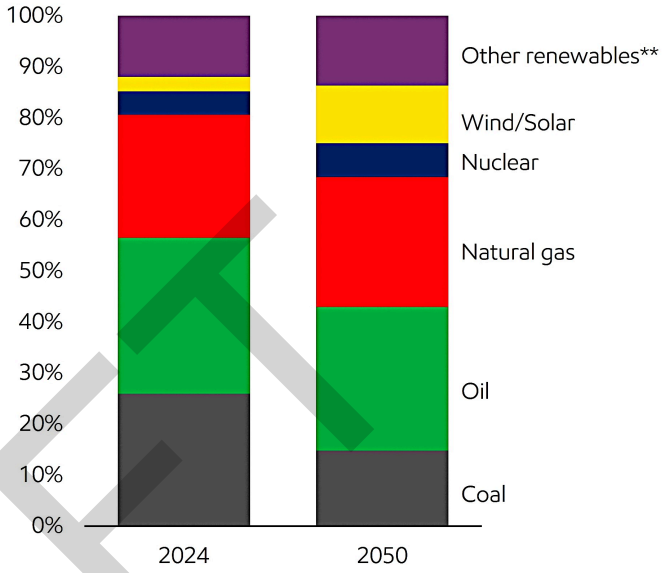
Oil and natural gas projected to play a critical role in the global energy mix

Primary energy - Quadrillion Btu



Source: ExxonMobil 2025 Global Outlook

Percent of primary energy



Source: ExxonMobil 2025 Global Outlook

** Electricity and hydrogen are secondary energies derived from the primary energies shown.*

***Includes biomass, biofuels, hydropower, and geothermal.*

The world's energy mix is highly diverse and will remain so through 2050. Oil is expected to continue as the largest source of energy with its share remaining close to 30 percent in 2050. Coal and natural gas are the next largest sources of energy today, with the share of natural gas growing to more than 25 percent by 2050, while the share of coal falls to about half that of natural gas. Nuclear power is projected to grow, as many nations are likely to expand nuclear capacity to address rising electricity needs as well as energy security and environmental issues. Total renewable energy is expected to exceed 20 percent of global energy by 2050, with other renewables (e.g., biomass, hydropower, geothermal) contributing a combined share of more than 10 percent. Total energy supplied from wind and solar is expected to increase rapidly, growing nearly 350 percent from 2024 to 2050, when they are projected to be greater than 10 percent of the world energy mix.

Decarbonization of industrial activities will require a suite of lower-carbon technologies supported by stable policies. Lower-emission fuels, hydrogen-based fuels, and carbon capture and storage are three key lower-carbon solutions needed to support a lower-emission future, in addition to wind and solar. Along with electrification, lower-emission fuels are expected to play an important role in decarbonization of the transportation sector, particularly in hard-to-decarbonize areas, such as aviation. Hydrogen will be a key enabler replacing traditional furnace fuel to decarbonize the industrial sector. Hydrogen and hydrogen-based fuels like ammonia are also expected to make inroads into commercial transportation as technology improves to lower its cost and policy develops to support the needed infrastructure development. Carbon capture and storage on its own, or in combination with hydrogen production, is among the few proven technologies that could enable CO2 emission reductions from high-emitting and hard-to-decarbonize sectors such as power generation and heavy industries, including manufacturing, refining, and petrochemicals.

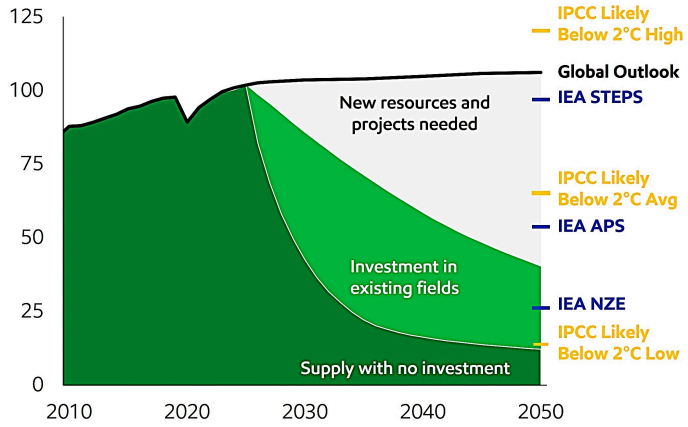
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MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Significant oil and natural gas investment needed to meet projected global demand

Projected global oil supply and demand

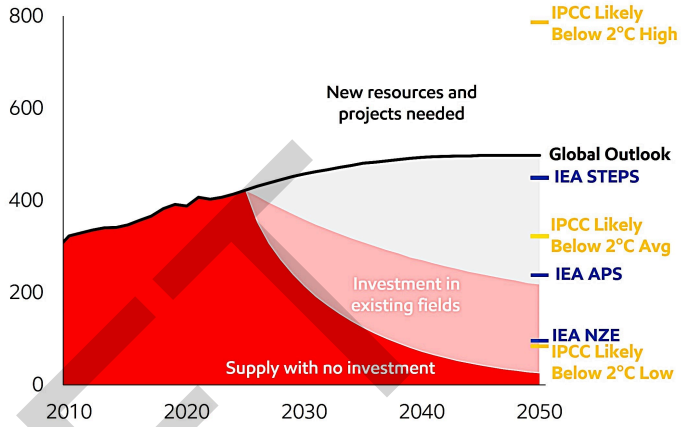
Million barrels per day



Excludes biofuels; IEA STEPS and IEA NZE Source: IEA WEO 2025; IEA APS Source: IEA WEO 2024; Global Outlook Source: ExxonMobil 2025 Global Outlook; IPCC Likely Below 2°C Average Source: IPCC AR6 Scenarios Database hosted by IIASA release 1.0 average IPCC C3:311 "Likely below 2°C" scenarios used; decline rates based on 10-yr Compound Annual Grown Rate (CAGR)

Projected global natural gas supply and demand

Billion cubic feet per day



Excludes flaring; IEA STEPS and IEA NZE Source: IEA WEO 2025; IEA APS Source: IEA WEO 2024; Global Outlook Source: ExxonMobil 2025 Global Outlook; IPCC Likely Below 2°C Average Source: IPCC AR6 Scenarios Database hosted by IIASA release 1.0 average IPCC C3: 311 "Likely below 2°C" scenarios used; decline rates based on 10-yr CAGR

Our Outlook projects that oil demand will remain above 100 million barrels per day to 2050. Even under the average of IPCC Likely Below 2°C scenarios, oil demand still comes to 65 million barrels per day in 2050 – about two thirds of current consumption.

Our Outlook shows oil production declines at a rate of about 15 percent per year. At that rate, in the absence of continued investment, by 2030 oil supplies would fall from 100 million barrels per day to less than 30 million barrels, more than 70 million barrels per day short of what is needed to meet demand. Limiting investment to only existing fields would slow the decline to about 4 percent; however, this would still be well below the oil demand in the average of IPCC Likely Below 2°C scenarios.

To meet projected demand, the Corporation anticipates that the world's available oil and gas resource base will grow, not only from new discoveries, but also from increases in previously discovered fields. Technology will underpin these increases. The investments to develop and supply resources to meet global demand through 2050 will be significant and would be needed to meet even rapidly declining demand for oil and gas envisioned in aggressive decarbonization scenarios.

International accords and underlying regional and national regulations covering greenhouse gas emissions continue to evolve with uncertain timing and outcome, making it difficult to predict their business impact. For many years, the Corporation has taken into account policies established to reduce energy-related greenhouse gas emissions in its long-term Outlook. The climate accord reached at the 2015 Conference of the Parties (COP 21) in Paris set many new goals, and many related policies are still emerging. Our Outlook reflects an environment with increasingly stringent climate policies and seeks to identify potential impacts of these climate-related government policies, which often target specific sectors. For purposes of the Outlook, a proxy cost on energy-related CO2 emissions is assumed, based on regional considerations and relative levels of economic development, and by 2050, reaches up to $150 per metric ton for OECD nations and up to $100 per metric ton for non-OECD nations. As people and nations look for ways to reduce risks of global climate change, they will continue to need practical solutions that do not jeopardize the affordability or reliability of the energy they need. The Corporation continues to monitor the updates to the Nationally Determined Contributions (NDCs) that are submitted by nations that are signatories to the Paris Agreement, as well as other policy developments in light of net-zero ambitions formulated by some nations.

The information provided in the Outlook includes ExxonMobil's internal estimates and projections based upon internal data and analyses as well as publicly available information from external sources including the International Energy Agency.

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MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Progress Reducing Emissions

The Corporation's strategy seeks to maximize the advantages of our scale, business integration, leading technology, execution excellence, and our people to build globally competitive businesses that lead industry in earnings and cash flow growth across a range of future scenarios. We strive to play a leading role, regardless of how an energy transition unfolds. Across our portfolio of opportunities, we retain investment flexibility to maximize shareholder value. In 2022, we announced our ambition to achieve net-zero Scope 1 and 2 greenhouse gas emissions in our operated assets by 2050, with advancements in technology and clear, consistent, stable, and effective government policies. Society's progress continues to lag in these areas. Without supportive policies and the innovations they drive, net zero 2050 will remain out of reach — for society and ExxonMobil. Our net-zero ambition is backed by a comprehensive approach centered on detailed emission-reduction roadmaps for our major operated assets that were completed in 2022. The roadmaps build on the Company's 2030 emission-intensity reduction plans. We continue to update the roadmaps, including to account for portfolio changes, to reflect technology and policy, and to account for the many potential pathways and pace of an energy transition. Our plans include reaching net-zero Scope 1 and 2 emissions in our integrated Permian Basin operated assets by 2035, including Pioneer assets acquired in 2024. By 2030, we plan to reduce emissions in our combined Permian operations by more than the equivalent of achieving net-zero Scope 1 and 2 emissions in our operated heritage ExxonMobil assets.

Compared to 2016 levels, our 2030 plans are expected to drive the following reductions:

- 20-30 percent reduction in corporate-wide greenhouse gas intensity;
- 70-80 percent reduction in corporate-wide methane intensity;
- 40-50 percent reduction in upstream greenhouse gas intensity; and
- 60-70 percent reduction in corporate-wide flaring intensity.

As of year-end 2025, we are exceeding our 2030 plans across the portfolio, having already achieved our plans for reducing Corporate greenhouse gas and flaring intensity. We expect to reach the plan for methane intensity reductions later this year.

Our emission-reduction plans and 2050 net-zero ambition cover Scope 1 and 2 emissions from assets we operate.

The Corporation plans to continue to pursue advantaged growth opportunities and lower-emission investments. These investments are targeted at reducing emissions in the Company's operations as well as reducing the emissions of other companies. At this early stage, stable and supportive policy remains critical to enable emissions reductions, advance technology, and drive scale to improve costs.

ExxonMobil's Low Carbon Solutions business is working with the Product Solutions and Upstream businesses to grow a pipeline of emission-reduction opportunities in carbon capture and storage, hydrogen and ammonia, lower-emission fuels, Proxxima™ resin systems, carbon materials, and low-carbon data centers, as well as lithium to supply the global battery and electric vehicle markets. Our customers, many governments, and strategic partners recognize our combination of experience, skills, and capabilities that have the potential to help reduce emissions for ourselves and others. For example, on the U.S. Gulf Coast, we see an opportunity to grow a carbon capture and storage business that will enable industrial customers to reduce their emissions. Stable policy support, along with technology advancements and the development of market-driven mechanisms, will continue to be important to the development and deployment of lower-emission solutions.

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MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Recent Business Environment

During 2025, the price of crude oil remained near the middle of the pre-COVID 10-year range (2010-2019) as global markets remained broadly balanced. Record crude demand was met by increasing industry supply, resulting in modestly lower prices. Natural gas prices rose to the top end of the 10-year range due to robust demand. Industry refining margins improved in 2025, supported by record full-year demand and an increase in supply disruptions driving higher margins. Despite record demand, global oversupply resulted in Chemical margins remaining at bottom-of-cycle.

During 2025, the U.S. announced a variety of trade-related actions, including the imposition of tariffs on imports from several countries. In response, many countries announced their own retaliatory tariffs. Despite the current uncertainty as to what effects these actions will ultimately have on the Corporation, our suppliers and our customers, as well as on the overall macroeconomic environment, we do not anticipate any material near-term financial impacts.

The Corporation closely monitors market trends and works to mitigate both operating and capital cost impacts in all price environments. Strategic changes implemented over the past several years enabled the Corporation to capture $15.1 billion of structural cost savings[(1)] versus 2019, including $3 billion of savings during 2025, through increased operational efficiencies, workforce reductions, divestment-related reductions, and other cost-saving measures. The Company sees additional opportunities in areas such as centralization of activities, system implementations, continued improvement of maintenance and turnarounds, and simplified business processes. These savings are key drivers to reduce our structural costs by $20 billion between 2019 and 2030, thereby improving the earnings power of the Corporation.

[(1)] *Refer to Frequently Used Terms for definition of structural cost savings.*

Transportation of Kazakhstan Production

The Corporation holds a 25 percent interest in Tengizchevroil, LLP (TCO), which operates the Tengiz and Korolev oil fields in Kazakhstan, and a 16.8 percent working interest in the Kashagan field in Kazakhstan. Oil production from those operations is exported primarily through the Caspian Pipeline Consortium (CPC), in which the Corporation holds a 7.5 percent interest. CPC traverses parts of Kazakhstan and Russia to tanker-loading facilities on the Russian coast of the Black Sea. In the event geopolitical issues escalate in the region, including ongoing military conflict, it is possible that the transportation of Kazakhstan oil through the CPC pipeline could be disrupted, curtailed, temporarily suspended, or otherwise restricted. In such a case, the Corporation could experience a loss of cash flows of uncertain duration from its operations in Kazakhstan. For reference, after-tax earnings related to the Corporation's interests in Kazakhstan in 2025 were approximately $1.1 billion, and its share of combined oil and gas production was approximately 320 thousand oil-equivalent barrels per day.

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MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

BUSINESS RESULTS

Upstream

ExxonMobil has a diverse growth portfolio of exploration and development opportunities, which allows the Corporation to be selective in our investments, maximizing shareholder value, and mitigating political and technical risks. ExxonMobil's competitive strengths enable the Upstream's business strategy, which is focused on developing an industry-leading portfolio underpinned by advantaged growth projects, applying ExxonMobil's technology to enhance value and improve development efficiency, and leveraging the unique capabilities of the Company's Global Projects organization to deliver projects on time and in line with budgets.

The Upstream capital program is focused on low cost-of-supply opportunities. ExxonMobil has a strong pipeline of development projects, including continued growth in Guyana and the Permian Basin, as well as LNG expansion opportunities in Qatar, Mozambique, Papua New Guinea, and the United States. In 2025, Upstream production averaged 4.7 million oil-equivalent barrels per day (Moebd), our highest production in over 40 years. As future development projects and drilling activities bring new production online, the Corporation expects a shift in the geographic mix and in the type of opportunities from which volumes are produced. Based on the current investment plans, the proportion of oil-equivalent production from the Americas is generally expected to increase over the next several years. Currently about two thirds of the Corporation's global production comes from Permian, Guyana, and LNG resources. This proportion is generally expected to grow.

The Corporation anticipates several projects will come online over the next few years providing additional production capacity. However, actual volumes typically vary from year to year due to the timing of individual project start-ups, operational outages, reservoir performance, regulatory changes, the impact of fiscal and commercial terms, asset sales, weather events, price effects on production sharing contracts, changes in the amount and timing of capital investments that may vary depending on the oil and gas price environment, international trade patterns and relations, and other factors described in Item 1A.

In 2025, crude prices remained within the 10-year historical range (2010-2019), while robust demand helped to move natural gas price above the top of the 10-year range. ExxonMobil believes prices over the long term will continue to be driven by market supply and demand, with the demand side largely being a function of general economic activities, levels of prosperity, technology advances, consumer preference, and government policies. On the supply side, prices may be significantly impacted by political events, the actions of OPEC or OPEC+ and other large government resource owners, alternative energy sources, and other factors.

Key Recent Events

Guyana: Liza Destiny, Liza Unity and Prosperity floating production, storage and offloading (FPSO) vessels continued to produce above investment basis capacity in 2025. Yellowtail entered service in August and progressed to ramp up throughout the fourth quarter achieving an average gross production of 240 kbd. The combined gross production from the four operating vessels exceeded 870 kbd in the fourth quarter of 2025. With start-up of a fourth vessel, Guyana achieved record annual production in 2025 of 715 kbd. Uaru, and Whiptail, the fifth and sixth developments on the Stabroek Block, respectively, are progressing on schedule and each has an investment basis capacity of approximately 250 kbd. In September 2025, ExxonMobil made a final investment decision for the Hammerhead development, after receiving the required regulatory approvals from the government of Guyana; Hammerhead is anticipated to come online in 2029. We anticipate eight FPSO vessels will be in operation on the Stabroek Block by year-end 2030.

Permian: ExxonMobil delivered strong and efficient growth in Permian production volumes in 2025. Total production volumes averaged a record 1.6 Moebd in 2025, approximately 0.4 Moebd higher than the previous year. ExxonMobil operations continue to deliver industry-leading capital efficiency and cost performance by leveraging scale, integration, and technology. Examples include deploying ExxonMobil cube design and proprietary lightweight proppant as well as leading capabilities and technology in drilling and completions. ExxonMobil expects to increase production in the Permian Basin to approximately 2.5 Moebd by 2030. ExxonMobil remains on track to achieve Scope 1 and 2 net zero greenhouse gas emissions in the integrated Permian Basin operated assets by 2035.

LNG: ExxonMobil continued work on LNG growth projects in 2025. In Papua New Guinea (PNG), the Papua LNG project has been optimizing the development plan and enhancing project cost competitiveness. Force majeure was lifted in Mozambique, as the Rovuma LNG project continues with the front-end engineering and design stage, in support of a final investment decision in 2026 to develop the Area 4 offshore gas resources. Mechanical completion was achieved for the Golden Pass LNG project, with expected first LNG production in the first quarter of 2026.

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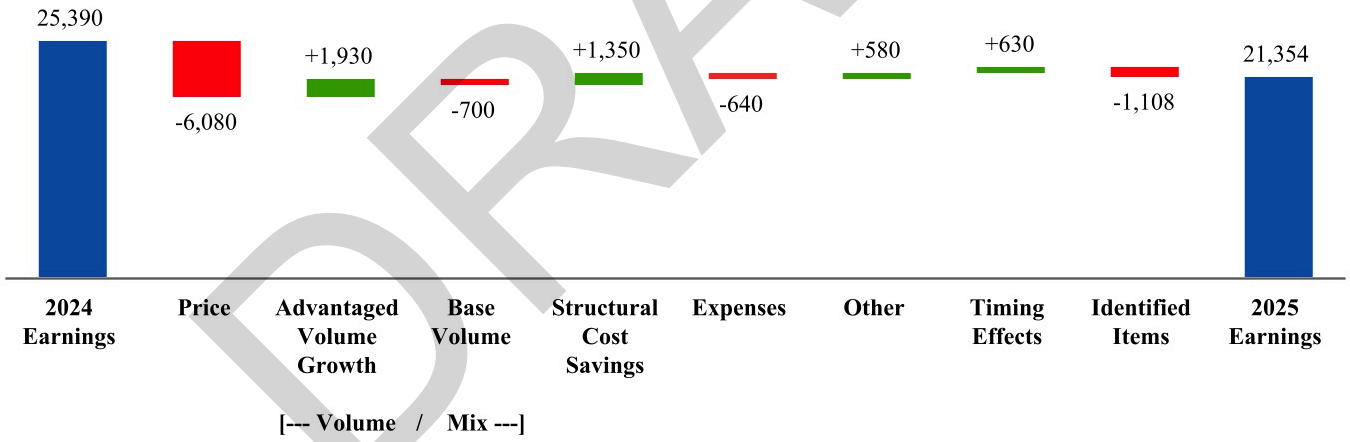
MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Upstream Financial Results

(millions of dollars)	2025	2024	2023
Earnings (loss) (U.S. GAAP)			
United States	5,063	6,426	4,202
Non-U.S.	16,291	18,964	17,106
Total	**21,354**	**25,390**	**21,308**
Identified Items [1]			
United States	(471)	(360)	(1,489)
Non-U.S.	(422)	575	(812)
Total	**(893)**	**215**	**(2,301)**
Earnings (loss) excluding Identified Items [1] (Non-GAAP)			
United States	5,534	6,786	5,691
Non-U.S.	16,713	18,389	17,918
Total	**22,247**	**25,175**	**23,609**

2025 Upstream Earnings Driver Analysis [1]

(millions of dollars)



Price – Lower realizations decreased earnings by $6.1 billion, primarily driven by lower crude prices as record demand was more than offset by increased industry supply.

Advantaged Volume Growth – Increased earnings by $1.9 billion, mainly driven by record production in Permian and Guyana.

Base Volume – Decreased earnings by $0.7 billion as a result of non-strategic asset divestments.

Structural Cost Savings [1] – Increased earnings by $1.4 billion.

Expenses – Decreased earnings by $0.6 billion, primarily higher depreciation from the Tengiz expansion.

Other – Increased earnings by $0.6 billion, mainly driven by favorable tax and foreign exchange impacts.

Timing Effects – Favorable timing effects from derivatives mark-to-market impacts increased earnings by $0.6 billion.

Identified Items [1] – 2024 $0.2 billion gain mainly due to Argentina divestment, partly offset by Nigeria divestment and U.S. impairment; 2025 $(0.9) billion loss mainly due to asset impairments.

[1] *Refer to Frequently Used Terms for definition of Structural Cost Savings, Identified Items, and Earnings (loss) excluding Identified Items.*

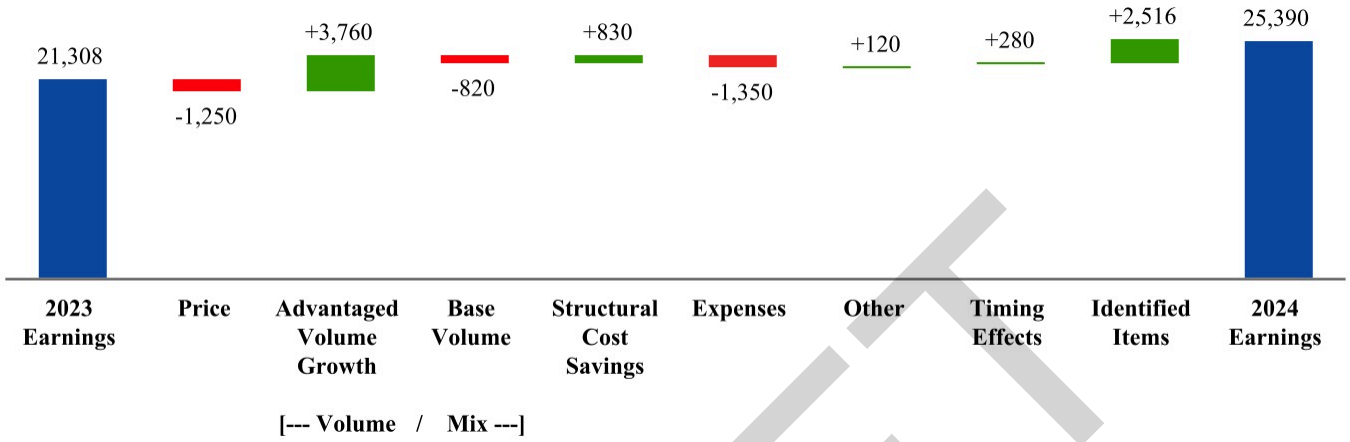
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MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

2024 Upstream Earnings Driver Analysis [1]

(millions of dollars)



Price – Price impacts decreased earnings by $1.3 billion, driven by lower gas realizations.

Advantaged Volume Growth – Higher volumes from advantaged assets increased earnings by $3.8 billion, as a result of record production in Permian, driven by the Pioneer acquisition and growth in the heritage Permian [2], and record production in Guyana driven by the Prosperity FPSO start-up.

Base Volume – Divestments of non-strategic assets and entitlements decreased earnings by $0.8 billion.

Structural Cost Savings [1] – Increased earnings by $0.8 billion.

Expenses – Higher expenses decreased earnings by $1.4 billion, primarily from higher depreciation (non-cash).

Other – All other items increased earnings by $0.1 billion, mainly driven by favorable impacts from divestments, partially offset by unfavorable tax and foreign exchange impacts.

Timing Effects – Less unfavorable timing effects from derivatives mark-to-market impacts increased earnings by $0.3 billion.

Identified Items [1] – 2023 $(2.3) billion loss primarily due to the impairment of the idled Santa Ynez Unit assets and associated facilities in California; 2024 $0.2 billion gain mainly due to Argentina divestment, partly offset by Nigeria divestment and U.S. impairment.

[1] *Refer to Frequently Used Terms for definition of Structural Cost Savings, Identified Items, and Earnings (loss) excluding Identified Items.*

[2] *Heritage Permian Basin assets exclude assets acquired as part of the acquisition of Pioneer that closed May 3, 2024.*

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MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Upstream Operational Results

	2025	2024	2023
Net production of crude oil, natural gas liquids, bitumen and synthetic oil *(thousands of barrels daily)*			
United States	1,522	1,248	803
Canada/Other Americas	835	784	664
Europe	3	3	4
Africa	142	209	221
Asia	800	713	721
Australia/Oceania	25	30	36
Worldwide	**3,329**	**2,987**	**2,449**
Net natural gas production available for sale *(millions of cubic feet daily)*			
United States	3,364	2,887	2,311
Canada/Other Americas	27	101	96
Europe	299	352	414
Africa	114	152	125
Asia	3,354	3,322	3,490
Australia/Oceania	1,283	1,264	1,298
Worldwide	**8,442**	**8,078**	**7,734**
Oil-equivalent production [1] *(thousands of oil-equivalent barrels daily)*	**4,736**	**4,333**	**3,738**

[1] *Natural gas is converted to an oil-equivalent basis at six million cubic feet per one thousand barrels.*

Upstream Additional Information

(thousands of barrels daily)	2025	2024
Volumes Reconciliation (Oil-equivalent production) [1]		
Prior Year	4,333	3,738
Entitlements - Net Interest	(33)	(13)
Entitlements - Price / Spend / Other	45	(23)
Government Mandates	(1)	9
Divestments	(133)	(63)
Growth / Other	525	685
Current Year	**4,736**	**4,333**

[1] *Natural gas is converted to an oil-equivalent basis at six million cubic feet per one thousand barrels.*

2025 versus 2024	2025 production of 4.7 million oil-equivalent barrels per day increased 403 thousand barrels per day from 2024. Permian reached 1.6 million net oil-equivalent barrels per day and Guyana production exceeded 700 thousand gross oil-equivalent barrels per day, more than offsetting impacts from divestments and entitlements. Excluding the impacts from entitlements, divestments, and government-mandated curtailments, net production grew by 525 thousand oil-equivalent barrels per day.
2024 versus 2023	2024 production of 4.3 million oil-equivalent barrels per day increased 595 thousand barrels per day from 2023. Permian and Guyana production grew by 680 thousand oil-equivalent barrels per day, more than offsetting impacts from divestments and entitlements. Excluding the impacts from entitlements, divestments, and government-mandated curtailments, net production grew by 685 thousand oil-equivalent barrels per day.

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MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Listed below are descriptions of ExxonMobil's volumes reconciliation drivers, which are provided to facilitate understanding of the terms.

Entitlements - Net Interest are changes to ExxonMobil's share of production volumes caused by non-operational changes to volume-determining drivers. These drivers consist of net interest changes specified in Production Sharing Contracts (PSCs), which typically occur when cumulative investment returns or production volumes achieve defined thresholds, changes in equity upon achieving pay-out in partner investment carry situations, equity redeterminations as specified in venture agreements, or as a result of the termination or expiry of a concession. Once a net interest change has occurred, it typically will not be reversed by subsequent events, such as lower crude oil prices.

Entitlements - Price, Spend and Other are changes to ExxonMobil's share of production volumes resulting from temporary changes to non-operational volume-determining drivers. These drivers include changes in oil and gas prices or spending levels from one period to another. According to the terms of contractual arrangements or government royalty regimes, price or spending variability can increase or decrease royalty burdens and/or volumes attributable to ExxonMobil. For example, at higher prices, fewer barrels are required for ExxonMobil to recover its costs. These effects generally vary from period to period with field spending patterns or market prices for oil and natural gas. Such drivers can also include other temporary changes in net interest as dictated by specific provisions in production agreements.

Government Mandates are changes to ExxonMobil's sustainable production levels as a result of production limits or sanctions imposed by governments.

Divestments are reductions in ExxonMobil's production arising from commercial arrangements to fully or partially reduce equity in a field or asset in exchange for financial or other economic consideration.

Growth and Other drivers comprise all other operational and non-operational drivers not covered by the above definitions that may affect volumes attributable to ExxonMobil. Such drivers include, but are not limited to, production enhancements from project and work program activities, acquisitions including additions from asset exchanges, downtime, market demand, natural field decline, and any fiscal or commercial terms that do not affect entitlements.

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Energy Products

ExxonMobil's Energy Products is one of the largest, most integrated businesses of its kind among international oil companies, with significant representation across the entire fuels value chain, including refining, logistics, trading, and marketing. This segment includes the fuels, aromatics, and NGL value chains, as well as catalysts and licensing.

With the largest refining footprint among international oil companies, ExxonMobil's Energy Products earnings are closely tied to industry refining margins. Refining margins are largely driven by differences in commodity prices and are a function of the difference between what a refinery pays for its raw materials and the market prices for the products produced. Crude oil and many products are widely traded with published prices, including those quoted on multiple exchanges around the world (e.g., New York Mercantile Exchange and Intercontinental Exchange). Prices for these commodities are determined by the global marketplace and are influenced by many factors, including global and regional supply/demand balances, inventory levels, industry refinery operations, import/export balances, currency fluctuations, seasonal demand, weather, and geopolitical considerations. While industry refining margins significantly impact Energy Products earnings, strong operational performance, product mix optimization, and disciplined cost control are also critical to strong financial performance.

In 2025, refining margins increased from the prior year on record demand, but remained within the 10-year historical range (2010-2019). Refining margins are expected to remain volatile with changes in global factors, including geopolitical developments; demand growth; recession fears; inventory levels; and refining capacity utilization, additions, and rationalizations.

Key Recent Events

Strathcona Renewable Diesel project: Started up the project at the Strathcona refinery, which is designed to use low-carbon hydrogen, locally-sourced and grown feedstocks, and our proprietary catalyst to produce renewable diesel.

Fawley Hydrofiner project: Started up the project at the Fawley site to increase production of ultra-low sulfur diesel and reduce production of other products, including high-sulfur distillates.

France divestment: In November 2025, ExxonMobil completed the divestments of Esso Société Anonyme Française SA and ExxonMobil Chemical France SAS, including the refinery and related assets.

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MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

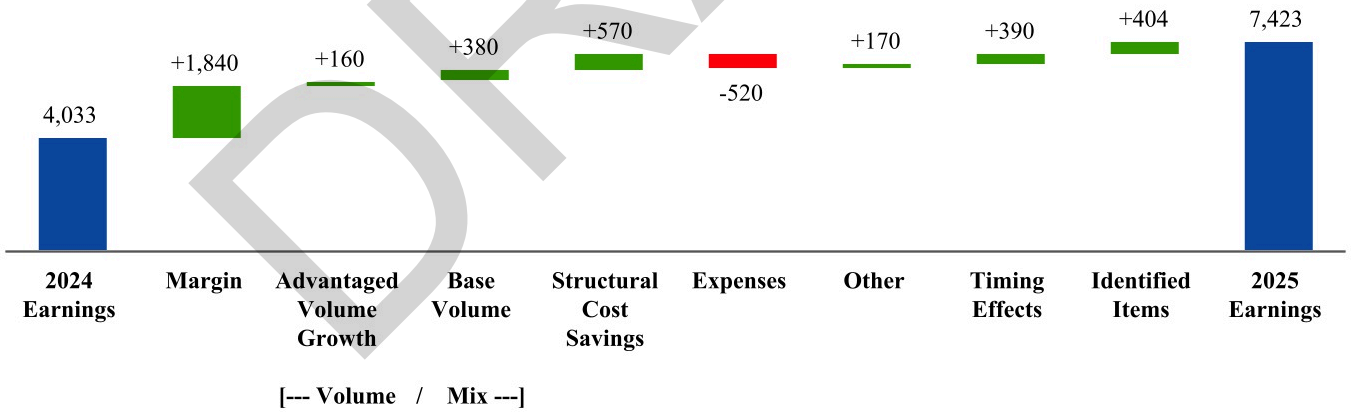
Energy Products Financial Results

(millions of dollars)	2025	2024	2023
Earnings (loss) (U.S. GAAP)			
United States	2,992	2,099	6,123
Non-U.S.	4,431	1,934	6,019
Total	**7,423**	**4,033**	**12,142**
Identified Items [1]			
United States	(118)	(34)	192
Non-U.S.	601	113	(48)
Total	**483**	**79**	**144**
Earnings (loss) excluding Identified Items [1] (Non-GAAP)			
United States	3,110	2,133	5,931
Non-U.S.	3,830	1,821	6,067
Total	**6,940**	**3,954**	**11,998**

Due to rounding, numbers presented may not add up precisely to the totals indicated.

2025 Energy Products Earnings Driver Analysis [1]

(millions of dollars)



Margin – Increased earnings by $1.8 billion, mainly driven by robust demand and supply disruptions.

Advantaged Volume Growth – Higher volumes from advantaged projects growth increased earnings by $0.2 billion.

Base Volume – Higher volumes driven by lower scheduled maintenance increased earnings by $0.4 billion.

Structural Cost Savings [1] – Increased earnings by $0.6 billion.

Expenses – Decreased earnings by $0.5 billion, mainly driven by growth projects.

Other – Increased earnings by $0.2 billion mainly from favorable year-end inventory effects.

Timing Effects – Favorable timing effects from derivatives mark-to-market impacts increased earnings by $0.4 billion.

Identified Items [1] – 2024 $0.1 billion gain; 2025 $0.5 billion gain mainly driven by asset sales.

[1] *Refer to Frequently Used Terms for definition of Structural Cost Savings, Identified Items, and Earnings (loss) excluding Identified Items.*

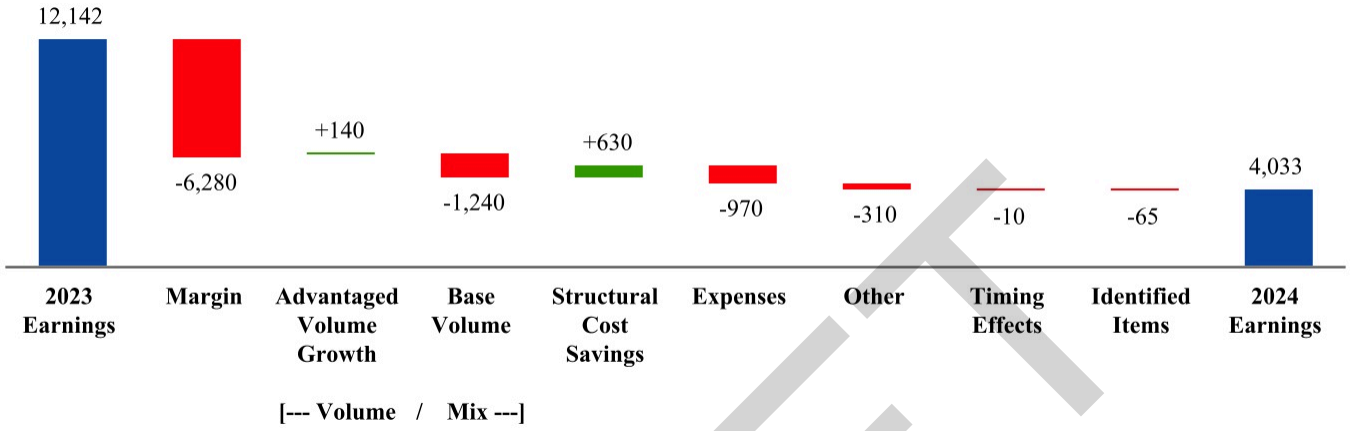
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MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

2024 Energy Products Earnings Driver Analysis [1]

(millions of dollars)



Margin – Significantly weaker industry refining margins decreased earnings by $6.3 billion. Margins declined from historically high levels as increased supply from industry capacity additions outpaced record global demand.

Advantaged Volume Growth – Higher volumes from advantaged projects, increased earnings by $0.1 billion.

Base Volume – Lower base volumes decreased earnings by $1.2 billion driven by scheduled maintenance and divestments.

Structural Cost Savings [1] – Increased earnings by $0.6 billion.

Expenses – Higher expenses related to scheduled turnarounds and maintenance, and advantaged project spend decreased earnings by $1.0 billion.

Other – All other items, mainly unfavorable tax and forex impacts, decreased earnings by $0.3 billion.

Timing Effects – Decreased earnings by $10 million.

Identified Items [1] – 2023 $0.1 billion gain driven by favorable tax effects partially offset by additional European taxes on the energy sector; 2024 $0.1 billion gain.

[1] *Refer to Frequently Used Terms for definition of Structural Cost Savings, Identified Items, and Earnings (loss) excluding Identified Items.*

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MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Energy Products Operational Results

(thousands of barrels daily)	2025	2024	2023
Refinery throughput			
United States	1,927	1,865	1,848
Canada	402	399	407
Europe	1,002	1,039	1,166
Asia Pacific	460	432	498
Other	188	165	149
Worldwide	**3,979**	**3,900**	**4,068**
Energy Products sales [(1)]			
United States	2,852	2,722	2,633
Non-U.S.	2,740	2,696	2,828
Worldwide	**5,593**	**5,418**	**5,461**
Gasoline, naphthas	2,290	2,251	2,288
Heating oils, kerosene, diesel	1,791	1,769	1,795
Aviation fuels	383	355	336
Heavy fuels	220	200	214
Other energy products	910	844	829
Worldwide	**5,593**	**5,418**	**5,461**

(1) Data reported net of purchases/sales contracts with the same counterparty.

Due to rounding, numbers presented may not add up precisely to the totals indicated.

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Chemical Products

ExxonMobil is a leading global manufacturer and marketer of petrochemicals that support modern living. Chemical Products help meet society's essential needs by providing a wide range of innovative products efficiently and responsibly. The Company is uniquely positioned with a combination of industry-leading scale, integration, and proprietary technology, which are fundamental to producing affordable products that are more sustainable, use less material, save energy, and reduce waste. These competitive advantages are underpinned by operational excellence, advantaged investments, and cost discipline. This segment includes olefins, polyolefins, and intermediates.

Over the long term, worldwide demand for chemicals is expected to grow faster than the overall economy, driven by global population growth, an expanding middle class, and improving living standards. Chemical Products integration with refineries, performance product mix, and project execution capability improves returns on investments across a range of market environments.

In 2025, chemical industry margins remained deeply bottom-of-cycle, below the 10-year historical range (2010-2019), as capacity additions have far exceeded demand growth. The Company optimized production across our global footprint to profitably meet customer demand. Our earnings benefited from solid reliability, record high-value products sales, and a large North American footprint where low ethane prices continue to provide a feed advantage.

Key Recent Events

China Chemical Complex: Started up a petrochemical complex in the Dayawan Petrochemical Industrial Park in Huizhou, Guangdong Province, which is a significant step in growing our global manufacturing footprint and is the first 100 percent foreign-owned petrochemical complex built in China. The facility, which focuses on producing our unique high-performance polyethylene and polypropylene products, is equipped with three polyethylene and two polypropylene production lines for a combined capacity of over 2.5 million metric tons per year. This capacity will more efficiently serve China's large and evolving domestic demand, which is currently being met with imports.

Advanced Recycling: ExxonMobil is combining proprietary technology and advantaged integrated sites to process hard-to-recycle plastic waste back into raw materials to produce valuable new products. In 2025, the Company added two new advanced recycling

units to the Baytown facility, tripling capacity at the site, and representing one of the largest advanced recycling facilities in North America. Additional units are being assessed as the Company aims to reach a global recycling capacity of 1 billion pounds per year to help reduce plastic waste.

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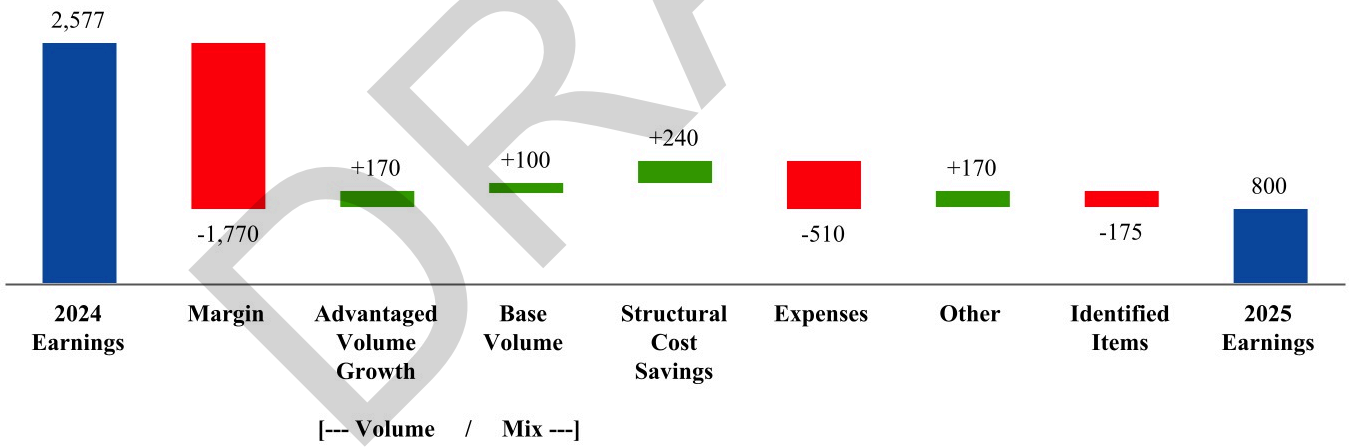
MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Chemical Products Financial Results

(millions of dollars)	2025	2024	2023
Earnings (loss) (U.S. GAAP)			
United States	903	1,627	1,626
Non-U.S.	(103)	950	11
Total	**800**	**2,577**	**1,637**
Identified Items [1]			
United States	(80)	(43)	32
Non-U.S.	(190)	(52)	(420)
Total	**(270)**	**(95)**	**(388)**
Earnings (loss) excluding Identified Items [1] (Non-GAAP)			
United States	983	1,670	1,594
Non-U.S.	87	1,002	431
Total	**1,070**	**2,672**	**2,025**

2025 Chemical Products Earnings Driver Analysis [1]

(millions of dollars)



Margin – Decreased earnings by $1.8 billion, as oversupply resulted in margins at bottom-of-cycle market conditions.

Advantaged Volume Growth – New projects increased earnings by $0.2 billion driven by high-value product sales.

Base Volume – Increased earnings by $0.1 billion.

Structural Cost Savings [1] – Increased earnings by $0.2 billion.

Expenses – Higher advantaged project spend, including China Chemical Complex ramp-up, decreased earnings by $0.5 billion.

Other – Increased earnings by $0.2 billion.

Identified Items [1] – 2024 $(0.1) billion loss driven by impairments; 2025 $(0.3) billion loss driven by impairments.

[1] *Refer to Frequently Used Terms for definition of Structural Cost Savings, Identified Items, and Earnings (loss) excluding Identified Items.*

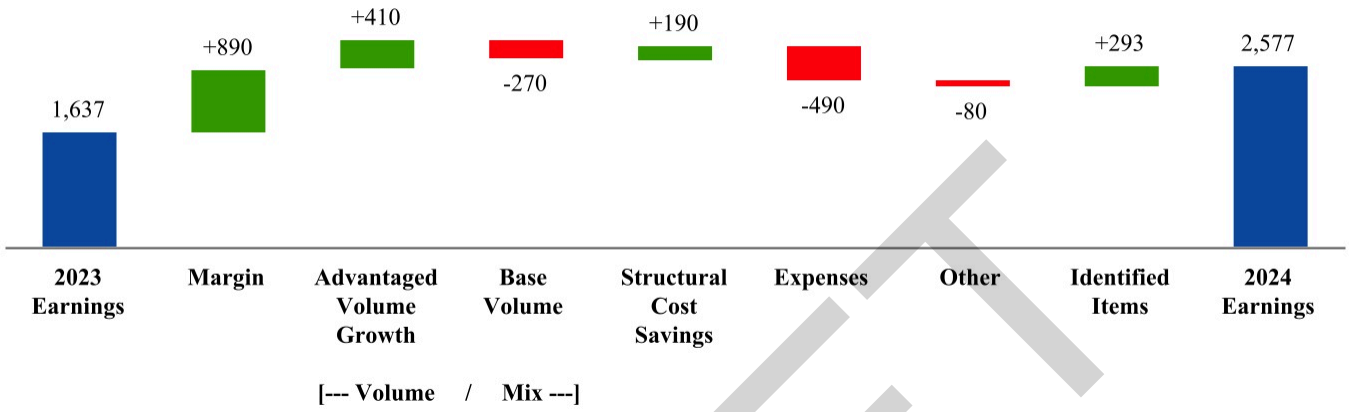
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2024 Chemical Products Earnings Driver Analysis [1]

(millions of dollars)



Margin – Improved company margins on North American ethane feed advantage and improved product realizations increased earnings by $0.9 billion, despite continued bottom-of-cycle market conditions.

Advantaged Volume Growth – Record high-value product sales increased earnings by $0.4 billion.

Base Volume – Portfolio optimization and product sales mix decreased earnings by $0.3 billion.

Structural Cost Savings [1] – Increased earnings by $0.2 billion.

Expenses – Higher advantaged projects spend and inflation effects decreased earnings by $0.5 billion.

Other – All other items decreased earnings by $0.1 billion.

Identified Items [1] – 2023 $(0.4) billion loss was primarily driven by impairments; 2024 $(0.1) billion loss driven by impairments.

[1] *Refer to Frequently Used Terms for definition of Structural Cost Savings, Identified Items, and Earnings (loss) excluding Identified Items.*

Chemical Products Operational Results

(thousands of metric tons)	2025	2024	2023
Chemical Products sales [2]			
United States	6,977	7,038	6,779
Non-U.S.	14,326	12,354	12,603
Worldwide	**21,303**	**19,392**	**19,382**

[2] *Data reported net of purchases/sales contracts with the same counterparty.*

Due to rounding, numbers presented may not add up precisely to the totals indicated.

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MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Specialty Products

ExxonMobil Specialty Products is a combination of business units that manufacture and market a range of performance products, including high-quality lubricants, basestocks, waxes, synthetics, elastomers, and resins. Leveraging ExxonMobil's proprietary technologies, Specialty Products focuses on providing performance products that help customers improve efficiency in the transportation and industrial sectors.

Specialty Products is well-positioned to help meet the demand for premium lubricant products through advantaged projects that leverage ExxonMobil's integration, technology, and world-class brands, such as Mobil 1™.

In 2025, Specialty Products continued to deliver strong earnings from our portfolio of high-value products and brand market position.

Key Recent Events

Singapore Resid Upgrade project: This project started up in 2025, leveraging two proprietary technologies to upgrade fuel oil to Group II lubricant basestock and diesel. It further strengthens ExxonMobil's position as the largest basestock producer in the world and introduces a first-of-its-kind basestock, EHC 340 MAX™, with superior performance attributes, to the market.

Proxxima™ Resin Systems: ExxonMobil's advanced polyolefin thermoset resin uses components of gasoline and catalyst technology to create a material that is lighter, stronger, and more durable than conventional products, providing alternatives for the construction, coatings, and transportation industries. These systems are designed to drive product substitutions in existing markets and enable expansion into new applications like structural composites and steel substitutes. In 2025, ExxonMobil more than tripled Proxxima™ resin blending capacity with plans to grow production to 200,000 tons per year by 2030.

Carbon Materials venture: ExxonMobil is growing its carbon materials venture by applying proprietary process technology to capture attractive opportunities in the battery anode market. The Company has developed an advanced coke product by converting low-value, bottom-of-the-barrel molecules that can deliver a higher performance differentiated graphite. These carbon materials enable batteries that can provide up to 30 percent higher available capacity, 30 percent faster charging time, and extended battery life. In 2025, ExxonMobil acquired key technology and assets from Superior Graphite. This acquisition, which complements ExxonMobil's process technology and expertise, enables a faster scale-up and a swifter entry into the battery anode market with our differentiated graphite product.

Specialty Products Financial Results

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(millions of dollars)	2025	2024	2023
Earnings (loss) (U.S. GAAP)			
United States	1,200	1,576	1,536
Non-U.S.	1,657	1,476	1,178
Total	**2,857**	**3,052**	**2,714**
Identified Items [(1)]			
United States	12	(4)	12
Non-U.S.	(12)	(9)	(105)
Total	**—**	**(13)**	**(93)**
Earnings (loss) excluding Identified Items [(1)] (Non-GAAP)			
United States	1,188	1,580	1,524
Non-U.S.	1,669	1,485	1,283
Total	**2,857**	**3,065**	**2,807**

[(1)] *Refer to Frequently Used Terms for definition of Identified Items and Earnings (loss) excluding Identified Items.*

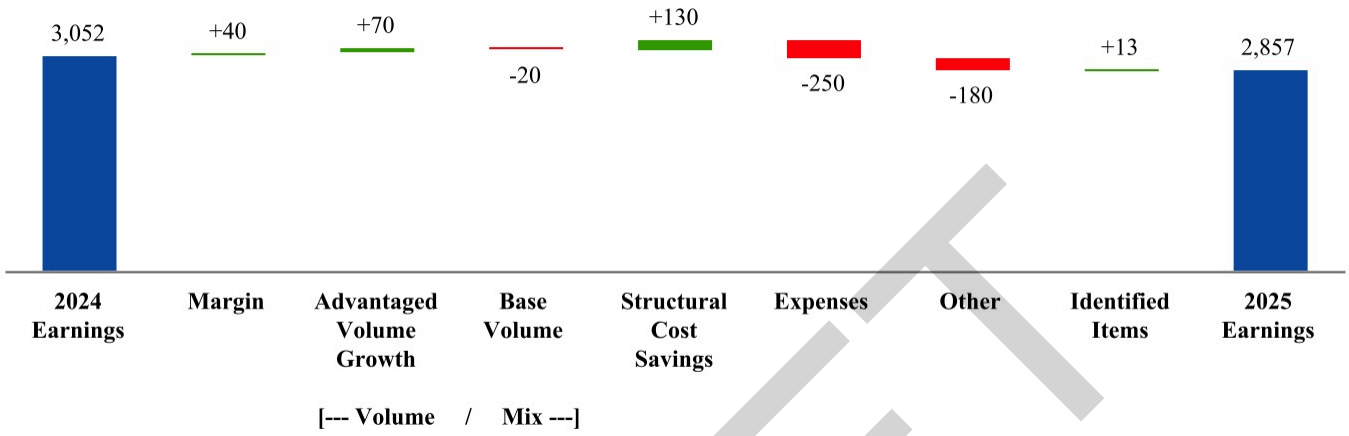
Due to rounding, numbers presented may not add up precisely to the totals indicated.

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MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

2025 Specialty Products Earnings Driver Analysis [1]

(millions of dollars)



Margin – Increased earnings by $40 million.

Advantaged Volume Growth – Increased earnings by $0.1 billion.

Base Volume – Decreased earnings by $20 million.

Structural Cost Savings [1] – Increased earnings by $0.1 billion.

Expenses – Higher expenses to develop markets for carbon materials and Proxxima™ resins decreased earnings by $0.2 billion.

Other – Decreased earnings by $0.2 billion, mainly from unfavorable foreign exchange effects.

Identified Items [1] – 2024 $(13) million loss.

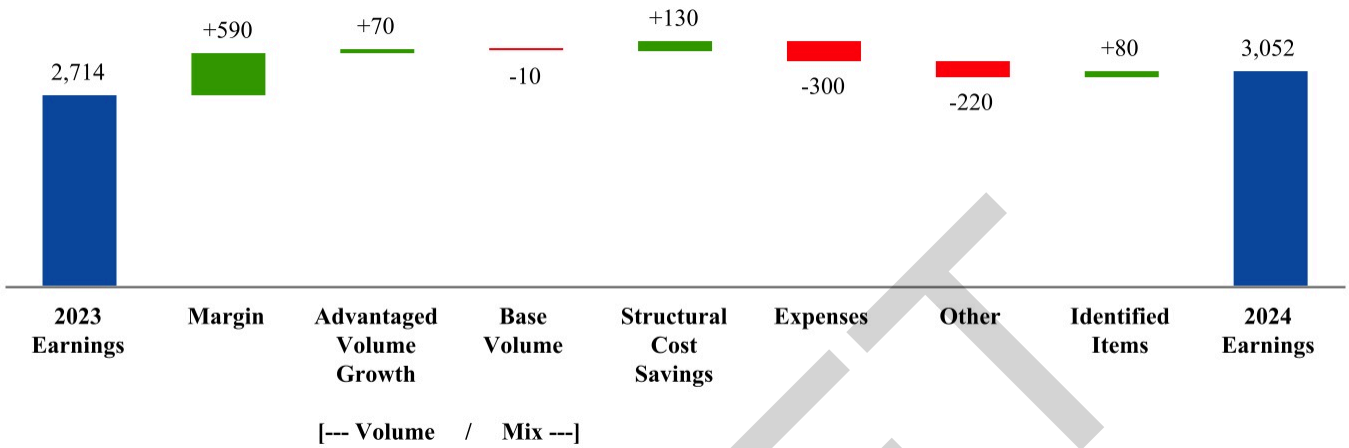
[1] *Refer to Frequently Used Terms for definition of Structural Cost Savings, Identified Items, and Earnings (loss) excluding Identified Items.*

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MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

2024 Specialty Products Earnings Driver Analysis [1]

(millions of dollars)



Margin – Stronger basestocks and finished lubes margins increased earnings by $0.6 billion.

Advantaged Volume Growth – High-value product volume growth increased earnings by $0.1 billion.

Base Volume – Decreased earnings by $10 million.

Structural Cost Savings [1] – Increased earnings by $0.1 billion.

Expenses – Higher expenses including new product development costs, decreased earnings by $0.3 billion.

Other – All other items decreased earnings by $0.2 billion, mainly unfavorable foreign exchange effects and absence of prior year favorable year-end inventory effects.

Identified Items [1] – 2023 $(93) million loss from impairments; 2024 $(13) million loss.

[1] *Refer to Frequently Used Terms for definition of Structural Cost Savings, Identified Items, and Earnings (loss) excluding Identified Items.*

Specialty Products Operational Results

(thousands of metric tons)	2025	2024	2023
Specialty Products sales [2]			
United States	1,894	1,922	1,962
Non-U.S.	5,897	5,745	5,635
Worldwide	**7,791**	**7,666**	**7,597**

[2] *Data reported net of purchases/sales contracts with the same counterparty.*

Due to rounding, numbers presented may not add up precisely to the totals indicated.

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MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Corporate and Financing

Corporate and Financing is comprised of corporate activities that support ExxonMobil's operating segments and Low Carbon Solutions business. Corporate activities include general administrative support functions, financing, and insurance activities. Low Carbon Solutions activities will be included in Corporate and Financing until the business is established with a material level of assets and revenue.

Corporate and Financing Financial Results

(millions of dollars)	2025	2024	2023
Earnings (loss) (U.S. GAAP)	(3,590)	(1,372)	(1,791)
Identified Items [1]	(585)	30	76
Earnings (loss) excluding Identified Items [1] (Non-GAAP)	(3,005)	(1,402)	(1,867)

[1] *Refer to Frequently Used Terms for definition of Identified Items and Earnings (loss) excluding Identified Items.*

2025	Corporate and Financing expenses were $3.6 billion in 2025 compared to $1.4 billion in 2024, with the increase mainly due to higher financing costs.
2024	Corporate and Financing expenses were $1.4 billion in 2024 compared to $1.8 billion in 2023, with the decrease mainly due to lower financing costs.

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MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

LIQUIDITY AND CAPITAL RESOURCES

Sources and Uses of Cash

(millions of dollars)	2025	2024	2023
Net cash provided by/(used in)			
Operating activities	51,970	55,022	55,369
Investing activities	(25,927)	(19,938)	(19,274)
Financing activities	(39,081)	(42,789)	(34,297)
Effect of exchange rate changes	532	(676)	105
Increase/(decrease) in cash and cash equivalents	**(12,506)**	**(8,381)**	**1,903**
Total cash and cash equivalents (December 31)	**10,681**	**23,187**	**31,568**

Total cash and cash equivalents were $10.7 billion at the end of 2025, down $12.5 billion from the prior year. The major sources of funds in 2025 were net income including noncontrolling interests of $29.8 billion, the adjustment for the noncash provision of $26.0 billion for depreciation and depletion, proceeds from asset sales of $3.2 billion, and other investing activities of $3.4 billion. The major uses of funds included spending for additions to property, plant, and equipment of $28.4 billion; dividends to shareholders of $17.2 billion; the purchase of ExxonMobil stock of $20.3 billion; additional investments and advances of $4.1 billion; and a change in working capital of $7.7 billion.

Total cash and cash equivalents were $23.2 billion at the end of 2024, down $8.4 billion from the prior year. The major sources of funds in 2024 were net income including noncontrolling interests of $35.1 billion, the adjustment for the noncash provision of $23.4 billion for depreciation and depletion, proceeds from asset sales of $5.0 billion, and other investing activities of $1.9 billion, and cash acquired from mergers and acquisitions of $0.8 billion. The major uses of funds included spending for additions to property, plant, and equipment of $24.3 billion; dividends to shareholders of $16.7 billion; the purchase of ExxonMobil stock of $19.6 billion; debt repayment of $5.9 billion; additional investments and advances of $3.3 billion; and a change in working capital of $1.8 billion.

The Corporation has access to significant capacity of long-term and short-term liquidity. Internally generated funds are expected to cover the majority of financial requirements, supplemented by long-term and short-term debt. Commercial paper is used to balance short-term liquidity requirements and is reflected in "Notes and loans payable" on the Consolidated Balance Sheet, with changes in outstanding commercial paper between periods included in the Consolidated Statement of Cash Flows. On December 31, 2025, the Corporation had undrawn short-term committed lines of credit of $7.3 billion and undrawn long-term lines of credit of $1.0 billion. In the fourth quarter of 2025, the Corporation established a 364-day revolving credit facility of $7.0 billion to provide short-term borrowing capacity for general corporate purposes.

To support cash flows in future periods, the Corporation will need to continually find or acquire and develop new fields, and continue to develop and apply new technologies and recovery processes to existing fields, in order to maintain or increase production. After a period of production at plateau rates, it is the nature of oil and gas fields to eventually produce at declining rates for the remainder of their economic life. Decline rates can vary widely by individual field due to a number of factors, including, but not limited to, the type of reservoir, fluid properties, recovery mechanisms, work activity, and age of the field. In particular, the Corporation's key tight-oil plays have higher initial decline rates which tend to moderate over time. Furthermore, the Corporation's net interest in production for individual fields can vary with price and the impact of fiscal and commercial terms.

The Corporation has long been successful at mitigating the effects of natural field decline through disciplined investments in quality opportunities and project execution. The Corporation anticipates several projects will come online over the next few years providing additional production capacity. However, actual volumes will vary from year to year due to the timing of individual project start-ups, operational outages, reservoir performance, regulatory changes, the impact of fiscal and commercial terms, asset sales, weather events, price effects on production sharing contracts, changes in the amount and timing of investments that may vary depending on the oil and gas price environment, and international trade patterns and relations. The Corporation's cash flows are also highly dependent on crude oil and natural gas prices. Please refer to Item 1A for a more complete discussion of risks.

The Corporation's financial strength enables it to make large, long-term capital expenditures. Cash Capex in 2025 was $29.0 billion, including $2.6 billion of acquisitions, reflecting the Corporation's continued active investment program.

Upstream spending of $24.7 billion in 2025 was up $4.4 billion from 2024, reflecting higher spend in the U.S. Permian Basin which included the full-year impact from the Pioneer acquisition. Development projects typically take several years from the time of

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recording proved undeveloped reserves to the start of production and can exceed five years for large and complex projects. The percentage of proved developed reserves was 64 percent of total proved reserves at year-end 2025 and has been over 60 percent for the last ten years.

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MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Capital investments in the three Product Solutions businesses totaled $3.7 billion in 2025, a decrease of $0.8 billion from 2024, reflecting lower global project spending. Other spend of $0.6 billion primarily reflects investments in the Low Carbon Solutions business.

The Corporation plans to invest in the range of $27 billion to $29 billion in 2026. The investment range for 2026 excludes advances and collections not related to capital expenditures or equity investments, for example, supply and marketing related advances and associated collections. Included in the 2026 capital spend range is $8.5 billion of firm capital commitments. An additional $8.0 billion of firm capital commitments have been made for years 2027 and beyond. Actual spending could vary depending on the progress of individual projects and property acquisitions. The Corporation has a large and diverse portfolio of development projects and exploration opportunities, which helps mitigate the overall political and technical risks of the Corporation's Upstream segment and associated cash flow. Further, due to its financial strength and diverse portfolio of opportunities, the risk associated with failure or delay of any single project would not have a significant impact on the Corporation's liquidity or ability to generate sufficient cash flows for operations and its fixed commitments.

The Corporation, as part of its ongoing asset management program, continues to evaluate its mix of assets for potential upgrade. Because of the ongoing nature of this program, dispositions will continue to be made from time to time which will result in either gains or losses. Additionally, the Corporation continues to evaluate opportunities to enhance its business portfolio through acquisitions of assets or companies and enters into such transactions from time to time. Key criteria for evaluating acquisitions include strategic fit, cost and other synergies, potential for future growth, low cost of supply, and attractive valuations. Acquisitions may be made with cash, shares of the Corporation's common stock, or both.

Cash Flow from Operating Activities

2025

Cash provided by operating activities totaled $52.0 billion in 2025, $3.1 billion lower than 2024. The major source of funds was net income including noncontrolling interests of $29.8 billion, a decrease of $5.3 billion. The noncash provision for depreciation and depletion was $26.0 billion, up $2.6 billion from the prior year. The adjustment for the net gain on asset sales was $1.1 billion, a decrease of $0.1 billion. The adjustment for dividends received less than equity in current earnings of equity companies was an increase of $3.0 billion, compared to an increase of $0.2 billion in 2024. Changes in operational working capital, excluding cash and debt, decreased cash in 2025 by $7.7 billion.

2024

Cash provided by operating activities totaled $55.0 billion in 2024, $0.3 billion lower than 2023. The major source of funds was net income including noncontrolling interests of $35.1 billion, a decrease of $2.3 billion. The noncash provision for depreciation and depletion was $23.4 billion, up $2.8 billion from the prior year. The adjustment for the net gain on asset sales was $1.2 billion, an increase of $0.7 billion. The adjustment for dividends received less than equity in current earnings of equity companies was an increase of $0.2 billion, compared to an increase of $0.5 billion in 2023. Changes in operational working capital, excluding cash and debt, decreased cash in 2024 by $1.8 billion.

Cash Flow from Investing Activities

2025

Cash used in investing activities netted to $25.9 billion in 2025, $6.0 billion higher than 2024. Spending for property, plant, and equipment of $28.4 billion increased $4.1 billion from 2024. Proceeds from asset sales and returns of investments of $3.2 billion compared to $5.0 billion in 2024. Additional investments and advances were $0.8 billion higher in 2025, while proceeds from other investing activities including collection of advances increased by $1.5 billion.

2024

Cash used in investing activities netted to $19.9 billion in 2024, $0.7 billion higher than 2023. Spending for property, plant, and equipment of $24.3 billion increased $2.4 billion from 2023. Proceeds from asset sales and returns of investments of $5.0 billion compared to $4.1 billion in 2023. Additional investments and advances were $0.3 billion higher in 2024, while proceeds from other investing activities including collection of advances increased by $0.4 billion.

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MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Cash Flow from Financing Activities

2025

Cash used in financing activities was $39.1 billion in 2025, $3.7 billion lower than 2024. Dividend payments on common shares increased to $4.00 per share from $3.84 per share and totaled $17.2 billion.

During 2025, the Corporation continued its share repurchase program, including the purchase of 180.1 million shares at a book value of $20 billion in 2025. In its 2025 Corporate Plan Update released December 9, 2025, the Corporation stated that it is expected to continue its share repurchase program with a $20 billion repurchase pace per year through 2026, assuming reasonable market conditions. The stock repurchase program does not obligate the Company to acquire any particular amount of common stock, and it may be discontinued or resumed at any time. The timing and amount of shares actually purchased in the future will depend on market, business, and other factors.

2024

Cash used in financing activities was $42.8 billion in 2024, $8.5 billion higher than 2023. Dividend payments on common shares increased to $3.84 per share from $3.68 per share and totaled $16.7 billion. During 2024, the Corporation utilized cash to repay debt of $5.9 billion.

During 2024, the Corporation continued its share repurchase program, including the purchase of 167 million shares at a book value of $19.1 billion in 2024.

Contractual Obligations

The Corporation has contractual obligations involving commitments to third parties that impact its liquidity and capital resource needs. These contractual obligations are primarily for leases, debt, asset retirement obligations, pension and other postretirement benefits, take-or-pay and unconditional purchase obligations, and firm capital commitments. See Notes 4, 9, 12, and 13 for information related to pensions, asset retirement obligations, long-term debt, and leases, respectively.

In addition, the Corporation also enters into commodity purchase obligations (volumetric commitments with no fixed or minimum price) which are resold shortly after purchase, either in an active, highly liquid market, or under long-term, unconditional sales contracts with similar pricing terms. Examples include long-term, noncancelable LNG and natural gas purchase commitments and commitments to purchase refinery products at market prices. These commitments are not meaningful in assessing liquidity and cash flow because the purchases will be offset in the same periods by cash received from the related sales transactions.

Take-or-pay obligations are noncancelable, long-term commitments for goods and services. Unconditional purchase obligations are those long-term commitments that are noncancelable or cancelable only under certain conditions, and that third parties have used to secure financing for the facilities that will provide the contracted goods or services. These obligations mainly pertain to pipeline, manufacturing supply, and terminal agreements. The total obligation at year-end 2025 for take-or-pay and unconditional purchase obligations was $54.1 billion. Cash payments expected in 2026 and 2027 are $6.3 billion and $6.2 billion, respectively.

Guarantees

The Corporation and certain of its consolidated subsidiaries were contingently liable at December 31, 2025, for guarantees relating to notes, loans, and performance under contracts (Note 7). Where guarantees for environmental remediation and other similar matters do not include a stated cap, the amounts reflect management's estimate of the maximum potential exposure. Where it is not possible to make a reasonable estimation of the maximum potential amount of future payments, future performance is expected to be either immaterial or have only a remote chance of occurrence. Guarantees are not reasonably likely to have a material effect on the Corporation's financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures, or capital resources.

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MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Financial Strength

On December 31, 2025, the Corporation had total unused short-term committed lines of credit of $7.3 billion (Note 10) and total unused long-term committed lines of credit of $1.0 billion (Note 12). The table below shows the Corporation's consolidated debt to capital ratios.

(percent)	2025	2024	2023
Debt to capital	14.0	13.4	16.4
Net debt to capital [1]	11.0	6.5	4.5

[1] Net debt is total debt less cash and cash equivalents excluding restricted cash. Net debt to capital ratio is net debt divided by net debt plus total equity. Total debt is the sum of notes and loans payable and long-term debt, as reported in the Consolidated Balance Sheet.

Management views the Corporation's financial strength to be a competitive advantage of strategic importance. The Corporation's financial position gives it the opportunity to access the world's capital markets across a range of market conditions and enables the Corporation to take on large, long-term capital commitments in the pursuit of maximizing shareholder value.

The Corporation's total debt level remained relatively flat in 2025, ending the year at $43.5 billion.

Litigation and Other Contingencies

As discussed in Note 7, a variety of claims have been made against ExxonMobil and certain of its consolidated subsidiaries in a number of pending lawsuits. Based on a consideration of all relevant facts and circumstances, the Corporation does not believe the ultimate outcome of any currently pending lawsuit against ExxonMobil will have a material adverse effect upon the Corporation's operations, financial condition, or financial statements taken as a whole. There are no events or uncertainties beyond those already included in reported financial information that would indicate a material change in future operating results or financial condition. Refer to Note 7 for additional information on legal proceedings and other contingencies.

TAXES

(millions of dollars)	2025	2024	2023
Income taxes	11,504	13,810	15,429
Effective income tax rate	*31%*	*33%*	*33%*
Total other taxes and duties	28,930	29,894	32,191
Total	**40,434**	**43,704**	**47,620**

2025

Total taxes on the Corporation's income statement were $40.4 billion in 2025, a decrease of $3.3 billion from 2024. Income tax expense, both current and deferred, was $11.5 billion compared to $13.8 billion in 2024. The effective tax rate, which is calculated based on consolidated company income taxes and ExxonMobil's share of equity company income taxes, was 31 percent. This is down two percentage points compared to 2024 due primarily to favorable one-time items. Total other taxes and duties of $28.9 billion in 2025 decreased $1.0 billion.

2024

Total taxes on the Corporation's income statement were $43.7 billion in 2024, a decrease of $3.9 billion from 2023. Income tax expense, both current and deferred, was $13.8 billion compared to $15.4 billion in 2023. The effective tax rate, which is calculated based on consolidated company income taxes and ExxonMobil's share of equity company income taxes, was 33 percent. This is flat compared to 2023. Total other taxes and duties of $29.9 billion in 2024 decreased $2.3 billion from 2023.

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MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

ENVIRONMENTAL MATTERS

Environmental Expenditures

(millions of dollars)	2025	2024
Capital expenditures	3,053	3,607
Other expenditures	4,580	5,348
Total	**7,633**	**8,955**

Throughout ExxonMobil's businesses, new and ongoing measures are taken to prevent and minimize the impact of our operations on air, water, and ground. These include significant investments in refining infrastructure and technology to manufacture clean fuels; projects to monitor and reduce air, water, and waste emissions, both from the Company's operations and from other companies; and expenditures for asset retirement obligations. Using definitions and guidelines established by the American Petroleum Institute, ExxonMobil's 2025 worldwide environmental expenditures for all such preventative and remediation steps were $7.6 billion, of which $4.6 billion were included in expenses with the remainder in capital expenditures. As the Corporation progresses its emission-reduction plans, worldwide environmental expenditures are expected to increase to approximately $9 billion annually in 2026 and 2027, with capital expenditures expected to account for approximately 44 percent of the total expenditures.

Environmental Liabilities

The Corporation accrues environmental liabilities when it is probable that obligations have been incurred and the amounts can be reasonably estimated. This policy applies to assets or businesses currently owned or previously disposed. ExxonMobil has accrued liabilities for probable environmental remediation obligations at various sites, including multiparty sites where the U.S. Environmental Protection Agency has identified ExxonMobil as one of the potentially responsible parties. The involvement of other financially responsible companies at these multiparty sites could mitigate ExxonMobil's actual joint and several liability exposure. At present, no individual site is expected to have losses material to ExxonMobil's operations or financial condition. Consolidated company provisions made in 2025 for environmental liabilities were $0.4 billion ($0.3 billion in 2024), and the balance sheet reflects liabilities of $0.9 billion as of December 31, 2025, and $0.7 billion as of December 31, 2024.

MARKET RISKS

Worldwide Average Realizations [1]	2025	2024	2023
Brent ($ per barrel)	69.06	80.76	82.62
Henry Hub ($ per metric million British thermal unit)	3.43	2.27	2.74
TTF ($ per metric million British thermal unit)	12.39	10.77	15.15

[1] *Consolidated subsidiaries.*

Crude oil, natural gas, petroleum product, and chemical prices have fluctuated in response to changing market forces. The impacts of these price fluctuations on earnings have varied across the Corporation's operating segments. For the year 2026, a $1 per barrel change in the Brent price would have an approximately $700 million annual after-tax effect on Upstream consolidated plus equity company earnings, excluding the impact of derivatives. This Brent sensitivity includes oil-linked LNG sales which make up approximately 10 percent of the sensitivity. A $0.10 per million metric British thermal unit change in the Henry Hub price would have an approximately $90 million annual after-tax effect on Upstream consolidated plus equity company earnings, excluding the impact of derivatives. Similarly, a $0.10 per million metric British thermal unit change in the Title Transfer Facility (TTF) price would have an approximately $20 million annual after-tax effect on Upstream consolidated plus equity company earnings, excluding the impact of derivatives. This TTF sensitivity primarily represents LNG sales. These price markers have a direct impact on our realized prices. For any given period, the extent of actual benefit or detriment will be dependent on the price movements of individual types of crude oil, results of trading activities, taxes and other government take impacts, price adjustment lags in long-term gas contracts, and crude and gas production volumes. Accordingly, changes in benchmark prices for crude oil and natural gas only provide broad indicators of changes in the earnings experienced in any particular period.

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In the very competitive petroleum and petrochemical environment, earnings are primarily determined by margin capture rather than absolute price levels of products sold. Refining margins are a function of the difference between what a refiner pays for its raw materials (primarily crude oil) and the market prices for the range of products produced. These prices in turn depend on global and regional supply/demand balances, inventory levels, refinery operations, import/export balances and weather.

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MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The global energy markets can give rise to extended periods in which market conditions are adverse to one or more of the Corporation's businesses. Such conditions, along with the capital-intensive nature of the industry and very long lead times associated with many of our projects, underscore the importance of maintaining a strong financial position. Management views the Corporation's financial strength as a competitive advantage.

In general, segment results are not dependent on the ability to sell and/or purchase products to/from other segments. Instead, where such sales take place, they are the result of efficiencies and competitive advantages of integrated refinery and chemical complexes. Additionally, intersegment sales are at market-based prices. The products bought and sold between segments can also be acquired in worldwide markets that have substantial liquidity, capacity, and transportation capabilities. Refer to Note 3 for additional information on intersegment revenue.

Although price levels of crude oil and natural gas may rise or fall significantly over the short to medium term due to global economic conditions, political events, decisions by OPEC or OPEC+ and other major government resource owners and other factors, industry economics over the long term will continue to be driven by market supply and demand. The Corporation evaluates investments over a range of prices, including estimated greenhouse gas emission costs even in jurisdictions without a current greenhouse gas pricing policy.

The Corporation has an active asset management program in which nonstrategic assets are considered for divestment. The asset management program includes a disciplined, regular review to ensure assets are contributing to the Corporation's strategic objectives.

Risk Management

The Corporation's size, strong capital structure, geographic diversity, and the complementary nature of its business segments reduce the Corporation's enterprise-wide risk from changes in commodity prices, currency rates, and interest rates. In addition, the Corporation uses commodity-based contracts, including derivatives, to manage commodity price risk and to generate returns from trading. The Corporation's commodity derivatives are not accounted for under hedge accounting. At times, the Corporation also enters into currency and interest rate derivatives, none of which are material to the Corporation's financial position as of December 31, 2025 and 2024, or results of operations for the years ended 2025, 2024, and 2023. Credit risk associated with the Corporation's derivative position is mitigated by several factors, including the use of derivative clearing exchanges and the quality of and financial limits placed on derivative counterparties. No material market or credit risks to the Corporation's financial position, results of operations, or liquidity exist as a result of the derivatives described in Note 6. The Corporation maintains a system of controls that includes the authorization, reporting, and monitoring of derivative activity.

The Corporation is exposed to changes in interest rates, primarily on its short-term debt and the portion of long-term debt that carries floating interest rates. The impact of a 100-basis-point change in interest rates affecting the Corporation's debt would not be material to earnings or cash flow. The Corporation has access to significant capacity of long-term and short-term liquidity. Internally generated funds are generally expected to cover financial requirements, supplemented by long-term and short-term debt as required. Commercial paper is used to balance short-term liquidity requirements. Some joint-venture partners are dependent on the credit markets, and their funding ability may impact the development pace of joint-venture projects.

The Corporation conducts business in many foreign currencies and is subject to exchange rate risk on cash flows related to sales, expenses, financing, and investment transactions. Fluctuations in exchange rates are often offsetting and the impacts on ExxonMobil's geographically and functionally diverse operations are varied. The Corporation makes limited use of currency exchange contracts to mitigate the impact of changes in currency values, and exposures related to the Corporation's use of these contracts are not material.

CRITICAL ACCOUNTING ESTIMATES

The Corporation's accounting and financial reporting fairly reflect its integrated business model involving exploration for, and production of, crude oil and natural gas; manufacture, trade, transport, and sale of crude oil, natural gas, petroleum products, petrochemicals, and a wide variety of specialty products; and pursuit of lower-emission and other new business opportunities including carbon capture and storage, hydrogen and ammonia, lower-emission fuels, Proxxima™ resin systems, carbon materials, low-carbon data centers, and lithium. The preparation of financial statements in conformity with U.S. Generally Accepted Accounting Principles (GAAP) requires management to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues, and expenses and the disclosure of contingent assets and liabilities. The Corporation's accounting policies are summarized in Note 1.

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MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Oil and Natural Gas Reserves

The estimation of proved oil and natural gas reserve volumes is an ongoing process based on rigorous technical evaluations, commercial and market assessments, and detailed analysis of reservoir and well performance, development and production costs, and other factors. The estimation of proved reserves is controlled by the Corporation through long-standing approval guidelines. Reserve changes are made within a well-established, disciplined process driven by senior level geoscience and engineering professionals, assisted by the Global Reserves and Resources Group which has significant technical experience, culminating in reviews with, and approval by, senior management. Notably, the Corporation does not use specific quantitative reserve targets to determine compensation. Key features of the reserve estimation process are covered in Disclosure of Reserves in Item 2.

Oil and natural gas reserves include both proved and unproved reserves.

- Proved oil and natural gas reserves are determined in accordance with Securities and Exchange Commission (SEC) requirements. Proved reserves are those quantities of oil and natural gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible under existing economic and operating conditions and government regulations. Proved reserves are determined using the average of first-of-month oil and natural gas prices during the reporting year.

  Proved reserves can be further subdivided into developed and undeveloped reserves. Proved developed reserves include amounts which are expected to be recovered through existing wells with existing equipment and operating methods. Proved undeveloped reserves include amounts expected to be recovered from new wells on undrilled proved acreage or from existing wells where a relatively major expenditure is required for completion. Proved undeveloped reserves are recognized only if a development plan has been adopted indicating that the reserves are scheduled to be drilled within five years, unless specific circumstances support a longer period of time.

  The Corporation is reasonably certain that proved reserves will be produced. However, the timing and amount recovered can be affected by a number of factors including completion of development projects, reservoir performance, regulatory approvals, government policy, consumer preferences, and significant changes in oil and natural gas price levels.

- Unproved reserves are quantities of oil and natural gas with less than reasonable certainty of recoverability and include probable reserves. Probable reserves are reserves that, together with proved reserves, are as likely as not to be recovered.

Revisions in previously estimated volumes of proved reserves for existing fields can occur due to the evaluation or re-evaluation of (1) already available geologic, reservoir, or production data, (2) new geologic, reservoir, or production data, or (3) changes in the average of first-of-month oil and natural gas prices and/or costs that are used in the estimation of reserves. Revisions can also result from significant changes in development strategy or production equipment and facility capacity.

Unit-of-Production Depreciation

Oil and natural gas reserve volumes are used as the basis to calculate unit-of-production depreciation rates for most upstream assets. Acquisition costs of proved properties are depreciated using a ratio of asset cost to total proved reserves while capitalized drilling and developments costs are depreciated using a ratio of actual production volumes to proved developed reserves. The volumes produced and asset cost are known, while proved reserves are based on estimates that are subject to some variability.

In the event that the unit-of-production method does not result in an equitable allocation of cost over the economic life of an upstream asset, an alternative method is used. The straight-line method is used in limited situations where the expected life of the asset does not reasonably correlate with that of the underlying reserves. For example, certain assets used in the production of oil and natural gas have a shorter life than the reserves, and as such, the Corporation uses straight-line depreciation to ensure the asset is fully depreciated by the end of its useful life.

To the extent that proved reserves for a property are substantially de-booked and that property continues to produce such that the resulting depreciation charge does not result in an equitable allocation of cost over the expected life, assets will be depreciated using a unit-of-production method based on reserves determined at the most recent SEC price which results in a more meaningful quantity of proved reserves, appropriately adjusted for production and technical changes.

Fair Value Used in Business Combinations

In accounting for business combinations, the purchase price paid to acquire a business is allocated to its assets and liabilities based on their respective estimated fair values as of the date of acquisition. If applicable, any excess of the purchase price over the fair value is recorded as goodwill. The assessment of fair value is based upon the views of a likely market participant group.

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On May 3, 2024, the Corporation acquired Pioneer Natural Resources Company (Pioneer), an independent oil and gas exploration and production company. To effect the acquisition, we issued 545 million shares of ExxonMobil common stock having a fair value of $63 billion on the acquisition date and assumed debt with a fair value of $5 billion.

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MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

In respect of the Pioneer acquisition, the most significant amount of judgment involved the estimated fair values of property, plant, and equipment related to crude oil and natural gas properties, for which we used discounted cash flow models. Inputs and assumptions used in discounted cash flow models include estimates of future production volumes, commodity prices consistent with the average of third-party industry experts, drilling and development costs, and risk-adjusted discount rates.

The assumptions and inputs incorporated within the fair value estimates are subject to considerable management judgment and are based on industry, market, and economic conditions prevalent at the time of the acquisition. Actual results may differ from the projected results used to determine fair value.

See Note 20 for further information regarding the Pioneer acquisition during 2024.

Impairment

The Corporation tests assets or groups of assets for recoverability on an ongoing basis whenever events or changes in circumstances indicate that the carrying amounts may not be recoverable. The Corporation has a robust process to monitor for indicators of potential impairment across its asset groups throughout the year. This process is aligned with the requirements of ASC 360 and ASC 932, and relies, in part, on the Corporation's planning and budgeting cycle.

Because the lifespans of the vast majority of the Corporation's major assets are measured in decades, the future cash flows of these assets are predominantly based on long-term oil and natural gas commodity prices and industry margins, development costs, and production costs. Significant reductions in the Corporation's view of oil or natural gas commodity prices or margin ranges, especially the longer-term prices and margins, and changes in the development plans, including decisions to defer, reduce, or eliminate planned capital spending, can be an indicator of potential impairment. Other events or changes in circumstances, including indicators outlined in ASC 360, can be indicators of potential impairment as well.

In general, the Corporation does not view temporarily low prices or margins as an indication of impairment. Management believes that prices over the long term must be sufficient to generate investments in energy supply to meet global demand. Although prices will occasionally drop significantly, industry prices over the long term will continue to be driven by market supply and demand fundamentals. On the supply side, industry production from mature fields is declining. This is being offset by investments to generate production from new discoveries, field developments, and technology and efficiency advancements. OPEC+ investment activities and production policies also have an impact on world oil supplies. The demand side is largely a function of general economic activities, alternative energy sources, and levels of prosperity. During the lifespan of its major assets, the Corporation expects that oil and gas prices and industry margins will experience significant volatility. Consequently, these assets will experience periods of higher earnings and periods of lower earnings, or even losses. In assessing whether events or changes in circumstances indicate the carrying value of an asset may not be recoverable, the Corporation considers recent periods of operating losses in the context of its longer-term view of prices and margins.

Global Outlook and Cash Flow Assessment. The annual planning and budgeting process, known as the Corporate Plan, is the mechanism by which resources (capital, operating expenses, and people) are allocated across the Corporation. The foundation for the assumptions supporting the Corporate Plan is the Global Outlook (Outlook), which contains the Corporation's demand and supply projections based on its assessment of current trends in technology, government policies, consumer preferences, geopolitics, economic development, and other factors. Reflective of the existing global policy environment, the Outlook does not attempt to project the degree of necessary future policy and technology advancement and deployment for the world, or the Corporation, to meet net zero by 2050. As future policies and technology advancements emerge, they will be incorporated into the Outlook, and the Corporation's business plans will be updated accordingly.

If events or changes in circumstances indicate that the carrying value of an asset may not be recoverable, the Corporation estimates the future undiscounted cash flows of the affected properties to judge the recoverability of carrying amounts. In performing this assessment, assets are grouped at the lowest level for which there are identifiable cash flows that are largely independent of the cash flows of other groups of assets. Cash flows used in recoverability assessments are based on the assumptions developed in the Corporate Plan, which is reviewed and approved by the Board of Directors, and are consistent with the criteria management uses to evaluate investment opportunities. These evaluations make use of the Corporation's assumptions of future capital allocations, crude oil and natural gas commodity prices including price differentials, refining and chemical margins, volumes, development and operating costs including greenhouse gas emission prices, and foreign currency exchange rates. Notably, when assessing future cash flows, the Corporation includes the estimated costs in support of reaching its greenhouse gas emission-reduction plans, including its goal of net-zero Scope 1 and 2 greenhouse gas emissions from its Permian Basin operated assets by 2035. Volumes are based on projected field and facility production profiles, throughput, or sales. Management's estimate of upstream production volumes used for projected cash flows makes use of proved reserve quantities and may include risk-adjusted unproved reserve quantities. ExxonMobil considers a range of scenarios - including remote scenarios - to help inform perspective of the future and enhance strategic thinking over time. While

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third-party scenarios may be used for these purposes, they are not used as a basis for developing future cash flows for impairment assessments. As part of the Corporate Plan, the Company considers estimated greenhouse gas emission costs, even for jurisdictions without a current greenhouse gas pricing policy.

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MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Fair Value of Impaired Assets. An asset group is impaired if its estimated undiscounted cash flows are less than the asset group's carrying value. Impairments are measured by the excess of the carrying value over fair value. The assessment of fair value is based upon the views of a likely market participant. The principal parameters used to establish fair value include estimates of acreage values and flowing production metrics from comparable market transactions, market-based estimates of historical cash flow multiples, and discounted cash flows. Inputs and assumptions used in discounted cash flow models include estimates of future production volumes, throughput and product sales volumes, commodity prices (which are consistent with the average of third-party industry experts and government agencies), refining and chemical margins, drilling and development costs, operating costs, and discount rates which are reflective of the characteristics of the asset group.

Other Impairment Estimates. Unproved properties are assessed periodically to determine whether they have been impaired. Significant unproved properties are assessed for impairment individually, and valuation allowances against the capitalized costs are recorded based on the Corporation's future development plans, the estimated economic chance of success, and the length of time that the Corporation expects to hold the properties. Properties that are not individually significant are aggregated by groups and amortized based on development risk and average holding period.

Long-lived assets that are held for sale are evaluated for possible impairment by comparing the carrying value of the asset with its fair value less the cost to sell. If the net book value exceeds the fair value less cost to sell, the assets are considered impaired and adjusted to the lower value. Judgment is required to determine if assets are held for sale and to determine the fair value less cost to sell.

Investments accounted for by the equity method are assessed for possible impairment when events or changes in circumstances indicate that the carrying value of an investment may not be recoverable. Examples of key indicators include a history of operating losses, negative earnings and cash flow outlook, significant downward revisions to oil and gas reserves, and the financial condition and prospects for the investee's business segment or geographic region. If the decline in value of the investment is other than temporary, the carrying value of the investment is written down to fair value. In the absence of market prices for the investment, discounted cash flows are used to assess fair value, which requires significant judgment.

Recent Impairments. Impairments in 2025 totaled $2.0 billion after-tax, including a write-down to fair value of Upstream oil and gas assets held for sale and charges associated with the optimization of materials and supply inventory.

Impairments in 2024 were immaterial.

In 2023, the Corporation recognized after-tax charges of $3.4 billion, primarily related to the idled Upstream Santa Ynez Unit assets and associated facilities in California, which reflected the continuing challenges in the state regulatory environment that impeded progress towards restoring operations. Other impairments in the year included a $0.6 billion charge related to an Upstream equity investment.

Factors which could put further assets at risk of impairment in the future include reductions in the Corporation's price or margin outlooks, changes in the allocation of capital or development plans, reduced long-term demand for the Corporation's products, and operating cost increases which exceed the pace of efficiencies or the pace of oil and natural gas price or margin increases. However, due to the inherent difficulty in predicting future commodity prices or margins, and the relationship between industry prices and costs, it is not practicable to reasonably estimate the existence or range of any potential future impairment charges related to the Corporation's long-lived assets.

For further information regarding impairments in property, plant, and equipment and suspended wells, refer to Notes 9 and 16, respectively.

Asset Retirement Obligations

The Corporation is subject to retirement obligations for certain assets. The fair values of these obligations are recorded as liabilities on a discounted basis, which is typically at the time the assets are installed. In the estimation of fair value, the Corporation uses assumptions and judgments regarding such factors as the existence of a legal obligation for an asset retirement obligation, technical assessments of the assets, estimated amounts and timing of settlements, discount rates, and inflation rates. See Note 9 for further information regarding asset retirement obligations.

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MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Pension Benefits

The Corporation and its affiliates sponsor about 70 defined benefit (pension) plans in nearly 40 countries. Note 4 provides details on pension obligations, fund assets, and pension expense.

Some of these plans (primarily non-U.S.) provide pension benefits that are paid directly by their sponsoring affiliates out of corporate cash flow rather than a separate pension fund because applicable tax rules and regulatory practices do not encourage advance funding. Book reserves are established for these plans. The portion of the pension cost attributable to employee service is expensed as services are rendered. The portion attributable to the increase in pension obligations due to the passage of time is expensed over the term of the obligations, which ends when all benefits are paid. The primary difference in pension expense for unfunded versus funded plans is that pension expense for funded plans also includes a credit for the expected long-term return on fund assets.

For funded plans, including those in the U.S., pension obligations are financed in advance through segregated assets or insurance arrangements. These plans are managed in compliance with the requirements of governmental authorities and meet or exceed required funding levels as measured by relevant actuarial and government standards at the mandated measurement dates. In determining liabilities and required contributions, these standards often require approaches and assumptions that differ from those used for accounting purposes.

The Corporation will continue to make contributions to these funded plans as necessary. All defined-benefit pension obligations, regardless of the funding status of the underlying plans, are fully supported by the financial strength of the Corporation or the respective sponsoring affiliate.

Pension accounting requires explicit assumptions regarding, among others, the long-term expected earnings rate on fund assets, the discount rate for the benefit obligations, and the long-term rate for future salary increases. Pension assumptions are reviewed annually by outside actuaries and senior management. These assumptions are adjusted as appropriate to reflect changes in market rates and outlook. The long-term expected earnings rate on U.S. pension plan assets in 2025 was 6.0 percent. The 10-year and 20-year actual returns on U.S. pension plan assets were 5 percent over both periods. The Corporation establishes the long-term expected rate of return by developing a forward-looking, long-term return assumption for each pension fund asset class, taking into account factors such as the expected real return for the specific asset class and inflation. A single, long-term rate of return is then calculated as the weighted-average of the target asset allocation percentages and the long-term return assumption for each asset class. A worldwide reduction of 0.5 percent in the long-term rate of return on assets would increase annual pension expense by approximately $150 million before tax.

Differences between actual returns on fund assets and the long-term expected return are not recognized in pension expense in the year that the difference occurs. Such differences are deferred, along with other actuarial gains and losses, and are amortized into pension expense over the expected remaining service life of employees.

Litigation and Tax Contingencies

A variety of claims have been made against the Corporation and certain of its consolidated subsidiaries in a number of pending lawsuits. The Corporation accrues an undiscounted liability for those contingencies where the incurrence of a loss is probable and the amount can be reasonably estimated. For contingencies where an unfavorable outcome is reasonably possible and significant, the Corporation discloses the nature of the contingency and, where feasible, an estimate of the possible loss. As described in Note 7, for purposes of our contingency disclosures, "significant" includes material matters, as well as other matters, which management believes should be disclosed. Management has regular litigation reviews, including updates from corporate and outside counsel, to assess the need for accounting recognition or disclosure of these contingencies.

Management judgment is required related to contingent liabilities and the outcome of litigation because both are difficult to predict. However, the Corporation has been successful in defending litigation in the past. Payments have not had a material adverse effect on our operations or financial condition. In the Corporation's experience, large claims often do not result in large awards. Large awards are often reversed or substantially reduced as a result of appeal or settlement.

The Corporation is subject to income taxation in many jurisdictions around the world. The benefits of uncertain tax positions that the Corporation has taken or expects to take in its income tax returns are recognized in the financial statements if management concludes that it is more likely than not that the position will be sustained with the tax authorities. For a position that is likely to be sustained, the benefit recognized in the financial statements is measured at the largest amount that is greater than 50 percent likely of being realized. Significant management judgment is required in the accounting for income tax contingencies and tax disputes because the outcomes are often difficult to predict. The Corporation's unrecognized tax benefits and a description of open tax years are summarized in Note 15.

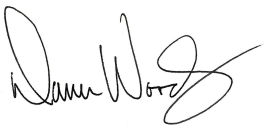
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MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management, including the Corporation's Chief Executive Officer, Chief Financial Officer, and Principal Accounting Officer, is responsible for establishing and maintaining adequate internal control over the Corporation's financial reporting. Management conducted an evaluation of the effectiveness of internal control over financial reporting based on criteria established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that Exxon Mobil Corporation's internal control over financial reporting was effective as of December 31, 2025.

PricewaterhouseCoopers LLP, an independent registered public accounting firm, audited the effectiveness of the Corporation's internal control over financial reporting as of December 31, 2025, as stated in their report included in the Financial Section of this report.



Darren W. Woods
Chief Executive Officer



Neil A. Hansen
Senior Vice President and
Chief Financial Officer



Len M. Fox
Vice President, Controller and Tax
(Principal Accounting Officer)

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of Exxon Mobil Corporation

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the accompanying consolidated balance sheet of Exxon Mobil Corporation and its subsidiaries (the "Corporation") as of December 31, 2025 and 2024, and the related consolidated statements of income, of comprehensive income, of changes in equity and of cash flows for each of the three years in the period ended December 31, 2025, including the related notes (collectively referred to as the "consolidated financial statements"). We also have audited the Corporation's internal control over financial reporting as of December 31, 2025, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Corporation as of December 31, 2025 and 2024, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2025, in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2025, based on criteria established in Internal Control - Integrated Framework (2013) issued by the COSO.

Basis for Opinions

The Corporation's management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control over Financial Reporting appearing under Item 9A. Our responsibility is to express opinions on the Corporation's consolidated financial statements and on the Corporation's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Corporation in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Critical Audit Matters

The critical audit matter communicated below is a matter arising from the current period audit of the consolidated financial statements that was communicated or required to be communicated to the audit committee and that (i) relates to accounts or disclosures that are material to the consolidated financial statements and (ii) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

The Impact of Proved Developed Oil and Natural Gas Reserves on Upstream Property, Plant, and Equipment, Net

As described in Notes 1, 3, and 9 to the consolidated financial statements, the Corporation's consolidated upstream property, plant, and equipment (PP&E), net balance was $228.2 billion as of December 31, 2025, and the related depreciation and depletion expense was $21.4 billion for the year ended December 31, 2025. Management uses the successful efforts method to account for its exploration and production activities. Costs incurred to purchase, lease, or otherwise acquire a property (whether unproved or proved) are capitalized when incurred. As disclosed by management, oil and natural gas reserve volumes are used as the basis to calculate unit-of-production depreciation rates for most upstream assets. Acquisition costs of proved properties are depreciated using a ratio of asset cost to total proved reserves while capitalized drilling and development costs are depreciated using a ratio of actual production volumes to proved developed reserves. The estimation of proved oil and natural gas reserve volumes is an ongoing process based on technical evaluations, commercial and market assessments, and detailed analysis of reservoir and well performance, development and production costs, and other factors. As further disclosed by management, reserve changes are made within a well-established, disciplined process driven by senior level geoscience and engineering professionals, assisted by the Global Reserves and Resources Group (together "management's specialists").

The principal considerations for our determination that performing procedures relating to the impact of proved developed oil and natural gas reserves on upstream PP&E, net is a critical audit matter are (i) the significant judgment by management, including the use of management's specialists, when developing the estimates of proved developed oil and natural gas reserves, which are derived using historical production volumes, and (ii) a high degree of auditor judgment, subjectivity, and effort in performing procedures and evaluating audit evidence related to the data, specifically historical production volumes, methods, and assumptions used by management and its specialists in developing the estimates of proved developed oil and natural gas reserves.

Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the consolidated financial statements. These procedures included testing the effectiveness of controls relating to management's estimates of proved developed oil and natural gas reserves. The work of management's specialists was used in performing the procedures to evaluate the reasonableness of the proved developed oil and natural gas reserves. As a basis for using this work, the specialists' qualifications were understood and the Corporation’s relationship with the specialists was assessed. The procedures performed also included (i) evaluating the methods and assumptions used by the specialists; (ii) testing the completeness and accuracy of the data used by the specialists related to historical production volumes; and (iii) evaluating the specialists' findings related to future production volumes by comparing the future production volumes to relevant historical and current period production volumes, as applicable.

/s/ PricewaterhouseCoopers LLP

Houston, Texas

February 18, 2026

We have served as the Corporation’s auditor since 1934.

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The information in the Notes to Consolidated Financial Statements is an integral part of these statements.

CONSOLIDATED STATEMENT OF INCOME

(millions of dollars)	Note Reference Number	2025	2024	2023
Revenues and other income				
Sales and other operating revenue	3	323,905	339,247	334,697
Income from equity affiliates	8	5,064	6,194	6,385
Other income		3,269	4,144	3,500
Total revenues and other income		**332,238**	**349,585**	**344,582**
Costs and other deductions				
Crude oil and product purchases		184,248	199,454	193,029
Production and manufacturing expenses		42,424	39,609	36,885
Selling, general and administrative expenses		11,128	9,976	9,919
Depreciation and depletion (includes impairments)	9	25,993	23,442	20,641
Exploration expenses, including dry holes		1,007	826	751
Non-service pension and postretirement benefit expense	4	400	121	714
Interest expense		603	996	849
Other taxes and duties	15	25,167	26,288	29,011
Total costs and other deductions		**290,970**	**300,712**	**291,799**
Income (loss) before income taxes		**41,268**	**48,873**	**52,783**
Income tax expense (benefit)	15	11,504	13,810	15,429
Net income (loss) including noncontrolling interests		**29,764**	**35,063**	**37,354**
Net income (loss) attributable to noncontrolling interests		920	1,383	1,344
Net income (loss) attributable to ExxonMobil		**28,844**	**33,680**	**36,010**
Earnings (loss) per common share *(dollars)*	2	**6.70**	**7.84**	**8.89**
Earnings (loss) per common share - assuming dilution *(dollars)*	2	**6.70**	**7.84**	**8.89**

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The information in the Notes to Consolidated Financial Statements is an integral part of these statements.

CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

(millions of dollars)	2025	2024	2023
Net income (loss) including noncontrolling interests	**29,764**	**35,063**	**37,354**
Other comprehensive income (loss) (net of income taxes)			
Foreign exchange translation adjustment	2,631	(3,550)	1,241
Adjustment for foreign exchange translation (gain)/loss included in net income	391	—	609
Postretirement benefits reserves adjustment (excluding amortization)	1,009	557	(369)
Amortization and settlement of postretirement benefits reserves adjustment included in net periodic benefit costs	38	43	61
Total other comprehensive income (loss)	**4,069**	**(2,950)**	**1,542**
Comprehensive income (loss) including noncontrolling interests	**33,833**	**32,113**	**38,896**
Comprehensive income (loss) attributable to noncontrolling interests	1,233	1,063	1,605
Comprehensive income (loss) attributable to ExxonMobil	**32,600**	**31,050**	**37,291**

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The information in the Notes to Consolidated Financial Statements is an integral part of these statements.

CONSOLIDATED BALANCE SHEET

(millions of dollars)	Note Reference Number	December 31, 2025	December 31, 2024
ASSETS			
Current assets			
Cash and cash equivalents		10,681	23,029
Cash and cash equivalents – restricted		—	158
Notes and accounts receivable – net	10	44,562	43,681
Inventories			
Crude oil, products and merchandise	14	22,979	19,444
Materials and supplies		3,323	4,080
Other current assets		1,837	1,598
Total current assets		**83,382**	**91,990**
Investments, advances, and long-term receivables	11	45,317	47,200
Property, plant, and equipment, at cost, less accumulated depreciation and depletion	9	299,373	294,318
Other assets, including intangibles – net		20,908	19,967
Total Assets		**448,980**	**453,475**
LIABILITIES			
Current liabilities			
Notes and loans payable	10	9,296	4,955
Accounts payable and accrued liabilities	10	60,911	61,297
Income taxes payable		2,123	4,055
Total current liabilities		**72,330**	**70,307**
Long-term debt	12	34,241	36,755
Postretirement benefits reserves	4	8,847	9,700
Deferred income tax liabilities	15	40,216	39,042
Long-term obligations to equity companies		542	1,346
Other long-term obligations		26,178	25,719
Total Liabilities		**182,354**	**182,869**
Commitments and contingencies	7		
EQUITY			
Common stock without par value (9,000 million shares authorized, 8,019 million shares issued)		46,150	46,238
Earnings reinvested		482,494	470,903
Accumulated other comprehensive income	5	(10,863)	(14,619)
Common stock held in treasury (3,840 million shares in 2025 and 3,666 million shares in 2024)		(258,395)	(238,817)
ExxonMobil share of equity		**259,386**	**263,705**
Noncontrolling interests		7,240	6,901
Total Equity		**266,626**	**270,606**
Total Liabilities and Equity		**448,980**	**453,475**

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The information in the Notes to Consolidated Financial Statements is an integral part of these statements.

CONSOLIDATED STATEMENT OF CASH FLOWS

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(millions of dollars)	Note Reference Number	2025	2024	2023
CASH FLOWS FROM OPERATING ACTIVITIES				
Net income (loss) including noncontrolling interests		29,764	35,063	37,354
Adjustments for noncash transactions				
Depreciation and depletion (includes impairments)	9	25,993	23,442	20,641
Deferred income tax charges/(credits)	15	765	(865)	634
Postretirement benefits expense in excess of/(less than) net payments		(64)	(358)	90
Other long-term obligation provisions in excess of/(less than) payments		(1,430)	(1,712)	(1,501)
Dividends received greater than/(less than) equity in current earnings of equity companies		3,006	191	509
Changes in operational working capital, excluding cash and debt				
Notes and accounts receivable *reduction/(increase)*		(3,042)	(6,030)	4,370
Inventories *reduction/(increase)*		(4,300)	(1,812)	(3,472)
Other current assets *reduction/(increase)*		(164)	389	(426)
Accounts and other payables *increase/(reduction)*		(222)	5,627	(4,727)
Net (gain)/loss on asset sales	17	(1,113)	(1,223)	(513)
All other items - net		2,777	2,310	2,410
Net cash provided by operating activities		**51,970**	**55,022**	**55,369**
CASH FLOWS FROM INVESTING ACTIVITIES				
Additions to property, plant, and equipment		(28,358)	(24,306)	(21,919)
Proceeds from asset sales and returns of investments		3,158	4,987	4,078
Additional investments and advances		(4,133)	(3,299)	(2,995)
Other investing activities including collection of advances		3,406	1,926	1,562
Cash acquired from mergers and acquisitions		—	754	—
Net cash used in investing activities		**(25,927)**	**(19,938)**	**(19,274)**
CASH FLOWS FROM FINANCING ACTIVITIES				
Additions to long-term debt [(1)]		2,311	899	939
Reductions in long-term debt		(1,108)	(1,150)	(15)
Additions to short-term debt [(2) (3)]		2,359	—	—
Reductions in short-term debt [(3)]		(5,404)	(4,743)	(879)
Additions/(reductions) in commercial paper, and debt with three months or less maturity		1,895	(18)	(284)
Contingent consideration payments		(79)	(27)	(68)
Cash dividends to ExxonMobil shareholders		(17,231)	(16,704)	(14,941)
Cash dividends to noncontrolling interests		(935)	(658)	(531)
Changes in noncontrolling interests		(704)	(791)	(894)
Inflows from noncontrolling interests for major projects		88	32	124
Common stock acquired		(20,273)	(19,629)	(17,748)
Net cash provided by (used in) financing activities		**(39,081)**	**(42,789)**	**(34,297)**
Effects of exchange rate changes on cash		532	(676)	105
Increase/(decrease) in cash and cash equivalents (including restricted)		**(12,506)**	**(8,381)**	**1,903**
Cash and cash equivalents at beginning of year (including restricted)		23,187	31,568	29,665
Cash and cash equivalents at end of year (including restricted)		**10,681**	**23,187**	**31,568**

[(1)] Includes $568 million issued to facilitate the sale of an entity where the buyer assumed the debt upon closing; no longer on the Consolidated Balance Sheet at the end of 2023.

[(2)] Includes $659 million of proceeds related to a financing arrangement to facilitate the sale of an entity where the buyer assumed the obligation at closing; no longer on the Consolidated Balance Sheet at the end of 2025.

[(3)] Includes commercial paper with a maturity greater than three months.

Non-Cash Transaction: *The Corporation acquired Pioneer Natural Resources Company in an all-stock transaction on May 3, 2024, having issued 545 million shares of ExxonMobil common stock having a fair value of $63 billion and assumed debt with a fair value of $5 billion. See Note 20 for additional information.*

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The information in the Notes to Consolidated Financial Statements is an integral part of these statements.

CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

	ExxonMobil Share of Equity						
(millions of dollars)	Common Stock	Earnings Reinvested	Accumulated Other Comprehensive Income	Common Stock Held in Treasury	ExxonMobil Share of Equity	Non-controlling Interests	Total Equity
Balance as of December 31, 2022	**15,752**	**432,860**	**(13,270)**	**(240,293)**	**195,049**	**7,424**	**202,473**
Amortization of stock-based awards	565	—	—	—	565	—	565
Other	(514)	(2)	—	—	(516)	89	(427)
Net income (loss) for the year	—	36,010	—	—	36,010	1,344	37,354
Dividends - common shares	—	(14,941)	—	—	(14,941)	(531)	(15,472)
Other comprehensive income	—	—	1,281	—	1,281	261	1,542
Share repurchases, at cost	—	—	—	(17,993)	(17,993)	(851)	(18,844)
Issued for acquisitions	1,978	—	—	2,866	4,844	—	4,844
Dispositions	—	—	—	503	503	—	503
Balance as of December 31, 2023	**17,781**	**453,927**	**(11,989)**	**(254,917)**	**204,802**	**7,736**	**212,538**
Amortization of stock-based awards	735	—	—	—	735	—	735
Other	(1,027)	—	—	—	(1,027)	(624)	(1,651)
Net income (loss) for the year	—	33,680	—	—	33,680	1,383	35,063
Dividends - common shares	—	(16,704)	—	—	(16,704)	(658)	(17,362)
Other comprehensive income	—	—	(2,630)	—	(2,630)	(320)	(2,950)
Share repurchases, at cost	—	—	—	(19,451)	(19,451)	(616)	(20,067)
Issued for acquisitions	28,749	—	—	34,603	63,352	—	63,352
Dispositions	—	—	—	948	948	—	948
Balance as of December 31, 2024	**46,238**	**470,903**	**(14,619)**	**(238,817)**	**263,705**	**6,901**	**270,606**
Amortization of stock-based awards	812	—	—	—	812	—	812
Other	(900)	(22)	—	—	(922)	762	(160)
Net income (loss) for the year	—	28,844	—	—	28,844	920	29,764
Dividends - common shares	—	(17,231)	—	—	(17,231)	(947)	(18,178)
Other comprehensive income	—	—	3,756	—	3,756	313	4,069
Share repurchases, at cost	—	—	—	(20,467)	(20,467)	(709)	(21,176)
Dispositions	—	—	—	889	889	—	889
Balance as of December 31, 2025	**46,150**	**482,494**	**(10,863)**	**(258,395)**	**259,386**	**7,240**	**266,626**

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Common Stock Share Activity *(millions of shares)*	Issued	Held in Treasury	Outstanding
Balance as of December 31, 2022	**8,019**	**(3,937)**	**4,082**
Share repurchases, at cost	—	(165)	(165)
Issued for acquisitions	—	46	46
Dispositions	—	8	8
Balance as of December 31, 2023	**8,019**	**(4,048)**	**3,971**
Share repurchases, at cost	—	(170)	(170)
Issued for acquisitions	—	545	545
Dispositions	—	7	7
Balance as of December 31, 2024	**8,019**	**(3,666)**	**4,353**
Share repurchases, at cost	—	(182)	(182)
Issued for acquisitions	—	—	—
Dispositions	—	8	8
Balance as of December 31, 2025	**8,019**	**(3,840)**	**4,179**

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The accompanying consolidated financial statements and the supporting and supplemental material are the responsibility of the management of Exxon Mobil Corporation.

The Corporation's principal business involves exploration for, and production of, crude oil and natural gas; manufacture, trade, transport, and sale of crude oil, natural gas, petroleum products, petrochemicals and a wide variety of specialty products; and pursuit of lower-emission and other new business opportunities including carbon capture and storage, hydrogen and ammonia, lower-emission fuels, Proxxima™ resin systems, carbon materials, low-carbon data centers, and lithium.

The preparation of financial statements in conformity with U.S. Generally Accepted Accounting Principles (GAAP) requires management to make estimates that affect the reported amounts of assets, liabilities, revenues, and expenses and the disclosure of contingent assets and liabilities. Actual results could differ from these estimates.

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Note 1. Summary of Accounting Policies

Principles of Consolidation and Accounting for Investments

The Consolidated Financial Statements include the accounts of subsidiaries the Corporation controls and any variable interest entities where it is deemed the primary beneficiary. They also include the Corporation's share of the undivided interest in certain upstream assets, liabilities, revenues, and expenses. Amounts representing the Corporation's interest in entities that it does not control, but over which it exercises significant influence, are included in "Investments, advances, and long-term receivables." Under the equity method of accounting, the Corporation recognizes its share of the net income of these companies in "Income from equity affiliates."

Majority ownership is normally the indicator of control that is the basis on which subsidiaries are consolidated. However, certain factors may indicate that a majority-owned investment is not controlled and, therefore, should be accounted for using the equity method of accounting. These factors occur where the minority shareholders are granted, by law or by contract, substantive participating rights. These include the right to approve operating policies, expense budgets, financing and investment plans, and management compensation and succession plans.

Investments accounted for by the equity method are assessed for possible impairment when events or changes in circumstances indicate that the carrying value of an investment may not be recoverable. Examples of key indicators include a history of operating losses, negative earnings and cash flow outlook, significant downward revisions to oil and gas reserves, and the financial condition and prospects for the investee's business segment or geographic region. If the decline in value of the investment is other than temporary, the carrying value of the investment is written down to fair value. In the absence of market prices for the investment, discounted cash flows are used to assess fair value. The Corporation's share of the cumulative foreign exchange translation adjustment for equity method investments is reported in "Accumulated other comprehensive income."

Investments in equity securities, other than consolidated subsidiaries and equity method investments, are measured at fair value with changes in fair value recognized in net income. The Corporation uses the modified approach for equity securities that do not have a readily determinable fair value. This modified approach measures investments at cost minus impairment, if any, plus or minus changes resulting from observable price changes in orderly transactions in a similar investment of the same issuer.

Revenue Recognition

The Corporation generally sells crude oil, natural gas, and petroleum and chemical products under short-term agreements at prevailing market prices. In some cases (e.g., natural gas), products may be sold under long-term agreements, with periodic price adjustments to reflect market conditions. Revenue is recognized at the amount the Corporation expects to receive when the customer has taken control, which is typically when title transfers and the customer has assumed the risks and rewards of ownership. The prices of certain sales are based on price indices that are sometimes not available until the next period. In such cases, estimated realizations are accrued when the sale is recognized, and are finalized when the price is available. Such adjustments to revenue from performance obligations satisfied in previous periods are not significant. Payment for revenue transactions is typically due within 30 days. Future volume delivery obligations that are unsatisfied at the end of the period are expected to be fulfilled through ordinary production or purchases. These performance obligations are based on market prices at the time of the transaction and are fully constrained due to market price volatility.

Purchases and sales of inventory with the same counterparty that are entered into in contemplation of one another are combined and recorded as exchanges measured at the book value of the item sold.

"Sales and other operating revenue" and "Notes and accounts receivable" include revenue and receivables both within the scope of ASC 606 "Revenue from Contracts with Customers" and those outside the scope of ASC 606. Long-term receivables are primarily

from receivables outside the scope of ASC 606. Contract assets are mainly from marketing assistance programs and are not significant. Contract liabilities are mainly customer prepayments and accruals of expected volume discounts and are not significant.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Income and Other Taxes

The Corporation excludes from the Consolidated Statement of Income certain sales and value-added taxes imposed on and concurrent with revenue-producing transactions with customers and collected on behalf of governmental authorities. Similar taxes, for which the Corporation is not considered to be an agent for the government, are reported on a gross basis (included in both "Sales and other operating revenue" and "Other taxes and duties").

The Corporation accounts for U.S. tax on global intangible low-taxed income as an income tax expense in the period in which it is incurred.

Derivative Instruments

The Corporation may use derivative instruments for trading purposes and to offset exposures associated with commodity prices, foreign currency exchange rates, and interest rates that arise from existing assets, liabilities, firm commitments, and forecasted transactions. All derivative instruments, except those designated as normal purchase and normal sale, are recorded at fair value. Derivative assets and liabilities with the same counterparty are netted if the right of offset exists and certain other criteria are met. Collateral payables or receivables are netted against derivative assets and derivative liabilities, respectively.

Recognition and classification of the gain or loss that results from adjusting a derivative to fair value depends on the purpose for the derivative. All gains and losses from derivative instruments for which the Corporation does not apply hedge accounting are immediately recognized in earnings. The Corporation may designate derivatives as fair value or cash flow hedges. For fair value hedges, the gain or loss from derivative instruments and the offsetting gain or loss from the hedged item are recognized in earnings. For cash flow hedges, the gain or loss from the derivative instrument is initially reported as a component of other comprehensive income and subsequently reclassified into earnings in the period that the forecasted transaction affects earnings.

Fair Value

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants. Hierarchy levels 1, 2, and 3 are terms for the priority of inputs to valuation techniques used to measure fair value. Hierarchy level 1 inputs are quoted prices in active markets for identical assets or liabilities. Hierarchy level 2 inputs are inputs other than quoted prices included within level 1 that are directly or indirectly observable for the asset or liability. Hierarchy level 3 inputs are inputs that are not observable in the market.

Inventories

Crude oil, products, and merchandise inventories are carried at the lower of current market value or cost (generally determined under the last-in, first-out method – LIFO). Inventory costs include expenditures and other charges (including depreciation) directly and indirectly incurred in bringing the inventory to its existing condition and location. Selling expenses and general and administrative expenses are reported as period costs and excluded from inventory cost. Inventories of materials and supplies are valued at cost or less.

Property, Plant, and Equipment

Cost Basis. The Corporation uses the "successful efforts" method to account for its exploration and production activities. Under this method, costs are accumulated on a field-by-field basis. Costs incurred to purchase, lease, or otherwise acquire a property (whether unproved or proved) are capitalized when incurred. Exploratory well costs are carried as an asset when the well has found a sufficient quantity of reserves to justify its completion as a producing well and where the Corporation is making sufficient progress assessing the reserves and the economic and operating viability of the project. Exploratory well costs not meeting these criteria are charged to expense. Other exploratory expenditures, including geophysical costs and annual lease rentals, are expensed as incurred. Development costs, including costs of productive wells and development dry holes, are capitalized.

Interest costs incurred to finance expenditures during the construction phase of multiyear projects are capitalized as part of the historical cost of acquiring the constructed assets. The project construction phase commences with the development of the detailed engineering design and ends when the constructed assets are ready for their intended use. Capitalized interest costs are included in property, plant, and equipment and are depreciated over the service life of the related assets.

Depreciation, Depletion, and Amortization. Depreciation, depletion, and amortization are primarily determined under either the unit-of-production method or the straight-line method, which is based on estimated asset service life, taking obsolescence into consideration.

Acquisition costs of proved properties are amortized using a unit-of-production method, computed on the basis of total proved oil and natural gas reserve volumes. Capitalized exploratory drilling and development costs associated with productive depletable extractive properties are amortized using the unit-of-production rates based on the amount of proved developed reserves of oil and gas that are estimated to be recoverable from existing facilities using current operating methods. Under the unit-of-production method, oil and

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natural gas volumes are considered produced once they have been measured through meters at custody transfer or sales transaction points at the outlet valve on the lease or field storage tank.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

In the event that the unit-of-production method does not result in an equitable allocation of cost over the economic life of an upstream asset, an alternative method is used. The straight-line method is used in limited situations where the expected life of the asset does not reasonably correlate with that of the underlying reserves. For example, certain assets used in the production of oil and natural gas have a shorter life than the reserves, and as such, the Corporation uses straight-line depreciation to ensure the asset is fully depreciated by the end of its useful life.

To the extent that proved reserves for a property are substantially de-booked and that property continues to produce such that the resulting depreciation charge does not result in an equitable allocation of cost over the expected life, assets will be depreciated using a unit-of-production method based on reserves determined at the most recent SEC price which results in a more meaningful quantity of proved reserves, appropriately adjusted for production and technical changes.

Investments in refinery, chemical process, and lubes basestock manufacturing equipment are generally depreciated on a straight-line basis over a 25-year life. Service station buildings and fixed improvements are generally depreciated over a 20-year life. Maintenance and repairs, including planned major maintenance, are expensed as incurred. Major renewals and improvements are capitalized, and the assets replaced are retired.

Impairment Assessment. The Corporation tests assets or groups of assets for recoverability on an ongoing basis whenever events or changes in circumstances indicate that the carrying amounts may not be recoverable. Among the events or changes in circumstances which could indicate that the carrying value of an asset or asset group may not be recoverable are the following:

- a significant decrease in the market price of a long-lived asset;
- a significant adverse change in the extent or manner in which an asset is being used or in its physical condition, including a significant decrease in current and projected reserve volumes;
- a significant adverse change in legal factors or in the business climate that could affect the value, including an adverse action or assessment by a regulator;
- an accumulation of project costs significantly in excess of the amount originally expected;
- a current-period operating loss combined with a history and forecast of operating or cash flow losses; and
- a current expectation that, more likely than not, a long-lived asset will be sold or otherwise disposed of significantly before the end of its previously estimated useful life.

The Corporation has a robust process to monitor for indicators of potential impairment across its asset groups throughout the year. This process is aligned with the requirements of ASC 360 and ASC 932, and relies, in part, on the Corporation's planning and budgeting cycle. Asset valuation analysis, profitability reviews, and other periodic control processes assist the Corporation in assessing whether events or changes in circumstances indicate the carrying amounts of any of its assets may not be recoverable.

Because the lifespans of the vast majority of the Corporation's major assets are measured in decades, the future cash flows of these assets are predominantly based on long-term oil and natural gas commodity prices and industry margins, development costs, and production costs. Significant reductions in the Corporation's view of oil or natural gas commodity prices or margin ranges, especially the longer-term prices and margins, and changes in the development plans, including decisions to defer, reduce, or eliminate planned capital spending, can be an indicator of potential impairment. Other events or changes in circumstances can be indicators of potential impairment as well.

In general, the Corporation does not view temporarily low prices or margins as an indication of impairment. Management believes that prices over the long term must be sufficient to generate investments in energy supply to meet global demand. Although prices will occasionally drop significantly, industry prices over the long term will continue to be driven by market supply and demand fundamentals. On the supply side, industry production from mature fields is declining. This is being offset by investments to generate production from new discoveries, field developments, and technology and efficiency advancements. OPEC+ investment activities and production policies also have an impact on world oil supplies. The demand side is largely a function of general economic activities, alternative energy sources, and levels of prosperity. During the lifespan of its major assets, the Corporation expects that oil and gas prices and industry margins will experience significant volatility. Consequently, these assets will experience periods of higher earnings and periods of lower earnings, or even losses. In assessing whether events or changes in circumstances indicate the carrying value of an asset may not be recoverable, the Corporation considers recent periods of operating losses in the context of its longer-term view of prices and margins.

In the Upstream, the standardized measure of discounted cash flows included in the Supplemental Information on Oil and Gas Exploration and Production Activities is required to use prices based on the average of first-of-month prices in the year. These prices represent discrete points in time and could be higher or lower than the Corporation's price assumptions which are used for impairment assessments. The Corporation believes the standardized measure does not provide a reliable estimate of the expected future cash flows to be obtained from the development and production of its oil and gas properties or of the value of its oil and gas reserves, and

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therefore, does not consider it relevant in determining whether events or changes in circumstances indicate the need for an impairment assessment.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Global Outlook and Cash Flow Assessment. The annual planning and budgeting process, known as the Corporate Plan, is the mechanism by which resources (capital, operating expenses, and people) are allocated across the Corporation. The foundation for the assumptions supporting the Corporate Plan is the Global Outlook (Outlook), which contains the Corporation's demand and supply projections based on its assessment of current trends in technology, government policies, consumer preferences, geopolitics, economic development, and other factors. Reflective of the existing global policy environment, the Outlook does not attempt to project the degree of necessary future policy and technology advancement and deployment for the world, or the Corporation, to meet net zero by 2050. As future policies and technology advancements emerge, they will be incorporated into the Outlook, and the Corporation's business plans will be updated accordingly.

If events or changes in circumstances indicate that the carrying value of an asset may not be recoverable, the Corporation estimates the future undiscounted cash flows of the affected properties to judge the recoverability of carrying amounts. In performing this assessment, assets are grouped at the lowest level for which there are identifiable cash flows that are largely independent of the cash flows of other groups of assets. Cash flows used in recoverability assessments are based on the assumptions developed in the Corporate Plan, which is reviewed and approved by the Board of Directors, and are consistent with the criteria management uses to evaluate investment opportunities. These evaluations make use of the Corporation's assumptions of future capital allocations, crude oil and natural gas commodity prices, including price differentials, refining and chemical margins, volumes, development and operating costs including greenhouse gas emission prices, and foreign currency exchange rates. Notably, when assessing future cash flows, the Corporation includes the estimated costs in support of reaching its greenhouse gas emission-reduction plans, including its goal of net-zero Scope 1 and 2 greenhouse gas emissions from its operated assets in the Permian Basin by 2035. Volumes are based on projected field and facility production profiles, throughput, or sales. Management's estimate of upstream production volumes used for projected cash flows makes use of proved reserve quantities and may include risk-adjusted unproved reserve quantities. Cash flow estimates for impairment testing exclude the effects of derivative instruments. As part of the Corporate Plan, the Company considers estimated greenhouse gas emission costs, even for jurisdictions without a current greenhouse gas pricing policy.

Fair Value of Impaired Assets. An asset group is impaired if its estimated undiscounted cash flows are less than the asset group's carrying value. Impairments are measured by the excess of the carrying value over fair value. The assessment of fair value is based upon the views of a likely market participant. The principal parameters used to establish fair value include estimates of acreage values and flowing production metrics from comparable market transactions, market-based estimates of historical cash flow multiples, and discounted cash flows. Inputs and assumptions used in discounted cash flow models include estimates of future production volumes, throughput and product sales volumes, commodity prices (which are consistent with the average of third-party industry experts and government agencies), refining and chemical margins, drilling and development costs, operating costs, and discount rates which are reflective of the characteristics of the asset group.

Other Impairments Related to Property, Plant, and Equipment. Unproved properties are assessed periodically to determine whether they have been impaired. Significant unproved properties are assessed for impairment individually, and valuation allowances against the capitalized costs are recorded based on the Corporation's future development plans, the estimated economic chance of success, and the length of time that the Corporation expects to hold the properties. Properties that are not individually significant are aggregated by groups and amortized based on development risk and average holding period.

Long-lived assets that are held for sale are evaluated for possible impairment by comparing the carrying value of the asset with its fair value less the cost to sell. If the net book value exceeds the fair value less cost to sell, the assets are considered impaired and adjusted to the lower value. Gains on sales of proved and unproved properties are only recognized when there is neither uncertainty about the recovery of costs applicable to any interest retained nor any substantial obligation for future performance by the Corporation.

Environmental Liabilities

Liabilities for environmental costs are recorded when it is probable that obligations have been incurred and the amounts can be reasonably estimated. These liabilities are not reduced by possible recoveries from third parties, and projected cash expenditures are not discounted.

Foreign Currency Translation

The Corporation selects the functional reporting currency for its international subsidiaries based on the currency of the primary economic environment in which each subsidiary operates. Operations in the Product Solutions businesses use the local currency. However, the U.S. dollar is used in countries with a history of high inflation (primarily in Latin America) and in Singapore, which predominantly sells into the U.S. dollar export market. Upstream operations which are relatively self-contained and integrated within a particular country, such as in Canada and Europe, use the local currency. Some Upstream operations, primarily in Asia and Africa, use the U.S. dollar because they predominantly sell crude and natural gas production into U.S. dollar-denominated markets.

For all operations, gains or losses from remeasuring foreign currency transactions into the functional currency are included in income.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 2. Earnings Per Share

Earnings per common share	2025	2024	2023
Net income (loss) attributable to ExxonMobil *(millions of dollars)*	28,844	33,680	36,010
Weighted-average number of common shares outstanding *(millions of shares)* [1]	4,305	4,298	4,052
Earnings (loss) per common share *(dollars)* [2]	6.70	7.84	8.89
Dividends paid per common share *(dollars)*	4.00	3.84	3.68

[1] *Includes restricted shares not vested as well as 545 million shares issued for the Pioneer acquisition on May 3, 2024.*

[2] *The earnings (loss) per common share and earnings (loss) per common share - assuming dilution are the same in each period shown.*

Note 3. Disclosures about Segments and Related Information

Our four reportable segments are Upstream, Energy Products, Chemical Products, and Specialty Products. The factors used to identify these reportable segments are based on the nature of the operations that are undertaken by each segment and reflect the nature of internal reviews by our Management Committee (MC). The MC is considered collectively, and not in their individual capacity, to be our Chief Operating Decision Maker (CODM), and includes our CEO, CFO, and two Senior Vice Presidents serving as contact executives overseeing the Upstream and Product Solutions businesses.

The Upstream segment is organized to explore for and produce crude oil and natural gas. Product Solutions consists of the Energy Products, Chemical Products, and Specialty Products segments, which are organized to manufacture and sell petroleum products and petrochemicals.

- Energy Products: Fuels, aromatics, and catalysts and licensing
- Chemical Products: Olefins, polyolefins, and intermediates
- Specialty Products: Finished lubricants, basestocks and waxes, synthetics, and elastomers and resins

The CODM generally allocates resources through an annual planning process. They also allocate capital based on detailed project economics and long-term strategic objectives across reportable segments. The CODM primarily uses changes in Net income (loss) attributable to ExxonMobil to assess segment financial performance.

Net income (loss) attributable to ExxonMobil includes transfers at estimated market prices. In Corporate and Financing, interest revenue relates to interest earned on cash deposits and marketable securities. Interest expense includes non-debt-related interest expense of $0.3 billion in 2025, $0.4 billion in 2024, and $0.2 billion in 2023.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(millions of dollars)	Upstream		Energy Products		Chemical Products		Specialty Products		Segment Total
	U.S.	Non-U.S.	U.S.	Non-U.S.	U.S.	Non-U.S.	U.S.	Non-U.S.	
Year ended December 31, 2025									
Revenues and other income									
Sales and other operating revenue	25,396	13,993	99,073	145,378	7,594	14,615	5,502	12,269	**323,820**
Income from equity affiliates	19	4,340	139	198	135	544	7	(52)	**5,330**
Intersegment revenue	25,637	36,769	19,172	26,694	6,777	3,324	2,133	499	**121,005**
Other income	437	560	113	849	3	(10)	13	89	**2,054**
Segment revenues and other income	**51,489**	**55,662**	**118,497**	**173,119**	**14,509**	**18,473**	**7,655**	**12,805**	**452,209**
Costs and other items									
Crude oil and product purchases	19,765	10,035	102,027	138,024	8,237	13,069	3,931	8,108	**303,196**
Operating expenses, excl. depreciation and depletion [1]	11,344	10,515	8,387	9,162	4,620	4,693	2,079	2,297	**53,097**
Depreciation and depletion (includes impairments)	13,906	7,451	828	749	595	760	107	163	**24,559**
Interest expense	128	40	5	37	—	(2)	—	13	**221**
Other taxes and duties	179	2,097	3,240	19,205	79	174	9	184	**25,167**
Total costs and other deductions	**45,322**	**30,138**	**114,487**	**167,177**	**13,531**	**18,694**	**6,126**	**10,765**	**406,240**
Segment income (loss) before income taxes	**6,167**	**25,524**	**4,010**	**5,942**	**978**	**(221)**	**1,529**	**2,040**	**45,969**
Income tax expense (benefit)	1,104	8,753	792	1,097	75	(144)	327	362	**12,366**
Segment net income (loss) incl. noncontrolling interests	**5,063**	**16,771**	**3,218**	**4,845**	**903**	**(77)**	**1,202**	**1,678**	**33,603**
Net income (loss) attributable to noncontrolling interests	—	480	226	414	—	26	2	21	**1,169**
Segment income (loss)	**5,063**	**16,291**	**2,992**	**4,431**	**903**	**(103)**	**1,200**	**1,657**	**32,434**

Reconciliation of consolidated revenues

Segment revenues and other income	452,209
Other revenues [2]	1,034
Elimination of intersegment revenues	(121,005)
Total consolidated revenues and other income	**332,238**

Reconciliation of income (loss) attributable to ExxonMobil

Total segment income (loss)	32,434
Corporate and Financing income (loss)	(3,590)
Net income (loss) attributable to ExxonMobil	**28,844**

(millions of dollars)	Upstream		Energy Products		Chemical Products		Specialty Products		Segment Total
	U.S.	Non-U.S.	U.S.	Non-U.S.	U.S.	Non-U.S.	U.S.	Non-U.S.	
As of December 31, 2025									
Additions to property, plant, and equipment [3]	15,872	9,490	703	1,251	800	522	368	227	**29,233**
Investments in equity companies	5,491	19,429	460	1,048	2,946	2,616	—	775	**32,765**
Total assets	153,042	134,529	32,652	47,265	17,365	17,991	2,961	8,020	**413,825**

Reconciliation to Corporate Total	Segment Total	Corporate and Financing	Corporate Total
Additions to property, plant, and equipment [3]	29,233	2,243	**31,476**
Investments in equity companies	32,765	(112)	**32,653**
Total assets	413,825	35,155	**448,980**

[1] Operating expenses, excl. depreciation and depletion includes the following GAAP line items, as reflected on the Income Statement: Production and manufacturing expenses; Selling, general and administrative expenses; Exploration expenses, including dry holes; and Non-service pension and postretirement benefit expense.

[2] Primarily Corporate and Financing Interest revenue of $1,212 million.

[3] Includes non-cash additions.

Due to rounding, numbers presented may not add up precisely to the totals indicated.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(millions of dollars)	Upstream		Energy Products		Chemical Products		Specialty Products		Segment Total
	U.S.	Non-U.S.	U.S.	Non-U.S.	U.S.	Non-U.S.	U.S.	Non-U.S.	
Year ended December 31, 2024									
Revenues and other income									
Sales and other operating revenue	22,929	14,202	101,325	159,531	8,558	14,338	5,790	12,463	**339,136**
Income from equity affiliates	(36)	5,649	140	(109)	166	615	—	(26)	**6,399**
Intersegment revenue	24,633	41,809	23,626	26,034	7,329	3,893	2,462	573	**130,359**
Other income	890	670	295	192	5	7	22	116	**2,197**
Segment revenues and other income	**48,416**	**62,330**	**125,386**	**185,648**	**16,058**	**18,853**	**8,274**	**13,126**	**478,091**
Costs and other items									
Crude oil and product purchases	18,325	10,388	110,205	153,811	8,510	12,621	4,160	8,753	**326,773**
Operating expenses, excl. depreciation and depletion [1]	9,822	10,695	8,034	8,924	4,781	4,419	1,931	2,316	**50,922**
Depreciation and depletion (includes impairments)	11,510	8,014	799	734	611	485	104	133	**22,390**
Interest expense	185	82	9	10	1	1	—	3	**291**
Other taxes and duties	334	2,750	3,421	19,699	68	78	7	185	**26,542**
Total costs and other deductions	**40,176**	**31,929**	**122,468**	**183,178**	**13,971**	**17,604**	**6,202**	**11,390**	**426,918**
Segment income (loss) before income taxes	**8,240**	**30,401**	**2,918**	**2,470**	**2,087**	**1,249**	**2,072**	**1,736**	**51,173**
Income tax expense (benefit)	1,814	10,622	631	164	460	262	494	243	**14,690**
Segment net income (loss) incl. noncontrolling interests	**6,426**	**19,779**	**2,287**	**2,306**	**1,627**	**987**	**1,578**	**1,493**	**36,483**
Net income (loss) attributable to noncontrolling interests	—	815	188	372	—	37	2	17	**1,431**
Segment income (loss)	**6,426**	**18,964**	**2,099**	**1,934**	**1,627**	**950**	**1,576**	**1,476**	**35,052**

Reconciliation of consolidated revenues

Segment revenues and other income	478,091
Other revenues [2]	1,853
Elimination of intersegment revenues	(130,359)
Total consolidated revenues and other income	**349,585**

Reconciliation of income (loss) attributable to ExxonMobil

Total segment income (loss)	35,052
Corporate and Financing income (loss)	(1,372)
Net income (loss) attributable to ExxonMobil	**33,680**

(millions of dollars)	Upstream		Energy Products		Chemical Products		Specialty Products		Segment Total
	U.S.	Non-U.S.	U.S.	Non-U.S.	U.S.	Non-U.S.	U.S.	Non-U.S.	
As of December 31, 2024									
Additions to property, plant, and equipment [3]	94,649	8,371	589	1,450	474	1,161	230	227	**107,151**
Investments in equity companies	4,884	21,396	444	915	3,016	2,649	—	814	**34,118**
Total assets	154,914	134,609	32,143	43,399	17,445	17,692	2,882	8,040	**411,124**

Reconciliation to Corporate Total	Segment Total	Corporate and Financing	Corporate Total
Additions to property, plant, and equipment [3]	107,151	2,181	**109,332**
Investments in equity companies	34,118	(108)	**34,010**
Total assets	411,124	42,351	**453,475**

[1] Operating expenses, excl. depreciation and depletion includes the following GAAP line items, as reflected on the Income Statement: Production and manufacturing expenses; Selling, general and administrative expenses; Exploration expenses, including dry holes; and Non-service pension and postretirement benefit expense.

[2] Primarily Corporate and Financing Interest revenue of $1,600 million.

[3] Includes non-cash additions. See Note 20 for additions resulting from the Pioneer acquisition in 2024.

Due to rounding, numbers presented may not add up precisely to the totals indicated.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(millions of dollars)	Upstream		Energy Products		Chemical Products		Specialty Products		Segment Total
	U.S.	Non-U.S.	U.S.	Non-U.S.	U.S.	Non-U.S.	U.S.	Non-U.S.	
Year ended December 31, 2023									
Revenues and other income									
Sales and other operating revenue	9,500	16,074	103,868	164,515	7,951	14,314	6,044	12,363	**334,629**
Income from equity affiliates	63	5,550	140	131	126	761	—	(25)	**6,746**
Intersegment revenue	20,971	38,982	23,481	28,258	7,991	3,643	2,570	555	**126,451**
Other income	631	466	183	87	6	12	19	139	**1,543**
Segment revenues and other income	**31,165**	**61,072**	**127,672**	**192,991**	**16,074**	**18,730**	**8,633**	**13,032**	**469,369**
Costs and other items									
Crude oil and product purchases	9,945	11,279	107,796	152,487	8,824	13,096	4,718	8,955	**317,100**
Operating expenses, excl. depreciation and depletion [1]	6,696	10,960	7,851	9,434	4,560	4,643	1,822	2,238	**48,204**
Depreciation and depletion (includes impairments)	8,863	7,737	765	797	605	706	93	222	**19,788**
Interest expense	82	74	4	7	2	2	—	2	**173**
Other taxes and duties	361	2,684	3,421	22,226	61	78	6	174	**29,011**
Total costs and other deductions	**25,947**	**32,734**	**119,837**	**184,951**	**14,052**	**18,525**	**6,639**	**11,591**	**414,276**
Segment income (loss) before income taxes	**5,218**	**28,338**	**7,835**	**8,040**	**2,022**	**205**	**1,994**	**1,441**	**55,093**
Income tax expense (benefit)	1,016	10,593	1,543	1,492	396	158	458	235	**15,891**
Segment net income (loss) incl. noncontrolling interests	**4,202**	**17,745**	**6,292**	**6,548**	**1,626**	**47**	**1,536**	**1,206**	**39,202**
Net income (loss) attributable to noncontrolling interests	—	639	169	529	—	36	—	28	**1,401**
Segment income (loss)	**4,202**	**17,106**	**6,123**	**6,019**	**1,626**	**11**	**1,536**	**1,178**	**37,801**

Reconciliation of consolidated revenues

Segment revenues and other income	469,369
Other revenues [2]	1,664
Elimination of intersegment revenues	(126,451)
Total consolidated revenues and other income	**344,582**

Reconciliation of income (loss) attributable to ExxonMobil

Total segment income (loss)	37,801
Corporate and Financing income (loss)	(1,791)
Net income (loss) attributable to ExxonMobil	**36,010**

[1] Operating expenses, excl. depreciation and depletion includes the following GAAP line items, as reflected on the Income Statement: Production and manufacturing expenses; Selling, general and administrative expenses; Exploration expenses, including dry holes; and Non-service pension and postretirement benefit expense.

[2] Primarily Corporate and Financing Interest revenue of $1,628 million.

Due to rounding, numbers presented may not add up precisely to the totals indicated.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Revenue from Contracts with Customers

Sales and other operating revenue include both revenue within the scope of ASC 606 and outside the scope of ASC 606. Revenue outside the scope of ASC 606 primarily relates to physically settled commodity contracts accounted for as derivatives. Contractual terms, credit quality, and type of customer are generally similar between contracts within the scope of ASC 606 and those outside it.

Sales and other operating revenue *(millions of dollars)*	2025	2024	2023
Revenue from contracts with customers	226,909	245,143	256,455
Revenue outside the scope of ASC 606	96,996	94,104	78,242
Total	**323,905**	**339,247**	**334,697**

Geographic

Sales and other operating revenue *(millions of dollars)*	2025	2024	2023
United States	137,639	138,657	127,374
Non-U.S.	186,266	200,590	207,323
Total	**323,905**	**339,247**	**334,697**
Significant non-U.S. revenue sources include: [1]			
Canada	27,363	29,746	28,994

[1] *Revenue is determined by primary country of operations. Excludes certain sales and other operating revenues in Non-U.S. operations where attribution to a specific country is not practicable.*

Long-lived assets *(millions of dollars)*	December 31,		
	2025	2024	2023
United States	183,619	178,633	95,792
Non-U.S.	115,754	115,685	119,148
Total	**299,373**	**294,318**	**214,940**
Significant non-U.S. long-lived assets include:			
Canada	29,973	28,761	31,682

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 4. Pension and Other Postretirement Benefits

The benefit obligations and plan assets associated with the Corporation's principal benefit plans are measured on December 31.

(millions of dollars, except where stated otherwise)	Pension Benefits				Other Postretirement Benefits	
	U.S.		Non-U.S.			
	2025	2024	2025	2024	2025	2024
Weighted-average assumptions used to determine benefit obligations at December 31						
Discount rate *(percent)*	5.50	5.70	5.00	4.60	5.50	5.80
Long-term rate of compensation increase *(percent)*	4.00	4.00	4.30	4.20	4.00	4.00
Change in benefit obligation						
Benefit obligation at January 1	**12,999**	**13,143**	**19,198**	**21,327**	**4,791**	**5,014**
Service cost	517	499	324	338	75	81
Interest cost	677	671	842	823	262	250
Actuarial loss/(gain) [1]	218	(441)	(1,231)	(658)	55	(81)
Benefits paid [2][3]	(1,104)	(874)	(1,273)	(1,240)	(449)	(534)
Foreign exchange rate changes	—	—	1,648	(1,274)	20	(40)
Amendments, divestments and other [5][6]	(795)	1	(990)	(118)	138	101
Benefit obligation at December 31	**12,512**	**12,999**	**18,518**	**19,198**	**4,892**	**4,791**
Accumulated benefit obligation at December 31	10,838	11,227	17,210	17,818	—	—

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For selection of the discount rate for U.S. plans, several sources of information are considered, including interest rate market indicators and the effective discount rate determined by use of a yield curve based on high-quality bonds applied to the estimated cash outflows for benefit payments. For major non-U.S. plans, the discount rate is determined by using a spot yield curve of high-quality, local-currency-denominated bonds at an average maturity approximating that of the liabilities.

The measurement of the accumulated postretirement benefit obligation assumes a health care cost trend rate of 4.0 percent in 2027 and subsequent years.

(millions of dollars)	Pension Benefits				Other Postretirement Benefits	
	U.S.		Non-U.S.			
	2025	2024	2025	2024	2025	2024
Change in plan assets						
Fair value at January 1	**11,244**	**11,367**	**17,378**	**18,431**	**364**	**371**
Actual return on plan assets	1,189	286	680	862	40	20
Foreign exchange rate changes	—	—	1,364	(1,051)	—	—
Company contribution	250	300	307	288	29	24
Benefits paid [4]	(878)	(709)	(940)	(931)	(49)	(51)
Other [5][6]	(767)	—	(641)	(221)	—	—
Fair value at December 31	**11,038**	**11,244**	**18,148**	**17,378**	**384**	**364**

[1] Actuarial loss/(gain) primarily reflects a lower discount rate in the U.S. and generally higher discount rates outside of the U.S.

[2] Benefit payments for funded and unfunded plans.

[3] For 2024, other postretirement benefits paid are net of $10 million of Medicare subsidy receipts.

[4] Benefit payments for funded plans.

[5] The U.S. ExxonMobil Pension Plan purchased a group annuity contract from an insurer in 2025 for $767 million to transfer obligations to pay future benefits. The transaction did not change the amount of pension benefits payable to transferred participants and did not require additional funding from the plan.

[6] Non-U.S. includes benefit obligation and plan asset reductions in 2025 of $1,059 million and $642 million, respectively, resulting from the divestment of Product Solutions affiliates in France.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The funding levels of all qualified pension plans are in compliance with standards set by applicable law or regulation. As shown in the table below, certain smaller U.S. pension plans and a number of non-U.S. pension plans are not funded because local applicable tax rules and regulatory practices do not encourage funding of these plans. All defined benefit pension obligations, regardless of the funding status of the underlying plans, are fully supported by the financial strength of the Corporation or the respective sponsoring affiliate.

(millions of dollars)	Pension Benefits			
	U.S.		Non-U.S.	
	2025	2024	2025	2024
Assets in excess of/(less than) benefit obligation				
Balance at December 31				
Funded plans	(81)	(267)	2,879	1,679
Unfunded plans	(1,393)	(1,488)	(3,249)	(3,499)
Total	**(1,474)**	**(1,755)**	**(370)**	**(1,820)**

The authoritative guidance for defined benefit pension and other postretirement plans requires an employer to recognize the overfunded or underfunded status of a defined benefit postretirement plan as an asset or liability in its Consolidated Balance Sheet and to recognize changes in that funded status in the year in which the changes occur through other comprehensive income.

(millions of dollars)	Pension Benefits				Other Postretirement Benefits	
	U.S.		Non-U.S.			
	2025	2024	2025	2024	2025	2024
Assets in excess of/(less than) benefit obligation						
Balance at December 31 [1]	(1,474)	(1,755)	(370)	(1,820)	(4,508)	(4,427)
Amounts recorded in the Consolidated Balance Sheet consist of:						
Other assets	3	2	3,175	2,399	—	—
Current liabilities	(199)	(213)	(208)	(207)	(276)	(283)
Postretirement benefits reserves	(1,278)	(1,544)	(3,337)	(4,012)	(4,232)	(4,144)
Total recorded	**(1,474)**	**(1,755)**	**(370)**	**(1,820)**	**(4,508)**	**(4,427)**
Amounts recorded in accumulated other comprehensive income consist of:						
Net actuarial loss/(gain)	79	631	(532)	557	(1,291)	(1,421)
Prior service cost	(222)	(252)	447	420	(345)	(405)
Total recorded in accumulated other comprehensive income	**(143)**	**379**	**(85)**	**977**	**(1,636)**	**(1,826)**

[1] *Fair value of assets less benefit obligation shown on the preceding page.*

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The long-term expected rate of return on funded assets shown below is established for each benefit plan by developing a forward-looking, long-term return assumption for each asset class, taking into account factors such as the expected real return for the specific asset class and inflation. A single, long-term rate of return is then calculated as the weighted-average of the target asset allocation percentages and the long-term return assumption for each asset class.

(millions of dollars, except where stated otherwise)	Pension Benefits						Other Postretirement Benefits		
	U.S.			Non-U.S.					
	2025	2024	2023	2025	2024	2023	2025	2024	2023
Weighted-average assumptions used to determine net periodic benefit cost for years ended December 31									
Discount rate *(percent)*	5.70	5.30	5.60	4.60	4.30	4.90	5.80	5.30	5.60
Long-term rate of return on funded assets *(percent)*	6.00	6.80	5.20	4.70	5.50	4.20	5.30	6.00	4.70
Long-term rate of compensation increase *(percent)*	4.00	4.50	4.50	4.20	4.50	5.20	4.00	4.50	4.50
Components of net periodic benefit cost									
Service cost	517	499	466	324	338	323	75	81	78
Interest cost	677	671	664	842	823	922	262	250	276
Expected return on plan assets	(596)	(724)	(532)	(838)	(955)	(688)	(16)	(20)	(14)
Amortization of actuarial loss/(gain)	73	83	85	37	97	108	(103)	(103)	(122)
Amortization of prior service cost	(31)	(31)	(29)	59	50	52	(62)	(63)	(42)
Net pension enhancement and curtailment/settlement cost	75	27	29	22	16	5	(1)	—	—
Net periodic benefit cost	**715**	**525**	**683**	**446**	**369**	**722**	**155**	**145**	**176**
Changes in amounts recorded in accumulated other comprehensive income:									
Net actuarial loss/(gain)	(406)	(3)	(39)	(1,073)	(611)	602	32	(81)	154
Amortization of actuarial (loss)/gain	(147)	(110)	(114)	(38)	(112)	(108)	103	103	122
Prior service cost/(credit)	—	—	(17)	19	81	153	—	(8)	(312)
Amortization of prior service (cost)/credit	31	31	29	(59)	(44)	(52)	63	63	42
Foreign exchange rate changes	—	—	—	89	(102)	46	(8)	9	(2)
Total recorded in other comprehensive income	**(522)**	**(82)**	**(141)**	**(1,062)**	**(788)**	**641**	**190**	**86**	**4**
Total recorded in net periodic benefit cost and other comprehensive income, before tax	**193**	**443**	**542**	**(616)**	**(419)**	**1,363**	**345**	**231**	**180**

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Costs for defined contribution plans were $0.4 billion, $0.4 billion, and $0.4 billion in 2025, 2024, and 2023, respectively.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

A summary of the change in accumulated other comprehensive income is shown in the table below:

	Total Pension and Other Postretirement Benefits		
(millions of dollars)	2025	2024	2023
(Charge)/credit to other comprehensive income, before tax			
U.S. pension	522	82	141
Non-U.S. pension	1,062	788	(641)
Other postretirement benefits	(190)	(86)	(4)
Total (charge)/credit to other comprehensive income, before tax	**1,394**	**784**	**(504)**
(Charge)/credit to income tax (see Note 5)	(376)	(208)	180
(Charge)/credit to investment in equity companies	29	24	16
(Charge)/credit to other comprehensive income including noncontrolling interests, after tax	**1,047**	**600**	**(308)**
Charge/(credit) to equity of noncontrolling interests	(59)	(120)	54
(Charge)/credit to other comprehensive income attributable to ExxonMobil	**988**	**480**	**(254)**

The Corporation's investment strategy for benefit plan assets reflects a long-term view, a careful assessment of the risks inherent in plan assets and liabilities, and broad diversification to reduce the risk of the portfolio. The benefit plan assets are primarily invested in passive global equity and local currency fixed income index funds to diversify risk while minimizing costs. The equity funds hold ExxonMobil stock only to the extent necessary to replicate the relevant equity index. The fixed income funds are largely invested in investment-grade corporate and government debt securities with interest rate sensitivity designed to approximate the interest rate sensitivity of plan liabilities.

Target asset allocations for benefit plans are reviewed periodically and set based on considerations such as risk, diversification, liquidity, and funding level. The target asset allocations for the major benefit plans range from 5 to 40 percent in equity securities and the remainder in fixed income securities. The equity allocation for the U.S. plan includes a target allocation of 10 percent to limited partnerships that focus on the venture capital, growth and buyout sectors of the private equity market. Certain non-U.S. plans include small allocations to private equity partnerships that primarily focus on early-stage venture capital.

The fair value measurement levels are accounting terms that refer to different methods of valuing assets. The terms do not represent the relative risk or credit quality of an investment.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The 2025 fair value of the benefit plan assets, including the level within the fair value hierarchy, is shown in the tables below:

(millions of dollars)	U.S. Pension					Non-U.S. Pension				
	Fair Value Measurement at December 31, 2025, Using:					Fair Value Measurement at December 31, 2025, Using:				
	Level 1	Level 2	Level 3	Net Asset Value	Total	Level 1	Level 2	Level 3	Net Asset Value	Total
Asset category:										
Equity securities										
U.S.	—	—	—	2,018	2,018	—	—	—	1,659	1,659
Non-U.S.	—	—	—	1,216	1,216	54 [1]	—	—	993	1,047
Private equity	—	—	—	728	728	—	—	—	337	337
Debt securities										
Corporate	—	985 [2]	—	4,238	5,223	—	54 [2]	—	3,980	4,034
Government	—	696 [2]	—	990	1,686	99 [3]	169 [2]	—	9,033	9,301
Asset-backed	—	—	—	1	1	—	18 [2]	—	149	167
Other	—	—	—	—	—	—	—	—	33	33
Real Estate	—	—	—	—	—	—	—	—	151	151
Cash	—	—	—	141	141	11	9 [4]	—	1,383	1,403
Other	—	23	—	—	23	—	—	—	—	—
Total at fair value	**—**	**1,704**	**—**	**9,332**	**11,036**	**164**	**250**	**—**	**17,718**	**18,132**
Insurance contracts at contract value					2					16
Total plan assets					**11,038**					**18,148**

[1] For non-U.S. equity securities held in separate accounts, fair value is based on observable quoted prices on active exchanges.

[2] For corporate, government and asset-backed debt securities, fair value is based on observable inputs of comparable market transactions.

[3] For government debt securities that are traded on active exchanges, fair value is based on observable quoted prices.

[4] For cash balances that are subject to withdrawal penalties or other adjustments, the fair value is treated as a level 2 input.

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(millions of dollars)	Other Postretirement				
	Fair Value Measurement at December 31, 2025, Using:				
	Level 1	Level 2	Level 3	Net Asset Value	Total
Asset category:					
Equity securities					
U.S.	95 [5]	—	—	—	95
Non-U.S.	41 [5]	—	—	—	41
Debt securities					
Corporate	—	58 [6]	—	—	58
Government	—	185 [6]	—	—	185
Asset-backed	—	3 [6]	—	—	3
Cash	—	2	—	—	2
Total at fair value	**136**	**248**	**—**	**—**	**384**

[5] For equity securities held in separate accounts, fair value is based on observable quoted prices on active exchanges.

[6] For corporate, government and asset-backed debt securities, fair value is based on observable inputs of comparable market transactions.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The 2024 fair value of the benefit plan assets, including the level within the fair value hierarchy, is shown in the tables below:

(millions of dollars)	U.S. Pension					Non-U.S. Pension				
	Fair Value Measurement at December 31, 2024, Using:					Fair Value Measurement at December 31, 2024, Using:				
	Level 1	Level 2	Level 3	Net Asset Value	Total	Level 1	Level 2	Level 3	Net Asset Value	Total
Asset category:										
Equity securities										
U.S.	—	—	—	2,263	2,263	—	—	—	2,865	2,865
Non-U.S.	—	—	—	1,225	1,225	43 [1]	—	—	1,560	1,603
Private equity	—	—	—	439	439	—	—	—	291	291
Debt securities										
Corporate	—	971 [2]	—	4,498	5,469	—	49 [2]	—	3,650	3,699
Government	—	592 [2]	—	1,126	1,718	77 [3]	141 [2]	—	8,222	8,440
Asset-backed	—	—	—	1	1	—	12 [2]	—	180	192
Other	—	—	—	—	—	—	—	—	13	13
Real Estate	—	—	—	—	—	—	—	—	107	107
Cash	—	—	—	113	113	78	6 [4]	—	69	153
Other	—	14	—	—	14	—	—	—	—	—
Total at fair value	**—**	**1,577**	**—**	**9,665**	**11,242**	**198**	**208**	**—**	**16,957**	**17,363**
Insurance contracts at contract value					2					15
Total plan assets					**11,244**					**17,378**

[1] For non-U.S. equity securities held in separate accounts, fair value is based on observable quoted prices on active exchanges.

[2] For corporate, government and asset-backed debt securities, fair value is based on observable inputs of comparable market transactions.

[3] For government debt securities that are traded on active exchanges, fair value is based on observable quoted prices.

[4] For cash balances that are subject to withdrawal penalties or other adjustments, the fair value is treated as a level 2 input.

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(millions of dollars)	Other Postretirement				
	Fair Value Measurement at December 31, 2024, Using:				
	Level 1	Level 2	Level 3	Net Asset Value	Total
Asset category:					
Equity securities					
U.S.	92 [5]	—	—	—	92
Non-U.S.	36 [5]	—	—	—	36
Debt securities					
Corporate	—	57 [6]	—	—	57
Government	—	174 [6]	—	—	174
Asset-backed	—	3 [6]	—	—	3
Cash	—	2	—	—	2
Total at fair value	**128**	**236**	**—**	**—**	**364**

[5] For equity securities held in separate accounts, fair value is based on observable quoted prices on active exchanges.

[6] For corporate, government and asset-backed debt securities, fair value is based on observable inputs of comparable market transactions.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

A summary of pension plans with an accumulated benefit obligation and projected benefit obligation in excess of plan assets is shown in the table below:

(millions of dollars)	Pension Benefits			
	U.S.		Non-U.S.	
	2025	2024	2025	2024
For funded pension plans with an accumulated benefit obligation in excess of plan assets:				
Accumulated benefit obligation	—	—	127	1,025
Fair value of plan assets	—	—	66	574
For funded pension plans with a projected benefit obligation in excess of plan assets:				
Projected benefit obligation	11,107	11,501	1,137	1,982
Fair value of plan assets	11,025	11,232	840	1,261
For unfunded pension plans:				
Projected benefit obligation	1,393	1,488	3,249	3,499
Accumulated benefit obligation	1,184	1,229	3,057	3,224

All other postretirement benefit plans are unfunded or underfunded.

(millions of dollars)	Pension Benefits		Other Postretirement Benefits	
	U.S.	Non-U.S.	Gross	Medicare Subsidy Receipt
Contributions expected in 2026	—	306	—	—
Benefit payments expected in:				
2026	1,024	1,107	350	1
2027	1,017	1,121	347	1
2028	1,049	1,135	346	1
2029	1,053	1,149	346	1
2030	1,060	1,149	348	1
2031 - 2035	5,701	5,759	1,775	3

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 5. Other Comprehensive Income Information

ExxonMobil Share of Accumulated Other Comprehensive Income *(millions of dollars)*	Cumulative Foreign Exchange Translation Adjustment	Postretirement Benefits Reserves Adjustment	Total
Balance as of December 31, 2022	**(14,591)**	**1,321**	**(13,270)**
Current period change excluding amounts reclassified from accumulated other comprehensive income [1]	1,108	(305)	803
Amounts reclassified from accumulated other comprehensive income	427	51	478
Total change in accumulated other comprehensive income	1,535	(254)	1,281
Balance as of December 31, 2023	**(13,056)**	**1,067**	**(11,989)**
Current period change excluding amounts reclassified from accumulated other comprehensive income [1]	(3,110)	449	(2,661)
Amounts reclassified from accumulated other comprehensive income	—	31	31
Total change in accumulated other comprehensive income	(3,110)	480	(2,630)
Balance as of December 31, 2024	**(16,166)**	**1,547**	**(14,619)**
Current period change excluding amounts reclassified from accumulated other comprehensive income [1]	2,360	952	3,312
Amounts reclassified from accumulated other comprehensive income	408	36	444
Total change in accumulated other comprehensive income	2,768	988	3,756
Balance as of December 31, 2025	**(13,398)**	**2,535**	**(10,863)**

[1] *Cumulative Foreign Exchange Translation Adjustment includes net investment hedge gain/(loss) net of taxes of $(294) million, $196 million, and $(135) million in 2025, 2024, and 2023, respectively.*

Amounts Reclassified Out of Accumulated Other Comprehensive Income - Before-tax Income/(Expense) *(millions of dollars)*	2025	2024	2023
Foreign exchange translation gain/(loss) included in net income (Statement of Income line: Other income)	(391)	—	(609)
Amortization and settlement of postretirement benefits reserves adjustment included in net periodic benefit costs (Statement of Income line: Non-service pension and postretirement benefit expense)	(46)	(70)	(81)

Income Tax (Expense)/Credit For Components of Other Comprehensive Income *(millions of dollars)*	2025	2024	2023
Foreign exchange translation adjustment	145	14	341
Postretirement benefits reserves adjustment (excluding amortization)	(368)	(181)	200
Amortization and settlement of postretirement benefits reserves adjustment included in net periodic benefit costs	(8)	(27)	(20)
Total	**(231)**	**(194)**	**521**

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 6. Financial Instruments and Derivatives

The estimated fair value of financial instruments and derivatives at December 31, 2025, and December 31, 2024, and the related hierarchy level for the fair value measurement was as follows:

	December 31, 2025							
	Fair Value							
(millions of dollars)	Level 1	Level 2	Level 3	Total Gross Assets & Liabilities	Effect of Counterparty Netting	Effect of Collateral Netting	Difference in Carrying Value and Fair Value	Net Carrying Value
Assets								
Derivative assets [1]	5,197	2,259	—	7,456	(6,261)	(341)	—	854
Advances to/receivables from equity companies [2][6]	—	1,935	3,938	5,873	—	—	256	6,129
Other long-term financial assets [3]	1,536	—	1,800	3,336	—	—	216	3,552
Liabilities								
Derivative liabilities [4]	4,994	2,043	—	7,037	(6,261)	(141)	—	635
Long-term debt [5]	24,678	3,909	—	28,587	—	—	3,248	31,835
Long-term obligations to equity companies [6]	—	—	542	542	—	—	—	542
Other long-term financial liabilities [7]	—	—	348	348	—	—	16	364

	December 31, 2024							
	Fair Value							
(millions of dollars)	Level 1	Level 2	Level 3	Total Gross Assets & Liabilities	Effect of Counterparty Netting	Effect of Collateral Netting	Difference in Carrying Value and Fair Value	Net Carrying Value
Assets								
Derivative assets [1]	3,223	1,206	—	4,429	(3,913)	(3)	—	513
Advances to/receivables from equity companies [2][6]	—	2,466	4,167	6,633	—	—	451	7,084
Other long-term financial assets [3]	1,468	—	1,504	2,972	—	—	247	3,219
Liabilities								
Derivative liabilities [4]	3,561	1,416	—	4,977	(3,913)	(341)	—	723
Long-term debt [5]	28,884	1,813	—	30,697	—	—	3,935	34,632
Long-term obligations to equity companies [6]	—	—	1,393	1,393	—	—	(47)	1,346
Other long-term financial liabilities [7]	—	—	583	583	—	—	57	640

[1] Included in the Balance Sheet lines: Notes and accounts receivable - net and Other assets, including intangibles - net.

[2] Included in the Balance Sheet line: Investments, advances, and long-term receivables.

[3] Included in the Balance Sheet lines: Investments, advances, and long-term receivables and Other assets, including intangibles - net.

[4] Included in the Balance Sheet lines: Accounts payable and accrued liabilities and Other long-term obligations.

[5] Excluding finance lease obligations.

[6] Advances to/receivables from equity companies and long-term obligations to equity companies are mainly designated as hierarchy level 3 inputs. The fair value is calculated by discounting the remaining obligations by a rate consistent with the credit quality and industry of the equity company.

[7] Included in the Balance Sheet line: Other long-term obligations. Includes contingent consideration related to a prior year acquisition where fair value is based on expected drilling activities and discount rates.

At December 31, 2025, and December 31, 2024, respectively, the Corporation had $0.5 billion and $0.5 billion of collateral under master netting arrangements not offset against the derivatives on the Consolidated Balance Sheet, primarily related to initial margin requirements.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Derivative Instruments. The Corporation's size, strong capital structure, geographic diversity, and the complementary nature of its business segments reduce the Corporation's enterprise-wide risk from changes in commodity prices, currency rates, and interest rates. In addition, the Corporation uses commodity-based contracts, including derivatives, to manage commodity price risk and to generate returns from trading. Commodity contracts held for trading purposes are presented in the Consolidated Statement of Income on a net basis in the line "Sales and other operating revenue" and in the Consolidated Statement of Cash Flows in "Cash Flows from Operating Activities" and included before-tax realized and unrealized gains of $1.1 billion, losses of $0.7 billion, and gains of $1.0 billion in 2025, 2024, and 2023, respectively. The Corporation's commodity derivatives are not accounted for under hedge accounting. At times, the Corporation also enters into currency and interest rate derivatives, none of which are material to the Corporation's financial position as of December 31, 2025 and 2024, or results of operations for 2025, 2024, and 2023.

The Corporation operates a program to hedge certain of its fixed-rate debt instruments against changes in fair value due to changes in the designated benchmark interest rate. This program utilizes fair value hedge accounting. The derivative (hedging) instruments are fixed-for-floating interest rate swaps, with settlement dates that correspond to the interest payments associated with the fixed-rate debt (hedged item). Changes in the fair values of the hedging instruments are perfectly offset by changes in the fair values of the hedged items; the effects of these changes in fair values are recorded in "Interest expense" in the Consolidated Statement of Income. This program was not material to the Consolidated Financial Statements.

Credit risk associated with the Corporation's derivative position is mitigated by several factors, including the use of derivative clearing exchanges and the quality of and financial limits placed on derivative counterparties. The Corporation maintains a system of controls that includes the authorization, reporting, and monitoring of derivative activity.

The net notional long/(short) position of derivative instruments at December 31, 2025, and December 31, 2024, was as follows:

(millions)	December 31, 2025	December 31, 2024
Crude oil (barrels)	6	13
Petroleum products (barrels)	(27)	(32)
Natural gas (MMBTUs)	(449)	(675)

Note 7. Litigation and Other Contingencies

Litigation. A variety of claims have been made against ExxonMobil and certain of its consolidated subsidiaries in a number of pending lawsuits. Management has regular litigation reviews, including updates from corporate and outside counsel, to assess the need for accounting recognition or disclosure of these contingencies. The Corporation accrues an undiscounted liability for those contingencies where the incurrence of a loss is probable and the amount can be reasonably estimated. If a range of amounts can be reasonably estimated and no amount within the range is a better estimate than any other amount, then the minimum of the range is accrued. The Corporation does not record liabilities when the likelihood that the liability has been incurred is probable but the amount cannot be reasonably estimated or when the liability is believed to be only reasonably possible or remote. For contingencies where an unfavorable outcome is reasonably possible and which are significant, the Corporation discloses the nature of the contingency and, where feasible, an estimate of the possible loss. For purposes of our contingency disclosures, "significant" includes material matters, as well as other matters, which management believes should be disclosed.

State and local governments and other entities in various jurisdictions across the United States and its territories have filed a number of legal proceedings against several oil and gas companies, including ExxonMobil, requesting unprecedented legal and equitable relief for various alleged injuries purportedly connected to climate change. These lawsuits assert a variety of novel, untested claims under statutory and common law. Additional such lawsuits may be filed. We believe the legal and factual theories set forth in these proceedings are meritless and represent an inappropriate attempt to use the court system to usurp the proper role of policymakers in addressing the societal challenges of climate change.

Local governments in Louisiana have filed unprecedented legal proceedings against a number of oil and gas companies, including ExxonMobil, requesting compensation for the restoration of coastal marsh erosion in the state. We believe the factual and legal theories set forth in these proceedings are meritless.

While the outcome of any litigation can be unpredictable, we believe the likelihood is remote that the ultimate outcomes of these lawsuits will have a material adverse effect on the Corporation's operations, financial condition, or financial statements taken as a whole. We will continue to defend vigorously against these claims.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Other Contingencies. The Corporation and certain of its consolidated subsidiaries were contingently liable at December 31, 2025, for guarantees relating to notes, loans and performance under contracts. Where guarantees for environmental remediation and other similar matters do not include a stated cap, the amounts reflect management's estimate of the maximum potential exposure. Where it is not possible to make a reasonable estimation of the maximum potential amount of future payments, future performance is expected to be either immaterial or have only a remote chance of occurrence.

(millions of dollars)	December 31, 2025		
	Equity Company Obligations [1]	Other Third-Party Obligations	Total
Guarantees			
Non-debt-related	667	6,185	6,852
Total	**667**	**6,185**	**6,852**

[1] *ExxonMobil share.*

Additionally, the Corporation and its affiliates have numerous long-term sales and purchase commitments in their various business activities, all of which are expected to be fulfilled with no adverse consequences material to the Corporation's operations or financial condition.

Note 8. Equity Company Information

The summarized financial information below includes amounts related to certain less-than-majority-owned companies and majority-owned subsidiaries where minority shareholders possess the right to participate in significant management decisions (see Note 1). These companies are primarily engaged in oil and gas exploration and production, natural gas marketing, transportation of crude oil, and petrochemical manufacturing in North America; natural gas production and distribution in Europe; LNG operations in Africa; and exploration, production, LNG operations, and the manufacture and sale of petroleum and petrochemical products in Asia and the Middle East. Also included are several refining and marketing ventures.

The share of total equity company revenues from sales to ExxonMobil consolidated companies was 10 percent, 9 percent, and 9 percent in 2025, 2024, and 2023, respectively.

The Corporation's ownership in these ventures is in the form of shares in corporate joint ventures as well as interests in partnerships. Differences between the Company's carrying value of an equity investment and its underlying equity in the net assets of the affiliate are assigned, to the extent practicable, to specific assets and liabilities based on the Company's analysis of the factors giving rise to the difference. The amortization of this difference, as appropriate, is included in "Income from equity affiliates" on the Consolidated Statement of Income.

Equity Company Financial Summary *(millions of dollars)*	2025		2024		2023	
	Total	ExxonMobil Share	Total	ExxonMobil Share	Total	ExxonMobil Share
Total revenues	**111,193**	**34,309**	**117,036**	**35,532**	**132,783**	**40,682**
Income before income taxes	26,493	7,106	33,357	9,304	35,999	10,078
Income taxes	8,174	2,054	11,434	3,209	11,404	3,085
Income from equity affiliates	**18,319**	**5,052**	**21,923**	**6,095**	**24,595**	**6,993**
Current assets	46,577	16,738	50,779	18,286	53,081	18,713
Long-term assets	138,809	37,398	145,671	39,092	150,198	40,986
Total assets	**185,386**	**54,136**	**196,450**	**57,378**	**203,279**	**59,699**
Current liabilities	28,135	8,947	26,786	8,699	30,721	9,652
Long-term liabilities	47,301	14,361	55,218	16,484	57,237	17,059
Net assets	**109,950**	**30,828**	**114,446**	**32,195**	**115,321**	**32,988**

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

A list of significant equity companies as of December 31, 2025, together with the Corporation's percentage ownership interest, is detailed below:

	Percentage Ownership Interest
Upstream	
Barzan Gas Company Limited	7
BEB Erdgas und Erdoel GmbH & Co. KG	50
Caspian Pipeline Consortium	8
Coral FLNG S.A.	25
Cross Timbers Energy LLC	50
GasTerra B.V.	25
Golden Pass LNG Terminal LLC	30
Golden Pass Pipeline LLC	30
Marine Well Containment Company LLC	13
Mozambique Rovuma Venture S.p.A.	36
Nederlandse Aardolie Maatschappij B.V.	50
Papua New Guinea Liquefied Natural Gas Global Company LDC	33
Permian Highway Pipeline LLC	17
QatarEnergy LNG N (2)	24
QatarEnergy LNG NFE (3)	25
QatarEnergy LNG S (2)	31
QatarEnergy LNG S (3)	30
South Hook LNG Terminal Company Limited	24
Tengizchevroil LLP	25
Energy Products, Chemical Products, and/or Specialty Products	
Al-Jubail Petrochemical Company	50
Alberta Products Pipe Line Ltd.	45
Fujian Refining & Petrochemical Co. Ltd.	25
Gulf Coast Growth Ventures LLC	50
Infineum USA L.P.	50
Permian Express Partners LLC	12
Saudi Aramco Mobil Refinery Company Ltd.	50
Saudi Yanbu Petrochemical Co.	50

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 9. Property, Plant, and Equipment and Asset Retirement Obligations

Property, Plant, and Equipment *(millions of dollars)*	December 31, 2025		December 31, 2024	
	Cost	Net	Cost	Net
Upstream	436,018	228,235	423,038	226,021
Energy Products	60,261	29,547	58,259	28,349
Chemical Products	39,594	20,053	39,224	19,973
Specialty Products	8,820	4,333	9,559	4,229
Other	25,366	17,205	23,823	15,746
Total	**570,059**	**299,373**	**553,903**	**294,318**

In 2025, the Corporation identified situations where events or changes in circumstances indicated that the carrying value of certain long-lived assets may not be recoverable and conducted impairment assessments. The Corporation recognized before-tax impairment charges of $1.6 billion in Upstream, $0.1 billion in Chemical Products, and $0.3 billion in Other.

In 2024, before-tax impairment charges recognized are immaterial.

In 2023, the Corporation recognized before-tax impairment charges of $3.3 billion, in large part due to impairing the idled Upstream Santa Ynez Unit assets and associated facilities in California, reflecting the continuing challenges in the state regulatory environment that impeded progress in restoring operations. Other before-tax impairment charges recognized during 2023 included $0.3 billion in Upstream, $0.3 billion in Chemical Products, and $0.1 billion in Specialty Products.

Impairment charges are primarily recognized in the lines “Depreciation and depletion” and “Exploration expenses, including dry holes” on the Consolidated Statement of Income. Accumulated depreciation and depletion totaled $270,686 million at the end of 2025 and $259,585 million at the end of 2024.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Asset Retirement Obligations

The Corporation incurs retirement obligations for certain assets. The fair values of these obligations are recorded as liabilities on a discounted basis, which is typically at the time the assets are installed. In the estimation of fair value, the Corporation uses assumptions and judgments regarding such factors as the existence of a legal obligation for an asset retirement obligation, technical assessments of the assets, estimated amounts and timing of settlements, discount rates, and inflation rates. Asset retirement obligations incurred in the current period were level 3 fair value measurements. The costs associated with these liabilities are capitalized as part of the related assets and depreciated as the reserves are produced. Over time, the liabilities are accreted for the change in their present value.

Asset retirement obligations for facilities in the Product Solutions business generally become firm at the time a decision is made to permanently shut down and dismantle the facilities. These obligations may include the costs of asset disposal and additional soil remediation. However, these sites generally have indeterminate lives based on plans for continued operations and as such, the fair value of the conditional legal obligations cannot be measured, since it is impossible to estimate the future settlement dates of such obligations.

The following table summarizes the activity in the liability for asset retirement obligations:

(millions of dollars)	2025	2024	2023
Balance at January 1	**12,032**	**12,989**	**10,491**
Accretion expense and other provisions	623	709	734
Reduction due to property sales	(927)	(1,445)	(288)
Payments made	(1,289)	(1,191)	(693)
Liabilities incurred	539	728	985
Foreign currency translation	386	(447)	124
Revisions	1,154	689	1,636
Balance at December 31	**12,518**	**12,032**	**12,989**

The long-term Asset Retirement Obligations were $11.3 billion and $10.9 billion at December 31, 2025 and 2024, respectively, and are included in “Other long-term obligations” on the Consolidated Balance Sheet. Estimated cash payments in 2026 and 2027 are $1.3 billion and $1.5 billion, respectively.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 10. Additional Working Capital Information

(millions of dollars)	Dec 31, 2025	Dec 31, 2024
Notes and accounts receivable		
Trade, less reserves of $270 million and $162 million	35,744	35,282
Other, less reserves of $170 million and $314 million	8,818	8,399
Total	**44,562**	**43,681**
Notes and loans payable		
Bank loans	3	63
Commercial paper	3,059	—
Long-term debt due within one year	6,234	4,892
Total	**9,296**	**4,955**
Accounts payable and accrued liabilities		
Trade payables	36,049	36,145
Payables to equity companies	8,694	10,378
Accrued taxes other than income taxes	3,549	3,577
Other	12,619	11,197
Total	**60,911**	**61,297**

Trade notes and accounts receivables include both receivables within the scope of ASC 606 and outside the scope of ASC 606. Receivables outside the scope of ASC 606 primarily relate to physically settled commodity contracts accounted for as derivatives. Credit quality and type of customer are generally similar between receivables within the scope of ASC 606 and those outside it.

The Corporation has short-term committed lines of credit of $7.3 billion which were unused as of December 31, 2025. These lines of credit are available for general corporate purposes.

The weighted-average interest rate on short-term borrowings outstanding was 3.8 percent at December 31, 2025.

Note 11. Investments, Advances, and Long-Term Receivables

(millions of dollars)	Dec 31, 2025	Dec 31, 2024
Equity method company investments and advances		
Investments	32,653	34,010
Advances, net of allowances of $33 million and $40 million	6,130	7,084
Total equity method company investments and advances	**38,783**	**41,094**
Equity securities carried at fair value and other investments at adjusted cost basis	271	343
Long-term receivables and miscellaneous, net of reserves of $2,500 million and $2,433 million	6,263	5,763
Total	**45,317**	**47,200**

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 12. Long-Term Debt

At December 31, 2025, long-term debt consisted of $26.4 billion due in U.S. dollars and $7.8 billion representing the U.S. dollar equivalent at year-end exchange rates of amounts payable in foreign currencies. These amounts exclude that portion of long-term debt, totaling $6.2 billion, which matures within one year and is included in current liabilities.

The amounts of long-term debt, excluding finance lease obligations, maturing in each of the four years after December 31, 2026, are: 2027 – $2.5 billion; 2028 – $1.7 billion; 2029 – $1.7 billion; and 2030 – $5.3 billion. At December 31, 2025, the Corporation's unused long-term lines of credit were $1.0 billion.

The Corporation may use non-derivative financial instruments, such as its foreign currency-denominated debt, as hedges of its net investments in certain foreign subsidiaries. Under this method, the change in the carrying value of the financial instruments due to foreign exchange fluctuations is reported in accumulated other comprehensive income. As of December 31, 2025, the Corporation has designated its $3.5 billion of Euro-denominated debt and related accrued interest as a net investment hedge of its European business. The net investment hedge is deemed to be perfectly effective.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Summarized long-term debt at year-end 2025 and 2024 are shown in the table below:

(millions of dollars, except where stated otherwise)	Average Rate [1]	Dec 31, 2025	Dec 31, 2024
Exxon Mobil Corporation [2][3]			
3.043% notes due 2026		—	2,500
2.275% notes due 2026		—	1,000
3.294% notes due 2027		1,000	1,000
2.440% notes due 2029		1,250	1,250
3.482% notes due 2030		2,032	1,992
2.610% notes due 2030		2,016	2,000
2.995% notes due 2039		750	750
4.227% notes due 2040		2,043	2,076
3.567% notes due 2045		986	1,000
4.114% notes due 2046		2,497	2,500
3.095% notes due 2049		1,500	1,500
4.327% notes due 2050		2,750	2,750
3.452% notes due 2051		2,750	2,750
Exxon Mobil Corporation - Euro-denominated			
0.524% notes due 2028		1,175	1,039
0.835% notes due 2032		1,175	1,039
1.408% notes due 2039		1,175	1,039
XTO Energy Inc. [4]			
6.100% senior notes due 2036		186	187
6.750% senior notes due 2037		282	284
6.375% senior notes due 2038		219	221
Pioneer Natural Resources Company [5]			
1.125% senior notes due 2026		—	718
5.100% senior notes due 2026		—	1,097
7.200% senior notes due 2028		247	250
1.900% senior notes due 2030		958	931
2.150% senior notes due 2031		869	846
Parsley Energy LLC [6]			
4.125% senior notes due 2028		133	131
Industrial revenue bonds due 2026-2051	2.540%	2,005	2,032
Finance leases & other obligations	4.668%	6,313	3,951
Debt issuance costs		(70)	(78)
Total long-term debt		**34,241**	**36,755**

[1] Average effective or imputed interest rates at December 31, 2025.

[2] Includes impacts of hedge accounting of interest rate swaps.

[3] Includes premiums of $72 million in 2025 and $76 million in 2024.

[4] Includes premiums of $60 million in 2025and $66 million in 2024.

[5] Includes net discounts of $267 million in 2025 and $348 million in 2024.

[6] Includes discounts of $5 million in 2025 and $7 million in 2024.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 13. Leases

The Corporation and its consolidated affiliates generally purchase the property, plant, and equipment used in operations, but there are situations where assets are leased, primarily for drilling equipment, tankers, office buildings, railcars, and other moveable equipment. Right of use assets and lease liabilities are established on the balance sheet for leases with an expected term greater than one year by discounting the amounts fixed in the lease agreement for the duration of the lease which is reasonably certain, considering the probability of exercising any early termination and extension options. The portion of the fixed payment related to service costs for drilling equipment, tankers, and finance leases is excluded from the calculation of right of use assets and lease liabilities. Generally, assets are leased only for a portion of their useful lives and are accounted for as operating leases. In limited situations, assets are leased for nearly all of their useful lives and are accounted for as finance leases.

Variable payments under these lease agreements are not significant. Residual value guarantees, restrictions, covenants related to leases, and transactions with related parties are also not significant. In general, leases are capitalized using the incremental borrowing rate of the leasing affiliate. The Corporation's activities as a lessor are not significant.

Lease Cost *(millions of dollars)*	Operating Leases			Finance Leases		
	2025	2024	2023	2025	2024	2023
Operating lease cost	2,450	2,296	1,976			
Short-term and other (net of sublease rental income)	1,490	2,047	1,563			
Amortization of right of use assets				161	140	107
Interest on lease liabilities				167	149	140
Total [(1)]	**3,940**	**4,343**	**3,539**	**328**	**289**	**247**

[(1)] Includes $984 million, $1,195 million, and $999 million for drilling rigs and related equipment operating leases in 2025, 2024, and 2023, respectively.

Balance Sheet *(millions of dollars)*	Operating Leases		Finance Leases	
	December 31, 2025	December 31, 2024	December 31, 2025	December 31, 2024
Right of use assets				
Included in Other assets, including intangibles - net	7,224	7,123		
Included in Property, plant, and equipment - net			3,284	2,888
Total right of use assets	**7,224**	**7,123**	**3,284**	**2,888**
Lease liability due within one year				
Included in Accounts payable and accrued liabilities	1,942	1,852	7	6
Included in Notes and loans payable			137	117
Long-term lease liability				
Included in Other long-term obligations	4,892	4,626		
Included in Long-term debt			2,406	2,123
Included in Long-term obligations to equity companies			109	115
Total lease liability [(2)]	**6,834**	**6,478**	**2,659**	**2,361**
Weighted-average remaining lease term (years)	8	7	17	18
Weighted-average discount rate (percent)	4.7 %	4.9 %	8.1 %	6.4 %

[(2)] Includes $1,691 million and $2,198 million for drilling rigs and related equipment operating leases in 2025 and 2024, respectively.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Maturity Analysis of Lease Liabilities *(millions of dollars)*	Operating Leases	Finance Leases
	December 31, 2025	
2026	2,189	362
2027	1,609	351
2028	1,042	348
2029	502	341
2030	402	335
2031 and beyond	2,237	3,128
Total lease payments	**7,981**	**4,865**
Discount to present value	(1,147)	(2,206)
Total lease liability	**6,834**	**2,659**

In addition to the lease liabilities in the table immediately above, at December 31, 2025, undiscounted commitments for leases not yet commenced totaled $3.0 billion for operating leases and $0.8 billion for finance leases. Estimated cash payments for operating and finance leases not yet commenced are $0.2 billion and $0.3 billion for 2026 and 2027 respectively. Operating leases not yet commenced primarily relate to LNG transportation vessels.

Other Information *(millions of dollars)*	Operating Leases			Finance Leases		
	2025	2024	2023	2025	2024	2023
Cash paid for amounts included in the measurement of lease liabilities						
Cash flows from operating activities	1,522	1,301	1,135	20	20	20
Cash flows from investing activities	868	837	758			
Cash flows from financing activities				140	121	86
Noncash right of use assets recorded for lease liabilities						
In exchange for lease liabilities during the period	2,310	2,074	2,161	403	109	529

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Note 14. Miscellaneous Financial Information

Research and development expenses totaled $1.2 billion in 2025, $1.0 billion in 2024, and $0.9 billion in 2023.

Net income included before-tax aggregate foreign exchange transaction gains/(losses) of $0.2 billion, $(0.5) billion, and $(0.1) billion in 2025, 2024, and 2023, respectively.

LIFO Inventory. In 2025, 2024, and 2023, net income included gains of $0.3 billion, $0.2 billion, and $0.4 billion, respectively, attributable to the combined effects of LIFO inventory accumulations and drawdowns. The aggregate replacement cost of inventories was estimated to exceed their LIFO carrying values by approximately $7 billion and $10 billion at December 31, 2025 and 2024, respectively.

Crude oil, products, and merchandise as of year-end 2025 and 2024 consist of the following:

(millions of dollars)	Dec 31, 2025	Dec 31, 2024
Crude oil	7,976	6,483
Petroleum products	6,889	6,017
Chemical products [(1)]	4,261	4,142
Gas/other	3,853	2,802
Total	**22,979**	**19,444**

[(1)] Chemical products includes basic chemicals (olefins and aromatics), polymers (such as polyolefins, adhesions, specialty elastomers, & butyl), intermediates (e.g., hydrocarbon fluids, plasticizers), and synthetics.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Government Assistance. ASC 832 "Government Assistance" requires disclosure of certain types of government assistance not otherwise covered by authoritative accounting guidance. During 2023 to 2025, certain governments provided payments which, individually and in aggregate, were immaterial to the Corporation's consolidated financial statements. The terms and conditions of these programs, including their duration, vary by country. In connection with cap and trade programs in certain countries outside the United States, companies receive allowances from governments covering a specified level of emissions from facilities they operate. The Corporation records these allowances at a nominal amount, generally in "Inventories - Crude oil, products and merchandise" on the Consolidated Balance Sheet.

Note 15. Income and Other Taxes

(millions of dollars)	2025			2024			2023		
	U.S.	Non-U.S.	Total	U.S.	Non-U.S.	Total	U.S.	Non-U.S.	Total
Income tax expense (benefit)									
Federal and non-U.S.									
Current	143	10,271	10,414	2,061	11,940	14,001	1,987	12,111	14,098
Deferred - net	372	596	968	(318)	(512)	(830)	463	481	944
U.S. tax on non-U.S. operations	175	—	175	241	—	241	315	—	315
Total federal and non-U.S.	**690**	**10,867**	**11,557**	**1,984**	**11,428**	**13,412**	**2,765**	**12,592**	**15,357**
State	(53)	—	(53)	398	—	398	72	—	72
Total income tax expense (benefit)	**637**	**10,867**	**11,504**	**2,382**	**11,428**	**13,810**	**2,837**	**12,592**	**15,429**
All other taxes and duties									
Other taxes and duties	3,521	21,646	25,167	3,849	22,439	26,288	3,871	25,140	29,011
Included in production and manufacturing expenses	2,707	628	3,335	2,510	652	3,162	1,961	726	2,687
Included in SG&A expenses	155	273	428	179	265	444	183	310	493
Total other taxes and duties	**6,383**	**22,547**	**28,930**	**6,538**	**23,356**	**29,894**	**6,015**	**26,176**	**32,191**
Total	**7,020**	**33,414**	**40,434**	**8,920**	**34,784**	**43,704**	**8,852**	**38,768**	**47,620**

The above provisions for deferred income taxes include net expenses of $64 million in 2025, net benefits of $28 million in 2024, and net expenses of $24 million in 2023, related to changes in tax laws and rates.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The Company adopted the Financial Accounting Standards Board's ASU No. 2023-09, Improvements to Income Tax Disclosures, on a prospective basis for its 2025 annual reporting, in accordance with the transition provisions.

The reconciliation between income tax expense (credit) and a theoretical U.S. tax computed by applying a rate of 21 percent for 2025 is as follows:

(millions of dollars)	2025	
Income (loss) before income taxes		
United States	11,000	
Non-U.S.	30,268	
Total	**41,268**	
U.S. federal statutory theoretical tax	8,666	21 %
Non-U.S. taxes in excess of/(less than) theoretical U.S. tax	4,212	10 %
United Arab Emirates rate differential	3,405	8 %
Qatar	(552)	(1) %
Effect of equity method of accounting	(620)	(2) %
Other	68	0 %
All other countries	1,359	3 %
State taxes, net of federal tax benefit	(76)	0 %
Other	(1,298)	(3) %
Total income tax expense (credit)	**11,504**	**28 %**
Income tax expense (credit)	11,504	
ExxonMobil share of equity company income taxes	2,046	
Total income tax expense (credit)	**13,550**	
Net income (loss) including noncontrolling interests	29,764	
Total income (loss) before taxes	**43,314**	
Effective income tax rate	**31%**	

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The reconciliation between income tax expense (credit) and a theoretical U.S. tax computed by applying a rate of 21 percent for 2024, and 2023 is as follows:

(millions of dollars)	2024	2023
Income (loss) before income taxes		
United States	12,258	14,786
Non-U.S.	36,615	37,997
Total	**48,873**	**52,783**
Theoretical tax	10,263	11,084
Effect of equity method of accounting	(1,301)	(1,341)
Non-U.S. taxes in excess of/(less than) theoretical U.S. tax	4,986	5,888
State taxes, net of federal tax benefit	314	57
Other	(452)	(259)
Total income tax expense (credit)	**13,810**	**15,429**
Income tax expense (credit)	13,810	15,429
ExxonMobil share of equity company income taxes	3,197	3,058
Total income tax expense (credit)	**17,007**	**18,487**
Net income (loss) including noncontrolling interests	35,063	37,354
Total income (loss) before taxes	**52,070**	**55,841**
Effective income tax rate	**33%**	**33%**

Income taxes paid for 2025 U.S. and non-U.S. are shown in the table below:

(millions of dollars)	2025
Income taxes paid	
U.S. Federal	944
U.S. State	170
U.S.	**1,114**
Canada	1,207
Guyana	1,100
United Arab Emirates	5,000
All Other Countries	3,142
Non-U.S.	**10,449**
Total income taxes paid	**11,563**

Cash income taxes paid for 2024 and 2023 were $13,293 million and $15,473 million respectively.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Deferred income taxes reflect the impact of temporary differences between the amount of assets and liabilities recognized for financial reporting purposes and such amounts recognized for tax purposes.

Deferred tax liabilities/(assets) are comprised of the following at December 31:

Tax effects of temporary differences for: *(millions of dollars)*	2025	2024
Property, plant, and equipment	41,427	40,881
Other liabilities	8,358	8,113
Total deferred tax liabilities	**49,785**	**48,994**
Pension and other postretirement benefits	(972)	(1,365)
Asset retirement obligations	(3,249)	(3,156)
Tax loss carryforwards	(4,740)	(4,575)
Other assets	(7,016)	(7,308)
Total deferred tax assets	**(15,977)**	**(16,404)**
Asset valuation allowances	2,649	2,516
Net deferred tax liabilities	**36,457**	**35,106**

In 2025, asset valuation allowances of $2,649 million increased by $133 million and included net provisions of $39 million and foreign currency and other effects of $172 million.

Balance sheet classification *(millions of dollars)*	2025	2024
Other assets, including intangibles, net	(3,759)	(3,936)
Deferred income tax liabilities	40,216	39,042
Net deferred tax liabilities	**36,457**	**35,106**

The Corporation's undistributed earnings from subsidiary companies outside the United States include amounts that have been retained to fund prior and future capital project expenditures. Deferred income taxes have not been recorded for potential future tax obligations, such as foreign withholding tax and state tax, as these undistributed earnings are expected to be indefinitely reinvested for the foreseeable future. As of December 31, 2025, it is not practicable to estimate the unrecognized deferred tax liability. However, unrecognized deferred taxes on remittance of these funds are not expected to be material.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Unrecognized Tax Benefits. The Corporation is subject to income taxation in many jurisdictions around the world. The benefits of uncertain tax positions that the Corporation has taken or expects to take in its income tax returns are recognized in the financial statements if management concludes that it is more likely than not that the position will be sustained with the tax authorities. For a position that is likely to be sustained, the benefit recognized in the financial statements is measured at the largest amount that is greater than 50 percent likely of being realized. Unrecognized tax benefits reflect the difference between positions taken or expected to be taken on income tax returns and the amounts recognized in the financial statements. The following table summarizes the movement in unrecognized tax benefits:

Gross unrecognized tax benefits *(millions of dollars)*	2025	2024	2023
Balance at January 1	**4,035**	**3,935**	**3,398**
Additions based on current year's tax positions	206	376	350
Additions for prior years' tax positions	454	103	400
Reductions for prior years' tax positions	(377)	(293)	(38)
Reductions due to lapse of the statute of limitations	(4)	(17)	(25)
Settlements with tax authorities	(150)	(13)	(153)
Foreign exchange effects/other	(33)	(56)	3
Balance at December 31	**4,131**	**4,035**	**3,935**

The gross unrecognized tax benefit balances shown above predominantly relate to tax positions that would reduce the Corporation's effective tax rate if the positions are favorably resolved. Unfavorable resolution of these tax positions generally would not increase the effective tax rate. The 2025, 2024, and 2023 changes in unrecognized tax benefits did not have a material effect on the Corporation's net income.

Resolution of these tax positions through negotiations with the relevant tax authorities or through litigation may take many years to complete. It is difficult to predict the timing of resolution for these tax positions since the timing is not entirely within the control of the Corporation. The Corporation has various U.S. federal income tax positions at issue with the Internal Revenue Service for tax years beginning with 2010. Unfavorable resolution of these issues would not have a materially adverse effect on the Corporation's net income or liquidity.

The following table summarizes the tax years that remain subject to examination by major tax jurisdiction:

Country of Operation	Open Tax Years
Canada	2001 — 2025
Kazakhstan	2020 — 2025
Papua New Guinea	2008 — 2025
Qatar	2020 — 2025
United Arab Emirates	2024 — 2025
United States	2010 — 2025

The Corporation classifies interest on income tax-related balances as interest expense or interest income and classifies tax-related penalties as operating expense.

For 2025, 2024, and 2023 the Corporation's net interest expense on income tax reserves was $99 million, $142 million, and $60 million, respectively. The related interest payable balances were $365 million and $275 million at December 31, 2025 and 2024, respectively.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 16. Accounting for Suspended Exploratory Well Costs

The Corporation continues capitalization of exploratory well costs when the well has found a sufficient quantity of reserves to justify its completion as a producing well and the Corporation is making sufficient progress assessing the reserves and the economic and operating viability of the project. The term "project" as used in this report can refer to a variety of different activities and does not necessarily have the same meaning as in any government payment transparency reports.

The following two tables provide details of the changes in the balance of suspended exploratory well costs, including an aging summary of those costs.

Change in capitalized suspended exploratory well costs *(millions of dollars)*	2025	2024	2023
Balance beginning at January 1	**3,600**	**3,559**	**3,512**
Additions pending the determination of proved reserves	250	453	200
Charged to expense	(432)	(69)	(95)
Reclassifications to wells, facilities and equipment based on the determination of proved reserves	(141)	(292)	(142)
Divestments/Other	9	(51)	84
Ending balance at December 31	**3,286**	**3,600**	**3,559**
Ending balance attributed to equity companies included above	225	225	306

Period-end capitalized suspended exploratory well costs *(millions of dollars)*	2025	2024	2023
Capitalized for a period of one year or less	**250**	**453**	**200**
Capitalized for a period of between one and five years	933	583	1,030
Capitalized for a period of between five and ten years	1,144	1,544	1,411
Capitalized for a period of greater than ten years	959	1,020	918
Capitalized for a period greater than one year - subtotal	**3,036**	**3,147**	**3,359**
Total	**3,286**	**3,600**	**3,559**

Exploration activity often involves drilling multiple wells, over a number of years, to fully evaluate a project. The table below provides a breakdown of the number of projects with only exploratory well costs capitalized for a period of one year or less and those that have had exploratory well costs capitalized for a period greater than one year.

	2025	2024	2023
Number of projects that only have exploratory well costs capitalized for a period of one year or less	1	5	—
Number of projects that have exploratory well costs capitalized for a period greater than one year	25	24	31
Total	**26**	**29**	**31**

Of the 25 projects that have exploratory well costs capitalized for a period greater than one year as of December 31, 2025, 10 projects have drilling in the preceding year or exploratory activity planned in the next two years, while the remaining 15 projects are those with completed exploratory activity. These projects are currently being progressed toward development, including evaluation to tie into existing infrastructure, awaiting capacity, and aligning with the respective governments for development plans.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 17. Cash Flow Information

The Consolidated Statement of Cash Flows provides information about changes in cash and cash equivalents. Highly liquid investments with maturities of three months or less when acquired are classified as cash equivalents.

In 2025, the Corporation completed the sale of the Product Solutions affiliates in France. The sale included cash proceeds as well as cash from a financing arrangement which was assumed by the buyer upon closing.

In 2024, the Corporation completed the acquisition of Pioneer Natural Resources Company (Pioneer) through the issuance of 545 million shares of ExxonMobil common stock having a fair value of $63 billion on the acquisition date and assumed debt with a fair value of $5 billion. Additional information is provided in Note 20.

In 2023, the Corporation completed the acquisition of Denbury Inc. (Denbury) through the issuance of 46 million shares of ExxonMobil Corporation common stock having a fair value of $4.8 billion on the acquisition date. Additional information is provided in Note 20.

In 2023, the Corporation completed the sale of Esso Thailand. The sale included cash proceeds as well as cash from debt that was issued to facilitate the sale, which was assumed by the buyer upon closing.

For 2025, the “Net (gain)/loss on asset sales” on the Consolidated Statement of Cash Flows includes before-tax amounts mainly from the sale of upstream assets in the United States and Argentina and retail fuels assets in Singapore. For 2024, the number includes before-tax amounts mainly from the sale of upstream assets in the United States, Argentina, and Nigeria**.** For 2023, the number includes before-tax amounts from the sale of upstream assets in the United States. These net (gain)/loss amounts are reported in "Other income" on the Consolidated Statement of Income.

(millions of dollars)	2025	2024	2023
Cash interest paid			
Included in cash flows from operating activities	218	624	584
Capitalized, included in cash flows from investing activities	1,534	1,276	1,152
Total cash interest paid	**1,752**	**1,900**	**1,736**

Note 18. Incentive Program

The 2003 Incentive Program provides for grants of stock options, stock appreciation rights (SARs), restricted stock, and other forms of awards. Awards may be granted to eligible employees of the Company and those affiliates at least 50 percent owned by the Corporation. Outstanding awards are subject to certain forfeiture provisions contained in the program or award instrument. Options and SARs may be granted at prices not less than 100 percent of market value on the date of grant and have a maximum life of 10 years. The maximum number of shares of stock that may be issued under the 2003 Incentive Program is 220 million. Awards that are forfeited, expire, or are settled in cash, do not count against this maximum limit. The 2003 Incentive Program does not have a specified term. New awards may be made until the available shares are depleted, unless the ExxonMobil Board of Directors terminates the plan early. At the end of 2025, remaining shares available for award under the 2003 Incentive Program were 41 million.

Restricted Stock and Restricted Stock Units. Awards of restricted (nonvested) common stock units granted under the 2003 Incentive Program totaled 9,852 thousand, 10,393 thousand, and 9,701 thousand in 2025, 2024, and 2023, respectively. Compensation expense for these awards is based on the price of the stock at the date of grant and is recognized in income over the requisite service period. Shares for these awards are issued to employees from treasury stock. The units that are settled in cash are recorded as liabilities, and their changes in fair value are recognized over the vesting period. During the applicable restricted periods, the shares and units may not be sold or transferred and are subject to forfeiture. The majority of the awards have graded vesting periods, with 50 percent of the shares and units in each award vesting after three years, and the remaining 50 percent vesting after seven years. Some management, professional, and technical participants will receive awards that vest in full after three years. Awards granted to a small number of senior executives have vesting periods of five years for 50 percent of the award and of 10 years for the remaining 50 percent of the award, except that for awards granted prior to 2020 the vesting of the 10-year portion of the award is delayed until retirement if later than 10 years.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

In accordance with the terms of the merger agreement for the Pioneer acquisition, which closed on May 3, 2024, awards of Pioneer restricted stock units granted under the Pioneer Amended and Restated 2006 Long Term Incentive Plan (Pioneer LTIP) that did not vest as of immediately prior to the closing were cancelled and converted into awards of ExxonMobil restricted stock units based on the merger exchange ratio. The grant date for the converted Pioneer awards is considered to be the effective date of the acquisition for the purpose of calculating fair value. Compensation costs for the converted Pioneer awards is recognized in income over a period commensurate with the vesting schedule. Pioneer awards vest in three installments over a period of three years with approximately one third of the awards vesting each year. Shares for these awards are issued to employees from treasury stock. The units that are settled in cash are recorded as liabilities and their changes in fair value are recognized over the vesting period. The maximum term of the Pioneer awards is three years. As of the Pioneer acquisition closing on May 3, 2024, the maximum number of shares of stock that can be issued under the Pioneer LTIP was 9,458 thousand. At the end of 2025, remaining shares available for awards under the Pioneer LTIP were 9,426 thousand. The program is set to expire in May 2026.

The following tables summarize information about restricted stock and restricted stock units for the year ended December 31, 2025.

Restricted stock and units outstanding	2025 Shares *(thousands)*	2025 Weighted-Average Grant-Date Fair Value per Share *(dollars)*
Issued and outstanding at January 1	39,595	85.29
Awards issued in 2025	10,327	118.72
Vested	(8,716)	90.54
Forfeited	(552)	100.77
Issued and outstanding at December 31	40,654	92.45

Impacts of Pioneer awards incorporated in the totals above include 49 thousand awards issued in 2025, (189) thousand vested and (65) thousand forfeited.

Value of restricted stock units	2025	2024	2023
Grant price *(dollars)*	115.02	118.57	103.16
Value at date of grant:	*(millions of dollars)*		
Units settled in stock	1,031	1,193	900
Units settled in cash	108	129	101
Total value	**1,139**	**1,322**	**1,001**

As of December 31, 2025, there was $2.7 billion of unrecognized compensation cost related to the nonvested restricted awards. This cost is expected to be recognized over a weighted-average period of 4.6 years. The compensation cost charged against income for the restricted stock and restricted stock units was $1.0 billion, $0.8 billion, and $0.6 billion for 2025, 2024, and 2023, respectively. The income tax benefit recognized in income related to this compensation expense was $0.1 billion, $0.1 billion, and $0.1 billion for the same periods, respectively. The fair value of shares and units vested in 2025, 2024, and 2023 was $1.0 billion, $1.0 billion, and $0.9 billion, respectively. Cash payments of $0.1 billion, $0.1 billion, and $0.1 billion for vested restricted stock units settled in cash were made in 2025, 2024, and 2023, respectively.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 19. Divestment Activities

In 2025, the Corporation realized proceeds of approximately $3.2 billion and recognized net after-tax earnings of approximately $1.1 billion from its divestment activities. This included the sale of the Singapore retail fuels business, Mobil Argentina S.A., Product Solutions affiliates in France, certain conventional and unconventional assets in the United States, and other smaller divestments.

In 2024, the Corporation realized proceeds of approximately $5.0 billion and recognized net after-tax earnings of approximately $1.0 billion from its divestment activities. This included the sale of the Santa Ynez Unit and associated facilities in California, Mobil Producing Nigeria Unlimited, ExxonMobil Exploration Argentina, the Fos-sur-Mer Refinery (France), the Adriatic LNG terminal (Italy), and certain conventional and unconventional assets in the United States, as well as other smaller divestments.

In 2023, the Corporation realized proceeds of approximately $4.1 billion and recognized net after-tax earnings of approximately $0.6 billion from its divestment activities. This included the sale of the Aera Energy joint venture, Esso Thailand Ltd., the Billings Refinery, certain unconventional assets in the United States, as well as other smaller divestments.

Note 20. Mergers and Acquisitions

Pioneer Natural Resources Company

On May 3, 2024, the Corporation acquired Pioneer Natural Resources Company (Pioneer), an independent oil and gas exploration and production company. In connection with the acquisition, we issued 545 million shares of ExxonMobil common stock having a fair value of $63 billion on the acquisition date and assumed debt with a fair value of $5 billion.

The transaction was accounted for as a business combination in accordance with ASC 805, which requires that assets acquired and liabilities assumed be recognized at their fair values as of the acquisition date. The following table summarizes the fair values of the assets acquired and liabilities assumed.

(billions of dollars)	Pioneer
Current assets [1]	3
Other non-current assets	1
Property, plant, & equipment [2]	84
Total identifiable assets acquired	**88**
Current liabilities [1]	3
Long-term debt [3]	5
Deferred income tax liabilities [4]	16
Other non-current liabilities	2
Total liabilities assumed	**26**
Net identifiable assets acquired	**62**
Goodwill [5]	1
Net assets	**63**

[1] *Current assets and current liabilities consist primarily of accounts receivable and payable, with their respective fair values approximating historical values given their short-term duration, expectation of insignificant bad debt expense, and our credit rating.*

[2] *Property, plant, and equipment, of which a significant portion relates to crude oil and natural gas properties, was preliminarily valued using the income approach. Significant inputs and assumptions used in the income approach included estimates for commodity prices, future oil and gas production volumes, drilling and development costs, and risk-adjusted discount rates. Collectively, these inputs are level 3 inputs.*

[3] *Long-term debt was valued using market prices as of the acquisition date, which reflects the use of level 1 inputs.*

[4] *Deferred income taxes represent the tax effects of differences in the tax basis and acquisition date fair values of assets acquired and liabilities assumed.*

[5] *Goodwill was allocated to the Upstream segment.*

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Debt Assumed in the Merger

The following table presents long-term debt assumed at closing:

(millions of dollars)	Par Value	Fair Value as of May 2, 2024
0.250% Convertible Senior Notes due May 2025 [(1)]	450	1,327
1.125% Senior Notes due January 2026	750	699
5.100% Senior Notes due March 2026	1,100	1,096
7.200% Senior Notes due January 2028	241	252
4.125% Senior Notes due February 2028	138	130
1.900% Senior Notes due August 2030	1,100	914
2.150% Senior Notes due January 2031	1,000	832

[(1)] In June 2024, the Corporation redeemed in full all of the Convertible Senior Notes assumed from Pioneer for an amount consistent with the acquisition date fair value.

Actual and Pro Forma Impact of Merger

The following table presents revenues and earnings included in the Consolidated Statement of Income for Pioneer since the acquisition date (May 3, 2024) through December 31, 2024:

(millions of dollars)	Twelve Months Ended December 31, 2024
Sales and other operating revenues	17,008
Net income (loss) attributable to ExxonMobil	1,710

The following table presents unaudited pro forma information for the Corporation as if the merger with Pioneer had occurred at the beginning of January 1, 2023:

Unaudited *(millions of dollars)*	Twelve Months Ended December 31,	
	2024	2023
Sales and other operating revenues	347,406	358,014
Net income (loss) attributable to ExxonMobil	34,476	39,211

The historical financial information was adjusted to give effect to the pro forma events that were directly attributable to the merger and factually supportable. The unaudited pro forma consolidated results are not necessarily indicative of what the consolidated results of operations actually would have been had the merger been completed on January 1, 2023. In addition, the unaudited pro forma consolidated results reflect pro forma adjustments primarily related to conforming Pioneer's accounting policies to ExxonMobil, additional depreciation expense related to the fair value adjustment of the acquired property, plant, and equipment, our capital structure, Pioneer's transaction-related costs, and applicable income tax impacts of the pro forma adjustments.

Our transaction costs to effect the acquisition were immaterial.

Denbury Inc.

On November 2, 2023, the Corporation acquired Denbury, a developer of carbon capture, utilization, and storage solutions and enhanced oil recovery producing assets. The acquisition also included Gulf Coast and Rocky Mountain oil and natural gas operations.

Total consideration was $5.1 billion, which included the issuance of 46 million shares of ExxonMobil common stock from treasury having a fair value of $4.8 billion on the acquisition date, and cash payments of $0.3 billion related to repayment of Denbury's credit facility and settlement of fractional shares.

The transaction was accounted for as a business combination in accordance with ASC 805, which requires that assets acquired and liabilities assumed be recognized at their fair values as of the acquisition date. Substantially all of the purchase price was allocated to

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property, plant, and equipment and long-term liabilities. The Denbury acquisition resulted in an immaterial amount of goodwill. Revenues and earnings arising from Denbury's operations are immaterial in 2023 for pro forma disclosure purposes.

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SUPPLEMENTAL INFORMATION ON OIL AND GAS EXPLORATION AND PRODUCTION ACTIVITIES (unaudited)

The results of operations for producing activities shown below do not include earnings from other activities that ExxonMobil includes in the Upstream function, such as oil and gas transportation operations, LNG liquefaction and transportation operations, power operations, technical service agreements, gains and losses from derivative activity, other nonoperating activities, and adjustments for noncontrolling interests. These excluded amounts for both consolidated and equity companies totaled $1.9 billion in 2025, $1.4 billion in 2024 and $(0.5) billion in 2023. Oil sands mining operations are included in the results of operations in accordance with Securities and Exchange Commission and Financial Accounting Standards Board rules.

Results of Operations *(millions of dollars)*	United States	Canada/ Other Americas	Europe	Africa	Asia	Australia/ Oceania	Total
2025							
Consolidated Subsidiaries							
Sales to third parties	14,798	5,699	991	159	2,374	3,693	27,714
Transfers	13,696	11,866	49	3,233	9,821	501	39,166
Revenue	28,494	17,565	1,040	3,392	12,195	4,194	66,880
Production costs excluding taxes	8,397	4,793	450	1,053	1,192	488	16,373
Exploration expenses	26	354	97	127	311	92	1,007
Depreciation and depletion	13,538	3,367	331	802	1,505	707	20,250
Taxes other than income	2,101	96	50	88	1,780	279	4,394
Related income tax	880	1,406	64	505	5,631	594	9,080
Results of producing activities for consolidated subsidiaries	**3,552**	**7,549**	**48**	**817**	**1,776**	**2,034**	**15,776**
Equity Companies							
Sales to third parties	68	—	321	249	12,734	—	13,372
Transfers	—	—	9	—	28	—	37
Revenue	68	—	330	249	12,762	—	13,409
Production costs excluding taxes	64	—	486	32	670	—	1,252
Exploration expenses	—	—	1	—	—	—	1
Depreciation and depletion	16	—	41	39	2,051	—	2,147
Taxes other than income	6	—	9	—	4,406	—	4,421
Related income tax	—	—	(92)	52	1,953	—	1,913
Results of producing activities for equity companies	**(18)**	**—**	**(115)**	**126**	**3,682**	**—**	**3,675**
Total results of operations	**3,534**	**7,549**	**(67)**	**943**	**5,458**	**2,034**	**19,451**

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Results of Operations *(millions of dollars)*	United States	Canada/ Other Americas	Europe	Africa	Asia	Australia/ Oceania	Total
2024							
Consolidated Subsidiaries							
Sales to third parties	13,036	5,774	986	425	2,473	3,790	26,484
Transfers	13,745	13,140	43	5,764	10,825	817	44,334
Revenue	26,781	18,914	1,029	6,189	13,298	4,607	70,818
Production costs excluding taxes	6,869	4,745	406	1,723	1,163	610	15,516
Exploration expenses	43	485	46	213	31	8	826
Depreciation and depletion	11,114	3,343	94	1,436	1,390	852	18,229
Taxes other than income	2,163	115	31	479	1,987	370	5,145
Related income tax	1,502	2,025	202	605	6,562	805	11,701
Results of producing activities for consolidated subsidiaries	**5,090**	**8,201**	**250**	**1,733**	**2,165**	**1,962**	**19,401**
Equity Companies							
Sales to third parties	69	—	361	191	13,054	—	13,675
Transfers	—	—	15	—	142	—	157
Revenue	69	—	376	191	13,196	—	13,832
Production costs excluding taxes	58	—	422	50	659	—	1,189
Exploration expenses	—	—	2	—	—	—	2
Depreciation and depletion	239	—	36	35	781	—	1,091
Taxes other than income	6	—	10	—	4,469	—	4,485
Related income tax	—	—	(48)	24	2,495	—	2,471
Results of producing activities for equity companies	**(234)**	**—**	**(46)**	**82**	**4,792**	**—**	**4,594**
Total results of operations	**4,856**	**8,201**	**204**	**1,815**	**6,957**	**1,962**	**23,995**
2023							
Consolidated Subsidiaries							
Sales to third parties	5,098	4,027	1,345	298	2,490	4,588	17,846
Transfers	13,378	11,474	47	6,355	10,779	600	42,633
Revenue	18,476	15,501	1,392	6,653	13,269	5,188	60,479
Production costs excluding taxes	4,164	4,943	623	1,710	1,146	511	13,097
Exploration expenses	44	505	25	124	18	35	751
Depreciation and depletion	8,479	2,866	96	1,561	1,519	755	15,276
Taxes other than income	1,701	117	48	516	1,936	358	4,676
Related income tax	703	1,196	315	1,299	6,498	1,078	11,089
Results of producing activities for consolidated subsidiaries	**3,385**	**5,874**	**285**	**1,443**	**2,152**	**2,451**	**15,590**
Equity Companies							
Sales to third parties	182	—	1,211	214	14,653	—	16,260
Transfers	83	—	29	—	232	—	344
Revenue	265	—	1,240	214	14,885	—	16,604
Production costs excluding taxes	239	—	419	39	714	—	1,411
Exploration expenses	—	—	—	—	—	—	—
Depreciation and depletion	58	—	27	42	605	—	732
Taxes other than income	12	—	27	—	5,049	—	5,088
Related income tax	—	—	202	30	2,904	—	3,136
Results of producing activities for equity companies	**(44)**	**—**	**565**	**103**	**5,613**	**—**	**6,237**
Total results of operations	**3,341**	**5,874**	**850**	**1,546**	**7,765**	**2,451**	**21,827**

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Oil and Gas Exploration and Production Costs

The amounts shown for net capitalized costs of consolidated subsidiaries are $9.1 billion less at year-end 2025 and $9.6 billion less at year-end 2024 than the amounts reported as investments in property, plant, and equipment for the Upstream in Note 9. This is due to the exclusion from capitalized costs of certain transportation and research assets and assets relating to LNG operations. Assets related to oil sands and oil shale mining operations are included in the capitalized costs in accordance with Financial Accounting Standards Board rules.

Capitalized Costs *(millions of dollars)*		United States	Canada/ Other Americas	Europe	Africa	Asia	Australia/ Oceania	Total
As of December 31, 2025								
Consolidated Subsidiaries								
Property (acreage) costs	– Proved	33,548	3,187	33	694	2,962	688	41,112
	– Unproved	43,177	1,950	42	59	5	2,659	47,892
Total property costs		76,725	5,137	75	753	2,967	3,347	89,004
Producing assets		132,738	60,734	13,537	35,493	46,725	16,585	305,812
Incomplete construction		5,867	13,015	239	1,442	1,482	2,479	24,524
Total capitalized costs		215,330	78,886	13,851	37,688	51,174	22,411	419,340
Accumulated depreciation and depletion		76,273	31,036	13,165	33,603	34,165	11,915	200,157
Net capitalized costs for consolidated subsidiaries		**139,057**	**47,850**	**686**	**4,085**	**17,009**	**10,496**	**219,183**
Equity Companies								
Property (acreage) costs	– Proved	—	—	1	309	—	—	310
	– Unproved	—	—	—	3,111	—	—	3,111
Total property costs		—	—	1	3,420	—	—	3,421
Producing assets		1,390	—	4,225	402	21,842	—	27,859
Incomplete construction		3	—	24	466	2,225	—	2,718
Total capitalized costs		1,393	—	4,250	4,288	24,067	—	33,998
Accumulated depreciation and depletion		1,081	—	4,000	113	9,886	—	15,080
Net capitalized costs for equity companies		**312**	**—**	**250**	**4,175**	**14,181**	**—**	**18,918**
As of December 31, 2024								
Consolidated Subsidiaries								
Property (acreage) costs	– Proved	28,143	3,238	8	693	2,990	654	35,726
	– Unproved	49,903	2,367	42	108	5	2,656	55,081
Total property costs		78,046	5,605	50	801	2,995	3,310	90,807
Producing assets		131,125	50,905	12,304	34,991	45,482	15,317	290,124
Incomplete construction		6,685	12,854	196	1,317	2,269	2,078	25,399
Total capitalized costs		215,856	69,364	12,550	37,109	50,746	20,705	406,330
Accumulated depreciation and depletion		74,303	27,479	11,953	32,837	32,822	10,534	189,928
Net capitalized costs for consolidated subsidiaries		**141,553**	**41,885**	**597**	**4,272**	**17,924**	**10,171**	**216,402**
Equity Companies								
Property (acreage) costs	– Proved	—	—	3	309	—	—	312
	– Unproved	—	—	—	3,111	—	—	3,111
Total property costs		—	—	3	3,420	—	—	3,423
Producing assets		1,360	—	5,222	402	19,215	—	26,199
Incomplete construction		2	—	15	453	5,091	—	5,561
Total capitalized costs		1,362	—	5,240	4,275	24,306	—	35,183
Accumulated depreciation and depletion		1,046	—	4,935	76	8,564	—	14,621
Net capitalized costs for equity companies		**316**	**—**	**305**	**4,199**	**15,742**	**—**	**20,562**

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Oil and Gas Exploration and Production Costs (continued)

The amounts reported as costs incurred include both capitalized costs and costs charged to expense during the year. Costs incurred also include new asset retirement obligations established in the current year, as well as increases or decreases to the asset retirement obligation resulting from changes in cost estimates or abandonment date. Total consolidated costs incurred in 2025 were $27.8 billion, down $77.3 billion from 2024, due primarily to the absence of the Pioneer acquisition and partly offset by higher development costs. In 2024, costs were $105.1 billion, up $84.1 billion from 2023, due primarily to the Pioneer acquisition and higher development costs. Total equity company costs incurred in 2025 were $0.8 billion, down $0.3 billion from 2024, due to lower development costs.

Costs Incurred in Property Acquisitions, Exploration and Development Activities *(millions of dollars)*		United States	Canada/ Other Americas	Europe	Africa	Asia	Australia/ Oceania	Total
During 2025								
Consolidated Subsidiaries								
Property acquisition costs	– Proved	1,177	—	—	—	—	—	1,177
	– Unproved	2,591	—	—	—	—	—	2,591
Exploration costs		66	1,304	80	102	12	54	1,618
Development costs		12,463	7,310	238	634	967	823	22,435
Total costs incurred for consolidated subsidiaries		**16,297**	**8,614**	**318**	**736**	**979**	**877**	**27,821**
Equity Companies								
Property acquisition costs	– Proved	—	—	—	—	—	—	—
	– Unproved	—	—	—	—	—	—	—
Exploration costs		—	—	1	—	—	—	1
Development costs		9	—	21	15	769	—	814
Total costs incurred for equity companies		**9**	**—**	**22**	**15**	**769**	**—**	**815**
During 2024								
Consolidated Subsidiaries								
Property acquisition costs	– Proved	39,271	—	—	1	—	—	39,272
	– Unproved	45,196	—	5	—	—	—	45,201
Exploration costs		55	838	63	268	30	8	1,262
Development costs		10,903	5,839	113	910	750	844	19,359
Total costs incurred for consolidated subsidiaries		**95,425**	**6,677**	**181**	**1,179**	**780**	**852**	**105,094**
Equity Companies								
Property acquisition costs	– Proved	—	—	—	—	—	—	—
	– Unproved	—	—	—	—	—	—	—
Exploration costs		—	—	2	—	—	—	2
Development costs		3	—	20	18	1,091	—	1,132
Total costs incurred for equity companies		**3**	**—**	**22**	**18**	**1,091**	**—**	**1,134**
During 2023								
Consolidated Subsidiaries								
Property acquisition costs	– Proved	2,456	—	—	2	—	—	2,458
	– Unproved	171	—	—	6	—	—	177
Exploration costs		54	693	23	117	18	35	940
Development costs		8,978	5,914	55	562	822	1,046	17,377
Total costs incurred for consolidated subsidiaries		**11,659**	**6,607**	**78**	**687**	**840**	**1,081**	**20,952**
Equity Companies								
Property acquisition costs	– Proved	—	—	—	—	—	—	—
	– Unproved	—	—	—	—	—	—	—
Exploration costs		—	—	—	—	—	—	—
Development costs		10	—	5	7	1,488	—	1,510
Total costs incurred for equity companies		**10**	**—**	**5**	**7**	**1,488**	**—**	**1,510**

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Oil and Gas Reserves

The following information describes changes during the years and balances of proved oil and gas reserves at year-end 2023, 2024, and 2025.

The definitions used are in accordance with the Securities and Exchange Commission's Rule 4-10 (a) of Regulation S-X.

Proved oil and natural gas reserves are those quantities of oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible – from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations – prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain. In some cases, substantial new investments in additional wells and related facilities will be required to recover these proved reserves.

In accordance with the Securities and Exchange Commission's (SEC) rules, the Corporation's year-end reserves volumes, as well as the reserves change categories shown in the following tables, are required to be calculated on the basis of average prices during the 12-month period prior to the ending date of the period covered by this report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period. These reserves quantities are also used in calculating unit-of-production depreciation rates and in calculating the standardized measure of discounted net cash flows.

Revisions can include upward or downward changes in previously estimated volumes of proved reserves for existing fields due to the evaluation or re-evaluation of (1) already available geologic, reservoir or production data, (2) new geologic, reservoir or production data or (3) changes in the average of first-of-month oil and natural gas prices and/or costs that are used in the estimation of reserves. Revisions can also result from significant changes in either development strategy or production equipment/facility capacity.

Proved reserves include 100 percent of each majority-owned affiliate's participation in proved reserves and ExxonMobil's ownership percentage of the proved reserves of equity companies, but exclude royalties and quantities due others. Natural gas reserves exclude the gaseous equivalent of liquids expected to be removed from the natural gas on leases, at field facilities, and at gas processing plants. These liquids are included in net proved reserves of crude oil and natural gas liquids.

In the proved reserves tables, consolidated reserves and equity company reserves are reported separately. However, the Corporation does not view equity company reserves any differently than those from consolidated companies.

Reserves reported under production sharing and other nonconcessionary agreements are based on the economic interest as defined by the specific fiscal terms in the agreement. The production and reserves reported for these types of arrangements typically vary inversely with oil and natural gas price changes. As oil and natural gas prices increase, the cash flow and value received by the Company increase; however, the production volumes and reserves required to achieve this value will typically be lower because of the higher prices. When prices decrease, the opposite effect generally occurs. The percentage of total proved reserves (consolidated subsidiaries plus equity companies) at year-end 2025 that were associated with production sharing contract arrangements was 12 percent on an oil-equivalent basis (natural gas is converted to an oil-equivalent basis at six billion cubic feet per one million barrels).

Net proved developed reserves are those volumes that are expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well. Net proved undeveloped reserves are those volumes that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

Crude oil, natural gas liquids, and natural gas production quantities shown are the net volumes withdrawn from ExxonMobil's oil and natural gas reserves. The natural gas quantities differ from the quantities of natural gas delivered for sale by the producing function as reported in the Upstream Operational Results due to volumes consumed or flared and inventory changes.

The changes between 2025 year-end proved reserves and 2024 year-end proved reserves include worldwide production of 1.8 billion oil-equivalent barrels (GOEB), asset sales of 0.1 GOEB primarily in the United States, and downward revisions of 0.9 GOEB attributed primarily to the United States. Additions to proved reserves include 2.1 GOEB from extensions and discoveries primary in the United States and Guyana and 0.1 GOEB related to United States acquisitions.

The changes between 2024 year-end proved reserves and 2023 year-end proved reserves include worldwide production of 1.6 billion oil-equivalent barrels (GOEB) and asset sales of 0.1 GOEB primarily in Nigeria. Additions to proved reserves include 2.3 GOEB related to the Pioneer acquisition, 1.9 GOEB from extensions and discoveries primarily in the United States and Guyana, and net revisions of 0.6 GOEB primarily attributed to the United Arab Emirates, United States, Canada, and Guyana.

The changes between 2023 year-end proved reserves and 2022 year-end proved reserves include worldwide production of 1.4 billion GOEB, asset sales of 0.2 GOEB primarily in the United States, and downward revisions of 0.4 GOEB. Additions to proved reserves include 1.1 GOEB from extensions and discoveries primarily in the United States and Guyana and 0.2 GOEB related to the Denbury acquisition.

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Crude Oil, Natural Gas Liquids, Bitumen and Synthetic Oil Proved Reserves

(millions of barrels)	Crude Oil							Natural Gas Liquids	Bitumen	Synthetic Oil	
	United States	Canada/ Other Americas	Europe	Africa	Asia	Australia/ Oceania	Total	Worldwide	Canada/ Other Americas	Canada/ Other Americas	Total
Net proved developed and undeveloped reserves of consolidated subsidiaries											
January 1, 2023	2,204	945	5	271	2,794	66	6,285	1,176	2,420	353	10,234
Revisions	(398)	32	—	31	30	3	(302)	(110)	123	26	(263)
Improved recovery	—	—	—	—	—	—	—	—	—	—	—
Purchases	156	—	—	—	—	—	156	2	—	—	158
Sales	(12)	—	—	—	(4)	—	(16)	(5)	—	—	(21)
Extensions/discoveries	355	105	—	—	—	—	460	272	—	—	732
Production	(203)	(88)	(1)	(78)	(153)	(8)	(531)	(99)	(129)	(25)	(784)
December 31, 2023	**2,102**	**994**	**4**	**224**	**2,667**	**61**	**6,052**	**1,236**	**2,414**	**354**	**10,056**
Attributable to noncontrolling interests		*1*							*551*	*108*	
Proportional interest in proved reserves of equity companies											
January 1, 2023	119	—	2	5	756	—	882	355	—	—	1,237
Revisions	—	—	1	—	103	—	104	1	—	—	105
Improved recovery	—	—	—	—	—	—	—	—	—	—	—
Purchases	—	—	—	—	—	—	—	—	—	—	—
Sales	(108)	—	—	—	—	—	(108)	(1)	—	—	(109)
Extensions/discoveries	—	—	—	—	—	—	—	—	—	—	—
Production	(4)	—	—	—	(79)	—	(83)	(22)	—	—	(105)
December 31, 2023	**7**	**—**	**3**	**5**	**780**	**—**	**795**	**333**	**—**	**—**	**1,128**
Total liquids proved reserves at December 31, 2023	**2,109**	**994**	**7**	**229**	**3,447**	**61**	**6,847**	**1,569**	**2,414**	**354**	**11,184**
Net proved developed and undeveloped reserves of consolidated subsidiaries											
January 1, 2024	2,102	994	4	224	2,667	61	6,052	1,236	2,414	354	10,056
Revisions	(176)	116	—	62	603	1	606	(128)	152	(35)	595
Improved recovery	—	—	—	—	—	—	—	—	—	—	—
Purchases	877	—	—	—	—	—	877	730	—	—	1,607
Sales	(18)	(4)	—	(45)	(7)	—	(74)	(15)	—	—	(89)
Extensions/discoveries	804	138	—	25	—	—	967	489	—	—	1,456
Production	(316)	(126)	(1)	(75)	(154)	(7)	(679)	(148)	(137)	(23)	(987)
December 31, 2024	**3,273**	**1,118**	**3**	**191**	**3,109**	**55**	**7,749**	**2,164**	**2,429**	**296**	**12,638**
Attributable to noncontrolling interests		—							*552*	*90*	
Proportional interest in proved reserves of equity companies											
January 1, 2024	7	—	3	5	780	—	795	333	—	—	1,128
Revisions	—	—	—	2	19	—	21	3	—	—	24
Improved recovery	—	—	—	—	—	—	—	—	—	—	—
Purchases	—	—	—	—	—	—	—	—	—	—	—
Sales	—	—	—	—	—	—	—	—	—	—	—
Extensions/discoveries	—	—	—	—	—	—	—	—	—	—	—
Production	(1)	—	(1)	—	(75)	—	(77)	(22)	—	—	(99)
December 31, 2024	**6**	**—**	**2**	**7**	**724**	**—**	**739**	**314**	**—**	**—**	**1,053**
Total liquids proved reserves at December 31, 2024	**3,279**	**1,118**	**5**	**198**	**3,833**	**55**	**8,488**	**2,478**	**2,429**	**296**	**13,691**

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Crude Oil, Natural Gas Liquids, Bitumen and Synthetic Oil Proved Reserves (continued)

(millions of barrels)	Crude Oil							Natural Gas Liquids	Bitumen	Synthetic Oil	
	United States	Canada/ Other Americas	Europe	Africa	Asia	Australia/ Oceania	Total	Worldwide	Canada/ Other Americas	Canada/ Other Americas	Total
Net proved developed and undeveloped reserves of consolidated subsidiaries											
January 1, 2025	3,273	1,118	3	191	3,109	55	7,749	2,164	2,429	296	12,638
Revisions	(652)	124	1	78	13	6	(430)	(373)	42	17	(744)
Improved recovery	—	—	—	—	—	—	—	—	—	—	—
Purchases	38	—	—	—	—	—	38	41	—	—	79
Sales	(72)	—	—	—	—	—	(72)	(12)	—	—	(84)
Extensions/discoveries	890	92	—	—	—	6	988	513	—	—	1,501
Production	(367)	(139)	(1)	(52)	(162)	(7)	(728)	(194)	(141)	(25)	(1,088)
December 31, 2025	**3,110**	**1,195**	**3**	**217**	**2,960**	**60**	**7,545**	**2,139**	**2,330**	**288**	**12,302**
Attributable to noncontrolling interests		—							*529*	*88*	
Proportional interest in proved reserves of equity companies											
January 1, 2025	6	—	2	7	724	—	739	314	—	—	1,053
Revisions	—	—	3	—	(2)	—	1	7	—	—	8
Improved recovery	—	—	—	—	—	—	—	—	—	—	—
Purchases	—	—	—	—	—	—	—	—	—	—	—
Sales	—	—	—	—	—	—	—	—	—	—	—
Extensions/discoveries	—	—	—	—	—	—	—	—	—	—	—
Production	(1)	—	—	—	(97)	—	(98)	(23)	—	—	(121)
December 31, 2025	**5**	**—**	**5**	**7**	**625**	**—**	**642**	**298**	**—**	**—**	**940**
Total liquids proved reserves at December 31, 2025	**3,115**	**1,195**	**8**	**224**	**3,585**	**60**	**8,187**	**2,437**	**2,330**	**288**	**13,242**

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Crude Oil, Natural Gas Liquids, Bitumen and Synthetic Oil Proved Reserves (continued)

(millions of barrels)	Crude Oil and Natural Gas Liquids							Bitumen	Synthetic Oil	
	United States	Canada/ Other Americas	Europe	Africa	Asia	Australia/ Oceania	Total	Canada/ Other Americas	Canada/ Other Americas	Total
As of December 31, 2023										
Proved developed reserves										
Consolidated subsidiaries	1,735	433	4	217	1,996	45	4,430	2,307	242	6,979
Equity companies	11	—	3	5	438	—	457	—	—	457
Proved undeveloped reserves										
Consolidated subsidiaries	1,498	561	—	20	751	28	2,858	107	112	3,077
Equity companies	—	—	—	—	671	—	671	—	—	671
Total liquids proved reserves at December 31, 2023	**3,244**	**994**	**7**	**242**	**3,856**	**73**	**8,416**	**2,414**	**354**	**11,184**
As of December 31, 2024										
Proved developed reserves										
Consolidated subsidiaries	3,053	473	3	153	1,969	40	5,691	2,308	190	8,189
Equity companies	9	—	2	7	569	—	587	—	—	587
Proved undeveloped reserves										
Consolidated subsidiaries	2,308	646	—	38	1,208	22	4,222	121	106	4,449
Equity companies	—	—	—	—	466	—	466	—	—	466
Total liquids proved reserves at December 31, 2024	**5,370**	**1,119**	**5**	**198**	**4,212**	**62**	**10,966**	**2,429**	**296**	**13,691**
As of December 31, 2025										
Proved developed reserves										
Consolidated subsidiaries	2,627	587	3	185	1,915	38	5,355	2,230	288	7,873
Equity companies	8	—	2	7	596	—	613	—	—	613
Proved undeveloped reserves										
Consolidated subsidiaries	2,546	609	—	32	1,112	30	4,329	100	—	4,429
Equity companies	—	—	3	—	324	—	327	—	—	327
Total liquids proved reserves at December 31, 2025	**5,181**	**1,196**	**8**	**224**	**3,947**	**68**	**10,624** [(1)]	**2,330**	**288**	**13,242**

(1) See previous pages for natural gas liquids proved reserves attributable to consolidated subsidiaries and equity companies. For additional information on natural gas liquids proved reserves see "Item 2. Properties" in ExxonMobil's 2025 Form 10-K.

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Natural Gas and Oil-Equivalent Proved Reserves

	Natural Gas (billions of cubic feet)							Oil-Equivalent Total All Products [1]
	United States	Canada/ Other Americas	Europe	Africa	Asia	Australia/ Oceania	Total	(millions of oil-equivalent barrels)
Net proved developed and undeveloped reserves of consolidated subsidiaries								
January 1, 2023	13,645	708	413	312	3,061	6,008	24,147	14,258
Revisions	(1,945)	(201)	(3)	(49)	121	339	(1,738)	(553)
Improved recovery	—	—	—	—	—	—	—	—
Purchases	7	—	—	—	—	—	7	159
Sales	(417)	(1)	—	—	(9)	—	(427)	(92)
Extensions/discoveries	1,930	67	—	—	—	—	1,997	1,065
Production	(957)	(53)	(103)	(43)	(379)	(489)	(2,024)	(1,121)
December 31, 2023	**12,263**	**520**	**307**	**220**	**2,794**	**5,858**	**21,962**	**13,716**
Attributable to noncontrolling interests		*26*						
Proportional interest in proved reserves of equity companies								
January 1, 2023	127	—	380	663	12,309	—	13,479	3,484
Revisions	(27)	—	18	157	(32)	—	116	124
Improved recovery	—	—	—	—	—	—	—	—
Purchases	—	—	—	—	—	—	—	—
Sales	(35)	—	—	—	—	—	(35)	(115)
Extensions/discoveries	—	—	—	—	—	—	—	—
Production	(8)	—	(54)	(40)	(956)	—	(1,058)	(281)
December 31, 2023	**57**	**—**	**344**	**780**	**11,321**	**—**	**12,502**	**3,212**
Total proved reserves at December 31, 2023	**12,320**	**520**	**651**	**1,000**	**14,115**	**5,858**	**34,464**	**16,928**
Net proved developed and undeveloped reserves of consolidated subsidiaries								
January 1, 2024	12,263	520	307	220	2,794	5,858	21,962	13,716
Revisions	(911)	22	198	24	124	97	(446)	521
Improved recovery	—	—	—	—	—	—	—	—
Purchases	4,044	—	—	—	—	—	4,044	2,281
Sales	(83)	(10)	—	(105)	(5)	—	(203)	(123)
Extensions/discoveries	2,683	68	—	2	—	1	2,754	1,915
Production	(1,153)	(59)	(99)	(46)	(373)	(477)	(2,207)	(1,355)
December 31, 2024	**16,843**	**541**	**406**	**95**	**2,540**	**5,479**	**25,904**	**16,955**
Attributable to noncontrolling interests		*20*						
Proportional interest in proved reserves of equity companies								
January 1, 2024	57	—	344	780	11,321	—	12,502	3,212
Revisions	(3)	—	9	80	49	—	135	46
Improved recovery	—	—	—	—	—	—	—	—
Purchases	—	—	—	—	—	—	—	—
Sales	—	—	—	—	—	—	—	—
Extensions/discoveries	—	—	—	—	—	—	—	—
Production	(7)	—	(37)	(44)	(904)	—	(992)	(264)
December 31, 2024	**47**	**—**	**316**	**816**	**10,466**	**—**	**11,645**	**2,994**
Total proved reserves at December 31, 2024	**16,890**	**541**	**722**	**911**	**13,006**	**5,479**	**37,549**	**19,949**

[1] *Natural gas is converted to an oil-equivalent basis at six billion cubic feet per one million barrels.*

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Natural Gas and Oil-Equivalent Proved Reserves (continued)

	Natural Gas (billions of cubic feet)							Oil-Equivalent Total All Products [1]
	United States	Canada/ Other Americas	Europe	Africa	Asia	Australia/ Oceania	Total	(millions of oil-equivalent barrels)
Net proved developed and undeveloped reserves of consolidated subsidiaries								
January 1, 2025	16,843	541	406	95	2,540	5,479	25,904	16,955
Revisions	(1,482)	21	21	34	68	228	(1,110)	(929)
Improved recovery	—	—	—	—	—	—	—	—
Purchases	234	—	—	—	—	—	234	118
Sales	(248)	(28)	—	—	(14)	—	(290)	(132)
Extensions/discoveries	2,769	26	—	—	—	485	3,280	2,048
Production	(1,329)	(33)	(89)	(16)	(395)	(482)	(2,344)	(1,478)
December 31, 2025	**16,787**	**527**	**338**	**113**	**2,199**	**5,710**	**25,674**	**16,582**
Attributable to noncontrolling interests		*15*						
Proportional interest in proved reserves of equity companies								
January 1, 2025	47	—	316	816	10,466	—	11,645	2,994
Revisions	7	—	(3)	4	80	—	88	23
Improved recovery	—	—	—	—	—	—	—	—
Purchases	—	—	—	—	—	—	—	—
Sales	—	—	(24)	—	—	—	(24)	(4)
Extensions/discoveries	—	—	—	—	—	—	—	—
Production	(6)	—	(26)	(45)	(898)	—	(975)	(284)
December 31, 2025	**48**	**—**	**263**	**775**	**9,648**	**—**	**10,734**	**2,729**
Total proved reserves at December 31, 2025	**16,835**	**527**	**601**	**888**	**11,847**	**5,710**	**36,408**	**19,311**

[1] *Natural gas is converted to an oil-equivalent basis at six billion cubic feet per one million barrels.*

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Natural Gas and Oil-Equivalent Proved Reserves (continued)

	Natural Gas (billions of cubic feet)							Oil-Equivalent Total All Products [1]
	United States	Canada/ Other Americas	Europe	Africa	Asia	Australia/ Oceania	Total	(millions of oil-equivalent barrels)
As of December 31, 2023								
Proved developed reserves								
Consolidated subsidiaries	8,138	329	307	220	1,935	3,163	14,092	9,327
Equity companies	57	—	290	780	4,223	—	5,350	1,349
Proved undeveloped reserves								
Consolidated subsidiaries	4,125	191	—	—	859	2,695	7,870	4,389
Equity companies	—	—	54	—	7,098	—	7,152	1,863
Total proved reserves at December 31, 2023	**12,320**	**520**	**651**	**1,000**	**14,115**	**5,858**	**34,464**	**16,928**
As of December 31, 2024								
Proved developed reserves								
Consolidated subsidiaries	11,671	296	406	93	1,900	3,204	17,570	11,118
Equity companies	47	—	262	816	4,242	—	5,367	1,481
Proved undeveloped reserves								
Consolidated subsidiaries	5,172	245	—	2	640	2,275	8,334	5,838
Equity companies	—	—	54	—	6,224	—	6,278	1,512
Total proved reserves at December 31, 2024	**16,890**	**541**	**722**	**911**	**13,006**	**5,479**	**37,549**	**19,949**
As of December 31, 2025								
Proved developed reserves								
Consolidated subsidiaries	11,206	356	338	111	2,010	3,057	17,078	10,722
Equity companies	48	—	207	775	4,782	—	5,812	1,582
Proved undeveloped reserves								
Consolidated subsidiaries	5,581	171	—	2	189	2,653	8,596	5,860
Equity companies	—	—	56	—	4,866	—	4,922	1,147
Total proved reserves at December 31, 2025	**16,835**	**527**	**601**	**888**	**11,847**	**5,710**	**36,408**	**19,311**

[1] Natural gas is converted to an oil-equivalent basis at six billion cubic feet per one million barrels.

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Standardized Measure of Discounted Future Cash Flows

As required by the Financial Accounting Standards Board, the standardized measure of discounted future net cash flows is computed by applying first-day-of-the-month average prices, year-end costs and legislated tax rates, and a discount factor of 10 percent to net proved reserves. The standardized measure includes costs for future dismantlement, abandonment, and rehabilitation obligations. The Corporation believes the standardized measure does not provide a reliable estimate of the Corporation's expected future cash flows to be obtained from the development and production of its oil and gas properties or of the value of its proved oil and gas reserves. The standardized measure is prepared on the basis of certain prescribed assumptions, including first-day-of-the-month average prices, which represent discrete points in time and therefore may cause significant variability in cash flows from year to year as prices change.

Standardized Measure of Discounted Future Cash Flows *(millions of dollars)*	United States	Canada/Other Americas [1]	Europe	Africa	Asia	Australia/ Oceania	Total
As of December 31, 2023							
Consolidated Subsidiaries							
Future cash inflows from sales of oil and gas	213,623	227,365	3,918	19,282	221,822	63,204	749,214
Future production costs	68,753	113,875	1,611	5,025	52,672	13,971	255,907
Future development costs	37,784	38,436	1,881	4,466	11,926	6,393	100,886
Future income tax expenses	14,270	15,973	509	4,337	121,751	12,119	168,959
Future net cash flows	92,816	59,081	(83)	5,454	35,473	30,721	223,462
Effect of discounting net cash flows at 10%	49,199	23,471	(762)	402	18,537	16,215	107,062
Discounted future net cash flows	**43,617**	**35,610**	**679**	**5,052**	**16,936**	**14,506**	**116,400**
Equity Companies							
Future cash inflows from sales of oil and gas	818	—	5,101	4,393	158,643	—	168,955
Future production costs	503	—	982	233	73,496	—	75,214
Future development costs	75	—	697	100	5,452	—	6,324
Future income tax expenses	—	—	1,539	1,120	24,374	—	27,033
Future net cash flows	240	—	1,883	2,940	55,321	—	60,384
Effect of discounting net cash flows at 10%	76	—	672	1,635	20,135	—	22,518
Discounted future net cash flows	**164**	**—**	**1,211**	**1,305**	**35,186**	**—**	**37,866**
Total consolidated and equity interests in standardized measure of discounted future net cash flows	**43,781**	**35,610**	**1,890**	**6,357**	**52,122**	**14,506**	**154,266**

[1] *Includes discounted future net cash flows attributable to noncontrolling interests in ExxonMobil consolidated subsidiaries of $3,055 million in 2023.*

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Standardized Measure of Discounted Future Cash Flows (continued) *(millions of dollars)*	United States	Canada/Other Americas [1]	Europe	Africa	Asia	Australia/ Oceania	Total
As of December 31, 2024							
Consolidated Subsidiaries							
Future cash inflows from sales of oil and gas	312,279	236,954	4,339	15,493	250,850	54,247	874,162
Future production costs	109,915	96,932	1,583	3,167	60,404	12,599	284,600
Future development costs	48,781	37,253	1,921	3,675	17,608	6,083	115,321
Future income tax expenses	21,728	21,738	644	2,801	129,925	9,846	186,682
Future net cash flows	131,855	81,031	191	5,850	42,913	25,719	287,559
Effect of discounting net cash flows at 10%	64,731	34,232	(387)	1,419	23,172	12,898	136,065
Discounted future net cash flows	**67,124**	**46,799**	**578**	**4,431**	**19,741**	**12,821**	**151,494**
Equity Companies							
Future cash inflows from sales of oil and gas	614	—	3,557	5,685	138,978	—	148,834
Future production costs	379	—	766	534	66,969	—	68,648
Future development costs	69	—	709	55	4,243	—	5,076
Future income tax expenses	—	—	1,106	1,431	19,566	—	22,103
Future net cash flows	166	—	976	3,665	48,200	—	53,007
Effect of discounting net cash flows at 10%	42	—	298	2,099	16,397	—	18,837
Discounted future net cash flows	**124**	**—**	**677**	**1,566**	**31,803**	**—**	**34,170**
Total consolidated and equity interests in standardized measure of discounted future net cash flows	**67,248**	**46,799**	**1,255**	**5,997**	**51,544**	**12,821**	**185,664**
As of December 31, 2025							
Consolidated Subsidiaries							
Future cash inflows from sales of oil and gas	280,283	209,345	3,918	15,372	210,088	54,992	773,998
Future production costs	105,265	94,251	1,458	3,887	51,049	12,502	268,412
Future development costs	57,000	38,312	2,287	4,299	16,712	6,683	125,293
Future income tax expenses	20,341	15,943	345	2,831	106,859	9,376	155,695
Future net cash flows	97,677	60,839	(172)	4,355	35,468	26,431	224,598
Effect of discounting net cash flows at 10%	47,868	22,760	(523)	1,150	19,436	14,066	104,757
Discounted future net cash flows	**49,809**	**38,079**	**351**	**3,205**	**16,032**	**12,365**	**119,841**
Equity Companies							
Future cash inflows from sales of oil and gas	490	—	3,537	3,563	114,161	—	121,751
Future production costs	386	—	736	499	55,221	—	56,842
Future development costs	59	—	623	55	3,285	—	4,022
Future income tax expenses	—	—	1,031	806	15,740	—	17,577
Future net cash flows	45	—	1,147	2,203	39,915	—	43,310
Effect of discounting net cash flows at 10%	2	—	280	1,220	12,520	—	14,022
Discounted future net cash flows	**43**	**—**	**867**	**983**	**27,395**	**—**	**29,288**
Total consolidated and equity interests in standardized measure of discounted future net cash flows	**49,852**	**38,079**	**1,218**	**4,188**	**43,427**	**12,365**	**149,129**

[1] Includes discounted future net cash flows attributable to noncontrolling interests in ExxonMobil consolidated subsidiaries of $4,466 million in 2024 and $3,132 million in 2025.

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Change in Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

Consolidated and Equity Interests *(millions of dollars)*	2023 Consolidated Subsidiaries	2023 Share of Equity Method Investees	2023 Total Consolidated and Equity Interests
Discounted future net cash flows as of December 31, 2022	189,609	69,247	258,856
Value of reserves added during the year due to extensions, discoveries, improved recovery and net purchases/sales less related costs	5,658	(1,701)	3,957
Changes in value of previous-year reserves due to:			
Sales and transfers of oil and gas produced during the year, net of production (lifting) costs	(43,836)	(10,218)	(54,054)
Development costs incurred during the year	15,343	1,502	16,845
Net change in prices, lifting and development costs	(120,924)	(51,923)	(172,847)
Revisions of previous reserves estimates	4,953	5,096	10,049
Accretion of discount	23,006	8,962	31,968
Net change in income taxes	42,591	16,901	59,492
Total change in the standardized measure during the year	**(73,209)**	**(31,381)**	**(104,590)**
Discounted future net cash flows as of December 31, 2023	116,400	37,866	154,266

Consolidated and Equity Interests *(millions of dollars)*	2024 Consolidated Subsidiaries	2024 Share of Equity Method Investees	2024 Total Consolidated and Equity Interests
Discounted future net cash flows as of December 31, 2023	116,400	37,866	154,266
Value of reserves added during the year due to extensions, discoveries, improved recovery and net purchases/sales less related costs	42,405	—	42,405
Changes in value of previous-year reserves due to:			
Sales and transfers of oil and gas produced during the year, net of production (lifting) costs	(51,236)	(8,268)	(59,504)
Development costs incurred during the year	18,924	1,135	20,059
Net change in prices, lifting and development costs	(4,549)	(5,811)	(10,360)
Revisions of previous reserves estimates	20,779	1,690	22,469
Accretion of discount	15,232	4,853	20,085
Net change in income taxes	(6,461)	2,705	(3,756)
Total change in the standardized measure during the year	**35,094**	**(3,696)**	**31,398**
Discounted future net cash flows as of December 31, 2024	151,494	34,170	185,664

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Consolidated and Equity Interests *(millions of dollars)*	2025 Consolidated Subsidiaries	Share of Equity Method Investees	Total Consolidated and Equity Interests
Discounted future net cash flows as of December 31, 2024	151,494	34,170	185,664
Value of reserves added during the year due to extensions, discoveries, improved recovery and net purchases/sales less related costs	12,392	216	12,608
Changes in value of previous-year reserves due to:			
Sales and transfers of oil and gas produced during the year, net of production (lifting) costs	(48,105)	(7,828)	(55,933)
Development costs incurred during the year	18,361	811	19,172
Net change in prices, lifting and development costs	(61,606)	(5,319)	(66,925)
Revisions of previous reserves estimates	14,666	636	15,302
Accretion of discount	18,328	4,207	22,535
Net change in income taxes	14,311	2,395	16,706
Total change in the standardized measure during the year	**(31,653)**	**(4,882)**	**(36,535)**
Discounted future net cash flows as of December 31, 2025	119,841	29,288	149,129

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INDEX TO EXHIBITS

Exhibit	Description
3(i)	Restated Certificate of Incorporation, as restated November 30, 1999, and as further amended effective June 20, 2001 (incorporated by reference to Exhibit 3(i) to the Registrant's Annual Report on Form 10-K for 2015).
3(ii)	By-Laws, as amended effective October 25, 2022 (incorporated by reference to Exhibit 3(ii) to the Registrant's Report on Form 8-K of October 31, 2022).
4(vi)	Description of ExxonMobil Capital Stock (incorporated by reference to Exhibit 4(vi) to the Registrant's Annual Report on Form 10-K for 2019).
10(iii)(a.1)	2003 Incentive Program, as approved by shareholders May 28, 2003 (incorporated by reference to Exhibit 10(iii)(a.1) to the Registrant's Annual Report on Form 10-K for 2017).*
10(iii)(a.2)	Extended Provisions for Restricted Stock Agreements (incorporated by reference to Exhibit 10(iii)(a.2) to the Registrant's Annual Report on Form 10-K for 2016).*
10(iii)(a.3)	Extended Provisions for Restricted Stock Unit Agreements – Settlement in Shares.*
10(iii)(b.1)	Short Term Incentive Program, as amended (incorporated by reference to Exhibit 10(iii)(b.1) to the Registrant's Annual Report on Form 10-K for 2023).*
10(iii)(b.2)	Earnings Bonus Unit instrument (incorporated by reference to Exhibit 10(iii)(b.2) to the Registrant's Annual Report on Form 10-K for 2019).*
10(iii)(b.3)	Amendment of 2018 and 2019 Earnings Bonus Unit instruments, effective November 23, 2021 (incorporated by reference to Exhibit 99.1 to the Registrant's Report on Form 8-K of November 30, 2021).*
10(iii)(b.4)	Pioneer Natural Resources Company Second Amended and Restated 2006 Long-Term Incentive Plan (incorporated by reference to Exhibit 10(iii)(b.4) to the Registrant's Report on Form 10-Q for the quarter ended June 30, 2024).*
10(iii)(c.1)	ExxonMobil Supplemental Savings Plan (incorporated by reference to Exhibit 10(iii)(c.1) to the Registrant's Annual Report on Form 10-K for 2022).*
10(iii)(c.2)	ExxonMobil Supplemental Pension Plan (incorporated by reference to Exhibit 10(iii)(c.2) to the Registrant's Annual Report on Form 10-K for 2022).*
10(iii)(c.3)	ExxonMobil Additional Payments Plan (incorporated by reference to Exhibit 10(iii)(c.3) to the Registrant's Annual Report on Form 10-K for 2023).*
10(iii)(d)	ExxonMobil Executive Life Insurance and Death Benefit Plan (incorporated by reference to Exhibit 10(iii)(d) to the Registrant's Annual Report on Form 10-K for 2016).*
10(iii)(f.1)	2004 Non-Employee Director Restricted Stock Plan (incorporated by reference to Exhibit 10(iii)(f.1) to the Registrant's Annual Report on Form 10-K for 2018).*
10(iii)(f.2)	Standing resolution for non-employee director restricted grants dated September 26, 2007 (incorporated by reference to Exhibit 10(iii)(f.2) to the Registrant's Annual Report on Form 10-K for 2016).*
10(iii)(f.3)	Form of restricted stock grant letter for non-employee directors.*
10(iii)(f.4)	Standing resolution for non-employee director cash fees dated November 25, 2025, as amended effective January 1, 2026.*
10(iii)(g)	Aircraft Time Share Agreement dated as of August 29, 2023, between Exxon Mobil Corporation and Darren W. Woods (incorporated by reference to Exhibit 10(iii)(g) to the Registrant's Report on Form 10-Q for the quarter ended October 31, 2023).*
14	Code of Ethics and Business Conduct.
19	Insider Trading Policy (incorporated by reference to Exhibit 19 to the Registrant's Annual Report on Form 10-K for 2024).
21	Subsidiaries of the registrant.
23	Consent of PricewaterhouseCoopers LLP, Independent Registered Public Accounting Firm.
31.1	Certification (pursuant to Securities Exchange Act Rule 13a-14(a)) by Chief Executive Officer.
31.2	Certification (pursuant to Securities Exchange Act Rule 13a-14(a)) by Chief Financial Officer.
31.3	Certification (pursuant to Securities Exchange Act Rule 13a-14(a)) by Principal Accounting Officer.
32.1	Section 1350 Certification (pursuant to Sarbanes-Oxley Section 906) by Chief Executive Officer.
32.2	Section 1350 Certification (pursuant to Sarbanes-Oxley Section 906) by Chief Financial Officer.
32.3	Section 1350 Certification (pursuant to Sarbanes-Oxley Section 906) by Principal Accounting Officer.
97	Policy Relating to Recovery of Erroneously Awarded Compensation (incorporated by reference to Exhibit 97 to the Registrant's Annual Report on Form 10-K for 2023).
101	Interactive data files (formatted as Inline XBRL).
104	Cover page interactive data file (formatted as Inline XBRL and contained in Exhibit 101).

* Management contract or compensatory plan or arrangement required to be identified pursuant to Item 15(a)(3) of this Annual Report on Form 10-K.

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The registrant has not filed with this report copies of the instruments defining the rights of holders of long-term debt of the registrant and its subsidiaries for which consolidated or unconsolidated financial statements are required to be filed. The registrant agrees to furnish a copy of any such instrument to the Securities and Exchange Commission upon request.

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

EXXON MOBIL CORPORATION

By: /s/ DARREN W. WOODS
Darren W. Woods, Chairman of the Board

Dated February 18, 2026

POWER OF ATTORNEY

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Each person whose signature appears below constitutes and appoints Matthew R. Rasmussen, Wendi J. Powell, and Antony E. Peters and each of them, his or her true and lawful attorneys-in-fact and agents, with full power of substitution and resubstitution, for him or her and in his or her name, place and stead, in any and all capacities, to sign any and all amendments to this Annual Report on Form 10-K, and to file the same, with all exhibits thereto, and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents, and each of them, full power and authority to do and perform each and every act and thing requisite and necessary to be done, as fully to all intents and purposes as he or she might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents or any of them, or their or his or her substitute or substitutes, may lawfully do or cause to be done by virtue hereof.

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated and on February 18, 2026.

Principal Executive Officer

/s/ DARREN W. WOODS
Darren W. Woods, Chairman of the Board

Principal Financial Officer

/s/ NEIL A. HANSEN
Neil A. Hansen, Senior Vice President and Chief Financial Officer

Principal Accounting Officer

/s/ LEN M. FOX
Len M. Fox, Vice President, Controller and Tax

Directors

/s/ MICHAEL J. ANGELAKIS
Michael J. Angelakis

/s/ JOSEPH L. HOOLEY
Joseph L. Hooley

/s/ ANGELA F. BRALY
Angela F. Braly

/s/ STEVEN A. KANDARIAN
Steven A. Kandarian

/s/ MARIA S. DREYFUS
Maria S. Dreyfus

/s/ ALEXANDER A. KARSNER
Alexander A. Karsner

/s/ GREG C. GARLAND
Greg C. Garland

/s/ LAWRENCE W. KELLNER
Lawrence W. Kellner

/s/ JOHN D. HARRIS II
John D. Harris II

/s/ DINA POWELL MCCORMICK
Dina Powell McCormick

/s/ KAISA H. HIETALA
Kaisa H. Hietala

/s/ JEFFREY W. UBBEN
Jeffrey W. Ubben

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Appendix H2: Most Recent Quarterly Report Filed with SEC

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549



FORM 10-Q

☑ QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended March 31, 2026

or

☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from _____ to _____

Commission File Number 1-2256

Exxon Mobil Corporation

(Exact name of registrant as specified in its charter)

New Jersey	**13-5409005**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification Number)

22777 Springwoods Village Parkway, Spring, Texas 77389-1425

(Address of principal executive offices) (Zip Code)

(972) 940-6000

(Registrant's telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Trading Symbol	Name of Each Exchange on Which Registered
Common Stock, without par value	**XOM**	**New York Stock Exchange**
0.524% Notes due 2028	**XOM28**	**New York Stock Exchange**
0.835% Notes due 2032	**XOM32**	**New York Stock Exchange**
1.408% Notes due 2039	**XOM39A**	**New York Stock Exchange**

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☑ No ☐

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☑ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and “emerging growth company” in Rule 12b-2 of the Exchange Act.

Large accelerated filer	☑	Accelerated filer	☐
Non-accelerated filer	☐	Smaller reporting company	☐
		Emerging growth company	☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☑

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date.

Class	Outstanding as of March 31, 2026
Common stock, without par value	**4,144,947,162**

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EXXON MOBIL CORPORATION
FORM 10-Q
FOR THE QUARTERLY PERIOD ENDED MARCH 31, 2026
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PART I. FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

The information in the Notes to Condensed Consolidated Financial Statements is an integral part of these statements.

Due to rounding, numbers presented may not add up precisely to the totals indicated.

CONDENSED CONSOLIDATED STATEMENT OF INCOME

(millions of dollars, unless noted)	Note Reference Number	Three Months Ended March 31,	
		2026	2025
Revenues and other income			
Sales and other operating revenue	3	83,161	81,058
Income from equity affiliates		1,369	1,369
Other income		608	703
Total revenues and other income		**85,138**	**83,130**
Costs and other deductions			
Crude oil and product purchases		51,802	46,788
Production and manufacturing expenses		10,695	10,083
Selling, general and administrative expenses		2,684	2,540
Depreciation and depletion (includes impairments)		6,771	5,702
Exploration expenses, including dry holes		126	64
Non-service pension and postretirement benefit expense	4	62	113
Interest expense		295	205
Other taxes and duties		5,736	6,035
Total costs and other deductions		**78,171**	**71,530**
Income (loss) before income taxes		**6,967**	**11,600**
Income tax expense (benefit)		2,495	3,567
Net income (loss) including noncontrolling interests		**4,472**	**8,033**
Net income (loss) attributable to noncontrolling interests		289	320
Net income (loss) attributable to ExxonMobil		**4,183**	**7,713**
Earnings (loss) per common share *(dollars)*	2	**1.00**	**1.76**
Earnings (loss) per common share - assuming dilution *(dollars)*	2	**1.00**	**1.76**

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CONDENSED CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

(millions of dollars)	Three Months Ended March 31,	
	2026	2025
Net income (loss) including noncontrolling interests	**4,472**	**8,033**
Other comprehensive income (net of income taxes)		
Foreign exchange translation adjustment	(263)	302
Adjustment for foreign exchange translation (gain)/loss included in net income	(5)	—
Postretirement benefits reserves adjustment (excluding amortization)	(35)	(34)
Amortization and settlement of postretirement benefits reserves adjustment included in net periodic benefit costs	(27)	23
Total other comprehensive income (loss)	**(330)**	**291**
Comprehensive income (loss) including noncontrolling interests	**4,142**	**8,324**
Comprehensive income (loss) attributable to noncontrolling interests	194	330
Comprehensive income (loss) attributable to ExxonMobil	**3,948**	**7,994**

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CONDENSED CONSOLIDATED BALANCE SHEET

(millions of dollars, unless noted)	Note Reference Number	March 31, 2026	December 31, 2025
ASSETS			
Current assets			
Cash and cash equivalents		8,435	10,681
Notes and accounts receivable – net		61,783	44,562
Inventories			
Crude oil, products and merchandise		21,838	22,979
Materials and supplies		3,137	3,323
Other current assets		2,594	1,837
Total current assets		**97,787**	**83,382**
Investments, advances and long-term receivables		46,125	45,317
Property, plant and equipment – net		298,781	299,373
Other assets, including intangibles – net		21,717	20,908
Total Assets		**464,410**	**448,980**
LIABILITIES			
Current liabilities			
Notes and loans payable		14,531	9,296
Accounts payable and accrued liabilities		77,088	60,911
Income taxes payable		2,759	2,123
Total current liabilities		**94,378**	**72,330**
Long-term debt		33,130	34,241
Postretirement benefits reserves		8,940	8,847
Deferred income tax liabilities		40,018	40,216
Long-term obligations to equity companies		562	542
Other long-term obligations		26,386	26,178
Total Liabilities		**203,414**	**182,354**
Commitments and contingencies	7		
EQUITY			
Common stock without par value (9,000 million shares authorized, 8,019 million shares issued)		46,426	46,150
Earnings reinvested		482,344	482,494
Accumulated other comprehensive income	5	(11,098)	(10,863)
Common stock held in treasury (3,874 million shares at March 31, 2026 and 3,840 million shares at December 31, 2025)		(263,291)	(258,395)
ExxonMobil share of equity		**254,381**	**259,386**
Noncontrolling interests		6,615	7,240
Total Equity		**260,996**	**266,626**
Total Liabilities and Equity		**464,410**	**448,980**

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CONDENSED CONSOLIDATED STATEMENT OF CASH FLOWS

(millions of dollars)	Three Months Ended March 31, 2026	2025
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income (loss) including noncontrolling interests	4,472	8,033
Depreciation and depletion (includes impairments)	6,771	5,702
Changes in operational working capital, excluding cash and debt	(1,758)	(878)
All other items – net	(780)	96
Net cash provided by operating activities	**8,705**	**12,953**
CASH FLOWS FROM INVESTING ACTIVITIES		
Additions to property, plant and equipment	(6,470)	(5,898)
Proceeds from asset sales and returns of investments	219	1,823
Additional investments and advances	(387)	(153)
Other investing activities including collection of advances	632	93
Net cash used in investing activities	**(6,006)**	**(4,135)**
CASH FLOWS FROM FINANCING ACTIVITIES		
Additions to long-term debt	894	280
Reductions in long-term debt	(158)	(7)
Reductions in short-term debt [(1)]	(5,402)	(4,541)
Additions/(reductions) in commercial paper, and debt with three months or less maturity	9,075	(41)
Cash dividends to ExxonMobil shareholders	(4,334)	(4,335)
Cash dividends to noncontrolling interests	(168)	(141)
Changes in noncontrolling interests	61	(12)
Inflows from noncontrolling interests for major projects	—	22
Common stock acquired	(4,868)	(4,804)
Net cash used in financing activities	**(4,900)**	**(13,579)**
Effects of exchange rate changes on cash	(45)	86
Increase/(decrease) in cash and cash equivalents (including restricted)	**(2,246)**	**(4,675)**
Cash and cash equivalents at beginning of period (including restricted)	10,681	23,187
Cash and cash equivalents at end of period (including restricted)	**8,435**	**18,512**
SUPPLEMENTAL DISCLOSURES		
Cash interest paid		
Included in cash flows from operating activities	362	211
Capitalized, included in cash flows from investing activities	199	326
Total cash interest paid	561	537
Noncash right of use assets recorded in exchange for lease liabilities		
Operating leases	938	243
Finance leases	20	6

[(1)] Includes commercial paper with a maturity greater than three months.

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CONDENSED CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

(millions of dollars, unless noted)	Common	Earnings	Accumulated Other	Common Stock Held	ExxonMobil Share of	Non-controlling	Total

	ExxonMobil Share of Equity						
	Common Stock	Reinvested Earnings	Accumulated Other Comprehensive Income	Common Stock Held in Treasury	ExxonMobil Share of Equity	Noncontrolling Interests	Total Equity
Balance as of December 31, 2024	**46,238**	**470,903**	**(14,619)**	**(238,817)**	**263,705**	**6,901**	**270,606**
Amortization of stock-based awards	194	—	—	—	194	—	194
Other	(6)	9	—	—	3	(4)	(1)
Net income (loss) for the period	—	7,713	—	—	7,713	320	8,033
Dividends - common shares	—	(4,335)	—	—	(4,335)	(141)	(4,476)
Other comprehensive income (loss)	—	—	281	—	281	10	291
Share repurchases, at cost	—	—	—	(4,852)	(4,852)	—	(4,852)
Dispositions	—	—	—	11	11	—	11
Balance as of March 31, 2025	**46,426**	**474,290**	**(14,338)**	**(243,658)**	**262,720**	**7,086**	**269,806**
Balance as of December 31, 2025	**46,150**	**482,494**	**(10,863)**	**(258,395)**	**259,386**	**7,240**	**266,626**
Amortization of stock-based awards	304	—	—	—	304	—	304
Other	(28)	1	—	—	(27)	(637)	(664)
Net income (loss) for the period	—	4,183	—	—	4,183	289	4,472
Dividends - common shares	—	(4,334)	—	—	(4,334)	(182)	(4,516)
Other comprehensive income (loss)	—	—	(235)	—	(235)	(95)	(330)
Share repurchases, at cost	—	—	—	(4,917)	(4,917)	—	(4,917)
Dispositions	—	—	—	21	21	—	21
Balance as of March 31, 2026	**46,426**	**482,344**	**(11,098)**	**(263,291)**	**254,381**	**6,615**	**260,996**

	Three Months Ended March 31, 2026			Three Months Ended March 31, 2025		
Common Stock Share Activity *(millions of shares)*	Issued	Held in Treasury	Outstanding	Issued	Held in Treasury	Outstanding
Balance as of December 31	**8,019**	**(3,840)**	**4,179**	**8,019**	**(3,666)**	**4,353**
Share repurchases, at cost	—	(34)	(34)	—	(43)	(43)
Balance as of March 31	**8,019**	**(3,874)**	**4,145**	**8,019**	**(3,709)**	**4,310**

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Due to rounding, numbers presented may not add up precisely to the totals indicated.

Note 1. Basis of Financial Statement Preparation

These unaudited Condensed Consolidated Financial Statements should be read in the context of the Consolidated Financial Statements and notes thereto filed with the Securities and Exchange Commission in the Corporation's 2025 Annual Report on Form 10-K. In the opinion of the Corporation, the information furnished herein reflects all known accruals and adjustments necessary for a fair statement of the results for the periods reported herein. All such adjustments are of a normal recurring nature.

The Corporation's exploration and production activities are accounted for under the "successful efforts" method.

Note 2. Earnings Per Share

Earnings per common share	Three Months Ended March 31,	
	2026	2025
Net income (loss) attributable to ExxonMobil *(millions of dollars)*	4,183	7,713
Weighted-average number of common shares outstanding *(millions of shares)* [1]	4,202	4,372
Earnings (loss) per common share *(dollars)* [2]	1.00	1.76
Dividends paid per common share *(dollars)*	1.03	0.99

[1] *Includes restricted shares not vested.*

[2] *Earnings (loss) per common share and earnings (loss) per common share – assuming dilution are the same in each period shown.*

Note 3. Disclosures about Segments and Related Information

Our four reportable segments are Upstream, Energy Products, Chemical Products, and Specialty Products.

	U.S.	Non-U.S.	U.S.	Non-U.S.	U.S.	Non-U.S.	U.S.	Non-U.S.
Three Months Ended March 31, 2026								

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(millions of dollars)	Upstream U.S.	Upstream Non-U.S.	Energy Products U.S.	Energy Products Non-U.S.	Chemical Products U.S.	Chemical Products Non-U.S.	Specialty Products U.S.	Specialty Products Non-U.S.	Segment Total
Revenues and other income									
Sales and other operating revenue	7,265	2,813	25,990	37,204	1,970	3,504	1,372	3,018	**83,136**
Income from equity affiliates	(61)	906	34	438	32	102	1	(18)	**1,434**
Intersegment revenue	7,593	10,023	6,421	7,105	1,692	977	496	140	**34,447**
Other income	246	39	29	51	—	1	3	29	**398**
Segment revenues and other income	**15,043**	**13,781**	**32,474**	**44,798**	**3,694**	**4,584**	**1,872**	**3,169**	**119,415**
Costs and other items									
Crude oil and product purchases	6,083	2,843	28,194	39,967	1,950	3,561	972	2,109	**85,679**
Operating expenses, excl. depreciation and depletion [1]	3,035	2,513	2,313	2,117	1,175	1,038	502	497	**13,190**
Depreciation and depletion (includes impairments)	3,838	1,870	207	216	149	157	23	38	**6,498**
Interest expense	(5)	6	2	3	—	—	1	—	**7**
Other taxes and duties	68	329	731	4,492	15	47	4	50	**5,736**
Total costs and other deductions	**13,019**	**7,561**	**31,447**	**46,795**	**3,289**	**4,803**	**1,502**	**2,694**	**111,110**
Segment income (loss) before income taxes	**2,024**	**6,220**	**1,027**	**(1,997)**	**405**	**(219)**	**370**	**475**	**8,305**
Income tax expense (benefit)	450	1,956	301	(201)	86	(17)	97	90	**2,762**
Segment net income (loss) incl. noncontrolling interests	**1,574**	**4,264**	**726**	**(1,796)**	**319**	**(202)**	**273**	**385**	**5,543**
Net income (loss) attributable to noncontrolling interests	—	101	65	127	—	7	(1)	8	**307**
Segment income (loss)	**1,574**	**4,163**	**661**	**(1,923)**	**319**	**(209)**	**274**	**377**	**5,236**

Reconciliation of consolidated revenues

Segment revenues and other income	119,415
Other revenues [2]	170
Elimination of intersegment revenues	(34,447)
Total consolidated revenues and other income	**85,138**

Reconciliation of income (loss) attributable to ExxonMobil

Total segment income (loss)	5,236
Corporate and Financing income (loss)	(1,053)
Net income (loss) attributable to ExxonMobil	**4,183**

(millions of dollars)	Upstream U.S.	Upstream Non-U.S.	Energy Products U.S.	Energy Products Non-U.S.	Chemical Products U.S.	Chemical Products Non-U.S.	Specialty Products U.S.	Specialty Products Non-U.S.	Segment Total
Three Months Ended March 31, 2026									
Additions to property, plant and equipment [3]	3,275	1,885	851	166	152	25	34	19	**6,407**
As of March 31, 2026									
Investments in equity companies	5,669	19,909	463	1,479	2,931	2,627	—	752	**33,830**
Total assets	153,871	137,240	39,224	54,765	17,682	18,097	2,887	7,843	**431,609**

Reconciliation to Corporate Total

	Segment Total	Corporate and Financing	Corporate Total
Three Months Ended March 31, 2026			
Additions to property, plant and equipment [3]	6,407	347	**6,754**
As of March 31, 2026			
Investments in equity companies	33,830	(117)	**33,713**
Total assets	431,609	32,801	**464,410**

[1] Operating expenses, excl. depreciation and depletion includes the following GAAP line items, as reflected on the Income Statement: Production and manufacturing expenses; Selling, general and administrative expenses; Exploration expenses, including dry holes; and Non-service pension and postretirement benefit expense.

[2] Primarily Corporate and Financing Interest revenue of $206 million.

[3] Includes non-cash additions.

	U.S.	Non-U.S.	U.S.	Non-U.S.	U.S.	Non-U.S.	U.S.	Non-U.S.	
Three Months Ended March 31, 2025									
Revenues and other income									
Sales and other operating revenue	7,318	3,960	23,885	36,077	2,022	3,385	1,367	3,025	**81,039**
Income from equity affiliates	4	1,247	36	1	23	140	—	(22)	**1,429**
Intersegment revenue	6,556	9,850	4,624	6,672	1,675	739	549	114	**30,779**
Other income	(135)	374	56	24	1	(1)	—	27	

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(millions of dollars)	Upstream U.S.	Upstream Non-U.S.	Energy Products U.S.	Energy Products Non-U.S.	Chemical Products U.S.	Chemical Products Non-U.S.	Specialty Products U.S.	Specialty Products Non-U.S.	Segment Total
Segment revenues and other income	**13,743**	**15,431**	**28,601**	**42,774**	**3,721**	**4,263**	**1,916**	**3,144**	**113,593**
Costs and other items									
Crude oil and product purchases	5,429	3,261	25,106	35,046	2,154	3,015	997	2,079	**77,087**
Operating expenses, excl. depreciation and depletion [1]	2,763	2,281	2,082	2,159	1,063	1,084	472	570	**12,474**
Depreciation and depletion (includes impairments)	3,038	1,689	195	173	145	122	27	38	**5,427**
Interest expense	37	6	—	1	—	—	—	—	**44**
Other taxes and duties	64	539	787	4,562	16	22	2	44	**6,036**
Total costs and other deductions	**11,331**	**7,776**	**28,170**	**41,941**	**3,378**	**4,243**	**1,498**	**2,731**	**101,068**
Segment income (loss) before income taxes	**2,412**	**7,655**	**431**	**833**	**343**	**20**	**418**	**413**	**12,525**
Income tax expense (benefit)	542	2,598	94	187	88	(6)	96	77	**3,676**
Segment net income (loss) incl. noncontrolling interests	**1,870**	**5,057**	**337**	**646**	**255**	**26**	**322**	**336**	**8,849**
Net income (loss) attributable to noncontrolling interests	—	171	40	116	—	8	—	3	**338**
Segment income (loss)	**1,870**	**4,886**	**297**	**530**	**255**	**18**	**322**	**333**	**8,511**

Reconciliation of consolidated revenues	
Segment revenues and other income	113,593
Other revenues [2]	316
Elimination of intersegment revenues	(30,779)
Total consolidated revenues and other income	**83,130**

Reconciliation of income (loss) attributable to ExxonMobil	
Total segment income (loss)	8,511
Corporate and Financing income (loss)	(798)
Net income (loss) attributable to ExxonMobil	**7,713**

(millions of dollars)	Upstream U.S.	Upstream Non-U.S.	Energy Products U.S.	Energy Products Non-U.S.	Chemical Products U.S.	Chemical Products Non-U.S.	Specialty Products U.S.	Specialty Products Non-U.S.	Segment Total
Three Months Ended March 31, 2025									
Additions to property, plant and equipment [3]	2,780	2,022	116	228	145	117	49	53	**5,510**
As of December 31, 2025									
Investments in equity companies	5,491	19,429	460	1,048	2,946	2,616	—	775	**32,765**
Total assets	153,042	134,529	32,652	47,265	17,365	17,991	2,961	8,020	**413,825**

Reconciliation to Corporate Total	Segment Total	Corporate and Financing	Corporate Total
Three Months Ended March 31, 2025			
Additions to property, plant and equipment [3]	5,510	519	**6,029**
As of December 31, 2025			
Investments in equity companies	32,765	(112)	**32,653**
Total assets	413,825	35,155	**448,980**

[1] Operating expenses, excl. depreciation and depletion includes the following GAAP line items, as reflected on the Income Statement: Production and manufacturing expenses; Selling, general and administrative expenses; Exploration expenses, including dry holes; and Non-service pension and postretirement benefit expense.

[2] Primarily Corporate and Financing Interest revenue of $363 million.

[3] Includes non-cash additions.

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Revenue from Contracts with Customers

Sales and other operating revenue include both revenue within the scope of ASC 606 and outside the scope of ASC 606. Trade receivables in "Notes and accounts receivable – net" reported on the Balance Sheet also includes both receivables within the scope of ASC 606 and those outside the scope of ASC 606. Revenue and receivables outside the scope of ASC 606 primarily relate to physically settled commodity contracts accounted for as derivatives. Contractual terms, credit quality, and type of customer are generally similar between those revenues and receivables within the scope of ASC 606 and those outside it.

Sales and other operating revenue (millions of dollars)	Three Months Ended March 31, 2026	2025
Revenue from contracts with customers	56,866	56,931
Revenue outside the scope of ASC 606	26,295	24,127
Total	**83,161**	**81,058**

Geographic Sales and Other Operating Revenue (millions of dollars)	Three Months Ended March 31, 2026	2025
United States	36,627	34,607
Non-U.S.	46,534	46,451
Total	**83,161**	**81,058**
Significant Non-U.S. revenue sources include: [1]		
Canada	7,483	6,990

[1] *Revenue is determined by primary country of operations. Excludes certain sales and other operating revenues in non-U.S. operations where attribution to a specific country is not practicable.*

Note 4. Pension and Other Postretirement Benefits

(millions of dollars)	Three Months Ended March 31, 2026	2025
Components of net benefit cost		
Pension Benefits - U.S.		
Service cost	127	136
Interest cost	165	170
Expected return on plan assets	(164)	(149)
Amortization of actuarial loss/(gain)	5	18
Amortization of prior service cost	(8)	(7)
Net pension enhancement and curtailment/settlement cost	(1)	36
Net benefit cost	**124**	**204**
Pension Benefits - Non-U.S.		
Service cost	72	78
Interest cost	239	222
Expected return on plan assets	(231)	(221)
Amortization of actuarial loss/(gain)	(10)	9
Amortization of prior service cost	15	13
Net pension enhancement and curtailment/settlement cost	28	—
Net benefit cost	**113**	**101**
Other Postretirement Benefits		
Service cost	21	23
Interest cost	65	65
Expected return on plan assets	(4)	(4)
Amortization of actuarial loss/(gain)	(22)	(24)
Amortization of prior service cost	(15)	(15)
Net benefit cost	**45**	**45**

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Note 5. Other Comprehensive Income Information

Balance as of December 31, 2024	**(16,166)**	**1,547**	**(14,619)**
Current period change excluding amounts reclassified from accumulated other comprehensive income [1]	295	(36)	259
Amounts reclassified from accumulated other comprehensive income	—	22	22
Total change in accumulated other comprehensive income	295	(14)	281

ExxonMobil Share of Accumulated Other Comprehensive Income (millions of dollars)	Cumulative Foreign Exchange Translation Adjustment	Postretirement Benefits Reserves Adjustment	Total
Balance as of March 31, 2025	**(15,871)**	**1,533**	**(14,338)**
Current period change excluding amounts reclassified from accumulated other comprehensive income [1]	(174)	(29)	(203)
Amounts reclassified from accumulated other comprehensive income	(5)	(27)	(32)
Total change in accumulated other comprehensive income	(179)	(56)	(235)
Balance as of December 31, 2025	**(13,398)**	**2,535**	**(10,863)**

[1] *Cumulative Foreign Exchange Translation Adjustment includes net investment hedge gain/(loss) net of taxes of $55 million and $(99) million in 2026 and 2025, respectively.*

Amounts Reclassified Out of Accumulated Other Comprehensive Income - Before-tax Income/(Expense) (millions of dollars)	Three Months Ended March 31,	
	2026	2025
Foreign exchange translation gain/(loss) included in net income (Statement of Income line: Other income)	5	—
Amortization and settlement of postretirement benefits reserves adjustment included in net periodic benefit costs (Statement of Income line: Non-service pension and postretirement benefit expense)	35	(30)

Income Tax (Expense)/Credit For Components of Other Comprehensive Income (millions of dollars)	Three Months Ended March 31,	
	2026	2025
Foreign exchange translation adjustment	57	59
Postretirement benefits reserves adjustment (excluding amortization)	1	22
Amortization and settlement of postretirement benefits reserves adjustment included in net periodic benefit costs	8	(7)
Total	**66**	**74**

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Note 6. Financial Instruments and Derivatives

The estimated fair value of financial instruments and derivatives at March 31, 2026 and December 31, 2025, and the related hierarchy level for the fair value measurement was as follows:

(millions of dollars)	Fair Value							
	Level 1	Level 2	Level 3	Total Gross Assets & Liabilities	Effect of Counterparty Netting	Effect of Collateral Netting	Difference in Carrying Value and Fair Value	Net Carrying Value
Assets								
Derivative assets [1]	42,237	8,357	—	50,594	(47,389)	(281)	—	2,924
Advances to/receivables from equity companies [2][3]	—	1,369	4,134	5,503	—	—	226	5,729

Other long-term financial assets [4]	1,552	—	1,788	3,340	—	—	228	3,568

	March 31, 2026							
Liabilities								
Derivative liabilities [5]	44,879	8,430	—	53,309	(47,389)	(2,912)	—	3,008
Long-term debt [6]	23,269	4,108	—	27,377	—	—	3,382	30,759
Long-term obligations to equity companies [3]	—	—	562	562	—	—	—	562
Other long-term financial liabilities [7]	—	—	352	352	—	—	13	365

	December 31, 2025							
	Fair Value							
(millions of dollars)	Level 1	Level 2	Level 3	Total Gross Assets & Liabilities	Effect of Counterparty Netting	Effect of Collateral Netting	Difference in Carrying Value and Fair Value	Net Carrying Value
Assets								
Derivative assets [1]	5,197	2,259	—	7,456	(6,261)	(341)	—	854
Advances to/receivables from equity companies [2][3]	—	1,935	3,938	5,873	—	—	256	6,129
Other long-term financial assets [4]	1,536	—	1,800	3,336	—	—	216	3,552
Liabilities								
Derivative liabilities [5]	4,994	2,043	—	7,037	(6,261)	(141)	—	635
Long-term debt [6]	24,678	3,909	—	28,587	—	—	3,248	31,835
Long-term obligations to equity companies [3]	—	—	542	542	—	—	—	542
Other long-term financial liabilities [7]	—	—	348	348	—	—	16	364

[1] Included in the Balance Sheet lines: Notes and accounts receivable - net and Other assets, including intangibles - net.

[2] Included in the Balance Sheet line: Investments, advances and long-term receivables.

[3] Advances to/receivables from equity companies and long-term obligations to equity companies are mainly designated as hierarchy level 3 inputs. The fair value is calculated by discounting the remaining obligations by a rate consistent with the credit quality and industry of the equity company.

[4] Included in the Balance Sheet lines: Investments, advances and long-term receivables and Other assets, including intangibles - net.

[5] Included in the Balance Sheet lines: Accounts payable and accrued liabilities and Other long-term obligations.

[6] Excluding finance lease obligations.

[7] Included in the Balance Sheet line: Other long-term obligations. Includes contingent consideration related to a prior year acquisition where fair value is based on expected drilling activities and discount rates.

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At March 31, 2026 and December 31, 2025, respectively, the Corporation had $1.9 billion and $0.5 billion of collateral under master netting arrangements not offset against the derivatives on the Condensed Consolidated Balance Sheet, primarily related to initial margin requirements.

The Corporation may use non-derivative financial instruments, such as its foreign currency-denominated debt, as hedges of its net investments in certain foreign subsidiaries. Under this method, the change in the carrying value of the financial instruments due to foreign exchange fluctuations is reported in accumulated other comprehensive income. As of March 31, 2026, the Corporation has designated $3.4 billion of its Euro-denominated debt and related accrued interest as a net investment hedge of its European business. The net investment hedge is deemed to be perfectly effective.

The Corporation had undrawn short-term committed lines of credit of $7.3 billion and undrawn long-term committed lines of credit of $0.3 billion as of the end of first quarter 2026.

Derivative Instruments

The Corporation's size, strong capital structure, geographic diversity, and the complementary nature of its business segments reduce the Corporation's enterprise-wide risk from changes in commodity prices, currency rates, and interest rates. In addition, the Corporation uses commodity-based contracts, including derivatives, to manage commodity price risk and to generate returns from trading. Commodity contracts held for trading purposes are presented in the Condensed Consolidated Statement of Income on a net basis in the line "Sales and other operating revenue" and in the Consolidated Statement of Cash Flows in "Cash Flows from Operating Activities" and included before-tax realized and unrealized losses of $3.8 billion and gains of $19 million for the periods ended March 31, 2026 and 2025, respectively. The Corporation's commodity derivatives are not accounted for under hedge accounting. At times, the Corporation also enters into currency and interest rate derivatives, none of which are material to the Corporation's financial position as of March 31, 2026 and December 31, 2025, or results of operations for the periods ended March 31, 2026 and 2025.

The Corporation operates a program to hedge certain of its fixed-rate debt instruments against changes in fair value due to changes in the designated benchmark interest rate. This program utilizes fair value hedge accounting. The derivative (hedging) instruments are fixed-for-floating interest rate swaps, with settlement dates that correspond to the interest payments associated with the fixed-rate debt (hedged item). Changes in the fair values of the hedging instruments are perfectly offset by changes in the fair values of the hedged items; the effects of these changes in fair values are recorded in "Interest expense" in the Consolidated Statement of Income. This program was not material to the Consolidated Financial Statements as of the end of first quarter 2026.

Credit risk associated with the Corporation's derivative position is mitigated by several factors, including the use of derivative clearing exchanges and the quality of and financial limits placed on derivative counterparties. The Corporation maintains a system of controls that includes the authorization, reporting, and monitoring of derivative activity.

The net notional long/(short) position of derivative instruments at March 31, 2026 and December 31, 2025, was as follows:

(millions)	March 31, 2026	December 31, 2025
Crude oil (barrels)	25	6
Petroleum products (barrels)	(47)	(27)
Natural gas (MMBTUs)	(658)	(449)

Note 7. Litigation and Other Contingencies

Litigation

A variety of claims have been made against ExxonMobil and certain of its consolidated subsidiaries in a number of pending lawsuits. Management has regular litigation reviews, including updates from corporate and outside counsel, to assess the need for accounting recognition or disclosure of these contingencies. The Corporation accrues an undiscounted liability for those contingencies where the incurrence of a loss is probable and the amount can be reasonably estimated. If a range of amounts can be reasonably estimated and no amount within the range is a better estimate than any other amount, then the minimum of the range is accrued. The Corporation does not record liabilities when the likelihood that the liability has been incurred is probable but the amount cannot be reasonably estimated or when the liability is believed to be only reasonably possible or remote. For contingencies where an unfavorable outcome is reasonably possible and which are significant, the Corporation discloses the nature of the contingency and, where feasible, an estimate of the possible loss. For purposes of our contingency disclosures, "significant" includes material matters, as well as other matters, which management believes should be disclosed.

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State and local governments and other entities in various jurisdictions across the United States and its territories have filed a number of legal proceedings against several oil and gas companies, including ExxonMobil, requesting unprecedented legal and equitable relief for various alleged injuries purportedly connected to climate change. These lawsuits assert a variety of novel, untested claims under statutory and common law. Additional such lawsuits may be filed. We believe the legal and factual theories set forth in these proceedings are meritless and represent an inappropriate attempt to use the court system to usurp the proper role of policymakers in addressing the societal challenges of climate change.

Local governments in Louisiana have filed unprecedented legal proceedings against a number of oil and gas companies, including ExxonMobil, requesting compensation for the restoration of coastal marsh erosion in the state. We believe the factual and legal theories set forth in these proceedings are meritless.

While the outcome of any litigation can be unpredictable, we believe the likelihood is remote that the ultimate outcomes of these lawsuits will have a material adverse effect on the Corporation's operations, financial condition, or financial statements taken as a whole. We will continue to defend vigorously against these claims.

Other Contingencies

The Corporation and certain of its consolidated subsidiaries were contingently liable at March 31, 2026, for guarantees relating

to notes, loans and performance under contracts. Where guarantees for environmental remediation and other similar matters do not include a stated cap, the amounts reflect management's estimate of the maximum potential exposure. Where it is not possible to make a reasonable estimation of the maximum potential amount of future payments, future performance is expected to be either immaterial or have only a remote chance of occurrence.

	March 31, 2026		
(millions of dollars)	Equity Company Obligations [1]	Other Third-Party Obligations	Total
Guarantees			
Non-debt-related	665	5,832	6,497
Total	**665**	**5,832**	**6,497**

[1] *ExxonMobil share.*

Additionally, the Corporation and its affiliates have numerous long-term sales and purchase commitments in their various business activities, all of which are expected to be fulfilled with no adverse consequences material to the Corporation's operations or financial condition.

Note 8. Divestment Activities

Through March 31, 2026, the Corporation realized proceeds of approximately $0.2 billion from its divestment activities with negligible impact on after-tax earnings. This included the sale of certain conventional assets in the United States, as well as other smaller divestments.

In 2025, the Corporation realized proceeds of approximately $3.2 billion and recognized net after-tax earnings of approximately $1.1 billion from its divestment activities. This included the sale of the Singapore retail fuels business, Mobil Argentina S.A., Product Solutions affiliates in France, certain conventional and unconventional assets in the United States, and other smaller divestments.

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ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Due to rounding, numbers presented may not add up precisely to the totals indicated.

FORWARD-LOOKING STATEMENTS

Statements related to future events; projections; descriptions of strategic, operating, and financial plans and objectives; statements of future ambitions and plans; future earnings power; potential addressable markets; and other statements of future events or conditions are forward-looking statements. Similarly, discussion of future plans related to carbon capture, transportation and storage, lower-emission fuels, hydrogen and ammonia, direct air capture, Proxxima™ systems, carbon materials, lithium, low-carbon data centers, and other future plans to reduce emissions and emission intensity of ExxonMobil, its affiliates, and third parties are dependent on future market factors, such as continued technological progress, stable policy support and timely rule-making and permitting, and represent forward-looking statements.

Actual future results, including financial and operating performance; potential earnings, cash flow, dividends or shareholder returns, including the timing and amounts of share repurchases; total capital expenditures and mix, including allocations of capital to low carbon and other new investments; realization and maintenance of structural cost reductions and efficiency gains, including the ability to offset inflationary pressure; plans to reduce future emissions and emissions intensity, including

ambitions to reach Scope 1 and Scope 2 net zero from operated assets by 2050, to reach Scope 1 and 2 net zero in integrated Upstream Permian Basin unconventional operated assets by 2035, to eliminate routine flaring in-line with World Bank Zero Routine Flaring, to reach near-zero methane emissions from operated assets and other methane initiatives; and to meet ExxonMobil's emission reduction plans and goals, divestment and start-up plans, and associated project plans as well as technology advances, including the timing and outcome of projects to capture, transport and store CO_2, produce hydrogen and ammonia, produce lower-emission fuels, produce Proxxima™ systems, produce carbon materials, produce lithium, and use plastic waste as feedstock for advanced recycling; future debt levels and credit ratings; business and project plans, timing, costs, capacities and profitability; resource recoveries and production rates; and planned Denbury and Pioneer integrated benefits, could differ materially due to a number of factors.

These include global or regional changes or imbalances in the supply and demand for oil, natural gas, petrochemicals, and feedstocks and other market factors; economic conditions and seasonal fluctuations that impact prices, differentials, margins, and volume/mix for our products; developments or changes in local, national, or international laws, regulations, taxes, trade sanctions, trade tariffs, or policies affecting our business, such as government policies supporting lower carbon and new market investment opportunities, the punitive European taxes on the oil and gas sector and unequal support for different technological methods of emissions reduction or evolving, ambiguous and unharmonized voluntary or mandatory standards or extraterritorial laws and regulations imposed by various jurisdictions related to sustainability and greenhouse gas reporting; timely granting of governmental permits, licenses, and certifications; uncertain impacts of deregulation on the legal and regulatory environment; price impacts and the broader government responses to inflationary pressures; changes in interest and exchange rates; variable impacts of trading activities and derivative positions, including timing effects, on our margins and results each quarter; actions of co-venturers or partners, competitors and commercial counterparties, including suppliers and customers; government actions in pursuit of national energy and security policies and priorities affecting our business; the outcome of commercial negotiations, including final agreed terms and conditions; the outcome of competitive bidding and project awards; the ability to access debt markets on favorable terms or at all; the occurrence, pace, rate of recovery and effects of public health crises; adoption of regulatory incentives consistent with law; reservoir performance and optimization, including variability and timing factors applicable to unconventional resources, the success of new unconventional technologies, and the ability of new technologies to improve recovery relative to competitors; the level, outcome, and timing of exploration and development projects and decisions to invest in future reserves and resources; timely completion of construction projects and commencement of start-up operations, including reliance on third-party suppliers and service providers; final management approval of future projects and any changes in the scope, terms, costs or assumptions of such projects as approved; the actions of governments, non-governmental organizations, or other actors against our core business activities and acquisitions, divestitures or financing opportunities; war, civil unrest, armed hostilities, attacks against the company or industry, and other geopolitical or security disturbances, including disruption of land or sea transportation routes or distribution or shipping channels; decoupling of economies; disruption, realignment, or breaking of current or historical trade or military alliances or global trade and supply chain networks; escalating geopolitical volatility, including regime changes; expropriations, seizure, or capacity, insurance, shipping, import or export limitations imposed directly or indirectly by governments or laws; opportunities for potential acquisitions, investments or divestments and satisfaction of applicable conditions to closing, including timely regulatory approvals; the capture of efficiencies within and between business lines and the ability to maintain near-term cost reductions as ongoing efficiencies without impairing our competitive positioning; unforeseen technical or operating disruptions or difficulties and unplanned maintenance; the development and competitiveness of alternative energy and emission reduction technologies; consumer preferences including willingness and ability to pay for reduced emission products; the results of research programs and the

ability to bring new technologies to commercial scale on a cost-competitive basis; and other factors discussed under "Item 1A. Risk Factors" of ExxonMobil's 2025 Form 10-K.

Forward-looking and other statements regarding environmental and other sustainability efforts and aspirations are not an indication that these statements are material to investors or require disclosure in our filing with the SEC or any other regulatory authority. In addition, historical, current, and forward-looking environmental and other sustainability-related statements may be based on standards for measuring progress that are still developing, internal controls and processes that continue to evolve, and assumptions that are subject to change in the future, including future rule-making.

Actions needed to advance ExxonMobil's 2030 greenhouse gas emission-reductions plans are incorporated into its medium term business plans, which are updated annually. The reference case for planning beyond 2030 is based on ExxonMobil's Global Outlook (Outlook) research and publication. The Outlook is reflective of the existing global policy environment and an assumption of increasing policy stringency and technology improvement to 2050. Current trends for policy stringency and development of lower-emission solutions are not yet on a pathway to achieve net-zero by 2050. As such, the Outlook does not project the degree of required future policy and technology advancement and deployment for the world, or ExxonMobil, to meet net zero by 2050. As future policies and technology advancements emerge, they will be incorporated into the Outlook, and ExxonMobil's business plans will be updated accordingly. References to projects or opportunities may not reflect investment decisions made by ExxonMobil or its affiliates. Individual projects or opportunities may advance based on a number of factors, including availability of stable and supportive policy, permitting, technological advancement for cost-effective abatement, insights from the Corporate planning process, and alignment with our partners and other stakeholders. Capital investment

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guidance in lower-emission investments is based on our Corporate plan; however, actual investment levels will be subject to the availability of the opportunity set and public policy support, and focused on returns.

The term “project” as used in this report can refer to a variety of different activities and does not necessarily have the same meaning as in any government payment transparency reports.

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Overview

Supply disruptions driven by geopolitical events in the Middle East impacted market conditions during the first quarter of 2026. March experienced the largest ever monthly gain in oil prices driven by reduced global oil supply. Despite a sharp increase in March, first quarter 2026 average crude oil prices increased slightly relative to fourth quarter 2025, remaining in the middle of the 10-year historical range (2010-2019). Significant LNG supply decline in March resulted in higher prices in Europe and Asia, driving natural gas prices above the 10-year average. Feedstock shortages resulted in lower refinery runs in the Middle East and Asia with global industry refining margins remaining above the 10-year historical range. Chemical margins remained at bottom of cycle, well below the 10-year range, because of higher feedstock costs, particularly in Asia.

During 2025, the U.S. and other countries implemented and adjusted a variety of trade-related measures, including tariffs on certain imports. Based on the Corporation’s assessment of these actions and their effects to date, we do not expect them to have a material impact on the Corporation's consolidated financial position, results of operations, or cash flows.

Selected Earnings Driver Definitions

The earnings drivers provide additional visibility into our business results. The Corporation evaluates these drivers periodically to determine if any enhancements may provide helpful insights to the market. Listed below are descriptions of the earnings drivers:

Advantaged Volume Growth. Represents earnings impacts from change in volume/mix from advantaged assets, advantaged projects, and high-value products.

- *Advantaged Assets (Advantaged growth projects).* Includes Permian, Guyana, and LNG.
- *Advantaged Projects.* Includes capital projects and programs of work that contribute to Energy, Chemical, and/or Specialty Products segments that drive integration of segments/businesses, increase yield of higher value products, or deliver higher than average returns.
- *High-Value Products.* Includes performance products and lower-emission fuels. Performance products (performance chemicals, performance lubricants) refers to products that provide differentiated performance for multiple applications through enhanced properties versus commodity alternatives and bring significant additional value to customers and end-users. Lower-emission fuels refers to fuels with lower life cycle emissions than conventional transportation fuels for gasoline, diesel and jet transport.

Base Volume. Represents all volume/mix drivers not included in Advantaged Volume Growth defined above.

Structural Cost Savings. Represents after-tax earnings effects of Structural Cost Savings as defined on page 19, including cash operating expenses related to divestments.

Expenses. Represents all expenses otherwise not included in other earnings drivers.

Estimated Timing Effects. Represents timing effects that are primarily related to unsettled derivatives which are required to be marked to current period-end prices (mark-to-market), where the associated physical shipments are not reflected in earnings until the physical transaction is complete. It also includes estimated recognition differences between the settlement of derivatives and their offsetting physical commodity realizations (due to LIFO inventory accounting). Impacts are expected to unwind in subsequent periods.

Identified Items. Represents individually significant non-operational events with, typically, an absolute corporate total earnings impact of at least $250 million in a given quarter. The impact of an Identified Item for an individual segment may be less than $250 million when the item impacts several segments or several periods.

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Cash Capital Expenditures (Non-GAAP)

Cash capital expenditures (Cash Capex) is the sum of "Additions to property, plant and equipment", "Additional investments and advances", and "Other investing activities including collection of advances", reduced by "Inflows from noncontrolling interests for major projects", each from the Consolidated Statement of Cash Flows, and excludes advances and collections not related to capital expenditures or equity investments, for example, supply and marketing related advances and associated collections. This measure is useful for investors to understand the current period cash impact of investments in the business.

	2026	2025
Additions to property, plant and equipment	6,470	5,898
Additional investments and advances	387	153
Other investing activities including collection of advances	(632)	(93)
Inflows from noncontrolling interests for major projects	—	(22)
Less: Advances and collections not related to capital expenditures or equity investments	(38)	—
Total Cash Capex (Non-GAAP)	**6,187**	**5,936**
Upstream	4,812	4,993
Energy Products	998	378
Chemical Products	182	291
Specialty Products	55	110
Other	140	164

Total Cash Capex (Non-GAAP) *(millions of dollars)*	Three Months Ended March 31,	
	6,187	**5,936**

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Structural Cost Savings (Non-GAAP)

Structural Cost Savings describes decreases in cash opex excluding energy and production taxes as a result of operational efficiencies, workforce reductions, divestment-related reductions, and other cost-savings measures that are expected to be sustainable compared to 2019 levels. Relative to 2019, estimated cumulative Structural Cost Savings totaled $15.6 billion, which included an additional $0.6 billion in the first three months of 2026. The total change between periods in expenses below will reflect both Structural Cost Savings and other changes in spend, including market factors, such as inflation and foreign exchange impacts, as well as changes in activity levels and costs associated with new operations, mergers and acquisitions, new business venture development, and early-stage projects. Structural Cost Savings from new operations, mergers and acquisitions, and new business venture developments are included in the cumulative Structural Cost Savings. Estimates of cumulative annual structural savings may be revised depending on whether cost reductions realized in prior periods are determined to be sustainable compared to 2019 levels. Structural Cost Savings are stewarded internally to support management's oversight of spending over time. This measure is useful for investors to understand the Corporation's efforts to optimize spending through disciplined expense management.

	2019	2025	2025	2026
Components of Operating Costs				
From ExxonMobil's Consolidated Statement of Income (U.S. GAAP)				
Production and manufacturing expenses	36.8	42.4	10.1	10.7
Selling, general and administrative expenses	11.4	11.1	2.5	2.7
Depreciation and depletion (includes impairments)	19.0	26.0	5.7	6.8

Dollars in billions (unless otherwise noted)	Twelve Months Ended December 31,		Three Months Ended March 31,	
Exploration expenses, including dry holes	1.3	1.0	0.1	0.1
Non-service pension and postretirement benefit expense	1.2	0.4	0.1	0.1
Subtotal	**69.7**	**81.0**	**18.5**	**20.3**
ExxonMobil's share of equity company expenses (Non-GAAP)	9.1	10.6	2.6	2.3
Total Adjusted Operating Costs (Non-GAAP)	**78.8**	**91.6**	**21.1**	**22.6**
Total Adjusted Operating Costs (Non-GAAP)	**78.8**	**91.6**	**21.1**	**22.6**
Less:				
Depreciation and depletion (includes impairments)	19.0	26.0	5.7	6.8
Non-service pension and postretirement benefit expense	1.2	0.4	0.1	0.1
Other adjustments (includes equity company depreciation and depletion)	3.6	6.2	1.3	1.3
Total Cash Operating Expenses (Cash Opex) (Non-GAAP)	**55.0**	**59.0**	**14.1**	**14.5**
Energy and production taxes (Non-GAAP)	11.0	14.9	3.9	3.7
Total Cash Operating Expenses (Cash Opex) excluding Energy and Production Taxes (Non-GAAP)	**44.0**	**44.1**	**10.2**	**10.8**

	Change vs 2019	Change vs 2025	Estimated Cumulative vs 2019
Total Cash Operating Expenses (Cash Opex) excluding Energy and Production Taxes (Non-GAAP)	0.1	0.6	
Market	+4.9	+0.5	
Activity / Other	+10.3	+0.6	
Structural Cost Savings	**-15.1**	**-0.6**	**-15.6**

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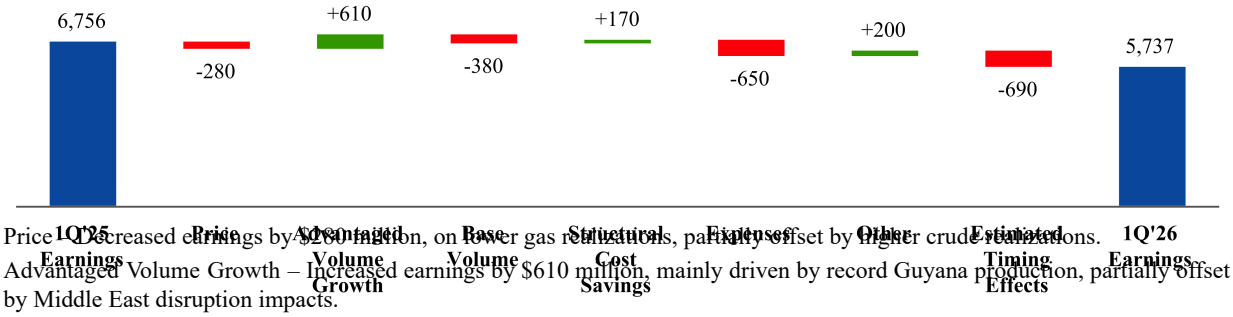
REVIEW OF FIRST QUARTER 2026 RESULTS

ExxonMobil's first quarter 2026 earnings were $4.2 billion, compared to $7.7 billion a year earlier. The decrease in earnings was mainly driven by unfavorable mark-to-market effects, higher expenses related to depreciation and Middle East volume impacts; partly offset by higher prices and margins, increased volumes from advantaged Upstream investments in Guyana and the Permian and structural cost savings. Cash capital expenditures were $6.2 billion, up $0.3 billion from first quarter 2025.

UPSTREAM

Upstream Financial Results	Three Months Ended March 31,	
(millions of dollars)	2026	2025
Earnings (loss) (U.S. GAAP)		
United States	1,574	1,870
Non-U.S.	4,163	4,886
Total	**5,737**	**6,756**

Upstream First Quarter Earnings Driver Analysis *(millions of dollars)*



Price – Decreased earnings by $280 million, on lower gas realizations, partially offset by higher crude realizations.

Advantaged Volume Growth – Increased earnings by $610 million, mainly driven by record Guyana production, partially offset by Middle East disruption impacts.

Base Volume – Decreased earnings by $380 million, from divestments and Kazakhstan downtime.

Structural Cost Savings – Increased earnings by $170 million.

Expenses – Decreased earnings by $650 million due to higher depreciation.

Other – Increased earnings by $200 million, primarily driven by one-time tax items.

Estimated Timing Effects – Decreased earnings by $690 million, mainly from unfavorable derivatives mark-to-market impacts to be reversed over time.

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Upstream Operational Results	Three Months Ended March 31,	
	2026	2025
Net production of crude oil, natural gas liquids, bitumen and synthetic oil *(thousands of barrels daily)*		
United States	1,586	1,418
Canada/Other Americas	936	760
Europe	3	4
Africa	138	137
Asia	611	796
Australia/Oceania	23	24
Worldwide	**3,297**	**3,139**
Net natural gas production available for sale *(millions of cubic feet daily)*		
United States	3,589	3,266
Canada/Other Americas	28	42
Europe	313	331
Africa	114	118
Asia	2,500	3,457
Australia/Oceania	1,236	1,256
Worldwide	**7,779**	**8,470**
Oil-equivalent production [(1)] *(thousands of oil-equivalent barrels daily)*	4,594	4,551

[(1)] Natural gas is converted to an oil-equivalent basis at six million cubic feet per one thousand barrels.

Upstream Additional Information *(thousands of barrels daily)*	Three Months Ended March 31,
Volumes reconciliation (Oil-equivalent production) [(1)]	
2025	**4,551**
Entitlements - Net Interest	(27)
Entitlements - Price / Spend / Other	(7)
Government Mandates	(4)
Divestments	(71)
Growth / Other	152
2026	**4,594**

[(1)] *Natural gas is converted to an oil-equivalent basis at six million cubic feet per one thousand barrels.*

1Q 2026 versus 1Q 2025	1Q 2026 production of 4.6 million oil-equivalent barrels per day increased 43 thousand oil-equivalent barrels per day from 1Q 2025, driven by Permian and Guyana growth, partially offset by Middle East disruptions and Kazakhstan downtime.

Listed below are descriptions of ExxonMobil's volumes reconciliation drivers which are provided to facilitate understanding of the terms.

Entitlements - Net Interest are changes to ExxonMobil's share of production volumes caused by non-operational changes to volume-determining drivers. These drivers consist of net interest changes specified in Production Sharing Contracts (PSCs), which typically occur when cumulative investment returns or production volumes achieve defined thresholds, changes in equity upon achieving pay-out in partner investment carry situations, equity redeterminations as specified in venture agreements, or as a result of the termination or expiry of a concession. Once a net interest change has occurred, it typically will not be reversed by subsequent events, such as lower crude oil prices.

Entitlements - Price / Spend / Other are changes to ExxonMobil's share of production volumes resulting from temporary changes to non-operational volume-determining drivers. These drivers include changes in oil and gas prices or spending levels from one period to another. According to the terms of contractual arrangements or government royalty regimes, price or spending variability can increase or decrease royalty burdens and/or volumes attributable to ExxonMobil. For example, at

higher prices, fewer barrels are required for ExxonMobil to recover its costs. These effects generally vary from period to period with field spending patterns or market prices for oil and natural gas. Such drivers can also include other temporary changes in net interest as dictated by specific provisions in production agreements.

Government Mandates are changes to ExxonMobil's sustainable production levels as a result of production limits or sanctions imposed by governments.

Divestments are reductions in ExxonMobil's production arising from commercial arrangements to fully or partially reduce equity in a field or asset in exchange for financial or other economic consideration.

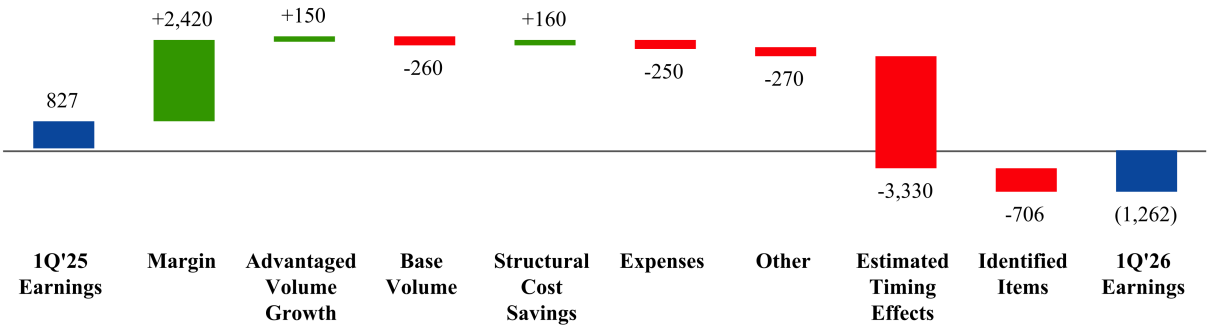
Growth and Other comprise all other operational and non-operational drivers not covered by the above definitions that may affect volumes attributable to ExxonMobil. Such drivers include, but are not limited to, production enhancements from project and work program activities, acquisitions including additions from asset exchanges, downtime, market demand, natural field decline, and any fiscal or commercial terms that do not affect entitlements.

ENERGY PRODUCTS

Energy Products Financial Results *(millions of dollars)*	Three Months Ended March 31, 2026	2025
Earnings (loss) (U.S. GAAP)		
United States	661	297
Non-U.S.	(1,923)	530
Total	**(1,262)**	**827**

Energy Products First Quarter Earnings Driver Analysis *(millions of dollars)*

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Margin – Increased earnings by $2,420 million, including strong results from trading and optimization.

Advantaged Volume Growth – Increased earnings by $150 million.

Base Volume – Decreased earnings by $260 million, mainly driven by Middle East supply disruptions.

Structural Cost Savings – Increased earnings by $160 million.

Expenses – Decreased earnings by $250 million, driven by scheduled maintenance and growth projects.

Other – Decreased earnings by $270 million, driven by unfavorable foreign exchange rate effects.

Estimated Timing Effects – Decreased earnings by $3,330 million, on unfavorable derivative mark-to-market impacts.

Identified Items – 1Q26 $(706) million loss due to supply disruptions in the Middle East preventing physical shipments associated with hedges.

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Energy Products Operational Results	Three Months Ended March 31,	
(thousands of barrels daily)	2026	2025
Refinery throughput		
United States	1,795	1,789
Canada	384	397
Europe	733	986
Asia Pacific	386	447
Other	195	191
Worldwide	**3,494**	**3,810**
Energy Products sales [(1)]		
United States	3,214	2,728
Non-U.S.	2,416	2,555
Worldwide	**5,630**	**5,283**
Gasoline, naphthas	2,214	2,162
Heating oils, kerosene, diesel	1,672	1,724
Aviation fuels	399	366
Heavy fuels	187	158
Other energy products	1,158	873
Worldwide	**5,630**	**5,283**

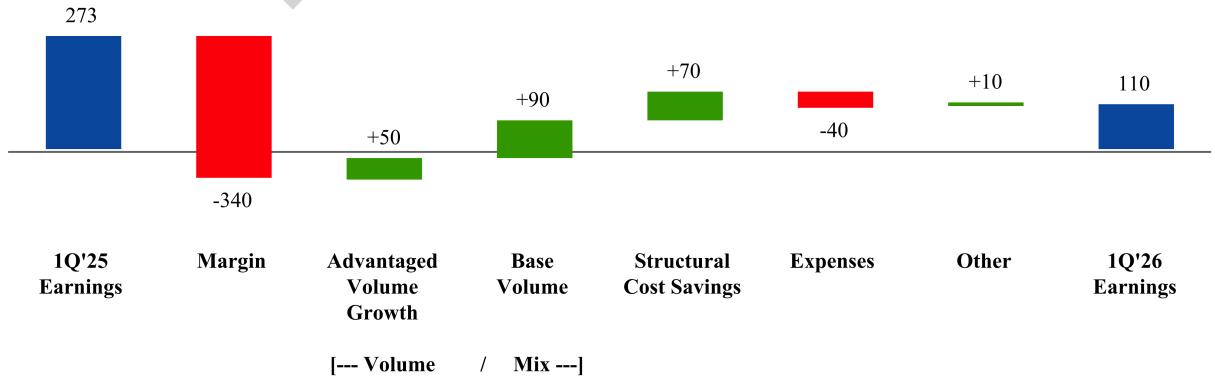
[(1)] *Data reported net of purchases/sales contracts with the same counterparty.*

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CHEMICAL PRODUCTS

Chemical Products Financial Results	Three Months Ended March 31,	
(millions of dollars)	2026	2025
Earnings (loss) (U.S. GAAP)		
United States	319	255
Non-U.S.	(209)	18
Total	**110**	**273**

Chemical Products First Quarter Earnings Driver Analysis *(millions of dollars)*



Margin – Compressed margins decreased earnings by $340 million on lower realizations and increased feed costs.

Advantaged Volume Growth – Increased earnings by $50 million.

Base Volume – Increased earnings by $90 million.

Structural Cost Savings – Increased earnings by $70 million.

Expenses – Decreased earnings by $40 million.

Other – Increased earnings by $10 million.

Chemical Products Operational Results	Three Months Ended March 31,	
(thousands of metric tons)	2026	2025
Chemical Products sales [1]		
United States	1,904	1,706
Non-U.S.	3,455	3,070
Worldwide	**5,358**	**4,776**

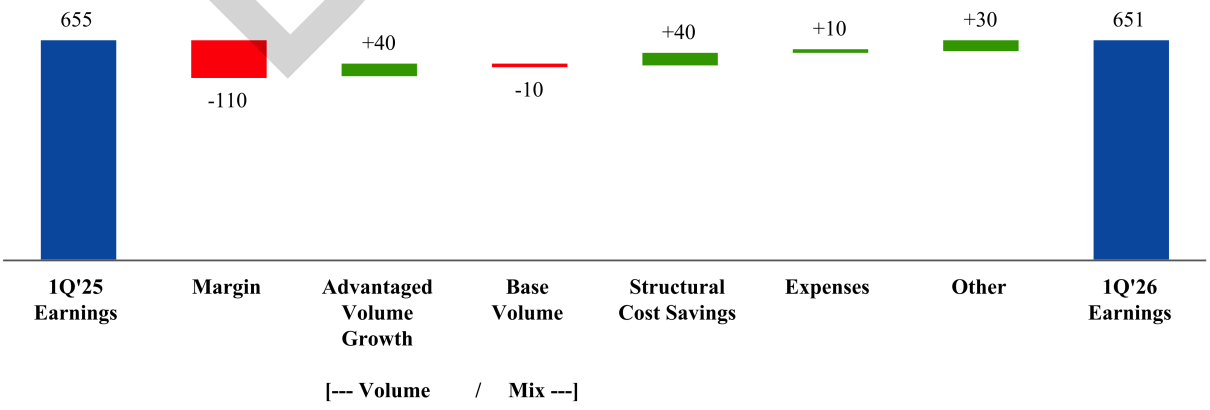
[1] *Data reported net of purchases/sales contracts with the same counterparty.*

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SPECIALTY PRODUCTS

Specialty Products Financial Results	Three Months Ended March 31,	
(millions of dollars)	2026	2025
Earnings (loss) (U.S. GAAP)		
United States	274	322
Non-U.S.	377	333
Total	**651**	**655**

Specialty Products First Quarter Earnings Driver Analysis *(millions of dollars)*



Margin – Compressed margins decreased earnings by $110 million on increased feed costs.

Advantaged Volume – Increased earnings by $40 million.

Base Volume – Decreased earnings by $10 million.

Structural Cost Savings – Increased earnings by $40 million.

Expenses – Increased earnings by $10 million.

Other – Increased earnings by $30 million.

Specialty Products Operational Results	Three Months Ended March 31,	
(thousands of metric tons)	2026	2025
Specialty Products sales [(1)]		
United States	536	473
Non-U.S.	1,439	1,463
Worldwide	**1,976**	**1,936**

[(1)] *Data reported net of purchases/sales contracts with the same counterparty.*

CORPORATE AND FINANCING

Corporate and Financing Financial Results	Three Months Ended March 31,	
(millions of dollars)	2026	2025
Earnings (loss) (U.S. GAAP)	(1,053)	(798)

Corporate and Financing expenses were $1,053 million for the first quarter of 2026, $255 million higher than the first quarter of 2025, due to lower interest income and the absence of favorable tax items.

LIQUIDITY AND CAPITAL RESOURCES

(millions of dollars)	Three Months Ended March 31,	
	2026	2025
Net cash provided by/(used in)		
Operating activities	8,705	12,953
Investing activities	(6,006)	(4,135)
Financing activities	(4,900)	(13,579)
Effect of exchange rate changes	(45)	86
Increase/(decrease) in cash and cash equivalents	**(2,246)**	**(4,675)**
Cash and cash equivalents (at end of period)	8,435	18,512
Cash flow from operations and asset sales		
Net cash provided by operating activities (U.S. GAAP)	8,705	12,953
Proceeds associated with sales of subsidiaries, property, plant & equipment, and sales and returns of investments	219	1,823
Cash flow from operations and asset sales (Non-GAAP)	**8,924**	**14,776**

Because of the ongoing nature of our asset management and divestment program, we believe it is useful for investors to consider proceeds associated with asset sales together with cash provided by operating activities when evaluating cash available for investment in the business and financing activities, including shareholder distributions.

Cash flow from operations and asset sales in the first quarter of 2026 was $8.9 billion, a decrease of $5.9 billion from the comparable 2025 period.

Cash provided by operating activities totaled $8.7 billion for the first three months of 2026, $4.2 billion lower than 2025. Net income including noncontrolling interests was $4.5 billion, a decrease of $3.6 billion from the prior year period. The adjustment for the noncash provision of $6.8 billion for depreciation and depletion was up $1.1 billion from 2025. Changes in operational working capital were a reduction of $1.8 billion during the period. All other items net decreased cash flows by $0.8 billion in 2026 versus an increase of $0.1 billion in 2025. See the Condensed Consolidated Statement of Cash Flows for additional details.

Investing activities for the first three months of 2026 used net cash of $6.0 billion, an increase of $1.9 billion compared to the prior year. Spending for additions to property, plant and equipment of $6.5 billion was $0.6 billion higher than 2025. Proceeds from asset sales were $0.2 billion, a decrease of $1.6 billion compared to the prior year. Net investments and advances decreased $0.3 billion from $0.1 billion in 2025.

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Net cash used in financing activities was $4.9 billion in the first three months of 2026, including $4.9 billion for the purchase of 33.6 million shares of ExxonMobil stock, as part of the previously announced buyback program. This compares to net cash used in financing activities of $13.6 billion in the prior year. Total debt at the end of the first quarter of 2026 was $47.7 billion compared to $43.5 billion at year-end 2025. The Corporation's debt to total capital ratio was 15.4 percent at the end of the first quarter of 2026 compared to 14.0 percent at year-end 2025. The net debt to capital ratio [(1)] was 13.1 percent at the end of the first quarter, an increase of 2.1 percentage points from year-end 2025. The Corporation's capital allocation priorities are investing in competitively advantaged, high-return projects, maintaining a strong balance sheet, and sharing our success with our shareholders through more consistent share repurchases and a growing dividend. The Corporation distributed a total of $4.3 billion to shareholders in the first three months of 2026 through dividends.

The Corporation has access to significant capacity of long-term and short-term liquidity. Internally generated funds are expected to cover the majority of financial requirements, supplemented by long-term and short-term debt. Commercial paper is used to balance short-term liquidity requirements and is reflected in "Notes and loans payable" on the Consolidated Balance Sheet, with changes in outstanding commercial paper between periods included in the Consolidated Statement of Cash Flows. The Corporation had undrawn short-term committed lines of credit of $7.3 billion and undrawn long-term committed lines of credit of $0.3 billion as of the end of first quarter 2026.

The Corporation’s financial strength enables it to make large, long-term capital expenditures. Cash capex in the first quarter of 2026 was $6.2 billion, up $0.3 billion from the first quarter of 2025. The Corporation plans to invest in the range of $27 billion to $29 billion in 2026. Actual spending could vary depending on the progress of individual projects.

[(1)] Net debt is total debt of $47.7 billion less $8.4 billion of cash and cash equivalents excluding restricted cash . Net debt to capital ratio is net debt divided by net debt plus total equity of $261.0 billion. Total debt is the sum of notes and loans payable and long-term debt, as reported in the Consolidated Balance Sheet.

The Corporation, as part of its ongoing asset management program, continues to evaluate its mix of assets for potential upgrade. Because of the ongoing nature of this program, dispositions will continue to be made from time to time which will result in either gains or losses. Additionally, the Corporation continues to evaluate opportunities to enhance its business portfolio through acquisitions of assets or companies, and enters into such transactions from time to time. Key criteria for evaluating acquisitions include strategic fit, cost synergies, potential for future growth, low cost of supply, and attractive valuations. Acquisitions may be made with cash, shares of the Corporation’s common stock, or both.

Litigation and other contingencies are discussed in Note 7 to the unaudited Condensed Consolidated Financial Statements.

TAXES

(millions of dollars)	Three Months Ended March 31,	
	2026	2025
Income taxes	2,495	3,567
Effective income tax rate	*40%*	*34%*
Total other taxes and duties [(1)]	6,775	7,066
Total	**9,270**	**10,633**

[(1)] Includes “Other taxes and duties” plus taxes that are included in “Production and manufacturing expenses” and “Selling, general and administrative expenses”, each from the Consolidated Statement of Income.

Total taxes were $9.3 billion for the first quarter of 2026, a decrease of $1.4 billion from 2025. Income tax expense was $2.5 billion compared to $3.6 billion in the prior year. The effective income tax rate, which is calculated based on consolidated company income taxes and ExxonMobil's share of equity company income taxes, was 40 percent, 6 percent higher than the prior year period driven by portfolio mix effects impacted by derivative mark-to-market losses. Total other taxes and duties decreased by $0.3 billion to $6.8 billion.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Information about market risks for the three months ended March 31, 2026, does not differ materially from that discussed under Item 7A of the registrant's Annual Report on Form 10-K for 2025.

ITEM 4. CONTROLS AND PROCEDURES

As indicated in the certifications in Exhibit 31 of this report, the Corporation’s Chief Executive Officer, Chief Financial Officer,

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and Principal Accounting Officer have evaluated the Corporation's disclosure controls and procedures as of March 31, 2026. Based on that evaluation, these officers have concluded that the Corporation's disclosure controls and procedures are effective in ensuring that information required to be disclosed by the Corporation in the reports that it files or submits under the Securities Exchange Act of 1934, as amended, is accumulated and communicated to them in a manner that allows for timely decisions regarding required disclosures and are effective in ensuring that such information is recorded, processed, summarized, and reported within the time periods specified in the Securities and Exchange Commission's rules and forms. There were no changes during the Corporation's last fiscal quarter that materially affected, or are reasonably likely to materially affect, the Corporation's internal control over financial reporting.

PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

ExxonMobil has elected to use a $1 million threshold for disclosing environmental proceedings.

Refer to the relevant portions of Note 7 of this Quarterly Report on Form 10-Q for further information on legal proceedings.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

Issuer Purchases of Equity Securities for Quarter Ended March 31, 2026

	Total Number of Shares Purchased [1]	Average Price Paid per Share [2]	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs [3]	Approximate Dollar Value of Shares that May Yet Be Purchased Under the Program (Billions of dollars) [4]
January 2026	12,345,353	$129.43	12,312,718	$18.4
February 2026	10,206,464	$148.60	10,189,486	$16.9
March 2026	11,101,977	$157.95	11,099,689	$15.1
Total	**33,653,794**	**$144.65**	**33,601,893**	

[1] Includes shares withheld from participants in the Corporation's incentive program for personal income taxes.

[2] Excludes 1% U.S. excise tax on stock repurchases.

[3] Purchases were made under terms intended to qualify for exemption under Rules 10b-18 and 10b5-1.

[4] The Corporation continued its share repurchase program, originally initiated in 2022. In its 2025 Corporate Plan Update released December 9, 2025, the Corporation stated that it expects share repurchases of $20 billion in 2026, assuming reasonable market conditions.

During the first quarter, the Corporation did not issue or sell any unregistered equity securities.

ITEM 5. OTHER INFORMATION

During the three months ended March 31, 2026, none of the Corporation's directors or officers adopted or terminated a "Rule 10b5-1 trading arrangement" or "non-Rule 10b5-1 trading arrangement," as each term is defined in Item 408(a) of Regulation S-K.

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ITEM 6. EXHIBITS

Exhibit	Description
10(iii)(c.2)	ExxonMobil Supplemental Pension Plan.*
10(iii)(c.3)	ExxonMobil Additional Payments Plan.*
31.1 **	Certification (pursuant to Securities Exchange Act Rule 13a-14(a)) by Chief Executive Officer.
31.2 **	Certification (pursuant to Securities Exchange Act Rule 13a-14(a)) by Chief Financial Officer.
31.3 **	Certification (pursuant to Securities Exchange Act Rule 13a-14(a)) by Principal Accounting Officer.
32.1 ***	Section 1350 Certification (pursuant to Sarbanes-Oxley Section 906) by Chief Executive Officer.
32.2 ***	Section 1350 Certification (pursuant to Sarbanes-Oxley Section 906) by Chief Financial Officer.
32.3 ***	Section 1350 Certification (pursuant to Sarbanes-Oxley Section 906) by Principal Accounting Officer.
101 **	Interactive Data Files (formatted as Inline XBRL).
104 **	Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101).

** Management contract or compensatory plan or arrangement.*

*** Filed herewith.*

**** Furnished herewith.*

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SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

EXXON MOBIL CORPORATION

Date: May 4, 2026

By: /s/ LEN M. FOX

Len M. Fox

Vice President, Controller and Tax
(Principal Accounting Officer)

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Appendix H3: Draft Performance Bond

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Confidential Business Information

BOND NO. _____

RAILROAD COMMISSION OF TEXAS
Oil and Gas Division

Date: _____

This bond covers the following type of facility(ies): Carbon Storage Facilities

1. Organization name, exactly as shown on Form P-5 Organization Report:	2. P-5 Number, if assigned:	3. Total number of injection and monitoring wells associated with the facility, if applicable:
ExxonMobil Low Carbon Solutions Onshore Storage LLC	101256	3 injection, 6 monitoring
4. Other Commission-regulated operations, if applicable: N/A		

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Background

1.1 ExxonMobil Low Carbon Solutions Onshore Storage LLC (operator name as shown on P-5 Organization Report), "Principal", operates or is applying for Railroad Commission approval to operate one of more Carbon Storage Facilities ("Facility" or "Facilities") subject to Texas laws. Texas Natural Resources Code §91.109 and Texas Administrative Code Vol. 16, §5.205, provide that the owner and operator of a Facility must maintain a bond or letter of credit that satisfies the Railroad Commission.

1.2 As specified in §5.205, Principal has retained Federal Insurance Company (surety), a State of Texas authorized Surety, to secure this promise to pay.

1.3 This bond covers the following facilities (*on one line for each facility, include the facility name, facility permit number and/or application control number, physical address, zip code, and county in which the facility is located.*

(A) Sunflower Carbon Capture and Storage Facility

(B) _____

(C) _____

(D) _____

Terms

2.1 Principal and Surety must pay the Railroad Commission of Texas, in Austin, Travis County, Texas, the sum of $ 31,488,275 U.S., according to the following paragraphs.

2.2 The Railroad Commission will notify the Surety after Principal fails to operate or close a Facility as required by Texas law, Railroad Commission rules, or the permit conditions. Notice will be mailed by registered or certified U.S. mail to the address shown below. After Surety receives notice of Principal's default, the Surety may either:

(A) pay up to the face amount of this bond to bring into compliance or close the Facility according to Texas law, Railroad Commission rules, and the permit conditions; or

(B) pay the face amount of this bond to the Railroad Commission to be used by the Railroad Commission to bring into compliance or close the Facility. The Railroad Commission will return unexpended funds to the Surety after the Facility is brought into compliance or closed.

Confidential Business Information

2.3 The Railroad Commission does not have to expend state funds before Surety must pay under this bond.

2.4 The State of Texas may enforce the Suretys obligation under this bond without first obtaining a judgment against Principal or exhausting its remedies against the Principals properties or assets.

2.5 Under paragraph 2.2(A), Surety must present to the Railroad Commission, within 60 days after it receives notice of Principals default, a plan demonstrating how the Facility will be brought into compliance or closed. Surety must also furnish an accounting, acceptable to the Railroad Commission, of all sums expended by it to bring into compliance or close the Facility according to Texas law, Railroad Commission rules, and the permit conditions. Surety will submit the accounting to the Railroad Commission within 30 days of its bringing into compliance or closing the Facility.

2.6 Under paragraph 2.2(A), Surety must present to the Railroad Commission, within 60 days after it receives notice of Principals default, a plan demonstrating how the Facility will be brought into compliance or closed. Surety must also furnish an accounting, acceptable to the Railroad Commission, of all sums expended by it to bring into compliance or close the Facility according to Texas law, Railroad Commission rules, and the permit conditions. Surety will submit the accounting to the Railroad Commission within 30 days of its bringing into compliance or closing the Facility.

2.7 Under paragraph 2.2, Surety remains obligated to pay for any other covered Facilities up to the face amount of the bond.

2.8 The term of this bond expires _____ (bond expiration date), and is renewable annually. The Principal or Surety will renew in writing this bond and submit it to the Railroad Commission 30 days before the bond expires. Obligations to pay part or all of the bond amount are released after four (4) years from the expiration date of the bond if no clean up or closure-related activities are initiated by the Railroad Commission or its authorized representative at the Facility during that four-year period. The Railroad Commission or its authorized representative may relieve in writing Principal and Surety from their obligations under this bond.

2.9 If the Surety does not fulfill its obligations according to the bond terms and if judgment for any part of the bond amount is awarded through action of the Attorney General in court, then the State shall be entitled to court costs and reasonable attorney's fees awarded by the court. Suretys liability for such costs and fees shall not be limited by the face amount of this bond.

2.10 Principal and Surety execute this bond and agree to pay proceeds under this bond in Austin, Travis County, Texas. A suit to collect on this bond or construe this bond lies in Travis County, Texas.

Dated _____

FEDERAL INSURANCE COMPANY

_____

SURETY (Attach Power of Attorney demonstrating the authority to sign)

_____

NAME AND TITLE (Type or Print)

202B Hall's Mill Road, P.O. Box 1650, Whitehouse Station, NJ 08889-1650

_____

SURETY'S FULL MAILING ADDRESS

_____

(Seal)

EXXONMOBIL LOW CARBON SOLUTIONS ONSHORE STORAGE LLC

_____

PRINCIPAL (Attach Power of Attorney demonstrating authority to sign)

_____

NAME AND TITLE AS LISTED ON THE P-5 ORGANIZATION REPORT (Type or print)

(Seal)

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Bond No. TBD

Confidential Business Information

Confidential Business Information

Appendix H4: Texas Certification for Bonding Company

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STATE OF TEXAS
STATE BOARD OF INSURANCE

Certificate № 9315 **Company No.** 08-28750

CERTIFICATE OF AUTHORITY

THIS IS TO CERTIFY THAT

FEDERAL INSURANCE COMPANY

INDIANAPOLIS, INDIANA

has complied with the laws of the State of Texas applicable thereto and is hereby authorized to transact the business of

Fire; Allied Coverages; Hail-growing crops only; Rain; Inland Marine; Ocean Marine; Aircraft--Liability & Physical Damage; Accident; Health; Workers' Compensation & Employers' Liability; Employers' Liability; Automobile--Liability & Physical Damage; Liability other than Automobile; Fidelity & Surety; Glass; Burglary & Theft; Forgery; Boiler & Machinery; Credit; Livestock and Reinsurance on all lines authorized to do business on a direct basis

insurance within the State of Texas. This Certificate of Authority shall be in full force and effect until it is revoked, canceled or suspended according to law.

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IN TESTIMONY WHEREOF, witness my hand and seal of office at Austin, Texas, this 31st day of July, A. D. 1990.

COMMISSIONER OF INSURANCE

FORM 6000

Appendix H5: Cost Estimate and Professional Engineering Certification

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Sunflower Carbon Capture and Storage Project

Jefferson and Liberty County, Texas

ExxonMobil Low Carbon Solutions Onshore Storage LLC

Section 9 Financial Assurance – Summary of Financial Assurance Cost Estimates by Geologic Sequestration (GS) Activity

GS Activity	Financial Assurance Cost Estimates
Corrective Action	$6,518,400
Well Plugging	$3,880,375
PISC and Site Closure	$10,029,500
ERR	$8,560,000
PISC Regulatory Fee	$2,500,000
Total	**$31,488,275**
Note: Section 3 – Area of Review and Corrective Action Plan, Section 5 – Testing and Monitoring Plan, Section 6 – Injection Well Plugging Plan, and Section 8 – Emergency and Remedial Response Plan provide detailed discussions of the work to be undertaken, which form the cost basis for the financial assurance coverage values summarized in this table.	

Professional Engineering Certification

Lonquist Sequestration, LLC is submitting this Financial Assurance Cost Estimate in support of the Sunflower Carbon Capture and Storage Project. I, William H. George, P.E., hereby certify that I have reviewed and prepared the cost estimate provided above for corrective action, well plugging, post-injection site care (PISC), site closure, and emergency response and remediation (ERR).

Certified By:
Lonquist Sequestration, LLC
Texas Firm License 22610



William H. George, P.E.
Vice President / Principal Engineer
Texas License 135476
(512) 787-7478
will@lonquist.com

Date Signed: June 1, 2026
Austin, Texas

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